CORPORATE GOVERNANCE AND RATIONAL ENERGY CHOICES

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I. IF THERE IS AN ENERGY CRISIS, WHY HAVE CORPORATIONS NOT IMPLEMENTED RENEWABLE ENERGY AND SELF-GENERATION?

Supposedly there is a shortage of energy.[1] Primary fuels, such as gasoline, heating oil, and natural gas, as well as carrier sources of energy, such as electricity, are selling for some of the highest prices in a generation.[2] If there is a shortage or even a crisis on the horizon, why have American corporations not moved faster to implement renewable energy and self-generation? Economic, legal, and regulatory disincentives to such implementation provide the initial answer, but there have also been mixed signals from regulatory agencies. Amid these disincentives and mixed signals, corporations have acted relatively rationally on a short-term planning horizon, but they will soon feel new pressure to reduce their "carbon footprints" by utilizing renewable energy sources.

Some disincentives are price related, in that generating electricity from photovoltaic panels ("PV") is several times more expensive for the corporation than buying traditional, centrally-generated electricity.[3] To justify such investments, corporations must lengthen their planning horizon. With the increasing costs of conventional power, the innovative

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[1] *See* EnergyShortage.Com, Welcome, http://www.energyshortage.com (last visited Dec. 1, 2006) (discussing the supposed energy shortage).

[2] *See* Oil Price Increases of 2004-2006, http://en.wikipedia.org/wiki/Oil_prices (last visited Aug. 24, 2006) (documenting how the price of oil and gasoline have reached "record highs" during the past year); Energy Information Administration, Natural Gas Prices, http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm (last visited Dec. 1, 2006) (discussing rising natural gas prices); Edison Electric Institute, Rising Electricity Costs, http://www.eei.org/industry_issues/electricity_policy/state_and_local_policies/rising_electricity_costs/index.htm (last visited Dec. 1, 2006).

[3] *See DOE Offers $170 Million in Solar Funds, Aiming to Cut PV Cost to 9-18 Cents/Kwh*, PLATTS ELECTRIC UTIL. WK., July 10, 2006, at 11. As of 2006, PV power costs range from 13-22 ¢/h. *Id.* Traditional fossil fuels produce power at about 3-6 ¢/h, depending on heat rate and fossil fuel costs. *See infra* note 63.

financing structures offered by some companies,[4] and various tax and other incentives,[5] on-site generation can make economic sense on a long-term basis. Fuel cells, powered by hydrogen, are less cost-effective.[6] Wind power is cost-competitive with traditional electricity production.[7] Biomass, trash-to-energy, and landfill-gas electric energy resources or projects are not inherently available at most corporate sites.[8] Their implementation requires being in the right place at the right time, often demands significant land areas, and is neither the province of nor available to most American corporations.[9]

A fundamental dichotomy exists between the availability and attributes of on-site renewable energy technologies. Some technologies are base-load, stable and generally available around-the-clock renewable technologies. These include biomass and landfill gas-to-energy projects.[10] However, these base-load projects are not universally distributed. Landfills occur only in places where garbage has been accumulated in a substantial quantity over time, and biomass projects involve the transport and processing of organic or agricultural matter.[11] Thus, these technologies are not inherently available at most locations for commercial or industrial customers. On the other hand, certain renewable technologies are universally distributed. Solar photovoltaic energy is available everywhere in the United States,[12] and many locations have harnessable wind energy.[13] However, these universally distributed renewable energy technologies are intermittent.[14] Wind power may only be available during twenty-five to forty percent of the hours in a month, and solar photovoltaic energy is available less than half the hours of the day.[15] For on-site

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[4] *See* 1 STEVEN FERREY, LAW OF INDEPENDENT POWER § 3:56, at 3-139 to -41 (24th ed. 2006) [hereinafter FERREY, LAW OF INDEPENDENT POWER].
[5] *See id.* § 3:53 (discussing tax incentives).
[6] *See id.* § 2:14, § 10:144, at 10-357 to -58.
[7] *See id.* § 2:11, at 2-29 to -30.
[8] *Id.* at 2-35 to -36.
[9] This is not to say that these don't make sense on a larger societal scale, but the trash-to-energy and landfill-gas resource potential in the nation have largely been overlooked during the last couple of decades. *See* Environmental Protection Agency, Landfill Methane Outreach Program (Nov. 1, 2006), http://www.epa.gov/lmop.
[10] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:11, at 2-35 to -36.
[11] *See id.*
[12] *See id.* § 2:11, at 2-26 to -28 & fig. 2.11 (giving a map of distributed solar resources).
[13] *See id.* § 2:11, at 2-28 to -34 & fig. 2.12.
[14] *See id.* § 2:11, at 2-23 to -34.
[15] *See id.* § 2:11, at 2-26, 2-30.

energy applications, these intermittent technologies require either on-site energy storage,[16] or the ability to sell surplus electricity to the regional power grid[17] and purchase back-up and stand-by power when required from the grid[18] or from other independent producers over the grid.[19] Therefore, renewable power has to be tailored to the specific application. While renewable technologies can stand alone, the modern corporation would do best to adopt them in conjunction with existing conventional grid-supplied power service.

Based strictly on economics and rational decision-making, renewable energy generation on-site does not lend itself to use by every corporation, a situation that provides one rational explanation for the lack of implementation of some renewable energy technologies. Moreover, while it is possible to buy so-called "green" energy resources from traditional energy suppliers,[20] in many cases such purchases do not increase the total amount of renewable energy. When a purchaser buys "green" energy, the allocation of renewable energy resources in the system to that dedicated purchaser only occurs on paper.[21] But that allocation does not necessarily result in any more use or deployment of centralized renewable energy resources.[22] In fact, in California, the demand for purchasing "green" centralized energy resources actually caused traditional purveyors of those energy resources to operate fossil fuel-fired facilities more than they otherwise would have.[23]

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[16] *See id.* § 2:20.

[17] *Id.* §§ 4:24-:29 (discussing renewable power sales).

[18] *See id.* §§ 4:32-:33 (discussing backup power sales).

[19] *See id.* § 4:27 (discussing net metering).

[20] *See id.* § 10:98 (discussing "green" energy sources).

[21] These are electric supply derived, at least on paper, from renewable resources. Particular power for sale over the common electric grid cannot be physically isolated for a particular buyer. *See* STEVEN FERREY, THE NEW RULES: A GUIDE TO ELECTRIC MARKET REGULATION 11 (2000) [hereinafter FERREY, THE NEW RULES]; S*ee also* ENVTL. MKTG. SUBCOMM. OF THE ENERGY DEREGULATION WORKING GROUP, NAT'L ASS'N ATT'YS GEN., ENVIRONMENTAL MARKETING GUIDELINES FOR ELECTRICITY 6 (1999), *available at* http://www.eere.energy.gov/greenpower/markets/pdfs/naag_0100.pdf.

[22] *See* FERREY, THE NEW RULES, *supra* note 21, at 11.

[23] *See* NANCY RADER, GREEN BUYERS BEWARE: A CRITICAL REVIEW OF 'GREEN ELECTRICITY' Part II.A (1998). This is because the renewable energy resources available today, largely in the form of hydroelectric power and wind, were already constructed as part of the generation portfolio and had a very low, or zero, marginal cost of operation. *Id.* Therefore, the owner of those resources would deploy them whenever available to minimize marginal system operating costs. Selling those "green" energy resource outputs to a particular buyer did not cause the renewable energy generation technology to operate

The disincentives to on-site renewable resources deployed directly by corporations go beyond economic considerations, however. There are significant impediments to interconnection, obtaining stand-by and back-up power from the utility, and integrating on-site renewable energy resources with the conventional system.[24] These additional disincentives overwhelm and discourage many corporations from deploying renewable resources.[25] These regulatory and legal disincentives are as pivotal as price. The system provides many disincentives, both subtle and obvious, for an individual corporation to deploy renewable energy resources.

Some renewable applications and many on-site distributed resource generation applications are nonetheless extremely economical for a large range of American corporations today.[26] Renewable energy resources may make sense in certain deployments: photovoltaics can be cost-effective in long-term applications, with subsidies, or in remote or specialized situations.[27] These specialized situations are often utilized as "demonstration" applications in other than remote situations.[28] Wind power is economical, but may pose siting problems at a particular corporate location[29] or present difficulties with integrating an intermittent resource with the grid.[30] The corporate decision-making horizon is often three to seven years, not the ten plus years that might be required to recover the financial investment on a solar photovoltaic system.[31] Because they are not reliable when the wind is not blowing or the sun

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any more when more customers signed up; since it was already running the plant at maximum levels so as to minimize portfolio operating costs, the purveyor would have to deploy more of its traditional fossil fuel-fired electric generation resources to meet the increased demand from new customers. *Id.* Therefore, while renewable power resources are allocated on paper to purchasers of "green" power, the traditional energy resources actually operate more. *Id.*

[24] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, §§ 4:32-:33.

[25] *See id.* §§ 4:34-:35.

[26] *See generally id.* § 10:144 (discussing distributed generation).

[27] *See id.* §§ 3:53, 2:11 at 2-26 to -28.

[28] *See id.*

[29] The author has completed a legal assessment of the impediments to siting and developing wind power (sources on file with author, article forthcoming 2007).

[30] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, §2:11, at 2-28 to -34.

[31] *See generally* DAVE ALGOSO, MARY BRAUN, & BERNADETTE DEL CHIARO, BRINGING SOLAR TO SCALE: CALIFORNIA'S OPPORTUNITY TO CREATE A THRIVING, SELF-SUSTAINING RESIDENTIAL SOLAR MARKET 22-23 (2005), *available at* http://www.environmentcalifornia.org/uploads/CG/RN/CGRNi2aeOwal_DGcyK9ewA/Bringing_Solar_to_Scale.pdf (suggesting a "dedicated fund" for incentivizing solar power installation, which could reduce break-even time for residential "retrofitted" systems to ten years).

does not shine, intermittent resources require either reliable back-up service from the conventional utility grid, which can be costly,[32] or practical energy storage.[33] These costs can be prohibitive and work as disincentives to the deployment of otherwise cost-effective renewable resources on-site at corporate locations.

However, on-site cogeneration and self-generation is cost-effective for many corporations in a variety of locations. The remainder of this article focuses on on-site self-generation or cogeneration, which can be, but does not need to be, powered by renewable energy applications. While there are still subtle, as well as transparent, regulatory system disincentives to individual corporate use of renewable and self-generation resources,[34] many states provide counterbalancing incentives for deployment of these technologies.[35]

Electricity has only been harnessed in approximately the last century and a quarter, or roughly the last 2/1000 of one percent of human history.[36] Despite its status as a relatively recent energy form, it has emerged as the premium carrier form of energy and has no substitute for use in the internet, telecommunications, computing, or information technology. These and other machine and appliance applications require electric voltage, as opposed to the heat produced by combusting oil, gas or other fossil fuels, as their motive force.[37] Electricity is also critical because it is not storable in large-scale economic forms, except for in certain hydroelectric pumped-storage technologies and expensive battery storage technologies.[38]

It is critical to note that there is enough space on rooftops in the U.S. to supply all of the country's electric power needs through existing photovoltaic solar technology.[39] Similarly, roads in the U.S. have enough surface area to supply that same amount of energy through photovoltaic technologies.[40] This is not to suggest that we should convert roads, al-

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[32] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 4:31 (discussing utility back-up rates).
[33] *See id.* § 2:20 (discussing energy storage).
[34] *See* discussion *infra* Part V.
[35] *See* discussion *infra* Part IV.
[36] *See generally* FERREY, THE NEW RULES, *supra* note 21, at 260.
[37] *See* ENERGY INFO. ADMIN., U.S. HOUSEHOLD ELECTRICITY REPORT (2005), http://www.eia.doe.gov/emeu/reps/enduse/er01_us.html (noting the increase in electricity's share of residential energy consumption in recent years).
[38] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:20.
[39] *Id.* § 2:11, at 2-26.
[40] *Id.* § 2:11, at 2-24.

though perhaps we should convert many building roofs, but merely to indicate that the land area necessary to use existing technologies to convert relatively diffuse photovoltaic energy sources is not prohibitive in its quantity. Furthermore, in addition to considering many renewable energy applications, corporations have options today with conventional fossil-fuel-fired cogeneration applications.

