

Distributed Resources and Western State Policy

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I. Introduction

“The trend over time has been to large, remote generating plants, which require large, complex transmission systems. Today there is a growing interest in distributed generation – generators of more modest size in close proximity to load centers. This trend may lead to a more flexible grid in which islanding to maintain key loads is easier to achieve. Improved security from distributed generation should be credited when planning the future of the grid.”

– National Research Council, Making the Nation Safer – The Role of Science and Technology in Countering Terrorism, 2002.

Distributed generation (DG) is commonly understood as the siting of small-scale electric generation facilities, typically less than 20 MW, close to loads and end users. DG is labeled as such because of how it is deployed. Distributed technologies come in all shapes and sizes and vary in the fuel they use and the way they generate power. Such technologies include reciprocating engines, microturbines, fuel cells and photovoltaics. Distributed resources have several applications including backup or emergency power, peak shaving, baseload and combined heat and power. They can be installed on either the customer or utility side of the meter and can be interconnected directly to the distribution system or act as stand-alone generators. Proponents of DG estimate that distributed resources could account for upwards of 20 percent of generation additions over the next two decades.¹

Stakeholders across the entire electrical system can benefit from distributed resources. Customer-owners typically cite reduced power costs and increased reliability as the motivation for installing DG. Utilities are finding that DG is often a least-cost alternative to wires solutions for accommodating load growth and addressing congestion in the distribution system. Certain DG technologies are also well suited to supplying the ancillary services necessary for the stability of the bulk electric system.

Under the prevailing cost-of-service regulatory regime, developed before most DG technologies were available, utilities have a considerable disincentive to embrace distributed resources. Accommodating customer-owned DG on its distribution system is not in line with a utility’s profit motive since its revenues are directly linked to the number of kWh that pass over its lines to serve customers. If a utility does agree to interconnect DG, the lack of standard procedures, agreements and technical requirements can compromise the economics of a project. These and other transmission and distribution policies affecting the deployment of DG in the West are the subject of this report.

This paper is submitted in partial fulfillment of DOE Grant No. DE-FC48-02R821205 on state and grid management policies affecting distributed generation in the western interconnection. Section II provides a summary of barriers to DG development and what

¹ Distributed Power Coalition of America <<http://www.distributed-generation.com/dpca/faq.html>>.

steps western states have taken to address them. Section III features a basic assessment of present and potential DG capacity in the West. Section IV identifies distribution and other state level policies that affect DG and suggests changes to facilitate DG development. Section V does the same for transmission policies. Appendix A is a primer on DG describing the different technologies, their applications, benefits and drawbacks. Appendices B and C are matrices of state policies and incentives for small scale renewables and combined heat and power. Lastly, Appendix D is a synopsis of DG provisions in western utility integrated resource plans.

II. SUMMARY OF BARRIERS TO DG AND WESTERN STATE RESPONSES

Other than in California, Western states have done little to address specific barriers to DG development addressed in detail later in this report. While net metering is available in some form or another in all western states, and four have renewable portfolio standards (RPS), distributed resources will continue to face impediments posed by a central station-based industry model unless concerted policy and regulatory action is taken. Table 1 below summarizes the primary barriers to DG. A survey of state actions dealing with these DG barriers follows.

Table 1

Primary Barriers to the Development of Distributed Resources
<ul style="list-style-type: none"> • Lack of interconnection standards – technical, procedural and contractual • Utility inexperience with DG technologies and modern grid protection electronics • Cost-of-service regulation incentive structure – distribution company revenues directly tied to kWh throughput • Lack of local integrated resource planning for the distribution grid • Distribution rates that reflect the costs of DG, but do not consider the benefits like peak shaving and congestion management – also holds for standby & backup rates, competitive transition charges, and exit fees • Inadequate permitting protocols • Air quality regulations based on fuel input rather than energy output don't recognize the environmental benefits of certain DG technologies and CHP • Utility business practices – refusal to interconnect, selective discounting, interconnection fees, insurance requirements, and complex power purchase agreements • Inconsistent tax treatment • Lack of knowledge on the part of electric consumers

Arizona²

Net Metering – The Arizona Corporation Commission’s (ACC) 1981 Order 52345 requires all investor owned utilities (IOU) and rural electric co-ops (REC) in the state to offer net metering to all customer class members with renewable or cogeneration units up to and including 100 kW.

RPS - Arizona implemented an environmental portfolio standard in 2000, whereby any regulated load-serving entity that sells electricity or aggregates customers for the purpose of selling electricity must derive at least 1.1% of its total retail energy sales from new solar resources or other renewable electric technologies by 2007. [AZ RPS](#)

The ACC released a [final report](#) on its investigation of distributed generation and interconnection in June 2000. The report identified key stakeholder issues and made recommendations for developing standards, policies, and tariffs for distributed generation. The Commission has yet to take any formal action on any of the suggestions.

As of July 2002, utilities operating in the state had adopted special contracts for the interconnection of distributed generation which they have been instructed to use until the Commission adopts formal rules.

California

Net Metering – Since 1995, all regulated utilities in the state have been required to offer net metering to members of customer classes who own solar, wind or renewable-fueled fuel cell generating units up to and including 1000 kW in size. [California Code § 2827](#).

RPS – In 2002, [SB 1078](#) was signed into law requiring that 20% of regulated utilities’ retail electricity sales be procured from renewable resources by 2017.

In December 2000, the California Energy Commission (CEC) issued a [report](#) that examines the need for local jurisdictions to streamline their environmental review and permitting processes related to DG.

Also in 2000, [SB 1298](#) was signed into law requiring the California Air Resources Board (CARB) to adopt emission standards and implement a [certification program](#) for DG units that are exempt from local air district permits. Exempt units are typically smaller units, but not emergency generators. The program went into effect January 2003. CARB was

² State survey sources include: Brown et al. (ACEE), State Opportunities For Action: Review Of States’ Combined Heat And Power Activities (2002).; State Environmental Resource Center (SERC) - state net metering activity, <<http://www.serconline.org/netmetering/stateactivity.html>>; U.S. DOE Office of Energy Efficiency and Renewable Energy - Distributed Energy and Electric Reliability Program <http://www.eren.doe.gov/distributedpower/interconnection_state.html>; U.S. DOE Office of Energy Efficiency and Renewable Energy - Distributed Energy and Electric Reliability Program - Denver Regional Office, Implementation Plan.; Conversation with John Nunley (WY Business Council) 3/6/03.; Conversation with Prasad Potturi (NM PUC) 3/6/03.; Conversation with John Candelaria (NV PUC) 3/4/03.; Conversation with Lisa Schwartz (OR Office of Energy) 2/18/03.; Conversation with Craig Marks (AZ Energy Office) 3/10/03.; E-mail from Bill Eastlake (ID PUC) 2/13/03.; E-mail from Jeff Burks (UT Energy Office) 3/7/03.

also required to issue guidance to the air districts on the permitting or certification of electrical generation technologies that are subject to district permits. The report, [Guidance for the Permitting of Electrical Generation Technologies](#), was released in November 2001.

Promoting customer and utility owned DG is one of five actions recommended in California's 2003 [Energy Action Plan](#).

In February 2003, the California PUC completed distributed generation Rulemaking 99-10-025. The resulting decisions follow below:

Interconnection Standards - In December 2000, the California PUC approved the Rule 21 language adopted by the California Energy Commission governing the connection of distributed resources to the electric grid. [00-12-037](#) PG&E, SDG&E, and SCE replaced their former Rule 21 with the approved model tariff, interconnection application, and interconnection agreement. Specific information regarding the interconnection of DER technologies is available from each of the utilities. [CEC Rule 21 utility links](#)

The [California Interconnection Guidebook](#) was posted in July 2003 for comment. The report provides guidance for interconnecting customer-owned electric generation equipment to the electric utility distribution system using California Electric Rule 21.

Standby Rate Design – In July 2001, the California PUC adopted standby rate design policies for distributed generation. [01-07-027](#)

Net Metering Cost Allocation - In March 2002, the California PUC issued a rule exempting generators eligible for net metering from paying costs associated with interconnection studies, distribution system modifications, or application review fees. [02-03-057](#).

Ownership & Operation of Distributed Systems – In February 2003, the California PUC issued its final decision in Rulemaking [99-10-025](#) governing the ownership and operation of distributed resources.

Exit Fees - The California PUC took [final action](#) in Rulemaking 02-01-011 and will implement cost responsibility surcharges (exit fees) for departing load to account for Department of Water Resources (DWR) expenditures during the electrical crisis of 2001. There are exemptions for distributed resources including: 1) systems smaller than 1 MW that are net-metered and/or eligible for CPUC or CEC incentives for being clean and super-clean are fully exempt from any surcharge, 2) ultra-clean and low-emission systems that are 1 MW or greater that meet Senate Bill 1038 requirements to comply with CARB 2007 air emission standards will pay 100% of the bond charge but no future DWR charges or utility undercollection surcharges, and 3) all other self-generation customers will pay all components of the surcharge except the DWR ongoing power charges. The PUC made no findings concerning specific dollar amounts that may be recovered, but will determine the level of direct access surcharges in Rate Stabilization Proceeding A00-11-038.

Colorado

Net Metering – The state has five utility net metering programs: [Aspen Electric/Holy Cross Electric](#), [Ft. Collins Utilities](#), [Gunnison County Electric](#), City of Glenwood Springs & Xcel Energy.

The Governor’s Office of Energy Management and Conservation (OEMC) hosted a workshop titled Colorado Wind & Distributed Energy: Renewables for Rural Prosperity on April 8-9, 2002. Topics addressed included rural economic development through wind and DG, policies and incentives for DG, and specific distributed technologies like microturbines fueled by farm waste and solar water pumping. [CO Wind & DG Workshop](#)

The OEMC also has several DG demonstration/research projects underway showcasing microturbines fueled by methane derived from hog waste, and the residential and commercial applications of fuel cells and combined heat and power.

Idaho

Net Metering – Beginning around 1980 when there were no formal net metering tariffs, anyone wishing to supply incidental energy was told that the non-firm QF rate was the only option available. Avista Utilities developed the first formal net metering tariff, Schedule 62, in 1999. [Order 28035](#) Idaho Power developed a net metering option for residential and small commercial in new Schedule 84 in 2002, and followed it with an extension to larger irrigation and commercial customers later that same year. [Order 28951](#) and [Order 29094](#) Currently, in response to a petition to the IPUC for establishment of a net metering tariff, PacifiCorp (Utah Power) has submitted a proposed Schedule 135 that has two tiers similar to Idaho Power’s program.

