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# Emissions Performance Standards In Selected States

***The Regulatory Assistance Project research staff prepared this summary of Emissions Performance Standards (EPS) that have been adopted by various states in the United States. It is designed to provide a comparative summary of key EPS components for the interested reader rather than attempt to evaluate the relative merits of the alternative policies discussed in the summary. Each of the state summaries includes links to applicable laws and rules.***

*Research Staff Authors:*

*Chris Simpson*
*Brenda Hausauer*
*Ajith Rao*

An Emissions Performance Standard (EPS) establishes a maximum level of carbon dioxide ($CO_2$) emissions, or $CO_2$ equivalent, per unit of output from an electricity-generating power plant. An EPS has been described as analogous to an energy efficiency standard for appliances such as refrigerators, in which minimum performance standards are set. Beyond that, it is up to the market to compete, so long as each of the manufactured appliances can meet or exceed the minimum standard.

California, Washington and Oregon have each adopted an EPS that applies to new and existing baseload generation for which electric utilities enter into long-term commitments (e.g., new construction and long-term contracts), with certain exceptions. Other states have adopted related emission performance conditions that are incorporated into policies designed to reduce $CO_2$ emissions specifically from coal-fired plants or encourage the development and deployment of carbon capture and sequestration. In Montana, the approval of new coal-fired plants is conditioned upon emissions reductions achieved through carbon capture and storage. In New Mexico, tax and cost recovery incentives are available to coal-fired plants that can meet an emissions performance standard. And in Illinois, emissions reduction requirements are incorporated into a clean-coal portfolio standard that obligates utilities to procure a certain percentage of electricity from new coal-fired plants that reduce emissions by at least 50% through carbon capture and sequestration. An overview of these policies is presented below.

## California

California's EPS statute, Senate Bill 1368, was enacted in September 2006 and detailed regulations were adopted in January 2007. In adopting SB 1368, the California Legislature concluded that an EPS was necessary to protect ratepayers and the economy from certain risks and costs and as a complement to other key policies that encouraged investment in cost-effective energy efficiency and renewable energy resources.[1]

SB 1368 set out a process by which the California Public Utilities Commission (CPUC) would issue EPS implementation rules for the investor-owned utilities (IOUs) it regulated, with the California Energy Commission following shortly thereafter with a set of consistent EPS rules for California's publically-owned utilities.

### *Covered Procurements*

The California EPS establishes a facility threshold based on the power plant's capacity factor.[2] More specifically, the EPS applies to any and all long-term financial commitments [3] with "baseload" facilities, defined as power plants that are designed and intended to provide electricity at an annualized plant capacity factor of at least 60%.[4] These are facilities that essentially operate "24/7" and are not able to ramp up and down quickly, provide spinning reserves, or exhibit other operating characteristics that are associated with load-following or peaking resources.

With some exceptions, California utilities must comply with the EPS for all new or renewed contracts of 5 years or longer that they enter into with baseload facilities, for all new plant investments--including upgrades under certain circumstances, or when acquiring a new or increased ownership interest in baseload facilities. Offsets or averaging of plant performance is not permitted. However, the CPUC may provide a case-by-base exemption from the EPS to address 1) unanticipated electric system reliability needs, or 2) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

Some facilities are grandfathered, or do not need to comply with the EPS: 1) existing baseload facilities owned by the IOUs or public utilities, unless they become subject to new long-term commitments; 2) existing combined-cycle gas turbine (CCGT) power plants in operation or permitted in California before June 30,2007. The CPUC's Decision 07-01-039 further describes the long-term commitments, both new ownership investments and new contract commitments that are covered by the California EPS.[5]

### *Level of Emissions Performance Standard*

Pursuant to SB 1368, the performance level of the EPS must be no higher than the emissions rate of a CCGT power plant but does not specify the emissions rate for a CCGT.[6] Based on its review of emissions rates associated with various CCGT power plants, the CPUC adopted an EPS emissions rate of 1100 lbs $CO_2$/MWh.