II. EFFICIENCY AND COGENERATION TECHNOLOGY CHOICES FOR BUSINESS

Technologies that leave the electricity grid, such as qualifying electric power production facilities ("QFs"), produce power more efficiently than either conventional electricity generation technologies and industrial process heat applications.[41] Conventional electricity generating technologies generally operate at only about thirty percent efficiency.[42] Conventional methods operate so inefficiently because they typically exhaust as much as two-thirds of the heat energy produced to power electric generators.[43] Conventional technologies use process steam most often in applications below 400 degrees Fahrenheit, but the combustion of fossil fuels to produce the steam results in temperatures of more than 3000 degrees Fahrenheit.[44] The unused heat is wasted.[45]

Cogeneration technologies use the otherwise wasted heat from the combustion process to make electricity and a second form of useful energy, usually heat.[46] Therefore, these technologies produce two forms

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[41] FERREY, THE NEW RULES, *supra* note 21, at 3-4, 7.
[42] *Id.* at 3.
[43] *See generally* BARRY COMMONER, THE POVERTY OF POWER: ENERGY AND THE ECONOMIC CRISIS (1976); ENERGY FUTURE (Robert Stobaugh & Daniel Yergin eds., 1979); AMORY B. LOVINS, SOFT ENERGY PATHS (1977); FERREY, THE NEW RULES, *supra* note 24, at 3.
[44] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:2, at 2-6.
[45] CAL. ENERGY COMM'N, COGENERATION HANDBOOK 1-1 (1982) [hereinafter COGENERATION HANDBOOK]. Typically, the design of a total energy system takes into account the usable quantity of heat, the electricity demand, and the output characteristics of various technologies in order to produce an appropriate split of thermal and electric energy. Cogeneration technologies, unlike conventional technologies, capture waste heat and harness it for additional purposes. *Id.* By harnessing and using what is usually lost as waste heat, cogenerations technologies realize a "cascading" effect and a double value use of the energy they produce. *Id.* This increases overall system efficiency and is cogeneration's principal advantage over conventional electricity generating technologies. *Id.* at 1-1 to 1-3.
[46] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:2, at 2-6.4.

of useful energy for the effort and price of one.[47] Producing two forms of usable energy allows cogeneration facilities operate at overall thermal efficiencies as great as 250-300 percent higher than conventional electric generating technologies.[48] The best cogeneration technologies "are more than twice as efficient as new coal-fired power plants."[49]

As conventional generating technologies become more efficient, they reduce the residual wasted heat energy.[50] Correspondingly, more of the fuel input is converted to electricity than thermal energy. This in turn diminishes the efficiency difference between cogeneration and conventional technologies. The overall efficiency gain is positive, however, because electricity is a much more valuable and refined energy product than heat.

Cogeneration technologies raise efficiency under the first and second laws of thermodynamics.[51] The efficiency rating for electricity production under the first law increases to as high as ninety percent with cogeneration technologies from about thirty-three percent for conventional generating technologies.[52] Cogeneration technologies can achieve as much as forty-nine percent efficiency under the second law, compared with thirty-five percent efficiency for conventional technologies.[53] The

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[47] *Id.*

[48] COGENERATION HANDBOOK, *supra* note 45, at 1-3.

[49] Barney L. Capehart & Lynne C. Capehart, *Efficiency in Industrial Cogeneration: The Regulatory Role,* PUB. UTIL. FORTNIGHTLY, Mar. 15, 1990, at 17, 17-18 (noting that new coal-fired, central-station power plants have a heat rate of 10,500 British thermal units per kilowatt-hour ("Btu/kWh"), while the best cogeneration units have a heat rate of only 4500 Btu/kWh).

[50] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:2, at 2-6.4.

[51] MARC H. ROSS & ROBERT H. WILLIAMS, OUR ENERGY: REGAINING CONTROL: A STRATEGY FOR ECONOMIC REVIVAL THROUGH REDESIGN IN ENERGY USE 156 (1981). The first and second laws of thermodynamics govern the efficiency of a heat engine, a device that converts chemical energy to mechanical or electric energy. The first law of thermodynamics compares the amount of energy created to the amount originally available in chemical form. The second law of thermodynamics governs the maximum amount of energy that a system can produce. *See generally id.*

[52] *Id.* at 160.

[53] *See id.* at 156. The second law of thermodynamics reflects the quality of energy a system produces. Electric energy is a much higher quality form of energy than thermal energy. The Carnot efficiency expresses the ratio of the useful (electric and heat) output of an engine to the total energy input. In essence, the Carnot efficiency predicts the maximum potential usable energy output different engine technologies will generate, without accounting for losses resulting from engine friction, heat loss, and heat exchanger limitations. The second law of thermodynamics and the Carnot efficiency provide a means to rate potential efficiencies of different technologies. *See* NASA,

increase in operating efficiency reduces the amount of fuel needed to generate a unit of usable energy; compared to conventional electricity generation technologies, cogeneration technologies save up to thirty-one percent on fuel.[54]

A total cogenerating energy system captures unused heat that can then be used for direct application heat, industrial process heat, or pre-heating the combustion air for a utility boiler.[55] Capturing and using waste heat in the process of electric generation achieves greater efficiency[56] by producing more useful energy while generating a lower amount of environmental pollutants and emissions.[57] Locating dispersed cogeneration systems close to load centers would require less transmission capability.[58] If cogeneration systems are close to load centers, some areas will no longer need additional transmission capacity, and furthermore, the load on existing transmission grids will be lessened.[59] Viewed another way, if natural gas cogeneration systems replace centrally dispatched electricity, energy will be moved more in its primary form, natural gas, and less in its derived form, electricity.[60]

A self-generation provider brings fuel to the user rather than moving electricity to the user.[61] This benefits the continental United States because it already has a well-developed underground gas distribution

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Thermodynamics, http://www.grc.nasa.gov/WWW/K-12/airplane/thermo.html (last visited Dec. 1, 2006); *see also* Robert H. Williams, *Industrial Cogeneration,* 3 ANN. REV. OF ENERGY 313, 318- 22 (1978).

[54] *See* FERREY, THE NEW RULES, *supra* note 21, at 3 (noting that cogenerators require eighty percent of the fuel that conventional generators need to produce the same amount of energy. Conventional fossil fuel technologies achieve efficiencies ranging from thirty-three percent for steam cycle to fifty-five percent for combined cycle).

[55] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:2, at 2-6.5. Many of these technologies are derived from the aircraft turbine industry. *Id.* at 2-6.5, n.5.

[56] *See id.* § 10:144, 10-353 to -357. Smaller facilities located on or near the site of consumption reduce the need for transmission facilities, and transmission losses and transmission-related outage problems are minimized. *Id.* at 10-353 to -356. Efficient gas turbine technology that operates below 50 MW can be placed near population centers. *See id.* at 10-356 to -357. Depending upon land-use, siting, emissions, and engineering factors involved, units up to 100 MW may be appropriately located near population centers. *See generally id.*

[57] *Id.* § 2.2, at 2-6.5.

[58] *See id.* § 10:144, at 10-353 to -356.

[59] *Id.*

[60] *Id.* § 2.2, at 2-6.5.

[61] *See generally* CONG. BUDGET OFFICE, PROSPECTS FOR DISTRIBUTED ELECTRICITY GENERATION, at ix (2003) [hereinafter CBO, PROSPECTS].

system,[62] but its electricity transmission corridors are constrained at points.[63] Gas fuel brought to the electricity user in lieu of electricity would reduce the strain on the electric transmission grid[64] and compete directly with the delivery of centralized electric power along the grid.[65] Switching to gas offers an alternative corridor that efficiently and effectively delivers power to end users.[66]

In 2003, the Congressional Budget Office concluded that producing power at or near customers' homes and businesses (distributed generation), could improve the reliability of the power supply, reduce the cost of electricity, and lower emissions of air pollutants.[67] Back-up generation is widespread in hospitals, hotels, commercial office buildings, malls, a variety of businesses, and even some residences.[68] One-fourth of commercial floor space in the country has some capacity to generate electricity on-site.[69] A program in New York revealed that participating telecommunications data centers, hotels, universities, banks and news organizations boasted sixty to one hundred percent more distributed capacity than their on-site demand.[70]

The United States Department of Energy estimates that distributed generation will account for more than eleven percent of future installed generating capacity.[71] Some estimates are that there are approximately 60,000 MW of installed distributed generation in North America as of 2004.[72] This would represent approximately eight percent of installed centrally-dispatched generating capacity.[73] A distributed energy system that includes increased use of cogeneration reduces the threat of disruption, whether from terrorism, weather, or other factors, that faces

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[62] *See* ENERGY INFO. ADMIN., U. S. DEP'T OF ENERGY, ADDITIONS TO CAPACITY ON THE U.S. NATURAL GAS PIPELINE NETWORK: 2005, at 1-7 (2006), *available at* http://www.eia.doe.gov/pub/oil_gas/natural_gas/feature_articles/2006/ngpipeline/ngpipeline.pdf.
[63] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 8:2.
[64] CBO, PROSPECTS, *supra* note 61, at xii.
[65] *Id.* at 16.
[66] *See id.* at 16.
[67] *Id.* at ix.
[68] *See id.* at 6.
[69] *Id.* (citing ENERGY INFO. ADMIN., U.S. DEP'T OF ENERGY, ANNUAL ENERGY OUTLOOK 2003, at tbl.A9 (2003)).
[70] N.Y. ST. ENERGY RES. & DEV. AUTH., DISTRIBUTED ENERGY & ELECTRIC RELIABILITY—FACT SHEET (2003).
[71] CBO, PROSPECTS, *supra* note 61, at 7.
[72] *Rapid Growth Predicted for Distributed Generation, If Cost, Other Hurdles Overcome*, PLATTS ELECTRIC UTIL. WK., May 17, 2004, at 26, 27.
[73] CBO, PROSPECTS, *supra* note 61, at 3.

centralized generation and distribution systems.[74] The value of a distributed, on-site, cogeneration-based system, likely fueled by natural gas, results from: reliance on a larger number of small generators, no one of which is critical to supply very large amounts of energy;[75] less reliance on a vulnerable centralized transmission and distribution grid;[76] and reliance on the movement of natural gas fuel in the more protected underground pipeline system to the electric generation located and distributed near the demand load center, rather than reliance on more vulnerable above-ground electric transmission infrastructure to distribute electric power to the load.[77] Gas can be stored in pipelines while electricity cannot be stored in transmission lines, especially where they are knocked out.[78] A distribution system with a large number of small units has greater collective reliability than one with a small number of large units.[79] The system has a greater collective reliability because distributed resources tend to fail less than centralized plants and are faster to fix.[80] In a comparison study, ten industrial independent power facilities were more reliable than five comparably sized and constructed utility facilities.[81] The ten independent power facilities had a mean value of availability of 95.6 percent.[82] The five utility facilities, ranging in size from 75 to 500 MW, scored worse with an 86.6 percent mean value of availability.[83] This limited study indicates that the private facilities are as reliable or more so than conventional utility facilities.

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[74] Steven Ferrey, *Power Future*, 15 DUKE ENVTL. L. & POL'Y F. 261, 272-78 (2005) [hereinafter Ferrey, *Power Future*]. *See also* AMORY B. LOVINS ET AL., SMALL IS PROFITABLE: THE HIDDEN ECONOMIC BENEFITS OF MAKING ELECTRICAL RESOURCES THE RIGHT SIZE 180-83 (2002); Hisham Zerriffi et al., *Electricity and Conflict: Advantages of a Distributed System*, ELECTRICITY J., Jan.-Feb. 2002, at 55, 57-58.
[75] Zerriffi et al., *supra* note 74, at 57.
[76] *Id.*
[77] *Id.* at 57-58.
[78] *See id.* at 58. A conventional system is up to five times more sensitive to loss of load from various sources than a distributed system. *Id.* at 63. This analysis concerns losses of generating capacity, and not losses of transmission or distribution. *Id.* It also does not examine the stability of the natural gas supply system. *Id.* at 62-63.
[79] LOVINS ET AL., *supra* note 74, at 181. They also reduce the reactive power flows by avoiding transformers. *Id.* at 225.
[80] *Id.* at 186.
[81] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 3:99, at 3-174.
[82] *See* Morton J. Smith, *Reliability and Maintainability of Utility and Industrial Cogeneration Power Plants*, 27 IEEE TRANSACTIONS ON INDUSTRY APPLICATIONS 669 (1991).
[83] *Id.*

The federal government estimates that microturbines generating power only, as well as small wind turbines, can generate power at a lifecycle cost of approximately 11¢/kWh.[84] Conversely, cogenerating microturbines, internal combustion engines producing power only or cogenerating power, fuel cells, and simple-cycle combustion turbines generating power only or cogenerating, can each produce power at a life-cycle cost of less than 10¢/kWh.[85] At these prices, these distributed energy technologies are competitive with the cost of power delivered to users in many of the higher cost areas of the country.[86] With cogeneration applications, these technologies are equivalent to the average all-in system cost of utility grid-delivered power in the United States.[87]

As described below, this is so even though the capital costs of distributed generation per kilowatt are approximately twice the cost of central station electric generation capacity.[88] Small distributed generators may also pay fuel prices fifty to seventy percent higher than the bulk fuel prices paid by central generators.[89] Certain subsidies for renewable distributed power in several of the states,[90] as well as state net metering incentives in forty of the states,[91] significantly improve the economics of on-site distributed energy technologies.