QF’s and small power producers – Existing rules were developed beginning in 1980 with IPUC determination of how to implement the PURPA purchase requirement that became part of federal law in 1978. Idaho has a long list of QF’s under contract to Idaho utilities that followed upon its rather generous early interpretation of how to set rates based on avoided cost. Those rates and other terms like length of contract and MW size limit were tightened drastically in the mid-1990s and have just been adjusted in the wake of the crisis of 2000-2001. Avoided cost rates are adjusted periodically based on assumed natural gas prices and the cost of a combustion turbine as the surrogate resource. Allowable contract length was raised from 5 to 20 years and maximum project size was raised from 1 to 10 MW. Projects within those limits are eligible for standard contracts at published avoided cost rates. Larger projects are subject to individual negotiation of rates and terms with the starting point for negotiations being rates computed using an established methodology based on utilities’ integrated resource plans. [Order 29194](#)

In 2002, the Idaho PUC considered changes to Idaho Power’s tariffs related to distributed generation. Modifications were made to Idaho Power Schedule 72 (Interconnection to Non-Utility Generation) to bring the Schedule into conformance with current standards of best utility practices for non-utility generation interconnection. Net metering projects and projects less than 100 kW now qualify for simplified interconnection. Projects between 100 kW and 1 MW in size and projects 1 MW and larger, are required to comply with

more complex interconnection standards. [Order 29092](#) Modifications were also made to existing Schedule 86 to drop the net metering option now that it has its own schedule and to alter the calculation of purchase price, setting it at an amount equal to eighty-five percent (85%) of the Dow Jones monthly weighted average Mid-C Index. [Order 29093](#)

Montana

Net Metering – Enacted in 1999, [SB 409](#) allows net metering for customers of IOUs with solar, wind, and hydropower systems of 50 kW or less that are intended primarily to offset part or all of the customer's requirements for electricity. All customer classes are eligible and no limit on enrollment or statewide installed capacity is specified.

The Montana Department of Environmental Quality is proposing to identify ways to reduce the transaction costs for new distributed energy resources. The project will address several market barriers that contribute to high transaction costs as well as demonstrate small-scale fuel-cell technologies in residential applications.

Nevada

Net Metering – In 1997, the Nevada state legislature passed net metering rules which permit the participation of the first 100 customers from each utility operating in the state and are limited to solar or wind systems up to and including 10 kW in size. [NRS 704.766](#)

RPS – Providers of electric service in the state must procure 15% of their resource mix from renewable resources by the year 2013. [NRS 704.7801](#)

In the face of 2001 price spikes, the Nevada PUC formed a Reliability Enhancement Group to address interconnection issues that included load-shedding tariffs and bringing more distributed generation on line. The group developed a parallel pilot program whereby customer generation facilities were connected in parallel with the utilities' systems so the companies could take advantage of the added capacity. Interest in the program dropped when FERC instituted price caps in 2001.

New Mexico

Net Metering – In 1999, the New Mexico Public Regulation Commission's Rule 571 required all utilities regulated by the PRC to offer net metering for cogeneration facilities and small power producers with systems of 10 kW or less. [Rule571.pdf](#)

RPS – In rule [17.9.573 NMAC](#), Renewable Energy As A Source Of Electricity, public utilities are required to provide 10% of their retail sales from renewable resources by 2011.

New Mexico PRC Rule 570 governs co-generation and small power production. The rule includes provisions on interconnection procedures, net metering, and rate design for purchases from qualifying facilities. [Rule570.pdf](#)

In 2000, the New Mexico PUC entertained a rulemaking for the interconnection of on-site self-generation (Case 3312). Comments were received during 2001, but the case is still under consideration by the Commission.

PNM has undertaken microturbine demonstration projects at a hospital and hotel as part of its Project Power, a public-participation process evaluating options for ensuring adequate supplies of electricity for Santa Fe and nearby Las Vegas, NM.

Oregon

Net Metering – In 1999, the Oregon legislature passed [HB 3219](#) which allows net metering for all customers of all utilities who own solar, wind, fuel cells or hydropower generators, up to and including 25 kW in size, as long as the amount of energy purchased does not exceed .5% of peak demand.

RPS – The state has no RPS per se, but a 3% public benefits charge is used to fund the Energy Trust of Oregon which facilitates the development of renewable resources and has a goal of 10% by 2012.

One of the Oregon PUC's [2002 objectives](#) was to identify and implement actions needed to remove barriers to the development of cost-effective distributed generation. A forthcoming staff report will address issues such as interconnection, standby rates, net metering, air quality, performance based ratemaking, wheeling and siting standards.

DG projects can qualify for state tax credits and low interest loans available through the Oregon Department of Energy.

Utah

Net Metering – Signed into law in March 2002, [HB 7](#) requires utilities to make net metering available to customers with fuel cells, solar, wind or small hydropower facilities which have a generating capacity of up to 25 kW. Total participation in the program is capped at 0.1 percent of the cumulative generating capacity of the utility's peak demand during 2001. In compliance with the law, the Utah PSC approved PacifiCorp's [Net Metering Schedule 135](#).

In October 2002, PacifiCorp requested approval of a new Service Schedule No. 38 which establishes procedures for power purchases from qualifying facilities (QF) larger than 1 MW. The procedures list the information required for a QF to request an indicative power price and sets a time frame for PacifiCorp to respond. The Commission approved PacifiCorp's revised schedule and supported the continuation of a work group to address two remaining issues: the identification of an avoided cost method to derive the indicative price, and consensus on a generic power purchase agreement. [Docket 02-035-T11](#)

In 2003, the Utah PSC formed a Natural Gas DSM Task Force and directed it to jointly fund a study of achievable, cost-effective gas DSM measures in Utah. The study will specifically evaluate opportunities for distributed gas-fired generation and combined heat and power.

Washington

Net Metering – Passed in 1998, SHB 2773 and [RCW 80.60](#) require all electric utilities in the state to offer net metering programs to customers with solar, wind and hydropower units of 25 kW or less in size. Total net metering capacity for each utility is set at the 0.1% of the utility's 1996 peak demand.

In June 2000, Washington passed legislation amending its net metering laws to add fuel cells to the list of eligible technologies. Not less than 0.05% of the cumulative generating capacity of net metering systems must continue to come from solar, wind, and hydropower. Utilities may not require customer-generators, whose systems meet standards specified in the law, to comply with additional safety or performance standards, perform or pay for additional tests, or purchase additional liability insurance.

In December 2002, the Washington Utilities and Transportation Commission approved PacifiCorp's request for the authority to charge a customer the company's net cost of removing utility facilities when a customer requests permanent disconnection of service, the company's facilities are not likely to be re-used at that location, and their removal is necessary for safety and operational reasons. The modified tariff sets a flat charge for normal residential overhead or underground removals, limits and defines the scope of distribution facilities involved, and establishes a sunset date and reporting requirements. [Docket UE-001734](#)

Wyoming

Net Metering – Passed in 2001, [HB 195](#) requires all of the state's utilities, including all electric cooperatives and irrigation districts, to offer net metering for solar, wind, and hydroelectric systems of 25 kW or less. In February 2002, the State Energy Program hosted a workshop to provide guidance for the implementation of HB 195. The workshop provided information on technical issues, contractual issues, and standards and codes relevant to connecting renewables to the electric grid.

The State Energy Program provided funds for microturbine demonstration programs at a high school and wastewater treatment plant in Cheyenne. The Program also oversaw the retrofit of a diesel genset used to power lighting at the city's airport.

III. INSTALLED WESTERN DG CAPACITY AND MARKET POTENTIAL

It is difficult to ascertain the market penetration and potential of DG technologies in western states since the definition of DG varies among those collecting the data. Additionally, the data that is publicly available deals with either specific DG technologies, such as CHP or backup generators, or is not broken down on a state-by-state basis. The World Alliance for Decentralized Energy cites 787 GW of overall generating capacity in the U.S. Distributed resources account for 46 GW, or roughly 6 percent, of the country's installed capacity. Ninety percent of this DG is industrial CHP.³

³ WADE, World Survey of Decentralized Energy 2002-2003, 23.

Energy and Environmental Analysis' 2000 CHP Database identifies 65,890 MW of CHP capacity in the U.S. However, some 60,640 MW are facilities over 20 MW in size and thus not considered distributed generation as defined in this paper. Thus EEA estimates there were 5,246 MW of DG capacity in the U.S. in 2000. The database reports 11,228 total MW of western CHP capacity, but it is unclear what percentage is made up by larger facilities (>20 MW).⁴ (See Figures 1 and 2 below)