### *Treatment of Renewables*

The CPUC made an up-front determination that the following renewable resources and technologies are EPS-compliant: solar thermal electric (with up to 25% gas heat input), wind, geothermal (with or without reinjection) and generating facilities using biomass (e.g., agricultural and wood waste, landfill gas) that would otherwise be disposed of utilizing open burning, forest accumulation, landfill, spreading or composting.[7]

### *Calculation of Net Emissions for Combined Heat and Power*

SB 1368 directed the CPUC to adopt a methodology for calculating the emissions rate associated with cogeneration facilities that recognizes both the thermal output (heat or steam) and the electrical output associated with cogeneration.[8] The CPUC discusses its calculation of emissions associated with cogeneration in Decision 07-01-039.

### *Consideration of Carbon Capture and Storage*

Carbon capture and storage (CCS) –also referred to as "carbon sequestration" [9] –is an approach to mitigating Greenhouse Gas (GHG) emissions based on capturing $CO_2$ from large point sources such as coal generation plants and storing it (e.g., by injecting the $CO_2$ into geological formations) instead of releasing it into the atmosphere. California's EPS statute provides that "[c]arbon dioxide that is injected in geographical formations, so as to prevent releases into the atmosphere, in compliance with applicable laws and regulations shall not be counted as emissions of the power plant in determining compliance" with the EPS.[10] In implementing this directive, the CPUC determined that any facility that proposes to use CCS to meet the standard must present a "reasonable and economically and technically feasible plan that will result in a permanent sequestration of $CO_2$ once the injection project [i.e., injection of $CO_2$ into permanent geological storage] is operational and that the $CO_2$ injection project complies with applicable laws and regulations." [11] The CPUC recently clarified that the plan must comply with federal and/or state monitoring, verification and reporting requirements applicable to projects designed to permanently sequester $CO_2$ and prevent its release from the subsurface, and further specified how a plan may meet monitoring, verification and reporting requirements if federal and/or state requirements do not exist or have not been finalized.[12]

The plan is reviewed in a formal CPUC proceeding, with stakeholder participation, and subject to full Commission vote of approval or denial.

### *Improvements to Existing Plants that Trigger EPS Compliance*

Improvements to existing baseload plants that will trigger the EPS (as a new, long-term financial commitment) are defined under the California rules as those that: [13]

(a) For combined-cycle, natural gas power plants in operation or permitted before June 30, 2007, increase the generation capacity by 50 megawatts (MW) or more.

(b) For other power plants, are intended to extend the life of one or more units by five years or more.

(c) Are intended to increase the rated capacity of the power plant.

(d) Are intended to convert a non-baseload power plant into a baseload power plant.

### *Citations*

Senate Bill 1368 (Stats 2006, ch. 598): http://www.energy.ca.gov/emission_standards/index.html

CPUC Decision 07-01-039 issued on January 25, 2007 in Rulemaking 06-04-009: http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm.

## Washington

Washington's EPS law, SB 6001, became effective July 22, 2007, and specific rules were adopted on June 24, 2008. Washington's EPS is modeled on California's law and it applies to both IOUs and consumer-owned utilities (COUs). The key features are summarized below.

### *Covered Procurements*

Like the California standard, Washington's EPS covers baseload electric generation for which electric utilities enter into long-term financial commitments (on or after July 1, 2008.) The definition of a baseload facility is identical to the one used in California—and the definitions of what constitutes a long-term commitment are very similar. (See above.)

Under SB 6001, the following facilities are grandfathered or do not need to comply with the EPS: 1) baseload generation facilities in operation as of June 30, 2008, until they are the subject of long-term financial commitments; 2) all electric generation facilities or power plants powered exclusively by renewable resources; and 3) cogeneration facilities fueled by natural gas or waste gas in operation as of June 30, 2008, until they are the subject of a new ownership interest or are upgraded.[14] As in California, the Commission may provide a case-by-case exemption from the EPS to address: 1) unanticipated electric system reliability needs; 2) catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

It appears to be an open question whether the law covers out-of-state generation. The issue is likely to be resolved by court decision or the commission's interpretation when an actual case tests the issue.[15]

### *Level of the Emissions Performance Standard*

The standard is the lower of 1) 1,100 pounds of GHG per MWh; or 2) the average available GHG emissions output as determined and updated by the Washington Department of Community, Trade & Economic Development (CTED). Washington's statute defines net emissions from combined heat and power on an output basis, similar to California.