A centralized power generator produces energy at a cost of approximately 4.5¢/kWh, which is lower than the cost of producing energy from a distributed generator.[92] Distributed generation, however, avoids the additional costs attendant to centralized energy, such as the

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[84] CBO, PROSPECTS, *supra* note 61, at 12.
[85] *Id.* The simultaneous co-production and use of thermal energy as well as electric energy significantly reduces the life-cycle operating cost and improves the economics of distributed generation. *See id.* at 10-14.
[86] *Id.* at 12-14.
[87] *Id.* at 12.
[88] Henry Lee, *Assessing the Challenges Confronting Distributive Electric Generation*, ELECTRICITY J., June 2003, at 20, 22.
[89] *Id.* at 23.
[90] *See generally* Steven Ferrey, *Sustainable Energy, Environmental Policy, and States' Rights: Discerning the Energy Future Through the Eye of the Dormant Commerce Clause*, 12 N.Y.U. ENVTL. L. J. 507 (2004) (discussing the incentives of renewable portfolio standards and system benefit charge trust funds in the states).
[91] *See infra* Part IV.C. *See generally* Steven Ferrey, *Nothing But Net: Renewable Energy and the Environment,* MidAmerican *Legal Fictions, and Supremacy Doctrine*, DUKE ENVTL. L. & POL'Y F. 1 (2003) (discussing regulation of net metering).
[92] CBO, PROSPECTS, *supra* note 61, at 21.

expense of transmission and distribution[93] to the consumer, stranded costs,[94] and any add-on regulatory costs or taxes.[95]

III. RELIABILITY OF TRADITIONAL POWER FOR BUSINESSES

The aftermath of the September 11 attacks has increased the level of scrutiny on the security of the United States' centralized electric supply and distribution system.[96] While experts worry about the security of large nuclear and fossil-fuel-fired power plants,[97] they view on-site distributed energy sources as more secure, more predictable, and more reliable than for the conventional fossil fuel counterparts.[98] While centralized generators shut down and trip off during system emergencies, most distributed generation resources remain fully operational.[99]

A typical electric customer experiences 2.5 hours of outage annually, with more than 80% of these failures attributable to distribution

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[93] *Id.* at 12, 16. On average, transmission and distribution costs add 25-50% to the delivered cost of power. *Id.* at 11. The average cost of transmission and distribution is deemed to be 2.4¢/kWh, adding approximately 30% to the average delivered price of electricity, which is 7.2¢/kWh. *Id.* at 12.

[94] FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 10:42.

[95] *Id.* at § 10:144, at 10-349 to -354.

[96] LOVINS ET AL., *supra* note 74, at 294.

[97] *Id.*

[98] *See id.* at 295-96.

> [F]luctuations in renewable energy flows are in this sense better understood and more predictable than those in the supply of conventional fuels and power. The methods used to forecast the path of the sun, or even next week's weather, are considerably more reliable than those which predict reactor accidents or Saudi politics.

Id. at 269.

> Thus renewable sources eliminate at a stroke two of the most fragile parts of today's energy system—the special localities (foremost among them the Persian Gulf) where rich deposits of fuel occur in the earth's crust; and the far flung links which carry raw fuels and deliver processed energy in copious but concentrated flows over long distances. In place of these power transportation systems, renewable sources rely on the automatic arrival of the natural energy flows, direct and indirect, which are distributed freely, equitably, and daily over the entire surface of the earth. This energy flow is not subject to embargoes, strikes, wars, sabotage, or other interferences, nor to depletion, scarcity, and exhaustion.

Id. at 268.

[99] *See id.* at 296.

system faults.[100] Outages and other significant power fluctuations cost the United States nearly $30 billion a year in 1999 in lost production, according to the U.S. Department of Energy.[101] A shortage of electricity has dire social and political consequences; a blackout has been equated to a natural disaster.[102]

Allowing rolling blackouts as a matter of policy, as occurred in California and ultimately led to the recall of Governor Davis and the election of Governor Schwarzenegger,[103] is a tremendously inefficient way to balance supply and demand differences.[104] During the 2001 rolling California blackouts, Silicon Valley businesses lost approximately $75 million a day.[105] The state economy lost $2.3 billion due to production cutbacks and lost wages during the rolling brownout in the first two weeks of January 2001.[106] The outages reduced gross state output by $21.8 billion and reduced household income by $4.6 billion more.[107]

The August 2003 blackout "cost the economy as much as $6 billion."[108] New York City Comptroller Bill Thompson estimated the twenty-nine hour August 2003 blackout "cost the city more than $1 billion in perishable goods and business—a $35 million-per-hour hit."[109] In addition to the comptroller's figure, the New York City Council estimated

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[100] *Id.* at 191.

[101] *See* KRISTINA HAMACHI LACOMMARE & JOSEPH H. ETO, LAWRENCE BERKELEY NAT'L LAB., U.S. DEP'T OF ENERGY, REP. NO. LBNL-55718, UNDERSTANDING THE COST OF POWER INTERRUPTIONS TO U.S. ELECTRICITY CONSUMERS (2004).

[102] Allen W. Williams, Jr., *The U.S. Electricity Sector: What After California?*, ELECTRICITY J., June 2001, at 51, 55.

[103] Thom Patterson, Genesis of Recall Rooted in California Energy Crisis (Oct. 7, 2003), http://www.cnn.com/2003/ALLPOLITICS/10/06/energy.crisis/.

[104] *See id.* at 51-53.

[105] Ann Deering, *The Expanding Energy Crisis*, RISK MGMT., May 1, 2001, at 10, 13-14.

[106] *Id.*

[107] AUS CONSULTANTS, IMPACT OF A CONTINUING ELECTRICITY CRISIS ON THE CALIFORNIA ECONOMY, at ii-iv (2001), *available at* http://www.caltax.org/member/taxletter/reference/AUSstudyfinal.pdf. *See also Study: Summer Blackouts Could Cost the State's Economy $21.8 Billion; 135,000 Jobs*, CAL-TAX DIG., June 2001, http://www.caltax.org/Digest/2001.06/06.2001.EnergyCrisis.02.htm (summarizing the study reported in IMPACT OF A CONTINUING ELECTRICITY CRISIS, *supra*).

[108] Lorraine Mirabella & Dan Thenh Dang, *Utilities Add Blackout to Woes,* BALT. SUN, Aug. 24, 2003, at 10. *See also Blackout to Cost Insurers $75 Million*, CHI. TRIB., Oct. 14, 2003, at 3. The Brattle Group estimated that the August 2003 blackout cost businesses $6 billion. *Id.* Given that less than ten percent of U.S. businesses have blackout insurance, businesses only recouped about $75 million of their losses. *Id.*

[109] Eric Herman et al., *New Yorkers Return to Work as Officials Assess Cost to Blackout*, Knight Ridder/Tribune News Service, Aug. 18, 2003.

$40 million in lost tax revenue,[110] and Mayor Bloomberg estimated $10 million in overtime pay for city workers, including extra police officers on patrol and sanitation crews that worked through the weekend to pick up spoiled food.[111] "The blackout cost the city's 22,000 eateries alone between $75 million to $100 million in wasted food and lost business," according to the New York State Restaurant Association.[112]

The cost of the 2003 blackout in Ohio alone was estimated at $1.1 billion by the Ohio Manufacturers Association.[113] Within seventy-two hours of the 2003 blackout, one New York-based law firm filed a class action suit against the Ohio utility, FirstEnergy, on behalf of all persons and corporations in the United States that lost energy.[114] The blackout cost Michigan about $1 billion, according to Governor Granholm,[115] where "[m]ore than 70 manufacturing companies shut down, and state and local authorities spent about $20 million on emergency services. . . ."[116] "The blackout also shut down water and sewage systems in Ohio, creating public health hazards for millions of people . . . ."[117]

Blackouts, like the one which occurred August 14, 2003, are not necessarily prevented by upgrading either of the primary generation or transmission sides of the power business.[118] In a major cascading blackout, additional generation would not have been sufficient to prevent the problem.[119] There were more than 250 then-operating generating units that tripped off to preserve the integrity of their generating

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[110] CNN.com, Power Returns to Most Areas Hit by Blackout (Aug. 15, 2003), http://www.cnn.com/2003/US/08/15/power.outage.
[111] Forbes.com, New York City Economy Loses $1 bln from Blackout (Aug. 18, 2003), http://www.forbes.com/home_europe/newswire/2003/08/18/rtr1060409.html.
[112] Sara Kugler, *NYC Calculates Blackout Losses May Have Topped $1 Billion*, Associated Press, Aug. 18, 2003, *available at* http://w4.stern.nyu.edu/news/news/2003/august/0818ap.html.
[113] Mark Niquette, *Blackout Cost to Ohio Factories Tops $1 Billion*, COLUMBUS DISPATCH (Ohio), Sept. 5, 2003.
[114] *See generally* Wolf Halderstein Adler Freeman & Herz LLP, *First Energy Corporation*, http://www.whafh.com/modules/case/index.php?action=view&id=220 (last visited Dec. 1, 2006).
[115] Brian Charlton, *Leaders Ask for Energy Bill*, THE STATE NEWS, Sept. 4, 2003, http://www.statenews.com/article.phtml?pk=18807 (last visited Dec. 1, 2006).
[116] Sumana Chatterjee, *Government Investigating Sharp Rise in Gas Prices*, CHARLOTTE OBSERVER, Sept. 4, 2003, at 1A.
[117] *Id.*
[118] *See* FERREY, THE LAW OF INDEPENDENT POWER, *supra* note 4, § 8.2.
[119] David White et al., *The 2003 Blackout Solution that Won't Cost a Fortune*, ELECTRICITY J., Nov. 2003, at 43, 46-47.

equipment when lines went down.[120] While reserve margins were adequate, the integrated grid as a whole was vulnerable.[121]

Upgrades in the transmission system do not necessarily prevent vulnerability during routine operation, terrorist events, or deliberate sabotage.[122] Currently, there are almost 30,000 circuit miles of high-voltage transmission lines (rated at 230 kV and above) in the northeast United States.[123] It is unclear precisely how to control against loss of transmission facilities. Whenever a transmission fault occurs, high-voltage breakers controlled by electronic sensors isolate the fault area to protect other facilities.[124] These high-voltage transmission facilities are not needed if there is distributed generation built close to the locus of power consumption, eliminating the dependent role of high-voltage transmission between generation and load.[125]

A power outage, even a short one, can have an expensive impact.[126] Brief power interruptions to businesses that rely on refrigeration or digital services can cause losses in the hundreds of thousands of dollars, or even millions if the outage affects pharmaceutical, brokerage and semi-conductor companies.[127] A one-hour blackout can cause millions of dollars in lost production, lost orders, or lost information.[128] The U.S. Department of Energy reports costs for power outages for communication-dependent businesses as: cellular communications, $41,000/h; telephone ticket sales, $72,000/h; airline reservations,

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[120] U.S. DEP'T OF ENERGY, IS OUR POWER GRID MORE RELIABLE ONE YEAR AFTER THE BLACKOUT? (2004), *available at* http://www.eere.energy.gov/state_energy_program/feature_detail_info.cfm/fid=32.
[121] *Id.*
[122] *See* White et al., *supra* note 119, at 46-48. *See also* North American Electricity Reliability Council, http://www.nerc.com (last visited Dec. 1, 2006).
[123] White et al., *supra* note 119, at 46.
[124] *Id.* at 47.
[125] *See id.* at 48.
[126] JOEL N. SWISHER, CLEANER ENERGY, GREENER PROFITS: FUEL CELLS AS COST-EFFECTIVE DISTRIBUTED ENERGY RESOURCES 21 (2002).
[127] *Id.* at 22.
[128] U.S. DEP'T OF ENERGY, STRATEGIC PLAN FOR DISTRIBUTED ENERGY RESOURCES 7 (2000). This study estimates that the value of a one-hour blackout to a brokerage firm is $6.5 million. *Id.* At this cost, the reliability value of distributed generation more than justifies its capital cost. This is because that level of reliability cannot be obtained at any price from the centralized utility grid. There are no substitutes for this. Therefore, the proper trade-off is the loss from disruption and this value should be added to the cost of not having distributed generation.