Figure 1

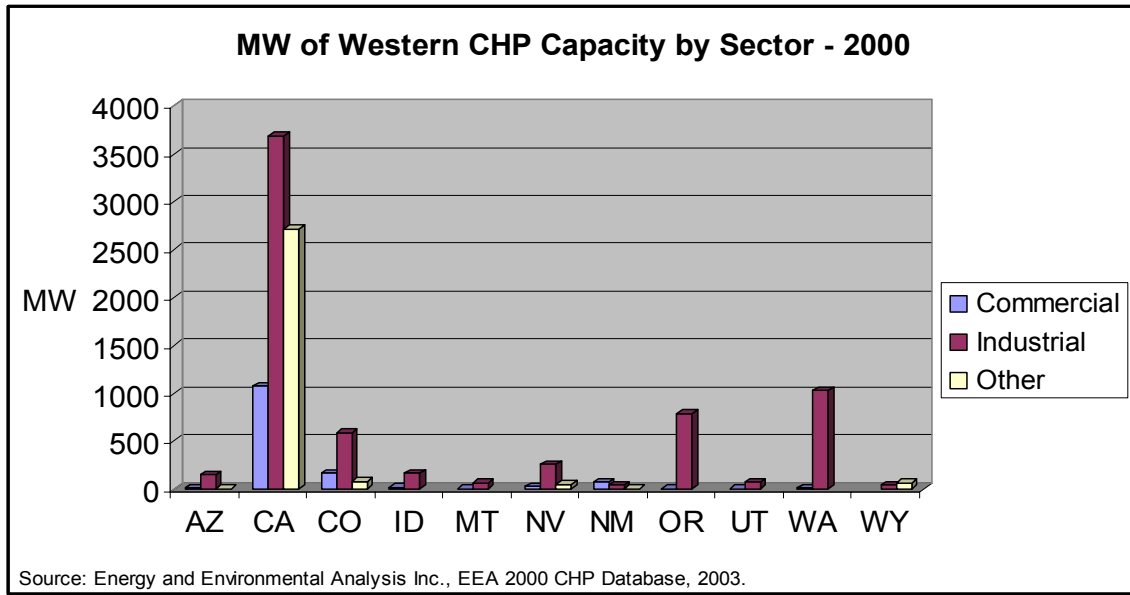
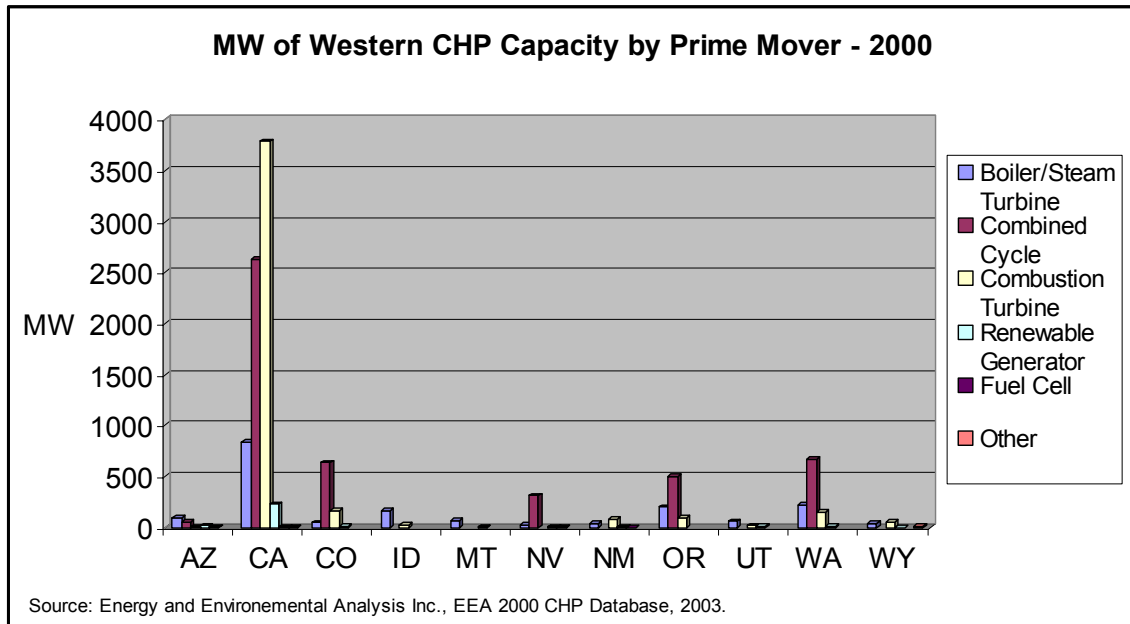


Figure 2



⁴ States in the EEA study include: AZ, CA, CO, ID, MT, NM, NV, OR, UT, WA, and WY

The state of California is clearly the leader in CHP and DG in general. The California Energy Commission's 2002 Distributed Generation Strategic Plan estimates there are 5,000 MW of installed DG capacity in the state. Backup generators represent roughly 3,200 MW of this total and are typically diesel gensets.⁵ In terms of numbers of units, the majority of DG facilities are small renewables units (e.g., photovoltaics) participating in net metering programs.⁶ In the near term, three to four hundred MW of DG is expected to come on line each year in the state.⁷

Efforts to estimate market potential for DG are hampered by the same definitional challenges faced in assessing installed capacity. The multitude of places and manners distributed resources can be deployed make it difficult to generate accurate figures. In a 2001 report to DOE, Onsite Sycom Energy Corporation (OSEC) estimated industrial sector installed DG capacity in the U.S. in excess of 45 GW. The majority of this was deployed as CHP (42 GW). The country's industrial DG potential is estimated at 140 GW, 88 GW of which could be CHP. Paper mills present the largest growth opportunity for CHP.⁸

OSEC conducted a similar assessment of CHP in the commercial and institutional sectors. Sites include shopping centers, universities, government buildings, hospitals, office buildings, airports, health clubs and the like. The commercial sector consumes roughly the same amount of electricity as the industrial sector, but DG penetration rates are much lower since the industrial sector features over five times the fuel demand for thermal processes and feedstocks. The study identified over 4,900 MW of installed commercial CHP capacity in the U.S. The majority (43%) is comprised of combined cycle units wherein waste heat from a combustion turbine is captured to drive a separate steam turbine. Commercial CHP market potential in the U.S. was estimated at 77,300 MW, with most opportunity in California, New York, Florida and Texas.⁹ Western states represented 15,526 MW of potential. (See Figure 3 below)

⁵ CEC, 2001 Database of Public Back-Up Generators (BUGS) in California, <http://www.energy.ca.gov/database/2001_PUBLIC_BUGS_INVENTORY_XLS>.

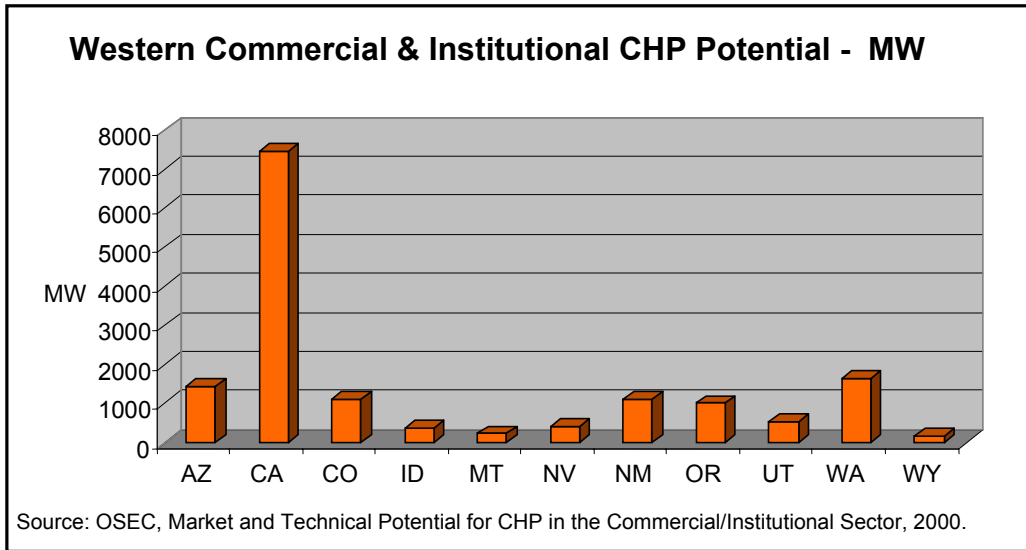
⁶ CEC, DG Strategic Plan 8 (2002).

⁷ *Id.* at 1.

⁸ OSEC, Assessment of On-Site Power Opportunities in the Industrial Sector 2-3 (2001).

⁹ OSEC, The Market and Technical Potential for Combined Heat and Power in the Commercial/Institutional Sector 2-10 (2000).

Figure 3



IV. DISTRIBUTION AND OTHER STATE POLICIES - BARRIERS AND SOLUTIONS

Electric distribution policy is the province of state legislatures and utility commissions. Issues that aren't addressed in legislatures or commissions are generally left up to utilities themselves. In addition to legislation and PUC rulemakings and rate cases, distribution policies that affect DG also cover areas outside the scope of electricity distribution like tax policy and air quality regulations.

Distributed resources make up a mere six percent of our generation mix.¹⁰ These technologies face barriers ranging from opposition from an industry founded on a central station model to plain inexperience with DG's grid impacts and benefits. A 1998 survey by the Distributed Power Coalition of America ranked the top five barriers to the deployment of distributed resources as:

1. Lack of interconnection standards;
2. Cost prohibitive utility rates and charges – standby & backup charges, competitive transition charges and exit fees;
3. Inadequate interconnection technologies;
4. Lack of public outreach and education about DG and its benefits; and
5. Burdensome permitting processes.¹¹

A 2000 DOE study also identified barriers to DG development. Barriers were not ranked, but those most frequently cited included the lack of appropriate technical, contractual and procedural standards for interconnection; a utility's limited experience with DG; onerous

¹⁰ WADE *supra* note 3, at 23.

¹¹ Chernoff, Harry & Lorand, Robert, *The Impact of Distributed Generation on Local Distribution Companies* 21 (2000).

rate structures and charges that do not reflect DG's grid benefits; and inconsistent permitting requirements.¹² The authors noted their findings weren't necessarily indicative of the market as a whole.

Given their jurisdiction over retail electric supply and environmental regulation, states are uniquely positioned to address barriers to the development of distributed resources. For example, distribution rates and local air quality standards can have a dramatic effect on the viability of DG projects. States can also employ distributed resources in their own buildings. The following is a discussion of issues facing DG and steps states can take to deal with them. Some states like California and Massachusetts have developed suggested DG tariffs that cover many of the issues identified below.¹³

Interconnection

Early designs notwithstanding, the distribution grid did not develop with two way power flows and small generators close to load in mind. Many utilities have little experience interconnecting DG to their distribution systems. Interconnection involves procedural, contractual and technical requirements that vary from state to state, utility to utility and even project to project. This piecemeal approach to interconnection leads to cost overruns and delays that can easily make a DG project uneconomic.

Prior to interconnection, a utility will assess a generator's impact on the grid. Utilities often lack DG-specific data and analysis tools to do this. Impact studies for DG can be expensive, unnecessarily detailed and duplicative given small generator size, unfamiliarity with the technology and existing studies which could be relied on. Developers are typically responsible for study costs so there is little incentive on the part of the utility to streamline the process. Negotiating the interconnection agreement can pose further delays as there is often no model document reflecting the interests of both parties and the smaller size of most DG. Crowded interconnection queues organized according to first-in-time priority can also take a long time to clear.

The technical interconnection requirements imposed by utilities often exceed the minimum standards necessary to ensure the safety, power quality and reliability of the distribution grid. Islanding is the primary safety concern and involves the supply of power to de-energized portions of the grid (e.g., during a power outage). Lineman injury or fire can result. Conventional relays and transfer switches used to prevent islanding are cost prohibitive for many DG installations. Modern anti-island circuitry integrated into DG inverters is less expensive, but has yet to be widely accepted by the industry¹⁴ and

¹² Alderfer, Brent et al., Making Connections – case studies of Interconnection Barriers and their impact on distributed power projects ii-iii (2000).

¹³ California Rule 21 Tariff, Appendix A to CA PUC Decision 00-12-037 <http://www.cpuc.ca.gov/word_pdf/FINAL_DECISION//4117.pdf>; Tariff to Accompany Proposed Uniform Standards for Interconnecting Distributed Generation in Massachusetts, <<http://www.state.ma.us/dpu/electric/02-38/515tariff.pdf>>.