$90,000/h; credit card operations, $2.58 million/h; and brokerage operations, $6.48 million/h.[129]

IV. STATE INCENTIVES FOR COMPANIES TO ADOPT RENEWABLE OR DISTRIBUTED TECHNOLOGIES

A. *The System Benefit Charge and Trust Fund*

The system benefits charge is a tax or surcharge mechanism for collecting funds from electric consumers, which can then support a range of activities.[130] In order to support demand-side management or renewable resources, funds are collected through a non-bypassable system benefits charge to users of electric distribution services.[131] The money raised from the system benefits charge is then used to "buy down" the cost of power produced from sustainable technologies, so that they can compete with more conventional technologies.[132] The overall design of the system is to allow electric utilities to recover certain costs from all retail electricity customers.[133]

Fourteen states have established renewable energy subsidy programs funded by system benefit charges that, between 1998 and 2012, should raise approximately $3.4 billion.[134] Approximately half of the amount collected—at least $135 million per year—comes just from

[129] R. COWART ET AL., NATIONAL RENEWABLE ENERGY LABORATORY, NREL/SR-560-32498, STATE ELECTRICITY REGULATORY POLICY AND DISTRIBUTED RESOURCES: DISTRIBUTED RESOURCES AND ELECTRIC SYSTEM RELIABILITY 10 (2002), *available at* http://www.nrel.gov/docs/fy03osti/32498.pdf (*quoting* NAT. RENEWABLE ENERGY LAB., U.S. DEP'T OF ENERGY, DISTRIBUTED ENERGY RESOURCE PROGRAM AND STRATEGIC PLAN (2000)).

[130] These activities could include energy efficiency programs, renewable energy projects, and low income customer assistance. The activities supported might range from research and development to pilot projects to the implementation of mature technologies. TELLUS INSTITUTE & STEVEN FERREY, SUSTAINABLE ELECTRICITY FOR NEW ENGLAND: DEVELOPING REGULATORY AND OTHER GOVERNMENTAL TOOLS TO PROMOTE AND SUPPORT ENVIRONMENTALLY-SUSTAINABLE TECHNOLOGIES IN THE CONTEXT OF ELECTRIC INDUSTRY RESTRUCTURING 33 (1996).

[131] Mark Bolinger et al., *States Emerge As Clean Energy Investors: A Review Of State Support For Renewable Energy*, ELECTRICITY J., Nov. 2001, at 82, 82.

[132] *Id.* at 82-83.

[133] *Id.*

[134] *Id.* at 83 (noting that those 14 states are California, Connecticut, Delaware, Illinois, Massachusetts, Montana, New Jersey, New Mexico, New York, Ohio, Oregon, Pennsylvania, Rhode Island and Wisconsin).

California.[135] The funding levels range from \$0.07/MWh in Wisconsin, up to almost \$0.6/MWh in Massachusetts.[136] The funds are disbursed as either investments, grants, other subsidies, or research and development grants by the funding agency.[137] Most only provide assistance to new projects and not existing renewable projects.[138]

"Normalizing all incentives to their 5-year production incentive equivalent" (using a 10% discount rate), states have subsidized large-scale renewable energy projects in a range of 0.l-7¢/kWh.[139] "Wind power has been a major beneficiary of these subsidies."[140] The subsidy level in California, Illinois, Pennsylvania, and Rhode Island ranges from 0.59-1.95¢/kWh for wind and hydroelectric projects, and from 0.11-0.57¢/kWh for landfill gas projects.[141] Table 1 shows state adoption.[142]

B. Renewable Resource Portfolio Requirements

Portfolio standards will more efficiently promote the renewable power industry than renewable trust funds.[143] Portfolio standards require that certain electricity sellers and buyers maintain a percentage of designated, clean resources in their wholesale supply mix.[144] Market participants must satisfy portfolio standards as efficiently as possible.[145] Trust funds are contractually obligated to create a discretionary gift program.[146] Portfolio standards require participants to take initiative and operate efficiently; renewable projects take as little action as possible while still conforming themselves to funding criteria.[147] Political manipulation of trust fund cash flows also is possible, and withdrawing

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[135] *Id.* (noting that "Connecticut, Massachusetts, and New Jersey are the next largest funds, each collecting on average between \$20 and \$30 million per year.").
[136] *Id.* at 83.
[137] *See id.* at 85.
[138] *Id.*
[139] MARK BOLINGER ET AL., CLEAN ENERGY FUNDS: AN OVERVIEW OF STATE SUPPORT FOR RENEWABLE ENERGY, at ix (2001), *available at* http://www.osti.gov/energycitations/servlets/purl/783499-FqqXYE/native/783499.pdf.
[140] Bolinger et al., *supra* note 131, at 86.
[141] BOLINGER ET AL., *supra* note 139, at 26.
[142] *See infra* tbl.1.
[143] *See* Ferrey, *Power Future*, *supra* note 74, at 285-86.
[144] *Id.*
[145] *Id.*
[146] *Id.*
[147] *Id.*

trust funds for general budget purposes has occurred already in Massachusetts and elsewhere.[148]

Portfolio standards are flexible so that market competition and innovation guide conformity.[149] Certain technologies can be included in the renewables definition, or certain subgroups of technologies can be targeted for inclusion at distinct levels.[150] Conditioning retail sale licensure on conformity makes the standards self-enforcing.[151] Excess credits are fungible; noncompliant retailers can purchase surplus credits at a market rate from those who overachieve the standard.[152] Resource portfolio requirements do not place either wholesale or retail competitors at a disadvantage.[153]

Some aspects of the renewable portfolio standards programs mirror provisions of the Kyoto Protocol, which the United States has notably declined to ratify.[154] The Protocol's Clean Development Mechanism ("CDM") allows projects that reduce greenhouses gases in developing nations to earn Certified Emission Reductions ("CER") for each ton of CO_2-equivalent of GHG reduced.[155] Those CERs are then traded or sold to activities in Annex I developed countries which increases that country's emission cap allocated in the Protocol.[156]

A second mechanism for compliance is Joint Implementation ("JI") where developed nation signatory parties can implement projects

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[148] *Id.*.
[149] *Id.*
[150] *Id.*
[151] *Id.*
[152] *Id.*
[153] *Id.*
[154] Kyoto Protocol to the United Nations Framework Convention on Climate Change, Dec. 10, 1997, 37 I.L.M 22 (1998) [hereinafter Kyoto Protocol], *available at* http://unfccc.int/resource/docs/convkp/kpeng.pdf. The Kyoto Protocol was adopted in 1997 at the third session of the Conference of the Parties ("COP3") to the United Nations Framework Convention on Climate Change ("UNFCCC") in Kyoto, Japan. For six greenhouse gases ("GHG") that are suspected of causing global warming, principally including carbon dioxide (CO_2) and methane (CH_4), major developed countries (called the Annex I parties) have targets for reduction of these GHGs in the period 2008-2012. One hundred sixty-two countries ratified the Protocol. The Kyoto Protocol received subsequent national adoption by fifty-five percent of Annex I party signatories, notably excluding the U.S., by February 2005 and then entered into effect. Most countries have committed to achieving an eight percent reduction in CO_2 below 1990 levels, although the European Union measures their reduction as a weighted overall average for all the European Union countries.
[155] *Id.* art. 12.
[156] *Id.* art. 12, para. 3(b).

in their or other Annex I nations that remove GHGs or create additional carbon sinks, which then is quantified in an Emission Reduction Unit ("ERU").[157] An ERU transfers a unit of allowed carbon emissions from a selling country's cap to the purchasing country.[158] Unlike a CDM CER, which creates an additional emission unit added to the cap, a JI project transfers a credit under the existing cap from one nation to another nation.[159] Thus, the emission cap of any country includes assigned Kyoto credit units plus removal units ("RMU") from forestation projects that remove CO_2 from the atmosphere, plus JI ERUs and CDM CERs.[160]

Carbon reduction projects are suggested and implemented by a variety of private entrepreneurs who try to create CERs at less capital cost than the revenue stream they generate. For-profit entities have become project proponents and traders in this new market. Once a project passes Executive Board review, it becomes a prototype for subsequent and similar projects.[161] CERs are only created for projects that reduce GHGs in excess of the business-as-usual baseline emissions of one of the six regulated GHGs. The manner by which a methodology estimated baseline carbon emissions is critical to its approval. Especially in developing nations, the baseline of existing carbon emissions is subject to some discretionary interpretation. The verification stage of the CDM process is meant to try to adjust the crediting mechanism with the carbon reduction reality of the given project. While monitoring is required, it can vary.

As states deregulate their retail electric sectors, they have implemented renewable portfolio ("RP") standards and/or trust funds.[162] Twelve states have elected RP standards.[163] Each defines an eligible renewable resource differently. The diverse pattern of "renewable" resources included under state definitions is set forth in Table 2.[164]

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[157] *Id.* art. 3, para. 10-12.
[158] *Id.*
[159] *Id.*
[160] *Id.* at art. 12. CDM projects have to be approved by the designated national authority in the developing nation where the project is sited, validation by an independent entity chartered under the Protocol, registered and approved after review by the Executive Board of the CDM, and later verified and certified when emission reductions are achieved.
[161] *Id.* art. 12.
[162] *Id.*
[163] *See infra* tbl.1.
[164] *See infra* tbl.2.

C. *State Net Metering*

Where the electric consumer generates its own electricity on-site, the concept of net metering[165] may be applicable. Net metering, or net billing, is the cornerstone of state energy policy to encourage private investment in distributed generation resources.[166] Under net billing, the customer who utilizes an alternate (typically renewable) energy production system connects with the utility grid employing a bi-directional single meter.[167]

Under a state's net metering policy, electric utility meters are designed and allowed by law to spin either forward or backward.[168] The direction of rotation depends upon who supplies the electricity at a certain instant as reflected in the net electricity flow.[169] For example, if a generator of exportable electricity also owns and operates a solar photovoltaic panel, the meter would run backwards, signifying an export of power to the electric utility provider during daylight hours when the solar panels were providing the customer-generator with excess electricity.[170] This surplus electricity would enter the grid with the electricity generated by the utility and enable the utility to sell it to another consumer along the transmission line.[171] Conversely, the solar photovoltaic panel would not generate power at night and the customer would purchase electricity from the generating utility, thus causing the meter to rotate forward in the conventional direction reflecting a sale to the customer.[172]

The process of net metering balances and nets the electricity flows at the end of the billing period. A net gain of electricity sold to the

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[165] Although the term "net metering" is generally used to refer to this process, states vary in their descriptions of this concept, using such phrases as "net metering," "net billing," "net energy metering," "net energy billing," "parallel billing," "reverse direction metering," and "distributed generation." In this paper the phrase "net metering" will refer to all of the different terms for the same concept.

[166] *See* Ferrey, *Power Future, supra* note 74, at 286.

[167] *Id.*

[168] *Id.*

[169] *Id.* States that have adopted net metering policies lay out the definition of net metering in statutes and regulations. For example, New Hampshire's public utilities statute defines net metering as follows: "'net energy metering' means measuring the difference between the electricity supplied over the electric distribution system and the electricity generated by an eligible customer-generator which is fed back into the electric distribution system over a billing period." N.H. REV. STAT. ANN. § 362-A:1-a(III-a) (2006).

[170] *See* Ferrey, *Power Future, supra* note 74, at 286.

[171] *See* FERREY, THE LAW OF INDEPENDENT POWER, *supra* note 4, § 4:27.

[172] *Id.*

consumer becomes an amount owed to the utility, and a net loss of electricity bought by the consumer becomes an amount owed by the customer. If the customer-generator's electricity production fell below its consumption, the utility company would bill the customer for the difference. If the customer-generator produced more electricity than it required, this excess electricity would be effectively banked for future credit in a form determined by the state's net metering law.

On March 28, 2001 the Federal Energy Regulatory Commission ("FERC")held that state net metering decisions were not preempted by Federal law.[173] In its holding, FERC held that "no sale occurs when an individual homeowner or farmer (or similar entity . . .) installs [distributed] generation and accounts for its dealings with the utility through the practice of netting."[174] This surprising decision appeared to contradict multiple FERC precedents when it upheld the state's jurisdiction over these types of net metering transactions, removed FERC jurisdiction, and deemed a change of title to power not to constitute a "sale."[175] FERC ultimately held that "no sale occurs when an individual installs [distributed] generation and accounts for its dealings with the utility through the practice of netting."[176] Thus FERC ignored the physical reality of the transfer of the electrons.

Forty U.S. states have adopted this relatively simple concept,[177] and as a result, each of these states has promulgated its own particular statutes and regulations.[178] The development of net metering implemen

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[173] *See* MidAmerican Energy Co., 94 F.E.R.C. ¶61, 340 (2001). In March 2001, MidAmerican Energy Company challenged before FERC the state of Iowa's regulations directing MidAmerican "to interconnect with three Alternate Energy facilities and to offer net billing arrangements to those facilities." *Id.* ¶61, 340, at 62,261. MidAmerican also requested a declaratory order that federal law preempted these regulations. *Id.* "MidAmerican asked the Commission to undertake enforcement action against the Iowa Board, or to issue a declaratory order" that the final orders of the Iowa Board are preempted by PURPA. *Id.*

[174] *Id.* at 62,263.

[175] *Id.*

[176] *Id.*

[177] *See* Interstate Renewable Energy Council, "Connecting to the Grid" Project: State and Utility Net-Metering Rules and Programs, http://www.irecusa.org/connect/net_metering .pdf (last visited Dec. 1, 2006). The first 30 states to adopt net metering before the *MidAmerican* decision were: Arizona, California, Colorado, Connecticut, Delaware, Hawaii, Idaho, Indiana, Iowa, Maine, Maryland, Massachusetts, Minnesota, Montana, Nevada, New Hampshire, New Jersey, New Mexico, New York, North Dakota, Ohio, Oklahoma, Oregon, Pennsylvania, Rhode Island, Texas, Vermont, Virginia, Washington and Wisconsin.

[178] *See* Database of State Incentives for Renewables & Efficiency, Summary Tables: Net

tation among the states occurred in two phases.[179] The enactment of the Public Utility Regulatory Policy Act ("PURPA") in the early 1980s spurred several states to adopt net metering policies.[180] More recently, some states implemented net metering in response to the proliferation of deregulation in the electric utility industry.[181]

While Minnesota was the first state to enact net metering, between 1980 and 2000, three dozen other states adopted some form of net metering.[182] They are displayed in Table 3.[183] For interpreting this data, FERC defines avoided costs as "the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[184]

Electricity cannot be stored efficiently.[185] If not consumed instantly, it is grounded and lost.[186] It has no shelf life.[187] Its value fluctuates dramatically by more than 200 percent across the hours in a typical day.[188] Therefore, a distribution generator or other seller exchanging power *to* the utility after midnight, when that power has its least value and may not be capable of resale and thus valueless, does not have the same market value as a distribution generator taking power *from* a utility at noon

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Incentives for Renewable Energy, http://www.dsireusa.org/summarytables/reg1.cfm (follow the "Net Metering" hyperlink) (last visited Dec. 1, 2006) [hereinafter DSIRE Net Metering Summary Table]; *see also* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4*,* § 4:25.

[179] *Id.*

[180] *See* DSIRE Net Metering Summary Table, *supra* note 178.

[181] *See id.*

[182] *See id.*

[183] *See infra* tbl. 3.

[184] 18 C.F.R. § 292.101(b)(6) (2006). *See* Seth M. Colton & James W. Brehl, *Cogeneration—-The Small Facility Perspective in Minnesota,* 11 WM. MITCHELL L. REV. 477, 480-84 (1985). It appeared that the Minnesota statute was clear that a customer-generator was only entitled to receive the utility's avoided cost for the excess electricity provided. *Id.* at 484-85. Originally, the Minnesota Public Utilities Commission ("MPUC") rules provided that a QF with a capacity of less than 20 kilowatts would be compensated at the lowest retail rate and a QF with a capacity of 20-40 kilowatts would be compensated at the utility's avoided cost. *Id.* at 485. The MPUC rule that provided for these alternative rates was subsequently amended to provide for the current rates as described above. *Id.* at 485-86. *See also* MINN. STAT. § 216B.164(3) (2005); MINN. R. 7835.3300 (2006).

[185] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, § 2:20.

[186] *See* STEVEN FERREY, ENVIRONMENTAL LAW 501 (3rd ed.2004).

[187] *Id.*

[188] *See, e.g.*, ISO NEW ENGLAND INC., HOURLY HISTORICAL DATA POST-MARKET: MAY 1999-FEB 2003, http://www.iso-ne.com/markets/hstdata/hourly/his_data_post/index.html (last visited Dec. 1, 2006) (showing hourly price fluctuations in New England).

when the marginal cost of power is high.[189] Yet, net metering values each transaction at the same rate.[190] In either direction through the retail meter, the electrons are accounted at the retail sale rate.[191]

V. UTILITY DISINCENTIVES TO COUNTER DISTRIBUTED GENERATION AT BUSINESS SITES

A. Business Power Grid Access

The 2003 Congressional Budget Office evaluation of distributed generation concluded that hindrances to cost-effective distributed generation could be diminished without compromising other important social goals by:

- "Ensur[ing] access to the grid for distributed generators under uniform technical and contractual terms and charges for interconnection that are based on true economic costs. . . ."[192]
- Establishing fair prices for sale of power to the grid and stand-by service back to distributed generators "consistent with utilities' wholesale hourly costs to deliver power to different locations. . . ."[193]
- Establishing uniform air emission permitting, land use and building code requirements that accommodate the role of distributed generation.[194]

The overlap of state, federal and local authority over environmental, economic and regulatory matters affecting electric power complicates

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[189] *See id.*
[190] Green Power Network, Net Metering Policies, http://www.eere.energy.gov/greenpower/markets/netmetering.shtml (last visited Dec. 1, 2006).
[191] *See id.*
[192] CBO, PROSPECTS, *supra* note 61, at 29. Several states, such as New York and Texas, have adopted interconnection standards for smaller distributed generators up to 150 kW. *Id.* at 30. FERC is developing "procedures and agreements for interconnection and parallel operation of [distributed] generators and utility transmission systems." *Id.* at 30. *See also* Standardization of Small Generator Interconnection Agreements and Procedures, 67 Fed. Reg. 54,749 (proposed Aug. 16, 2002).
[193] CBO, PROSPECTS, *supra* note 61, at 29.
[194] *Id.*

this equation.[195] Grid protection requirements can impose time-consuming and expensive burdens on each individual on-site distributed generator that remains connected to the grid for parallel operation.[196] The National Renewable Energy Laboratory documented several cases in which utilities insisted on duplicative additional equipment that was already employed in the packaged distributed generation systems they used.[197] The utilities' interconnection requirements often caused abandonment of planned distributed energy projects that were competitive to utility centralized power supply.[198]

When distributed generators use fossil technologies without cogenerating thermal energy, and thus do not become QFs under PURPA,[199] they have no right to sell power back to the utility unless the state has adopted a net metering or similar requirement. Even when the state has adopted such a requirement, in many cases the right to resell power back to the utility is limited to certain renewable distributed generators of a particular small size.[200] Where there is no right for certain particular distributed generators to sell power back to the utility, this provides economic disincentives to efficient operation of the distributed generator to coincide with regional electric system peak requirements.[201] Distributed generators that do not see pricing that truly reflects the value of their output to the grid may remain idle when they could help grid requirements.[202] Because many state regulatory commissions disregard distributed power, or at least do not evaluate all generating assets in an integrated fashion, many of the incentives provided to regular utilities are counterposed to incentives that would

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[195] *Id.*
[196] *Id.* at 23. "[A]dditional site-specific equipment may include voltage regulators, frequency synchronizers, isolation devices, monitoring devices, and network protection devices." *Id.* at 24. While specialized studies for individual operators are often required by utilities, on-site generators argue for a streamlined standard that would apply to all situations and eliminate the need to pay for individualized and time-consuming studies. *Id.*
[197] *See* NAT'L RENEWABLE ENERGY LAB., U.S. DEP'T OF ENERGY, MAKING CONNECTIONS: CASE STUDIES OF INTERCONNECTION BARRIERS AND THEIR IMPACT ON DISTRIBUTED POWER PROJECTS 9-10 (2000).
[198] *See id.* at 6.
[199] 16 U.S.C. § 824a-3 (2001).
[200] *See infra* tbl. 3.
[201] *See* NAT'L RENEWABLE ENERGY LAB., *supra* note 107, at 37.
[202] *Id.* at 68.

make the entire system, including distributed generators, operate in an economically efficient, integrated least-cost manner.[203]

B. Utility Stand-By Power Sales to Businesses

Electric utilities must make necessary "backup,"[204] "interruptible,"[205] "maintenance,"[206] or "supplemental"[207] power available to QFs.[208] Businesses generating their own power with cogeneration, renewables, or waste products, can qualify as QFs.[209] Pursuant to PURPA, such transactions must be made nondiscriminatorily and be "just and reasonable and in the public interest."[210] Essentially, any power sale to a QF that does not reflect sound economic principles must have a cost basis justification.[211]

Under federal law, price rates for backup and standby power must not be discriminatory towards business QFs that generate their own power or have third parties generate their power at their facilities.[212] As a result of the FERC's holding in *Alcon*,[213] businesses are allowed to

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[203] *Id.* at 36.

[204] "Back-up power" is defined as "electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility." 18 C.F.R. § 292.101(b)(9) (2005).

[205] "Interruptible power" is "electric energy or capacity supplied by an electric utility [to a QF] subject to interruption by the electric utility under specified conditions." 18 C.F.R. § 292.101(b)(10).

[206] "Maintenance power" is "electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility." 18 C.F.R. § 292.101(b)(11).

[207] "Supplementary power" is power or "capacity supplied by an electric utility" to a QF to augment self-generated electricity. 18 C.F.R. § 292.101(b)(8).

[208] 18 C.F.R. § 292.305(b)(1) (2005).

[209] *See id.* §§ 292.201-207.

[210] *Id.* § 292.305(a)(1).

[211] *Id.* § 292.305(a)(2).

[212] *See id.*

[213] Alcon, Inc., 32 F.E.R.C. ¶61,247, 61,576 (1985). The FERC reversed its prior decision and found upon rehearing that the host customer of a third-party-owned QF power endeavor was eligible to receive standby power. The relevant parties, two topping cycle cogeneration facilities with a combined capacity of 1.8 MW, were involved in the lease agreement. *Id.* at 61,576. O'Brien, the installer and operator of the cogeneration equipment, leased the equipment to Alcon, the site owner and consumer of the energy produced. *Id.* at 61,576-77. Alcon's argument that it was legally allowed to purchase backup power directly from the local electric utility was predicated on the assertion that it owned the equipment. *Id.* at 61,576. However, if O'Brien, as the owner of the QF facility, purchased backup power, it was prohibited from reselling or retailing that

receive backup power from the utility notwithstanding their acquiring primary power from a private third party.[214] In some jurisdictions, these rates are set and standardized, but in others they must be negotiated with the utility.[215] There are several factors, outlined by FERC, that utilities may consider when determining standby rates.[216]

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backup power to Alcon because such an action would cause it to be classified as an electric utility rather than a QF. *Id.* at 61,579. The FERC did not initially find the lease/purchase agreement between the parties to be persuasive in demonstrating that Alcon and O'Brien jointly owned the equipment. *Id.* at 61,577. In addition, FERC found that the entire Alcon pharmaceutical facility did not qualify as a cogeneration facility. *Id.* at 61,577-78. As a result of the FERC's initial findings, O'Brien and PREPA, O'Brien's back up power supplier, were prohibited from selling backup power to Alcon. *Id.* at 61,579. Commissioner Stalon vigorously dissented from this position on the grounds that the form of corporate ownership selected should not bias the right to backup power for a QF. *Id.* at 61,581-87. On rehearing, a wave of protests from QFs, states, and the natural gas industry, combined with a desire to encourage cogeneration, prompted the FERC to adopt Stanlon's dissent as the majority position and reverse its decision. *Id.* at 61,118-20. Alcon, Inc. (*Alcon II*), 38 F.E.R.C. ¶61,042, 61,118 (1987), *petition for review denied sub nom.* Puerto Rico Elec. Power Auth. V. FERC, 848 F.2d 243 (D.C. Cir. 1988) (stating that a broad reading of which entities may receive the benefits of QFs fulfills congressional purpose). FERC found that its previous order effectively denied backup power to entities which consume QF power as a result of their financial and legal structure. *Id.* at 61,119. This effect contradicts the legislative history of PURPA, which conveys a purpose of liberally affording a right to backup power without consideration of ownership and use. *Id.* at 61,119-20. Although Alcon did not own the equipment, they consumed the energy output and contracted for an option to purchase the QF equipment at the end of the lease. *Id.* at 61,120. On rehearing, FERC's realigned majority found distinctions in ownership to be immaterial in this situation because the output of the QF was dedicated to Alcon for consumption. *Id.* Although the owner of the QF equipment and consumer of the QF energy output were distinct, the distinction was compelled by tax and financing advantages. *Id.*

[214] *Alcon II*, 38 F.E.R.C. at 61,120.