¹⁴ USCHPA, National CHP Roadmap 13-14 (2001).

utilities sometimes refuse to rely on it.¹⁵ The same holds true for integrated power quality equipment used to regulate DG voltage and frequency.

States can simplify the interconnection process by adopting standard interconnection procedures, agreements and technical requirements. Standard procedures and agreements streamline interconnection and provide parties a contractual model on which to base negotiations. California, Texas, New York, Delaware and Ohio have adopted their own standards. NARUC has developed a set of interconnection procedures and an agreement for voluntary adoption by states. A manual for implementing the standards is currently under development.¹⁶

Technical standards help minimize engineering and design costs and increase the safety of DG. National efforts are underway at IEEE (Institute of Electrical and Electronics Engineers) and UL (Underwriter's Laboratory) to standardize the technical requirements for interconnection. The IEEE P1547 standard won approval by the IEEE Standards Board in early June 2003, and are available on their website. The IEEE technical standards contain requirements for performance, operation, testing, safety and maintenance of interconnections between distributed resources and other electric power systems.¹⁷

The interconnection process would further benefit from the pre-certification of specific DG technologies. Nationally recognized, independent or government testing labs (e.g., IEEE or UL) would conduct initial testing and characterization of the safety, power quality and system reliability impacts of DG. They would recommend technical parameters that state legislatures, regulatory agencies or individual utilities could adopt. These or other testing laboratories would then test specific products and pre-certify that they meet the technical parameters. These so called plug & play standards would allow pre-certified units to be interconnected without further technical review by a utility.

Distribution Ratemaking - Cost of Service vs. Performance-Based

Under the prevailing regulatory regime, developed before DG technologies were commercially available, utilities have an economic disincentive to embrace distributed resources. Traditional cost-of-service regulation ties distribution company revenues directly to sales. The more electricity that moves over their systems, the more money they make. Interconnecting customer-owned DG is plainly not in line with a utility's profit motive. The primary rationale for a distribution company to use DG is in instances where the cost savings from DG installed in congested areas will surpass lost utility revenues, but such scenarios likely represent a mere fraction of a company's entire distribution system.

¹⁵ Alderfer et al., *supra* note 12, at 9.

¹⁶ NARUC model DG Interconnection Procedures and Agreement, <<http://www.naruc.org/programs/dgia/dgiaip.pdf>>.

¹⁷ "IEEE Draft Standard Helps Solve Interconnection Problems," Kathy Kowalenko, The Institute, Feature Article, May 2001, <<http://www.spectrum.ieee.org/INST/may2001/fdistrib.html>>.

DG proponents advocate decoupling distribution profits from kWh throughput. Performance based regulation (PBR), if done properly, does just this. Much like the beginning of a conventional rate case, PBR begins with a cost-of-service review to determine a baseline test year. The resulting data is used to set either price or revenue caps under which the utility must operate over a predetermined regulatory lag time (e.g., 3-5 years). Prices or revenues may be adjusted according to a predetermined formula triggered by inflation or improved productivity for example. It is during the lag time that companies can reap the benefits of improved performance since the next rate case will incorporate any advances into the new test year and set new price or revenue caps.

Price-based PBR caps the price that utilities may charge for electric service. In addition to the built-in revenue requirement, an innovative company may retain any savings between the test year distribution cost assumptions and real time costs, at least until the next rate case adjusts prices accordingly. Price-based PBR, however, suffers from the same disincentives for efficiency and DG as cost-of-service regulation since profits are linked to sales volume.

DG advocates prefer revenue-based PBR which is generally discussed in terms of revenue-per-customer instead of an absolute revenue cap. The test year revenue requirement is divided by the number of test year customers overall or within certain classes. Customers continue to be charged as before with a combination of customer, energy and demand charges. Over the course of the regulatory lag time, actual revenues and allowed revenues are tracked. Any difference between the two appears in utility rates the next year as a surcharge companies keep or as a refund customers keep. Sharing mechanisms approved by the PUC can further control the specifics of how this difference is allocated. Revenue-based PBR reduces the disincentive for DG since fixed revenues mean profit depends more on cost control not customer usage. Companies don't forfeit distribution sales to DG, they can benefit from its reduced costs.¹⁸

Local Integrated Resource Planning

Utilities are slow to embrace DG because they don't have to. Unlike the generation component of regulated utility operations, states generally do not require distribution utilities to submit integrated resource plans identifying a range of options to meet future demand and encouraging stakeholder input. Without such an integrated planning approach, distributed resources that may very well represent least-cost solutions to load growth and congestion issues on the distribution grid are less likely to be considered along-side wires solutions.

Local integrated resource planning (a.k.a. Energy Resource Investment Strategy) is a process similar to IRP in which distribution utilities would be required to undertake least-cost planning of their systems to identify and implement options for serving load growth within specified zones. State regulatory commissions could identify congested zones in which the installation of DG would be encouraged through the provision of credits on

¹⁸ Much of the PBR discussion here is drawn from the Regulatory Assistance Project's *Performance Based Regulation for Distribution Utilities* (2000).

customer energy bills. Or a utility installing its own DG could be granted the right to recover capital and operating costs on an accelerated basis, or at a higher rate of return. The credits or cost recovery would sum to the infrastructure investment deferral and replacement value provided by the DG.¹⁹ With such a requirement, utilities would have a stronger incentive to consider a wide array of load growth and congestion solutions.

Rate Design

Most barriers that electric customers face are cost related. Commission-approved utility rates and fees can easily spoil the economics of a customer-owned DG project. If a customer wants the utility to supply only a portion of their load or provide backup power in case of unit failure, *standby* and *backup* rates apply. These fees are usually in the form of a monthly demand charge (\$/kW).²⁰ Some hold that these rates are unfairly high since they typically reflect the worst case scenario of requiring maximum load at peak demand periods. Proponents of DG argue that it would be fairer for PUCs to approve standby and backup rates based on actual time of use and the probability that a DG customer will adversely contribute to peak needs of the utility rather than the chance that the customer may need its maximum load fulfilled at any given time.

Another customer criticism of standby and backup rates involves the debate over the fixed charge component of distribution pricing. Distribution rates typically feature a fixed portion and a variable portion which fluctuates based on actual customer usage. Unbundled utilities increasingly dependent on distribution revenues have sought to dramatically increase fixed customer charges and minimize variable usage charges in order to manage utility risk and ensure recovery of their investments. Fixed charges are assessed irrespective of the amount of service customers require, reflecting the notion that distribution costs are not particularly usage sensitive and should be averaged among all users. Such rates are attractive due to their simplicity, surety of distribution company revenues and known costs to customers

DG owners question why they should pay the same fixed charges as a typical electric customer when they place fewer, if any, demands on the system. DG advocates oppose high fixed charges and disagree with the premise that distribution costs bear little relation to usage. They maintain that variable usage-based rates help ensure that customers pay the actual costs they impose on the system so that their consumption neither subsidizes nor is subsidized by the consumption of others.²¹ They posit that volumetric distribution charges promote economic efficiency by providing price signals for customers to employ resources in their most highly valued uses.

Reducing fixed charges and deaveraging distribution costs are central to true cost of service ratemaking under which a utility would charge more for service over constrained portions of the system and customers would receive proper price signals encouraging DG

¹⁹ R.S. Brent (Solar Turbines Inc.), *Distributed Generation – A Fair and Simple Plan for Utilities and Policy-Makers*, 2-4 (2002).

²⁰ IURC, *DG White Paper 10* (2002).

²¹ Frederick Weston, *Charging for Distribution Utility Services: Issues in Rate Design*, RAP 11 (2000).

where it makes most economic sense. The fixed versus usage-based rate debate is part of a broader criticism by DG advocates that distribution rates do not reflect DG's actual impacts and benefits to the grid. They hold that distribution rates and charges are too high because they don't reflect the benefits DG provides to the grid like congestion relief and peak shaving. This also holds true for *buyback* rates that utilities pay DG owners for excess generation. Some DG supporters suggest that utilities should pay more for excess electricity from DG that effectively reduces congestion or serves peak loads.

DG owners face the implications of the stranded costs of utility investment in restructured markets. *Competitive transition charges* and *exit fees* apply when DG owners seek to switch standby/backup providers or disconnect from the grid entirely. They ensure that utilities can recoup their investment costs if customers leave before traditional rate-based mechanisms have generated adequate cost recovery. Given the slim economic margins of a DG project, these fees can be quite expensive. In California, such charges have included unamortized nuclear plant cost overruns and expensive power purchases made by the state.²²

DG owners question why they should help pay for poor business decisions and a distribution system they may rarely, if ever, use. An alternative approach to stranded investment costs is for PUCs to approve fees only when overall DG market penetration reaches a certain threshold and actual losses are incurred on investments that were specifically approved under a regulatory scheme, not mere imprudent business decisions.²³

Permit Streamlining

Obtaining the necessary permits for DG operation can be lengthy, expensive and undermine the economics of a DG project. Depending on the state, regulated areas can include air quality, fuel supply, noise, public safety, environmental concerns, aesthetics, land use, and building and fire codes. Land use and emissions are the most common permitting areas. Most permitting requirements that DG developers face are assessed on a case-by-case basis at the local and state levels. These jurisdictions often do not have DG-specific performance data on hand or permitting processes in place.

Improving the permitting process should be aimed at cutting time and costs while ensuring environmental and consumer protection. States can adopt uniform procedures, thresholds, mitigation measures and application forms to streamline permitting processes. State funded training and technical assistance programs for local building department personnel can also expedite the permitting process.

Air quality permitting poses a particular difficulty for DG as emissions levels have traditionally been based on the amount of fuel required as an input to the generation of electricity. The more fuel that is required, the higher the allowable emissions. DG

²² E-mail from Gary Nakarado (NREL) April 9, 2003.

²³ Amory Lovins et al., *Small is Profitable – The Hidden Economic Benefits of Making Electrical Resources the Right Size*, 336 (2002).

advocates recommend that emissions standards be set according to the kWh of power produced, or in the case of CHP, according to kWh and energy equivalent produced. From this output-based perspective, more energy efficient plants could be seen as presently having to meet stricter emissions levels.²⁴

Setting emission standards according to fuel input neglects the efficiencies of certain DG technologies and combined heat and power (CHP) units whose heating and cooling functions would otherwise be achieved through conventional means. To be most effective, output-based emission standards should be scale-neutral, fuel-neutral, technology-neutral and specific to DG's modes of operation.²⁵ Such standards would be especially helpful when siting DG in non-attainment areas where older, and often dirtier, thermal plants are grandfathered under the Clean Air Act.