[215] *See id.*

[216] *See* Administrative Determination of Full Avoided Costs, Sales of Power to Qualifying Facilities, and Interconnection Facilities, 53 Fed. Reg. 9,331, 9,333 (proposed Mar. 22, 1988). These factors are:

> (i) The expected timing of forced outages of the qualifying facility, if there is any reason to expect they would not occur with random probability;
> (ii) The expected frequency of forced outages of the qualifying facility;
> (iii) The expected duration of forced outages of the qualifying facility;
> (iv) The expected demand placed on the supplying utility's generating resources in the event of a forced outage of the qualifying facility;
> (v) The expected cost of electrical energy associated with the capacity to be used to meet the demand in the event of a forced outage of the qualifying facility;

Utilities employ a variety of methodologies for standby rate design. The majority use a modification of a general service rate to price standby service.[217] A smaller number of utilities use complex analyses of costing and pricing analyses.[218] Stand-by service charges can raise a business's generation costs by up to twenty percent because the charges can be as high as $18.75/kWh/month.[219]

By arguing that, to a substantial degree, utility expenses scale with utility peak demand rather than with annual electricity sales, utilities are able to set high stand-by rates on distributed cogenerators needing back-up power.[220] Therefore, with a decrease in utility sales due to distributed generation, there is loss of revenue but no decrease in costs for peak demand services. The stand-by rate charge thus is posited to make a utility economically whole.

In a static environment this might be true, but with constantly growing U.S. electricity demand,[221] the justification for stand-by rates on distributed generation is less clear: any new surplus capacity created by businesses' self-generating power can help support the increasing annual demand of other consumers. "The ability of a distributed generator to [reduce] utility capacity is a function . . . of its coincident peak."[222] "Typically, the net reduction in utility peak resource utilization [attributable to a distributed generator] is usually only 50 to 90 percent of the

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> (vi) The costs, if any, associated with transmission and distribution facilities used to meet the demand resulting from a forced outage of the qualifying facility; and
>
> (vii) The terms of back-up service in regard to its position as firm or interruptible service, and the cost such terms of service imposed on the supplying utility.

Id.

[217] *See generally* EDISON ELECTRIC INST., STANDBY RATES: METHODS AND DESCRIPTIONS (1991).

[218] *Id.*

[219] *See* NAT'L RENEWABLE ENERGY LAB., *supra* note 197 at 22. The study concludes that variations in stand-by rates "demonstrate a lack of consistency and an absence of regulatory oversight of [stand-by] tariffs . . ." and "the lack of appropriate regulatory principles or standards . . . creates uncertainty." *Id.* at 23-24.

[220] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, at § 4:33, at4-96 to -101 (providing a description and comparison of utility stand-by rates).

[221] See Energy Information Administration, Electricity Supply and Demand Fact Sheet, http://www.eia.doe.gov/cneaf/electricity/page/fact_sheets/supply&demand.html (last visited Dec. 1, 2006).

[222] Sean Casten, *Are Standby Rates Ever Justified? The Case Against Electric Utility Standby Charges as a Response to On-Site Generation*, ELECTRICITY J. 58, 60 (2003).

rated power of the DG unit."[223] Conventional regulatory techniques do not credit a distributed generator with any rate reduction in transmission and distribution assets of the centralized utility system.[224]

C. *Exit Fees*

States regulate the free exit of corporate consumers from the electric system in drastically different ways.[225] On one extreme, states can, though non currently do, permanently ban the conventional utility retail service the network.[226] In order to curb certain forms of competition in the retail sector, a state can limit retail wheeling, the transmission of power across a utility's territory.[227] Another option for utilities is to impose "exit" fees on customers who switch to distributed generation and depart centralized service.[228] State electricity restructuring statutes vary as to whether they specifically address exit fees or ignore them completely.[229]

States also differ in their application of exemptions from exit fees: some fully exempt corporate self-generators, while others offer only conditional exemptions. Still other states affirmatively impose exit fees on self-generating consumers. Six states exempt new self-generation from all stranded costs or exit fees. Seven states do not exempt self-generation

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[223] *Id.* at 60. If distributed generation does not increase at a rate sufficient to fully offset increases in system electric demand, there are few stranded costs for the system as a whole attributed to existing distributed generation when existing generation capacity is freed and made available to serve increasing load in lieu of new centralized generation construction. *Id.* at 63. Once implemented, distributed generation is actually an asset cross-subsidizing the central utility system. *Id.* at 61-62. Therefore, a holistic look at societal impacts may not justify stranded costs imbedded in either exit fees or stand-by rates ascribed to distributed generation, as this may not take account of the benefits distributed generation has on constrained transmission and distribution investments. *Id.* at 63.

[224] *Id.* at 61. The author calculates that each kW of distributed generation on average eliminates the need for $1,300 of added construction of assets, primarily in the form of transmission and distribution assets, but also including substation assets. *Id.* at 61 (citing ARTHUR D. LITTLE, PRELIMINARY ASSESSMENT OF BATTERY ENERGY STORAGE AND FUEL CELL APPLICATIONS IN BUILDING APPLICATIONS (2000)). Many forms of distributed generation can be installed for less than $1,300/kW. *Id.* This savings accrues to all customers, not just those with distributed generation. *Id.* Therefore, there is a transmission and distribution subsidy to non-distributed generation customers by those who install distributed generation. *Id.* at 62.

[225] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, §10:45, 10-139 to -146.

[226] *Id.* at 10-140.

[227] *See* FERREY, THE NEW RULES, *supra* note 21, at Glossary.

[228] *See* FERREY, LAW OF INDEPENDENT POWER, *supra* note 4, §10:45, at 10-139 to -140.

[229] *See id.* at §10:45.

and impose exit fees, at least under certain conditions. Massachusetts and New Jersey conditionally allow self-generation without exit fees.[230] Connecticut imposed exit fees legislatively, only to have its regulatory agency back away administratively from enforcing such fees.[231] Pennsylvania imposes an exit fee only if the self-generation operates in parallel with the grid.[232]

1. No Exit Fees

Many states do not impose exit fees on departing cogenerators, instead adopting the deregulation approach. California, Maine, New York, and Ohio do not allow exit fees[233] and New Hampshire disfavors exit fees.[234] Texas does not impose exit fees on any facility unless it exceeds 10 MW.[235] Oregon, Rhode Island, and Vermont neither expressly impose or prohibit exit fees.[236] Thus, nine states allow companies to exit for self-generation without repercussions.

New Hampshire's disfavor of exit fees is conveyed in its restructuring legislation, which provides that "[e]ntry fees and exit fees are not preferred recovery mechanisms."[237] Maine's restructuring statute takes a similar approach and states:

> A customer who significantly reduces or eliminates consumption of electricity due to self-generation, conversion to an alternative fuel or demand-side management may not be assessed an exit or reentry fee in any form for the

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[230] *See infra* notes 249-58 and accompanying text.
[231] *See infra* notes 243-45 and accompanying text.
[232] *See infra* notes 246-48 and accompanying text.
[233] CAL. PUB. UTIL. CODE § 840E (2006), ME. REV. STAT. ANN. tit. 35-A, § 3209(3) (2005), N.Y. Pub. Serv. Comm'n Op. No. 96-8, Case No. 95-E-0172 (Mar. 29, 1996), OH. REV. CODE. ANN. § 4928.37 (A)(2)(b) (2006).
[234] *See infra* note 237 and accompanying text.
[235] *See infra* note 239 and accompanying text.
[236] OR. REV. STAT. § 757.607 (2006), R.I. GEN. LAWS § 39-1-27 (2006), VT. STAT. ANN. tit. 30, § 8003 (2006).
[237] N.H. REV. STAT. ANN. § 374-F:3(XII)(d) (2006). The statute further provides that "any recovery of stranded costs should be through a nonbypassable, nondiscriminatory, appropriately structured charge that is fair to all customer classes, lawful, constitutional, limited in duration, consistent with the promotion of fully competitive markets and consistent with these principles." *Id.*

> reduction or elimination of consumption or reestablishment of service with a transmission and distribution utility.[238]

Texas and some other states provide for the creation of various exemptions from the payment of exit fees. Since the 1999 passage of its deregulation legislation, Texas effectively authorizes an exit fee for new medium and large self-generation facilities by prohibiting any customer from utilizing an on-site self-generation system which exceeds 10MW in order to avoid stranded costs.[239]

Unlike Texas, Ohio specifically provides that the stranded cost transition charge only applies to service delivered over the central distribution system, and does not impose the charge on self-generated electricity that is both produced and consumed in Ohio.[240] It remains unclear whether this includes third-party on-site generation because self-generated electricity is undefined in the Ohio statute.[241]

2. Exit Fees

Some states, specifically Connecticut, Pennsylvania, and Maryland, impose some form of an exit fee on newly implemented self-generation practices. A Connecticut statute applies exit fees to operations that exit the system in order to use self-generation.[242] Although the Connecticut legislature issued a command to develop an exit fee structure for new self-generators,[243] the Connecticut Department of Public Utility Control ("DPUC") concluded that imposing exit fees would limit customer choice and consumer load management as well as increase costs discriminatorily against new self-generation.[244] The DPUC recommendations called for the prohibition of exit fees against self-generators of less than 2 MW or those employing renewable resources.[245]

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[238] ME. REV. STAT. ANN. tit. 35-A, § 3209(3) (2005).
[239] TEX. UTIL. CODE ANN. § 39.252 (Vernon 2005).
[240] OHIO REV. CODE ANN. § 4928.37(A)(2)(b) (2006).
[241] *Id.* § 4928.01(33).
[242] CONN. GEN. STAT. ANN. § 16-245w(b) (West 2005).
[243] *Id.* § 16-245w(d) (West 2005).
[244] CONN. DEP'T OF PUB. UTIL. CONTROL, DPUC REPORT TO THE GENERAL ASSEMBLY ON EXIT FEES 10 (1998).
[245] *Id.* at 9. The DPUC predicted that imposing a conservation exit fee on conserving self-generators, or a renewable trust fund exit fee on renewably powered self-generation, would have the perverse effect of discouraging the very technologies and measures that such fees, on their face, are designed to promote. *Id.*

In lieu of assessing an exit fee, Pennsylvania considers imposing a competitive transition cost that should be paid by the customer:

> [I]f a customer installs on-site generation which operates in parallel with other generation on the public utility's system and which significantly reduces the customer's purchases of electricity through the transmission and distribution network, the customer's fully allocated share of transition or stranded costs shall be recovered from the customer through a competitive transition charge.[246]

Although Pennsylvania appears to impose an exit fee, the statute only applies to self-generators that operate parallel to the utility.[247] On-site generation which does not utilize the central distribution lines avoids stranded costs in Pennsylvania. A facility that installs sufficient redundant power generation and ceases grid connection would therefore not be assessed exit fees or transition charges.[248]

3. Limited Exit at Own Risk

Another approach taken by some states is imposition of conditional exit fees based on the quantity of electricity that results from self-generation. Massachusetts, for example, promulgated a deregulation statute which instituted a conditional exit fee.[249] Under the Massachusetts statute, a customer is exempt from an exit fee if the state regulatory agency and the utility are given six months notice of its plan to (1) "install on-site cogeneration equipment, renewable energy technologies, [or] fuel cells;" or (2) obtain electricity "though the operation of, or [third-party] purchases from, on-site generation or cogeneration equipment."[250] The exemption is contingent on the installation meeting any one of the

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[246] 66 PA. CONS. STAT. ANN. § 2808(a) (West 2000).
[247] *Id.*
[248] In some cases, the self-generation equipment does not operate in parallel with that of the utility. Some consumers may opt to install oil-fired or other generation to provide backup power on-site and enable them to disconnect from the grid. Some self generators in the United States have done this, but this configuration is much more common where a grid-based source is unreliable or subject to frequent decreases in power, such as certain developing nations. Typically, the economic advantage of more reliable backup rate structures motivates the establishment of this structure.
[249] MASS. GEN. LAWS ANN. ch. 164, § 1G (West 2003).
[250] *Id.* § 1G(g).

following criteria: (a) the customer leaves the system and provides 10% or less of "the annual gross [power] revenues collected by its previous service provider in the year prior to the customer leaving the system;"[251] (b) "the customer reduces purchases through the operation of, or purchases from, onsite renewable energy technologies, fuel cells, or cogeneration equipment with a combined heat and power system efficiency of at least 50 per cent based upon the higher heating value of the fuel used in the system;"[252] or (c) "the customer reduces purchases through the operation of, or purchases from, an onsite generation or cogeneration facility of 60 kilowatts or less which is eligible for net metering."[253]

Effectively, Massachusetts does not hinder exit to on-site generation for any business for any type of technology if there is a gradual corporate exodus rather than a stampede. However, certain small net metered, efficient cogeneration, and renewable technologies are unconditionally protected from the threat of exit fees. At most, others pay only an exit fee proportionate to the amount exceeding the 10 percent cumulative system exodus cushion.[254] Now, almost a decade after deregulation, no corporate self-generator bears any exit fee charges.[255]

New Jersey's deregulation legislation[256] follows the model of the Massachusetts legislation, where exit fees are not applied to modest cumulative self-generation as long as it is not greater than 7.5% of prior

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[251] *Id.* § 1G(g)(i). In the event that two or more customers who represent in the aggregate at least 10 percent of the annual gross revenues collected by the previous service provider in the year prior to the initial exit from the system leave the same distribution system at any time within a rolling thirty-six month backward-looking period, "all such customers shall be subject to an exit charge based upon that portion of the annual gross revenues that exceeds the 10% threshold." *Id.* § 1G(g)(I). Such an exit fee is "prorated amongst customers who have left . . . the system based upon the proportion of annual gross revenues each [departing] customer represented within the total amount of gross revenues" exiting for self-generation. *Id.*

[252] *Id.* § 1G(g)(ii).

[253] *Id.* § 1G(g)(iii). "Except as provided in existing contracts or tariffs, the department and the utility shall not require more than six months notice of the customer's plans to install said equipment." *Id.* Massachusetts permits net metering of renewable and cogeneration customers of all rate classes that self-generate less than 60 kW. MASS. GEN. LAWS ANN. ch. 164, § 1G (West 2003). *See also* Mass. Dept of Telecomm. & Energy Order 97-11.

[254] *See id.* § 1(G)(g).

[255] Mass. Dept of Telecomm. & Energy Order 97-11.

[256] Electric Discount and Energy Competition Act, 1999 N.J. Sess. Law Serv. ch. 23 (West) (codified at N.J. STAT. ANN. §§ 48:3-49 to -98 (West 1998)).

centralized power sales.[257] Self-generation in existence prior to the statute's passage in 1999 is unconditionally exempt from exit fees.[258]

Many states have struggled with and resolved the conflict between the disincentive of exit fees and the promotion of distributed and renewable energy through free customer exit and entrance. This limited exit fee structure evidences a policy preference for decentralized and renewable power, but at the expense of using the rate base to cross-subsidize these technologies, which will have to support repayment of all utility stranded costs over fewer customers.

D. Permitting Distributed and Renewable Generation

For many on-site distributed generating facilities, which may burn fossil fuel or use renewable technology, the siting issue is not so much the difficulty of obtaining conventional environmental permits, but the complexities of interfacing smaller units into the utility grid and obtaining back-up power supplies when necessary.[259] The permits that may be required for large generation are illustrated in Table 4.[260] Of particular interest is that most on-site corporate-scale self-generation facilities avoid almost all of the state and federal approval requirements,

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[257] *See* N.J. STAT. ANN. § 48:3-77 (West 1998). Every customer's bill provides for a "shopping credit," which enables customers to directly compare the traditional utility supplier's prices to those of market alternatives. *Id.* §§ 48:3-51 to -52. An entire section of New Jersey's electricity deregulation legislation is dedicated to exit fees. Electric Discount and Energy Competition Act §28. Section 48:3-77 states:

> On-site generators that sell to off-site retail customers in this State shall be required to pay Societal Benefits Charges (SBC), Market Transition Charges (MTC), and Transition Bond Charges; existing on-site generators that sell only to on-site customers are exempt from paying SBC, MTC, and Transition Bond Charges; provides that on-site generator facilities, installed after the starting date of retail competition shall be subject to SBC, MTC, and Transition Bond Charges if the amount of generation from on-site generators has reduced the kilowatt hours distributed by an electric public utility to a level equal to 92.5 percent of the 1999 kilowatt hours distributed by the electric public utility; and provides that on-site generator facilities installed after the starting date of retail competition that do not cause such a reduction shall be exempt from paying the SBC, MTC, and Transition Bond Charges.

N.J. Stat. Ann. § 48:3-77.

[258] *Id.* § 48:3-77(d)(1).

[259] *See supra* notes 8-19 & accompanying text.

[260] *See infra* tbl. 4.

and many of the local ones.[261] As accessory users, unless there are significant air quality impacts from self-generation, the permitting process is very streamlined and straightforward.

CONCLUSION

The economics, reliability, and predictability of on-site renewable energy can be compelling. Moreover, under the Kyoto Protocol, which is not ratified by the U.S.,[262] the Regional Greenhouse Gas Initiative (RGGI) in eight Eastern states,[263] and the federal 1605(b) program,[264] corporations are under increasing pressure to limit their carbon emissions. Technical impediments and economics are not the major barriers to renewable power adaptation by businesses. The technology has evolved faster than the legal and regulatory infrastructure that supports the technology.

The impediments are regulatory, rather than technical. The problem manifests in disincentives such as high stand-by power rates, interconnection difficulties, and exit fees.[265] The countervailing financial benefits resulting from net metering and RPS renewable energy credits are not widely known by corporate decision makers. At the state level, it is a matter of facilitating corporate accessibility to on-site renewable energy options.

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[261] *Id.*
[262] Kyoto Protocol, *supra* note 154.
[263] *See generally* REGIONAL GREENHOUSE GAS INITIATIVE, MODEL RULE (2006), http://www.rggi.org/docs/model_rule_8_15_06.pdf. Connecticut, Delaware, Maine, New Hampshire, New Jersey, New York, and Vermont have agreed to implement this Model Rule. Regional Greenhouse Gas Initiative, Participating States, http://www.rggi.org/states.htm (last visited Dec. 1, 2006). *See* Memorandum of Understanding by Regional Greenhouse Gas Initiative 4-5 (Dec. 20, 2005), http://www.rggi.org/docs/mou_12_20_05.pdf.
[264] *See* Guidelines for Voluntary Greenhouse Gas Reporting, 70 Fed. Reg. 15,169 (Mar. 24, 2005) (to be codified at 10 C.F.R. pt. 300). Under the program pursuant to Section 1605(d) of the Energy Policy Act of 1992, companies can register or report their carbon emissions or carbon mitigation/sequestration. *Id.* at 15,170-71. These registered or reported carbon emissions are not presently tradable in any format pursuant to this program, but carbon credits can be registered and traded under a program administered by the Chicago Climate Exchange. *See* Chicago Climate Exchange, http://www.chicagoclimatex.com (last visited Dec. 1, 2006).
[265] *See supra* Part V.

TABLE 1

PORTFOLIO STANDARDS AND TRUST FUNDS IN VANGUARD STATES[266]

State Name	Renewable Energy Trust Fund	Portfolio Standards
Arizona		x
California	x	x
Connecticut	x	x
Delaware	x	x
Illinois	x	x
Iowa		x
Maine	x	x
Massachusetts	x	x
Minnesota	x	x
Montana	x	x
Nevada		x
New Jersey	x	x
New Mexico		x
New York	x	x
Ohio	x	
Oregon	x	
Pennsylvania	x	x
Rhode Island	x	x
Texas		x
Wisconsin	x	x

[266] This table is modified from a table appearing in Steven Ferrey, *Constitutional Barriers Confronting State Renewable Energy Programs*, ENERGY COMM. NEWSL. (Am. Bar Ass'n.), June 2006, at 1, 4.

TABLE 2

"RENEWABLE" RESOURCES AS DEFINED IN STATE STATUTES[267]

State	Solar	Wind	Fuel Cell	Methane/ Landfill	Biomass	Trash-to-Energy
California	x	x		x	x	x
Connecticut	x	x	x	x	x	x
Illinois	x	x			x	x
Maine	x	x	x		x	x
Massachusetts	x	x	x	x	x	x
Nevada	x	x	x			
New Jersey	x	x	x	x	x	x
New Mexico	x	x	x	x	x	x
New York	x	x				x
Oregon	x	x		x		x
Pennsylvania	x	x		x	x	x
Rhode Island	x	x		x	x	x
Texas	x	x		x	x	x
Wisconsin	x	x	x		x	x

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267 This table is reprinted from Steven Ferrey, *Constitutional Barriers Confronting State Renewable Energy Programs*, ENERGY COMM. NEWSL. (Am. Bar Ass'n.), June 2006, at 1, 5.

TABLE 3

NET METERING IN 36 STATES[268]

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
Arizona	Renewables and Cogeneration	All customer classes	≤100kW	NEG purchased at avoided cost	Ariz. Corp. Comm'n, Decision No. 52,345 (July 27, 2001).	None
Arkansas	Renewables, fuel cells and microturbines	All customer classes	≤25 kW residential ≤100kW Commercial	Monthly NEG granted to utilities	ARK. CODE ANN. § 23-18-603 (2006).	None
California	Solar and wind	All customer classes	≤1000 kW	Annual NEG granted to utilities	CAL. PUB. UTIL. CODE § 2827 (2006).	None
Colorado	Wind and Photovoltaic	Varies	≤10kW	NEG carried forward month-to-month	Co. Pub. Util. Comm'n, Decision No. C96-901 (Aug. 21, 1996).	NA
Connecticut	Renewables,	Residential	≤50kW co-	NEG purchased at	CONN. GEN. STAT. §	None

[268] This table is modified from a table appearing in Steven Ferrey, *Nothing but Net: Renewable Energy and the Environment, MidAmerican Legal Fictions, and Supremacy Doctrine*, 14 DUKE ENVTL. L. & POL'Y F. 1, 55 (2003).

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
	cogeneration and fuel cells	customers	generation ≤100kW renewables	avoided cost	16-243 (2006).	
Delaware	Renewables	All customer classes	≤25kW	Not Specified	DEL. CODE ANN. tit. 26, § 1014(d) (2006).	None
Georgia	Solar, wind, fuel cells	Residential and Commercial	≤10kW residential ≤100kW commercial	Monthly NEG or total generation purchased at avoided cost or higher rate if green priced	GA. CODE ANN. §§ 46-3-50 to -3-56 (2006).	0.2% of annual peak demand
Hawaii	Solar, wind, biomass, hydroelectric	Residential and small commercial	≤50kW	Monthly NEG granted to utilities	HAW. REV. STAT. §§ 269-101 to -124 (2006).	0.5% of annual peak demand
Idaho	Renewables and cogeneration	Residential and small commercial (Idaho Power only)	≤100kW	Monthly NEG purchased at avoided costs	Idaho Pub. Util. Comm'n, Order No. 26,750 (Jan. 22, 1997).	None
Illinois	Solar and wind	All customer classes; Commonwealth Edi-	≤40kW	NEG purchased at avoided cost monthly plus annual payment to bring payment to	Commonwealth Edison tariff special billing experiment	0.1% of annual peak demand

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
		son only		retail rate		
Indiana	Renewables and cogeneration	All customer classes	≤1000kWh/ month	Monthly NEG granted to utilities	170 IND. ADMIN. CODE 4-4.1-1 to -11 (2006).	None