States could further simplify the permitting process by pre-certifying and even exempting specific DG technologies from emissions regulations. National labs or other bodies could determine actual emissions levels for specific DG technologies. Local and state air quality agencies could then determine whether specific equipment meets their permitting requirements without further project review.

Other Policy & Regulatory Measures

State legislation and regulatory orders on net metering define when a utility must interconnect pre-determined classes of customer owned generation. Net metering could be extended to all or certain DG technologies to clarify utility obligations to DG owners. Additionally, tax incentives, production incentives, loans, grants and rebates could encourage further DG development.

The tax treatment of DG can thwart utility or customer DG development efforts. Under current federal tax law, depreciation schedules treat certain large DG units as having a tax life of 15-20 years. A similar engine in an airplane or industrial equipment has a 5-7 year tax life.²⁶ DG proponents argue that such discrepancies should be rectified by adopting accelerated tax depreciation schedules for DG.

Business Practices

Unless a generator qualifies under the Public Utility Regulatory Policies Act (PURPA), meets the requirements of a state net metering law, or participates in the wholesale market, there is generally no utility obligation to interconnect DG.²⁷ Thus, distribution owners have discretion in approving and handling interconnection requests. Some companies have been known to refuse interconnection all together. Others have been criticized for making it difficult to reach the appropriate representative and providing

²⁴ USCHPA, *supra* note 14, at 16.

²⁵ Lovins, *supra* note 23, at 327.

²⁶ USCHPA, *supra* note 14, at 18.

²⁷ Conversation with Gary Nakarado (NREL) April 2, 2003.

inconsistent responses.²⁸ Utilities have also been known to offer selective discounts to large customers or draft confusing power purchase agreements to discourage the use of onsite generation.

Sometimes utilities demand too much for a project to be feasible. High interconnection fees affect small DG in particular since facilities are often charged the same fee regardless of size. Some utilities have demanded millions in liability insurance coverage for possible damage caused by DG connected to their systems. In such cases, insurance costs alone dwarf any potential energy cost savings of DG. It should be noted that some consider modern protection electronics to have made DG as safe as common household appliances.

While PUCs don't have a place at the table in utility board meetings, they have some degree of authority over the business practices of companies they regulate. Commissions could mandate that utilities designate a specific contact person to review interconnection requirements and assist in procedures.²⁹ PUCs could define the maximum insurance coverage that interconnecting utilities could require. An independent interconnection dispute resolution body could be established. Simplified model power purchase agreements appropriate to DG's small sizes could be adopted and enforced.

Market

The market for distributed resources suffers from a lack of knowledge on the part of energy consumers and companies. The current scale of manufacturing prevents DG from achieving economies of scale critical to bringing prices for technologies like fuel cells and photovoltaics within reach of more electric customers. Finally, the lack of consistent interconnection standards, appropriate rate designs and adequate permitting procedures contribute to investors' perceptions of regulatory uncertainty and higher risk.

States could increase DG's exposure via demonstration programs in government buildings and public funds for research and development. To build experience with DG, states could sponsor or endorse technical training courses for utility technicians and DG installers. Adopting standard interconnection procedures, appropriate rate designs, oversight of business practices and improved permitting procedures could alleviate concerns over regulatory uncertainty and spur investment in DG projects. Increased confidence in the DG market could ramp up DG production so as to better capture economies of scale in manufacturing and bring prices down.

V. TRANSMISSION POLICIES – BARRIERS AND SOLUTIONS

Transmission policy is set by several entities. The U.S. Congress, the Federal Energy Regulatory Commission (FERC), regional reliability councils and transmission operators such as utilities, ISOs, RTOs and federal power marketers all play a role in determining

²⁸ Alderfer et al., *supra* note 12, at 13.

²⁹ Alderfer et al., *supra* note 12, at 12-14.

how the wholesale trade of electricity is conducted. It is important to note that since distributed generation is typically understood as small generators close to load interconnected, if at all, to the distribution system, transmission policy has a marginal effect on these resources. As DG continues to mature however, its presence on the transmission grid could expand as operators and customers discover its generation, ancillary service and congestion management capabilities.

The Federal Power Act vested jurisdiction over wholesale electric markets in what is now the FERC. In an effort to spur competition in the trade of bulk power, FERC's Order 888 required utilities and other transmission owners under their jurisdiction to file open access tariffs assuring electricity producers non-discriminatory access to the transmission grid. The elimination of monopoly control of transmission facilities has been a mainstay of FERC policy initiatives right up to its Standard Market Design NOPR of 2002. Open access does not have sweeping consequences for DG presently, but it is conceivable that DG could account for an increasing number of wholesale market participants in the future. The open access policy would help make this possible.

FERC's 2003 Notice of Proposed Rulemaking for the Standardization of Small Generator Interconnection Agreements and Procedures will impact DG considerably. These standards will apply to DG (<20 MW) connecting to the transmission system to participate in the wholesale market.³⁰ Standard procedures and agreements will minimize delays and the costs of impact studies and unnecessary safety equipment by streamlining the interconnection process and providing parties with a contractual model on which to base negotiations. Much of the FERC NOPR is based on the model procedures and agreement developed by NARUC for adoption by states.³¹

Policies for the reliability of the transmission grid are set by the North American Electric Reliability Council (NERC) and the Western Electricity Coordinating Council (WECC), which also enforces the standards. WECC is a nonprofit corporation whose mission is to 1) maintain a reliable electric power system in the western interconnection, and 2) assure open non-discriminatory transmission access among members. Membership is voluntary and includes transmission owners/operators, all categories of power producers, end users, advocacy groups and representatives from states and provinces. Members agree to subject themselves to fines for noncompliance, since WECC lacks the authority to impose sanctions otherwise. The Council is currently seeking such authority from Congress.

In the west, WECC reliability standards, criteria and guidelines govern the actions of transmission control areas, distinct regions that regulate their generation to balance load and maintain planned interchange schedules. WECC Minimum Operating Reliability Criteria (MORC)³² are designed to ensure the continuity of service to load. (See Table 2 below) The criteria apply to owner/operators of transmission facilities regardless of

³⁰ FERC Generator Interconnection, <http://www.ferc.gov/electric/gen_inter.htm>.

³¹ NARUC model DG Interconnection Procedures and Agreement, <<http://www.naruc.org/programs/dgia/dgiaip.pdf>>.

³² WECC Minimum Operating Reliability Criteria <http://www.wecc.biz/MORC_Pages_9-02.pdf>.

jurisdiction or what form of entity (e.g., utility, RTO, ISO etc.) Specific technical operational requirements to meet WECC reliability criteria exist, but are not listed here.

Table 2

WECC Minimum Operating Reliability Criteria (MORC)
<p>1) Generation Control & Performance</p> <ul style="list-style-type: none"> • Operating reserve – respond to load variations, outages and curtailment of imports • Automatic generation control – real time balancing of generation and interchange schedules with load • Frequency response and bias - set as close as possible to the control area’s natural frequency response characteristic • Time control – maintain 60 Hz frequency • Control performance – monitor and track control performance and disturbance recovery as against Control Performance Standards (CPS1 & CPS2) • Inadvertent interchange – requires tracking of power exchanges between control areas • Backup power supply – for safe shut down of islanded units and blackstart capability <p>2) Transmission</p> <ul style="list-style-type: none"> • Transmission operations – system to be operated to avoid instability, outages or voltage collapse from contingencies • Voltage & reactive control – maintain voltage and reactive power levels <p>3) Interchange</p> <ul style="list-style-type: none"> • Scheduling – coordinate and communicate schedule information • Transfer capability - determine transfer capability limits for delivery and receipt of scheduled interchange. • Unscheduled flow – minimize impact • Transfer capability – net schedule and actual flow cannot exceed rated capability limits <p>4) System Coordination – operators must coordinate with neighboring systems</p> <p>5) Emergency Operations</p> <ul style="list-style-type: none"> • Mitigation – requirement & procedures to inform & cooperate with other entities in mitigating disturbances • Restoration of power <p>6) Operations Planning</p> <ul style="list-style-type: none"> • Entities responsible for maintaining and implementing plans which evaluate options and set procedures for reliability through a reasonable future period <p>7) Telecommunications – adequate facilities are required</p> <p>8) Operating Personnel and Training – ensure personnel are properly trained and certified</p>

Taking a cue from NERC/WECC reliability policy, FERC mandated that transmission providers under their jurisdiction provide ancillary services to transmission customers in Order 888. Ancillary services are those services necessary for the reliable operation of the transmission grid. (See Table 3 below) FERC may require the services, but reliability councils retain their role in determining the technical operational requirements for providing them. The provision of ancillary services represents a niche that DG can fill in transmission markets. Given sufficient market penetration, certain distributed resources are well suited to providing reactive supply and voltage control, regulation and frequency response, energy imbalance service, operating reserve and blackstart capability.

Table 3

FERC Order 888 Ancillary Services	
1) Scheduling, System Control, and Dispatch Service	Provides for a) scheduling, b) confirming and implementing an interchange schedule with other Control Areas, including intermediary Control Areas providing transmission service, and c) ensuring operational security during the interchange transaction.
2) Reactive Supply and Voltage Control from Generation Sources Service	Provides reactive supply through changes to generator reactive output to maintain transmission line voltage and facilitate electricity transfers
3) Regulation and Frequency Response Service	provides for following the moment-to-moment variations in the demand or supply in a Control Area and maintaining scheduled Interconnection frequency
4) Energy Imbalance Service	Provides energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served
5) Operating Reserve: Spinning Reserve Service	Provides additional capacity from electricity generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur
6) Operating Reserve: Supplemental Reserve Service	Provides additional capacity from electricity generators that can be used to respond to a contingency within a short period, usually ten minutes

VI. CONCLUSION

The electric industry did not evolve to accommodate the needs of small generators sited close to end users. As such, distributed resources face a myriad of challenges to their further deployment. Some of these hurdles are rooted in the regulatory mechanisms that enable distribution companies to turn a profit while others stem from a mere lack of knowledge about DG options. As customers scrutinize their bills and demand more reliable electric service, and as utilities grapple with the pressures of increased competition and volatile natural gas prices, DG presents attractive opportunities for providing reliable, affordable and environmentally sound electricity.

Given their jurisdiction over retail electric service and environmental regulation, states are uniquely positioned to address barriers to the development of distributed resources. Aside from California, Western states have yet to take substantial steps towards enabling the widespread use of DG. This report offers a basic assessment of the existing and potential market for DG in the West. It identifies barriers to the technologies' deployment posed by transmission and distribution policies. Finally, the paper suggests several ways states can help utilities and customers alike better realize the benefits of DG, which can include lower energy prices, energy efficiency, congestion management, peak shaving and improved grid reliability.