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
Iowa	Renewables and cogeneration	All customer classes	No limit per system	Monthly NEG purchased at avoided cost	IOWA ADMIN. CODE r. 199-15.1 to -15.17 (2006).	105 MW
Kentucky	Solar, hydro-electric, wind	All customer classes	≤10kW	Annual NEG granted to utilities	Ky. Pub. Util. Comm'n, Order No. 2001-D0303 (Mar. 14, 2002).	First 25 customers for each utility
Maine	Renewables and fuel cells	All customer classes	≤100kW	Annual NEG granted to utilities	ME. REV. STAT. ANN. tit. 35-A, § 3210 (2006).	None
Maryland	Solar only	Residential and schools only	≤80kW	Monthly NEG granted to utilities	MD. CODE ANN., PUB. UTIL. COS. § 7-306 (2006).	0.2% of 1998 peak
Massachusetts	Renewables and cogeneration	All customer classes	≤60kW	Monthly NEG purchased at avoided cost	MASS. GEN. LAWS ch. 164, § 1G (2006).	None
Minnesota	Renewables and cogeneration	All customer classes	≤40kW	NEG purchased at utility average retail energy rate	MINN. STAT. § 216B.164(3) (2006).	None
Montana	Solar, wind and hydro-electric	All customer classes	≤50kW	Annual NEG granted to utilities at the end of each calendar year	MONT. CODE ANN. § 6-8-601 (2006).	None
Nevada	Solar and wind	All customer classes	≤10kW	NEG purchased at avoided cost	NEV. REV. STAT. § 704.766 (2006).	None

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
New Hampshire	Solar, wind and hydroelectric	All customer classes	≤25kW	NEG credited to next month	N.H. REV. STAT. ANN. §§ 362-A:1 to :9 (2006).	0.05% of utility's annual peak
New Jersey	PV and wind	Residential and small commercial	≤100kW	Annualized NEG purchased at avoided cost	N.J. STAT. ANN. § 48:3-49 (2006).	0.1% of peak or $2M annual financial impact
New Mexico	Renewables and cogeneration	All customer classes	≤10kW	NEG credited to next month, or monthly NEG purchased at avoided cost (utility choice)	N.M. ADMIN. CODE tit. 17, §§ 9.571.1 to 571.17 (2006).	None
New York	Solar only	Residential only	≤10kW	Annualized NEG purchased at avoided cost	N.Y. PUB. SERV. LAW § 66-j (2006).	0.1% 1996 peak demand
North Dakota	Renewables and cogeneration	All customer classes	≤100kW	Monthly NEG purchased at avoided cost	N.D. ADMIN. CODE 69-09-07-09 (2006).	None
Ohio	Renewables, microturbines and fuel cells	All customer classes	No size limit	NEG credited to next month	OHIO REV. CODE ANN. § 4928.67 (2006).	1.0% of aggregate customer demand
Oklahoma	Renewables	All	≤100kW and	Monthly NEG	OKLA. ADMIN. CODE §	None

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
	and cogeneration	customer classes	≤25,000kWh/ year	granted to utility	165:35-29-1 (2006).	
Oregon	Solar, wind, fuel cell and hydroelctric	All customer classes	≤25kW	Annual NEG granted to low-income programs, credited to customer, or other use determined by Commission	OR. REV. STAT. § 757.300 (2006).	0.5% of peak demand
Pennsylvania	Renewables	Residential	≤10kW	NEG purchased at avoided cost	52 PA. CODE § 57.34 (2006).	None
Rhode Island	Renewables and fuel cells	All customer classes	≤25kW	Annual NEG granted to utilities	R.I. Pub. Util. Comm'n, Order No. 11,789 (1998).	1MW for Narraganse tt Electric Company
Texas	Renewables only	All customer classes	≤100kW	Monthly NEG purchased at avoided cost	16 TEX. ADMIN. CODE § 25.242 (2006).	None
Utah	Solar, wind, hydroelectric and fuel cells	All customer classes	≤25kW	NEG credited within billing cycle at avoided cost, any unused credit granted to utility at end of calendar year	UTAH CODE ANN. §§ 54-15-102 to -105 (2006).	0.1% of 2001 peak demand
Vermont	PV, wind, fuel	Residential	≤15kW;	Annual NEG	VT. STAT. ANN. tit. 30,	1% of 1996

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
	cells, anaerobic digesters	commercial and agricultural	Farm biogas ≤150kW	granted to utilities	§ 219a (2006).	peak

State	Eligible Technology	Eligible Customers Limits	Size Limits	Price	Authorization	Statewide Limit
Virginia	Solar, wind and hydro-electric	All customer classes	≤10kW residential ≤25kW non-residential	Annual NEG granted to utilities (power purchase agreement is allowed)	VA. CODE ANN. § 56-594(A) (2006).	0.1% of peak of previous year
Washington	Solar, wind, fuel cells and hydroelectric	All customer classes	≤25kW	Annual NEG granted to utility	WASH. REV. CODE § 80.60.020 (2006).	0.1% of 1996 peak demand
Wisconsin	All technologies	All retail customers	≤20kW	Monthly NEG purchased at retail rate for renewables, avoided cost for non-renewables	Pub. Serv. Comm'n of Wisc., Order No. 6690-UR-107 (1993).	None
Wyoming	Solar, wind and hydro-electric	All customer classes	≤25kW	Annual NEG purchased at avoided cost	WYO. STAT. ANN. §§ 37-16-101 to 16-103 (2006).	None

TABLE 4

OVERVIEW OF POTENTIAL ENVIRONMENTAL PERMITTING REQUIREMENTS FOR LARGER POWER FACILITIES

PERMIT		**APPLICABILITY**
SITING		
1.	Energy Facility Siting Board Approval	New generating facilities in excess of specified size; Preconstruction approval. U.S. Department of Energy, Environmental Siting Guide, http://www.eere.energy.gov/femp/technologies/derchp_env_siting.cfm (last visited Dec. 1, 2006).
2.	N.E.P.A.	For significant environmental impacts, an EIS is required. 40 C.F.R. § 1502.3 (2006).
AIR		
3.	New Source Performance Standards—EPA/State	All new facilities for major sources of emissions greater than 250 MMBtu/hr. 40 C.F.R. § 60.40.
4.	Prevention of Significant Deterioration—State as Federal Delegate of EPA	Emission exceedances greater than threshold definition of major source—could apply to particulates, NOx, VOCs, CO. Must perform top-down BACT analysis to justify technology sources. 40 C.F.R. § 52.21.

PERMIT		APPLICABILITY
5.	New Source Review— State as Federal Delegate of EPA	Any source of oxides of nitrogen or VOCs in excess of 50 tpy in "serious" area or 25 tpy in "severe" area; will include typical repowering. Environmental Protection Agency, Clean Air Act Requirements, http://www.epa.gov/dfe/pubs/pwb/tech_rep/fedregs/regsecta.htm (last visited Dec. 1, 2006).
6.	Air Plan Approval Prior to Construction—State	Major stationary sources. Environmental Protection Agency, New Source Review: Basic Information, http://www.epa.gov/nsr/info.html (last visited Dec. 1, 2006).
7.	NOx Emission Reduction Credits	Obtain 120% of potential to emit oxides of nitrogen in "serious" region; 130% in "severe" region. *See* ENVTL. PROT. AGENCY, COMPARISON OF THE NEW SOURCE REVIEW (NSR) REFORM RULEMAKING PACKAGE AND CURRENT NSR RULES 24 (1996), http://www.epa.gov/ttn/nsr/gen/compare.pdf.
8.	Obtain Summer Ozone Season Allowances—State	For five summer months, must obtain by the conclusion of each year, actual budget allowances scaled to NOx emissions. Must maintain operating plan with State. *See* ENVTL. PROT. AGENCY, CAP AND TRADE: NOX PROGRAMS (n.d.), http://www.epa.gov/airmarkets/capandtrade/nox.pdf (summarizing state programs to reduce NOx emissions).
9.	Phase II Title IV	Compliance filing for any source of

PERMIT		APPLICABILITY
	Acid Rain Control	SO_2 and designation of representative. 40 C.F.R. §§ 72.44, 75.4.
10.	Class I PSD	Sources within 100 Km of a Class I area must do an impact analysis. *See* Memorandum from John S. Seitz, Director, Office of Air Quality Planning and Standards, Environmental Protection Agency (Oct. 19, 1992), http://www.epa.gov/Region7/programs/artd/air/nsr/nsrmemos/class1.pdf (clarifying prevention of significant deterioration guidelines).
11.	Title V Operating Permit	Consolidated air operating permit. 42 U.S.C. § 7661a (2006).
WATER WITHDRAWAL AND DISCHARGE		
12.	NPDES/EPA Region	All pollutant point source discharges to surface water body. 33 U.S.C. § 1311(a).
13.	Section 301 Water Quality Certification	Discharges to surface water body. 33 U.S.C. § 1341(a).
14.	Water Withdrawal Permit—State	Any water withdrawal from waters of the state in excess of specified quantity. *See, e.g.*, Kentucky Division of Water, Water Withdrawal Permitting, http://www.water.ky.gov/permitting/ withdrawal/ (last visited Dec. 1, 2006).

PERMIT		APPLICABILITY
15.	Coastal Zone Management Consistency Review ("CZM")	Demonstrated consistency with coastal zone management plan involving intake, outflow, and uses in coastal zone. *See* 16 U.S.C. § 1456(c).
16.	Storm Water Management Plan and Permit	For construction-phase activities, if the footprint of existing buildings is to be enlarged affecting 5 acres or more, a storm water management plan for non-point sources may be required depending upon the size of the area affected. 40 C.F.R. § 122.26.
17.	Spill Prevention and Countermeasure Plan—EPA	If oil is to be used and stored as a back-up fuel, a spill contingency plan may be required. 40 C.F.R. § 112.1.
18.	Fish and Wildlife	Coordination of any impact on streams. 16 U.S.C. § 661.
19.	Wetlands	Activities altering or construction occurring in wetlands, including coastal wetlands. 33 U.S.C. § 1344; 33 C.F.R. § 320.2.
LOCAL PERMITS		
20.	Industrial Use Permit	Discharges to sewers.

PERMIT		**APPLICABILITY**
		See, e.g., 314 MASS. CODE REGS. 7.03 (2006).
21.	Zoning and Non-Conforming Uses	Non-conforming uses and accessory uses as-of-right on the existing parcel. *See, e.g.*, City of Philadelphia, Pennsylvania, General Zoning Permit Information, http://www.phila.gov/li/faq/zoning/general.html (last visited Dec. 1, 2006).
22.	Special Use Permits or Use Variances	May be necessary as a prerequisite. *See, e.g.*, City of Tampa, Florida, Industrial Zoning District, http://www.tampagov.net/dept_Land_Development/Zoning/Zoning Industrial.asp (last visited Dec. 1, 2006).
OTHER APPROVALS/ITEMS		
23.	FERC Added Gas Compression Certification	Additional pipeline compression. *See* FED. ENERGY REGULATORY COMM'N, CERTIFICATED NATURAL GAS STORAGE PROJECTS SINCE 2000 (2006), http://www.ferc.gov/industries/gas/indus-act/storage/certificated.pdf; Federal Energy Regulatory Commission, Pre-Filing Environmental Review Process, http://www.ferc.gov/help/processes/flow/lng-1.asp (last visited Dec. 1, 2006).
24.	Gas Transportation	Reserve sufficient interruptible or firm gas transportation for facility. *See generally* Northeast Gas Association, *Firm vs. Non-Firm Gas Transportation: Rationale and Risks*, http://www.mass.gov/Eoca/docs/dte/repgtferop/apph.pdf (last visited Dec. 1, 2006) (describing two types of gas transportation).

PERMIT		**APPLICABILITY**
25.	Back-up Fuel Storage (Oil)	If oil is going to be used as a back-up fuel, this may have implications for fuel storage licenses from the city and state. *See, e.g.*, N.Y. COMP. CODES R. & REGS. tit. 17, § 30.3 (2006).

PERMIT		APPLICABILITY
26.	Noise Control	Could be implicated depending upon the cooling technology, stack height and exit velocity, and site layout. *See* Karen D. Durham et al., *Noise Abatement for Natural-Draft Burners in U-tube Equipped Heaters*, http://www.natcogroup.com/PDFContent/Consulting-Research/TechnicalPapers/Ultra%20Low%20Noise%20Paper.pdf (last visited Dec. 1, 2006).
27.	Transmission Interconnection	Prior to physical interconnection or upgrade of interconnection, facilities need to file an application and perform a system impact study. *See generally* Western Area Power Administration, The Interconnection Process, http://www.wapa.gov/transmission/interprocess.htm (last visited Dec. 1, 2006).
28.	Federal Aviation Administration Stack Height Approval	GEP and stack approval required if high new stack near air corridors. *See* 14 C.F.R. § 77.13.