APPENDIX A – DG PRIMER

Distributed Resource Technologies

Reciprocating Engines

Also known as internal combustion engines or gensets, reciprocating engines are best known for their use in automobiles. They represent the largest share of the distributed generation market. These engines are the least expensive DG technology and range in size from a few kW to over 10 MW. Reciprocating engines can be run on fuel oil, gasoline, natural gas or bio-fuels such as those derived from waste treatment processes, but diesel is the predominant fuel. Their portability and fast startup time provides great flexibility in their application. Gensets feature efficiencies of 25 to 45 percent, but efficiencies upwards of 80 percent are possible in a CHP system. Emissions are a major concern with reciprocating engines, as evidenced by the Bush administration's April 2003 proposal to cut 90 percent of harmful emissions from non-road diesel engines by 2014.³³

Combustion Turbine / Gas Turbine

Simple cycle combustion turbines have been in use for over 40 years. They range in size from several hundred kW to several hundred MW and usually run on natural gas. Electricity is produced when hot high pressure gas, resulting from the combustion of compressed air and fuel, is directed through a series of turbine blades. Efficiencies of 25-40 percent are achievable. In a combined cycle application, exhaust heat can be used to produce steam that drives a separate turbine which yields efficiencies up to 58 percent. Turbines used for CHP can achieve 85-97% efficiencies. Their reliability, ease of maintenance and high quality waste heat, make combustion turbines an attractive option for large industrial or commercial applications.

Microturbines

Microturbines are small combustion turbines that are on their way to achieving mass-market commercial availability. They range in size from 20 kW to 500 kW and can be powered by natural gas, diesel, propane, kerosene or bio-fuels. Several units can easily be sited together to serve larger loads. Microturbines offer efficiencies of 25-30 percent with the use of recuperators which capture waste heat to improve combustion efficiency. CHP applications enable further efficiencies up to 85 percent. Microturbines are reliable and cheap to maintain, because they have relatively few moving parts and are air cooled. Their small footprint, modularity, low noise and low emissions make them attractive for service in a wide variety of roles. Research is underway to bring prices down and efficiencies up.

Stirling Engines

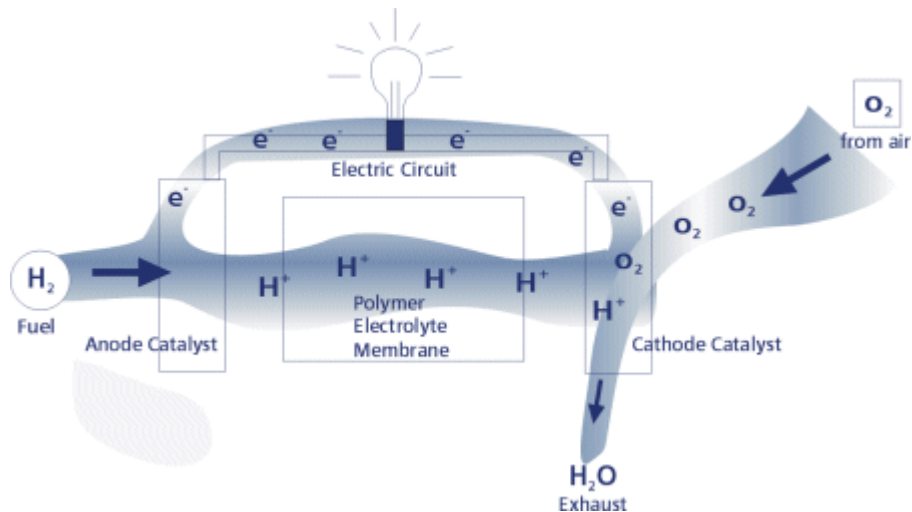
Stirling Engines are considered external combustion engines since fuel is burned outside the cylinder to warm inert gas sealed inside the cylinder in order to push the pistons. The

³³ Environmental Protection Agency, Proposed Non-road Diesel Emissions Rule, <<http://www.epa.gov/nonroad/>>.

units are small, typically 1-25 kW in size, and have yet to achieve full commercial availability. Stirling engines were developed in the early 1800's but have been overshadowed by steam and internal combustion engines. Interest in DG and the use of Stirling engines in the space and marine industries have spurred research and development efforts to bring their cost down and efficiency up.

Fuel Cells

Figure 4 – Fuel Cell Diagram (Source: DOE Office of Distributed Energy Resources)



Fuel cells are electrochemical energy conversion devices that use hydrogen and oxygen to produce electricity. If pure hydrogen is not available, fuel cells can derive it from other fuels such as gasoline, natural gas, and diesel through the use of a reformer. Fuel cells are quiet and clean, with byproducts being heat, water and reformer emissions far below what an internal combustion engine would produce. Fuel cells range in size from 1 kW to 10 MW and feature efficiencies of 40-60 percent. Direct electrochemical reactions are typically more efficient than using fuel to power a thermal generator. Higher efficiencies are possible in CHP applications or in combined cycle configurations with thermal units such as microturbines. Fuel cells are relatively new and comparatively expensive, but research is underway to lower prices and increase efficiency.

There are four primary types of fuel cell technologies. They differ based on the type of electrolyte employed. The electrolyte is the medium through which the positively charged hydrogen ions pass after their electrons flow off as electric current.³⁴

- **Phosphoric acid** fuel cells represent some of the earliest technology and are currently in early commercial development. They operate at low temperatures of roughly 400 degrees F with efficiencies of 40-45 percent.
- **Molten carbonate** fuel cells operate around 1,200 degrees F at efficiencies of 50-60 percent. They are being field tested and used in demonstration programs at this time.

³⁴ DOE Office of Distributed Energy Resources, <http://www.eere.energy.gov/der/fuel_cells.html>.

- **Solid oxide** technology uses a hard ceramic material instead of a liquid electrolyte. This permits higher operating temperatures of around 1,800 degrees F and greater flexibility in fuel choice. They can achieve efficiencies of 50-60 percent and are also in the field test and demonstration phase of development.
- **Proton exchange membrane** fuel cells use a thin plastic sheet as the electrolyte. The membrane is coated with metal particles (usually platinum) which act as the anode and cathode. These fuel cells operate at low temperatures around 200 degrees F and can vary their output quickly to adjust to changing loads. They also have a high power density so smaller units can meet larger loads.

Small Scale Renewables

Flat panels of photovoltaic (PV) cells are able to convert sunlight directly to electricity. Photons from sunlight transfer their energy into electrons within silicon semiconductors. The technology has efficiencies between 5 to 15 percent and are typically employed in small arrays of a few to a few hundred kW. Because of their modularity however, photovoltaics can be configured into larger installations wherever the sun shines. PV has no moving parts, requires little maintenance and operates quietly with no resulting emissions. The technology is not cost competitive for most applications, but is still an attractive power option on account of its ability to serve remote locations and minimal environmental impact. There are no fuel costs associated with PV but as an intermittent resource, it is a good candidate for hybrid projects in conjunction with a genset or microturbine. Considerable research is being conducted to reduce the cost of PV and increase its efficiency.

On-site wind turbines are typically small units of several hundred kW in size. Larger wind turbines of up to several MW each can be arranged together in wind farms, but the area necessary for siting such facilities often prevents deploying them as distributed generation per se. Wind turbines have no fuel requirements, but as an intermittent resource, wind turbines work well in hybrid systems with other distributed technologies serving a firming function. Wind turbines produce no emissions and operate quietly. Current research is aimed at producing larger units that operate more efficiently and in sync with the grid.

Small scale hydro generation does not require the construction of dams. Modern technology harnesses the potential energy of a river's flow without posing the environmental threats associated with larger hydro-electric projects. Small scale "run of the river" hydro projects can be up to 10 MW in size.

Bio-mass energy takes two forms. First, biomass material can be used to fuel a boiler to produce steam which turns a turbine to generate electricity. Second, processing biomass material in a gasifier yields gas which can fuel a combustion turbine, microturbine or genset. Biomass fuel is available from several sources such as forest thinning, agricultural waste or growing it outright.

Distributed Resource Applications

Standby Power

Even given the high reliability of the North American electric power grid, outages do occur. DG is most commonly used to supply standby or emergency backup power until utility service is restored. States often require that certain loads, such as hospitals, be served by standby generators for public health and safety reasons. Other utility customers like financial institutions and laboratories simply cannot afford to be without power for even the briefest of periods.

It is estimated that some 40,000 MW of standby capacity exists today and remains unused much of the time.³⁵ Utilities are recognizing the value of these existing resources and contracting with customer-owners of DG in demand side management programs or even the remote control of DG units. Portland General Electric's Dispatchable Standby Generation Program is such an example.³⁶ For some DG technologies, like diesel gensets, it is actually better for the unit to be run more consistently than on a standby basis.

Combined heat and Power

One of the primary criticisms of the present electric paradigm is that roughly two thirds of the fuel energy used in the production of power is released in the form of heat.³⁷ Combined heat and power, or cogeneration, can increase the efficiency of energy usage by harnessing waste heat for use in other power generation or industrial processes. Heat, usually in the form of steam or hot water, can not be easily transported and is most effectively utilized on-site. Thus, distributed generation presents ideal opportunities for combined heat and power. Waste heat from distributed resources is typically used for heating or cooling purposes in commercial and industrial settings, but domestic applications are also possible.

Peak Shaving

The cost of providing electric service varies according to the supply and demand for power. Utilities are acutely aware of this, as are the growing number of customers subject to time-of-use rates or participating in competitive electric markets. For DG owners, peak shaving involves reliance on on-site generation resources during peak demand hours, rather than receiving normal utility service. This is often a least cost alternative for both the utility and the customer and may be part of a demand side management program.

Baseload – Stand Alone

Sometimes it is more economic for an electricity customer to rely on DG for most or all its power needs. Depending on the rate structure and location, it could make sense to stay off the grid entirely. Remote loads located far from existing distribution lines often find that it makes financial sense to deploy DG in a stand alone capacity. High standby

³⁵ Distributed Generation Forum – Gas Research Institute, *The Role of Distributed Generation in Competitive Energy Markets*, 6.

³⁶ PGE Dispatchable Standby Generation Program, <http://www.portlandgeneral.com/business/large_industrial/dispatchable_generation.asp?bhcp=1>.

³⁷ GRI, *supra* note 35, at 5.

charges levied by a utility to supply power at times when a customer's own DG is unavailable or insufficient, can also make stand alone DG an attractive option.

Grid Support

DG can be connected to the transmission or distribution systems for grid support purposes. Strategic placement of DG can address congestion issues such as load pockets. Certain DG technologies are well suited to providing cost-competitive ancillary services which maintain the stability of the transmission system, although higher penetration levels are likely necessary (e.g., >15-20%).³⁸ Ancillary services include:

- Reactive supply and voltage control - reactive generator output to maintain transmission line voltage and facilitate electricity transfers,
- Regulation and frequency response - provides for following moment-to-moment variations in the demand or supply in a control area and maintaining scheduled interconnection frequencies,
- Energy imbalance service - energy correction for any hourly mismatch between a transmission customer's energy supply and the demand served,
- Spinning operating reserves - additional capacity from generators that are on-line, loaded to less than their maximum output, and available to serve customer demand immediately should a contingency occur
- Supplemental operating reserves - additional capacity from generators that can be used to respond to a contingency within a short period, usually ten minutes, and
- Blackstart capability – power to re-energize portions of the grid, usually necessary for restarting larger generators.

Benefits and Drawbacks of Distributed Generation

The benefits of DG can accrue to stakeholders across the electrical system on both sides of the meter. The value of these benefits vary according to different technology and installation options, market structures, fuel and electricity prices, and customer energy usage. Many advantages of DG don't fit neatly into specific categories, but they can be roughly classified into four areas: customer-owner, utility or energy service provider, transmission/distribution grid and society as a whole.

Customer-owner

Customer-owners typically cite energy efficiency, reduced power costs, increased reliability and improved power quality as the motivation for installing DG.³⁹ Combined heat and power installations capture generator waste heat as hot water or steam to power a separate turbine or for heating, cooling and other industrial processes. Considering that two thirds of fuel energy is released as heat from most thermoelectric generators, it is in a DG owner's best interest to use this heat rather than incur additional costs to procure services DG can already provide.

³⁸ CEC, DG Case Studies for Permit Streamlining and the Impact Upon Transmission and Distribution Services 119 (2002).

³⁹ Poore et al., Connecting DER to the Grid: Their Benefits to the DER Owner/Customer, Other Customers, the Utility and Society, ORNL 23 (2002).

Cost savings can also be realized in not having to purchase traditional electric service. Depending on market conditions and energy use patterns, it can be cheaper to make your own electricity, especially during periods of peak demand (peak shaving) or high fuel prices. Beyond cost savings, DG can be a source of revenue since owners can often sell excess generation back to their utility.

The power quality needs of today's high-tech economy play to another benefit of DG. Voltage fluctuations and harmonics can damage sensitive loads. Current reliability standards of 99.99% electric availability present a risk of loss that some companies can't afford to bear. Many firms now require up to 99.9999% or "six nines" availability.⁴⁰ The National Renewable Energy Laboratory estimates that with every hour of power outage, brokerages can stand to lose up to six and a half million dollars, while credit card companies risk two and a half million.⁴¹ Certain DG technologies are well suited to delivering high quality reliable power better than a central station based infrastructure dependent on the transmission grid.

Utility and Energy Service Provider

In a DOE survey, utilities cited meeting peak demand and addressing transmission and distribution constraints as primary reasons for owning DG.⁴² Utilities can use DG for peak shaving by supporting customer installation of DG and participation in demand side management programs. DG can also be sited on the utility side of the meter to be dispatched as peaking resources.

Distributed resources can be a least-cost alternative to wires solutions for addressing congestion in the transmission and distribution systems. The costs of new lines or substation upgrades can be greater than those for DG. Congestion issues aside, DG can defer the costs of replacing old equipment by helping maintain operation within rated levels thus avoiding damaging thermal overloads.

Another type of cost savings can be found in the reduced line losses associated with DG. Typically, over seven percent of power is lost in its delivery over the transmission system.⁴³ Losses are significantly lower for the distribution system given smaller changes in current.⁴⁴ Line loss in transporting onsite DG power to nearby neighbors is less than one third of the losses realized in moving power from central plants to load.⁴⁵

In an increasingly competitive industry, DG enables utilities and load serving entities to be faster and more agile in responding to opportunities or crises. DG is less capital

⁴⁰ Cowart et al., State Electricity Regulatory Policy and Distributed Resources: Distributed Resources and Electric System Reliability 10 (2002).

⁴¹ Arthur D. Little Inc., Reliability and Distributed Generation 13 (2000).

⁴² Poore, *supra* note 39.

⁴³ Casten, Thomas & Sean, "Transforming Electricity", Northeast Midwest Economic Review 4 (November/December 2001).

⁴⁴ CEC, *supra* note 38, at 122.

⁴⁵ Casten, *supra* note 43.

intensive and can be up and running in a fraction of the time necessary for the construction of large central station plants. This bodes well for investors since the risk of inaccurate development projections is smaller for a shorter period of time. These risks can include lower than forecasted demand, regulatory changes and technological innovation. If projections do prove erroneous, the portability and modularity of DG give utilities flexibility to stem any losses. Most DG can be relocated and scaled up or down with relative ease.

Transmission and Distribution Grid

Distributed resources affords benefits to those who own, operate and use the grid. DG can increase grid reliability in several ways. Overall, many small generators are collectively more reliable than a few big ones, and the consequences of a small unit's failure are fewer than those of a large central plant.

Managing congestion on the transmission and distribution grids reduces the likelihood of component failure from overload. DG can effectively manage congestion on the distribution grid, but much higher market penetration levels are needed before DG could perform this function for the transmission grid. Congestion management is very much a function of a unit's location.⁴⁶ DG can also address voltage drop, typically experienced at the end of feeder lines on the distribution system.

For the transmission grid, several DG technologies are well suited to provide the ancillary services necessary for the stability of the electrical system. These services are increasingly being competitively bid and thus represent revenue sources for companies who own DG. Ancillary services include reactive supply and voltage control, regulation and frequency response, energy imbalance service, spinning operating reserves, supplemental operating reserves, and blackstart capability.

Society

Society at large has much to gain from DG. Maintaining public health and safety standards means employing backup generators to supply emergency power to facilities like hospitals and water pumping stations. DG helps to "harden" the nation's electricity infrastructure against terrorist attacks. DG allows the convenient electrification of remote areas. Distributed resources can also work to keep electricity prices in check and discourage the exercise of market power. Market liquidity increases as more resources participate. Competitive liquid markets spur innovation and help keep prices down. Low prices reduce the likelihood that producers will perceive something to gain by withholding resources in order to raise prices.⁴⁷

Several DG technologies offer environmental benefits in the form of low CO₂, NO₂, and SO₂ emissions; small footprints; limited aesthetic impacts; and the avoided effects of

⁴⁶ CEC, *supra* note 38, at 121.

⁴⁷ Weston et al., State Electricity Regulatory Policy and Distributed Resources: Accommodating Distributed Resources in Wholesale Markets, RAP 6 (2002).

conventional generation and transmission that DG displaces. Energy efficient CHP requires less fuel, which translates into reduced impacts of traditional resource extraction and decreased dependence on foreign energy supplies. For these reasons, DG is likely to suffer less of the “NIMBYism” that plagues much new generation and transmission.

Drawbacks

Distributed generation is not a panacea. Some DG technologies, diesel gensets in particular, are dirtier than conventional generation, in part due to a lack of federal and state emissions standards. Regulated utilities might spurn DG because it could diminish their capital investment base used to determine rate recovery levels. Further, DG by definition decreases the amount of electricity traveling over the distribution system and thus reduces distribution utility revenues.

Natural gas prices are an obstacle to DG competing with central station power on a cost basis. Reciprocating engines and fuel cells can run on natural gas while microturbines rely on it exclusively. Large central station combined cycle combustion turbines require a great deal more natural gas to operate than these DG technologies and are often sited near interstate pipelines. Thus these plants have the buying power to negotiate cheaper fuel prices than any DG owner would and can often avoid distribution costs by taking delivery directly from larger transmission pipelines. It is estimated that DG owners pay fifty to seventy percent more for natural gas than do owners of central generators.⁴⁸

DG raises the question of how to allocate the costs of infrastructure investment among customers in a deregulated market. DG owners use the distribution system less than traditional customers, if at all. Depending on the rate structure, there is a danger of traditional utility customers subsidizing services provided to DG owners like standby service and voltage support. Net metering presents a similar quandary as DG owners could conceivably buy and sell equivalent amounts of electricity from the grid so as to get a free ride for ancillary type services.

⁴⁸ Henry Lee, *Assessing the Challenges Confronting Distributive Electric Generation*, 16 *The Electricity Journal* 5, June 2003, at 23.

APPENDIX B - WESTERN STATE SMALL-SCALE RENEWABLE ENERGY INCENTIVES AND POLICIES

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	Oregon	Utah	Washington	Wyoming
Financial Incentives											
Personal Tax	2-S	2-S	1-S	1-S	3-S			1-S	1-S		
Corporate Tax		1-S	1-S		1-S		1-S	1-S	1-S		
Sales Tax	1-S					1-S				1-S	
Property Tax		1-S			1-S	2-S		1-S			
Rebates / Buy-Down	2-U	2-S, 7-U	1-L			2-U		5-U		1-S, 1-U	
Grants		3-S			1-S			1-S			
Loans		2-S, 2-U		1-S	1-S			1-S, 4-U		1-U, 1-L	
Leasing / Sales	2-U	3-U			1-U						2-U
Production Incentive			2-L					1-U		2-U	
Regulations & Policies											
Interconnection Standards	Pending IOUs/Coops	Yes IOUs	No	No	No	Yes IOUs	Yes IOUs	Yes All	No	Pending All	Early Discussions
Installer Certification		1	1								
Outreach Programs	1-S, 3-L	1-S, 9-L	1-S, 3-L	1-S	1-S	1-S	1-S	1-S	1-S, 1-L	1-S, 1-U	1-S
PBF		1-S			1-S			1-S			
Disclosure	1-S	1-S	1-S		1-S	1-S		1-S		1-S	
RPS	1-S	1-S				1-S	1-S				
Net Metering	1-S	1-S	5-U	1-S	1-S	1-S	1-S	1-S, 1-L	1-S	1-S, 1-U	1-S
Extension Analysis	1-S		1-S				1-S				
Contractor License	1-S	1-S				1-S			1-S		
Equipment Certification	1-S								1-S		
Access Laws	1-S	1-S, 5-L	1-S, 1-L	1-S	1-S	1-S	1-S	1-S, 2-L	1-S	1-S	
Construction & Design Standards	1-S, 3-L	2-S, 1-U, 2-L	3-L					2-L		1-L	
Required Green Power Option					1-S					1-S	

= Number of Programs
S = State
L = Local

U = Utility / Energy Service Company
IOU = Investor owned Utilities
Coops = Rural Electric Cooperatives

Financial Incentives

Personal & Corporate Tax Incentives – credits or deductions to cover the expense of purchasing and installing renewable energy equipment

Sales Tax Incentives – exemptions for the cost of renewable energy equipment

Property Tax Incentives – exemptions, exclusions or credits based on the added value of renewable energy equipment

Rebates / Buy-Downs – one time payments to reduce the cost of purchasing renewable energy equipment

Grants – state money used to encourage the use and development of renewable energy technologies

Loans – low or no-interest financing for the purchase of renewable energy equipment

Industrial Recruitment – programs designed to attract renewable energy equipment manufacturers to locate within a state or city

Leasing/Sales – utility programs that target remote customers for which line extension would be costly

Production Incentives – per kWh payments to customers who own their own renewable generating units

Regulations & Policies

Interconnection Standards – standard procedures and contract for connecting customer-owned renewable generation units to the grid

Installer Certification – voluntary state programs that certify installers of renewable technologies

Outreach Programs – state efforts to promote renewables

PBF Public Benefit Fund (system benefits charge) – consumption charge used to assure support for renewable energy, efficiency and low-income programs

Disclosure – requirement that utilities provide customers with information about their energy (e.g., fuel mix and emissions)

Renewable Portfolio Standard – requirement that a certain percentage of a utility's new generation or sales be derived from renewable resources

Net Metering – allows customers with their own generating units to both buy energy from and sell energy to the utility through a single bi-directional meter

Extension Analysis – requirement that utilities provide customers with information on distributed renewable energy options when a line extension is requested

Contractor License – rules regarding the licensing of renewable energy contractors ensuring that they have the necessary experience and knowledge

Equipment Certification – rules requiring renewable energy equipment to meet certain standards

Access Laws – statutes providing for solar or wind easements or access rights

Construction & Design Standards – state policies, green building programs and energy codes requiring the consideration of renewables in new construction

Required Green Power Option - state requirement that certain classes of utilities offer customers the option to purchase power generated from renewable sources

Source: Database of State Incentives for Renewable Energy < <http://www.dsireusa.org/dsire/summarytables/index.cfm?CurrentPageID=7>>; Status of Interconnection Rules for Renewables and Distributed Generation, Interstate Renewable Energy Council <<http://www.irecusa.org/connect/state-by-state.pdf>>

APPENDIX C - WESTERN STATE COMBINED HEAT AND POWER INCENTIVES AND POLICIES

	Arizona	California	Colorado	Idaho	Montana	Nevada	New Mexico	Oregon	Utah	Washington	Wyoming
Financial Incentives											
Rebates / Buy Downs		1-S									
Regulations & Policies											
Interconnection Standards	Pending	CPUC Rule 21				Early Discussions	NMPRC Rule 570		Early Discussions		
Net Metering	1-S <100kW			1-S <100kW			1-S <10kW				
Emissions Standards		set by local districts									
Emission Certification		1-S									

= Number of Programs
 S = State
 L = Local

U = Utility / Energy Service Company
 IOU = Investor owned Utilities
 Coops = Rural Electric Cooperatives

Financial Incentives

Rebates / Buy-Downs – one time payments to reduce the cost of purchasing renewable energy equipment

Regulations & Policies

Interconnection Standards - standard procedures and contract for connecting customer-owned CHP units to the grid

Net Metering - allows customers with their own generating units to both buy energy from and sell energy to the utility through a single bi-directional meter

Emissions Standards – emission levels set by state or local authority above which some mitigation or enforcement action is to be taken

Emission Certification – state or local program that certifies specific CHP technologies for exemptions or pre-determined treatment under emissions standards

Source: State Opportunities for Action: Review of States’ Combined Heat and Power Activities, Brown et al., 2002.; Status of Interconnection Rules for Renewables and Distributed Generation, Interstate Renewable Energy Council <<http://www.irecusa.org/connect/state-by-state.pdf>>

APPENDIX D - DISTRIBUTED GENERATION PROVISIONS IN WESTERN UTILITY INTEGRATED RESOURCE PLANS

- The following are excerpts from Western utility IRPs -

Avista

The Company views DG as not a threat but as another choice available to the utility. In the future there will be a vibrant market for personalized power that uses DG technology. The Company is financially supporting fuel cell development and therefore is a part of the DG movement. The key to any DG project is the source location relative to the substation. Presently within the Company, any proposed DG project includes analysis to look at the effects on its system.

(Avista Corp. 2003 IRP Technical Appendices, pages M-1 through M-6)

Idaho Power

Idaho Power identified microturbines, diesel and natural gas internal combustion generators, and fuel cells as future resource options. These resources are likely to be deployed in a distributed manner - connected to the distribution system close to end users. Identification of the resource options themselves does not constitute a resource plan, but the specification of resource options is a first step in the resource planning process.

Microturbines -

As of June 2002, there were no microturbine generators operating on the Idaho Power system.

Diesel and Natural Gas Internal Combustion Generators -

Many industrial and large commercial facilities in the service territory rely on internal combustion generators for back up power, but no utility dispatch program is in place or planned. Idaho Power owns two 2.5 MW diesel-engine generators in Salmon, ID that are primarily used for backup power. Otherwise, the company cites its 2001 trial with diesel generators in Treasure Valley as problematic at best.

(Idaho Power Company 2002 IRP pages 35-44)

Nevada Power

There has been almost no penetration of large-scale DG project's in the Company's territory. However there has been a marked recent increase in customer interest in large-scale high duty-cycle DG applications in Nevada.

At the present time, it is too difficult to predict likely penetration rates for large-scale DG projects in the Company's service territory... the Company will focus its internal efforts on studying large-scale projects... to gain a better understanding of the economics of DG applications and to better anticipate potential changes that may be warranted in future energy supply and resource plans.

The Company is proposing through its demand side plan to develop a program that will monitor and track the installation of DG ranging from smaller photovoltaic installations through the larger installations... The data collected will be shared with customers through the Company's web based DSM information site.

(Nevada Power 2003 Resource Plan – Volume VI pages 13-16)

PacifiCorp

For the purpose of portfolio modeling, PacifiCorp identified prospective resources for balancing resource supply with electricity demand based on options uniquely available to PacifiCorp. DG resources considered include:

Combined Heat and Power -

Utah combined heat and power (CHP) was developed to represent a cogeneration opportunity along the Wasatch Front. The "Cogen-CT" CHP represents a combustion turbine generating steam for industrial purposes. A large CT is modeled. This option is dependent on the proper host and is considered a low probability considering the industrial base in Utah. The "Non CT" case is intended to be a boiler or waste heat application that could apply a topping steam turbine at relatively low cost. No specific candidate cogeneration sites are currently identified.

Fuel Cells -

Fuel cell technology continues to improve and become more cost effective. A fuel cell is an electricity-generating device that utilizes the reaction between hydrogen and oxygen with the only by product being water. Attractive fuel cell characteristics include:

- High energy conversion efficiency
- Modular design
- Very low chemical and acoustical pollution
- Fuel flexibility
- Cogeneration capability
- Rapid load response.

Fuel cell disadvantages include high capital costs and technological uncertainty.

Microturbines -

Microturbines were identified as "not currently feasible for meeting PacifiCorp's resource needs."

(PacifiCorp 2003 IRP pages 70-76)

Portland General Electric

PGE is developing interconnection and other requirements for customer owned generation. They expect their final interconnection requirements to conform to anticipated FERC rules on the subject. The company is developing a website that will feature information on interconnection and other procedures as a guide to prospective DG customers. PGE is also developing a pre-certification process by which smaller generation facilities will be pre-certified for interconnection and avoid a complete review.

PGE could acquire up to 100 MW through its Dispatchable Standby Generation Program (DSG) from on-site generators at high technology, medical and telecommunication businesses within their service territory. Under the program, generators are always available to back up the owner's facility, but can be remotely dispatched for up to 400 hours in a single year to supply system peaking power. PGE is responsible for reconfiguring the grid connection to make the units dispatchable and for operating and maintaining the generators. PGE also pays for the fuel consumed when units are run for their benefit. As of January 2003, the utility had 9.75 MW of DSG on line and was negotiating contracts for additional projects.

(PGE 2002 IRP Supplement page 76)

Puget Sound Energy

PSE strives to incorporate DG elements into its distribution system facilities planning process. PSE has developed DG screening tools to identify projects with the highest probability of serving the least cost capacity deferral alternative. Three DG projects have been identified with the screening tool:

1. Peak Shaving at Crystal Mountain – PSE deferred a \$2.5 million wires upgrade with the installation of a 2.4 MVA diesel standby generator.
2. Installation of a 1.2 MW generator on Lummi Island – PSE employed a 1.2 MVA diesel unit to act as an emergency response to the failure of an old line.
3. Selection of the Dierenger substation as a DG site – a project feasibility study prompted PSE to defer the implementation of a DG project at this site.

PSE views DG technology as an alternative in delivering reliable energy at low cost. Currently, PSE monitors and evaluates DG developments at the federal, state and utility levels. PSE has been contracted to perform the DOE/NREL/GE/PSE project, Universal Interconnect Detail Design. PSE is one of three companies developing the functional requirements for this project. DOE/NREL/GE/PSE project backers hope to develop an advanced universal modular interconnection technology that can provide cross DG platform capability and increased functionality for load management and grid support. (PSE April 2003 Draft Least Cost Plan, VII 11-14)

PSE's Schedule 150 net metering customers provide another existing resource. These customers operate fuel cells or hydro, solar or wind power generators with a total capacity of no more than 25 kW on their own premises. Such generators must operate in parallel with PSE's transmission and distribution facilities. In total, these customers represent approximately 37 kW of supply from 18 photovoltaic sources, four micro-hydro and one wind power project.

(PSE April 2003 Draft Least Cost Plan, VIII 5)

The following is an excerpt from PSE's two-year "Action Plan" which lists steps to be taken to implement PSE's recommended long-term resource strategy:

IX. Distribution Facilities Planning

- Participate with other EEI utilities in the FERC NOPR process for distributed generation. The FERC NOPR for distributed generation will be issued in the spring of 2003.
- Seek opportunities to deploy distributed generation for least cost capacity deferral.
- Continue the collaboration with the DOE/NREL/GE Universal Interconnect project.
- Track distributed generation technologies and applications that can impact and improve the distribution gas and electric planning process.

(PSE April 2003 Draft Least Cost Plan, XVII 14-16)

Xcel Energy

No consideration of DG in resource solicitations or modeling.

(Xcel 1999 IRP pages 1-13 thru 1-15, 2002 Update)

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