To update the standard, CTED will conduct a survey every 5 years of new CCGTs commercially available and offered for sale by manufacturers and purchased in the US. CTED must use the survey results to adopt by rule the average available GHG emissions output. The survey results must be reported to the legislature every five years, beginning June 30, 2013. The CTED must also consult with specified groups (such as the Bonneville Power Authority) and consider the effects of the standard on system reliability and the overall costs to electricity consumers.

### *Treatment of Renewables*

As discussed under "Covered Procurements" above, electric generation facilities or power plants powered exclusively by renewable resources do not have to comply with the EPS. "Renewable resources" are defined as electricity generation facilities fueled by: (a) water; (b) wind; (c) solar energy; (d) geothermal energy; (e) landfill gas; (f) biomass energy utilizing animal waste, solid organic fuels from wood, forest, or field residues or dedicated energy crops that do not include wood pieces that have been treated with chemical preservatives such as creosote, pentachlorophenol, or copper-chrome-arsenic; (g) byproducts of pulping or wood manufacturing processes, including but not limited to bark, wood chips, sawdust, and lignin in spent pulping liquors; (h) ocean thermal, wave, or tidal power; or (i) gas from sewage treatment facilities.[16]

### *Consideration of Carbon Capture and Storage*

In calculating compliance with the EPS, the Washington statute excludes emissions that are injected permanently in geological formations or other $CO_2$ storage methods/ mitigation plans approved by the Washington Department of Ecology and Energy Facility Site Evaluation Council. SB6001 permits utilities to apply for pre-approval of a plan to sequester carbon for purposes of meeting the EPS, and are under obligation to demonstrate financial, technical and economic feasibility in their submittal—similar to the implementing rules adopted for California. However, the Washington statute includes additional provisions not currently included in the

California rules or statute: 1) a requirement that carbon sequestration must begin within 5 years of plant operation, and 2) penalty provisions for failure to achieve the implementation plan on schedule.[17]

### *Improvements to Existing Plants that Trigger EPS Compliance*

Under Washington's EPS, the following conditions will trigger EPS compliance for an existing plant:[18]

(a) The unmodified station generating capability is 350 MWh or greater;

(b) The increase to the facility or units is the greater of the following measures:

(i) An increase in station-generating capability of more than 25 MWh; or

(ii) An increase in $CO_2$ emissions output by fifteen percent or more.

### *Other Information*

The Washington EPS is enforced as follows: For IOUs, the Washington Utilities and Transportation Commission (WUTC) must review a long-term financial commitment in a general rate case. WUTC must also review an IOU's proposed decision to acquire electric generation or enter into a power purchase agreement for electricity. WUTC must consult with the Washington Department of Ecology when verifying compliance with the EPS. For COU's, the utility's governing board must review a long-term financial commitment in consultation with the Washington Department of Ecology, after which the State Auditor is responsible for auditing compliance with the EPS and the Attorney General is responsible for enforcing compliance.

The EPS must be reviewed at least every five years or upon implementation of a federal or state law or rule regulating carbon dioxide emissions of electric utilities.

### *Citations*

SB 6001:
http://apps.leg.wa.gov/billinfo/summary.aspx?year=2007&bill=6001

Washington Administrative Code rules to implement the law:
http://www.efsec.wa.gov/rulerev.shtml#CO2

## Oregon

Oregon's EPS law, SB 101, was enacted on July 22, 2009, and all sections of the bill became operative on July 1, 2010.[19]

SB 101 expands the 1997 standards established by HB 3283, which specified that baseload gas power plants, non-baseload power plants, and non-generating energy facilities must reduce their net carbon dioxide emissions 17% below the most efficient baseload gas plant in the United States.

As indicated below, SB 101 incorporated many of the key features of the California and Washington EPS laws.

### *Covered Procurements*

Covered procurements under SB 101 are new, long-term financial commitments to baseload facilities entered into by the utility. Long-term commitments includes contracts (or contract renewals) of more than five years with a baseload facility. Oregon's statute explicitly excludes renewable (as defined below) from the EPS, as well as any generating source that uses natural gas or petroleum distillates as a fuel source and is primarily used to serve either peak demand or to integrate energy from a renewable energy source.

SB 101 also exempts certain facilities, including co-generation facilities in operation prior to July 1, 2010 unless subject to a new long-term financial commitment. The statute permits the governing board of a COU to exempt long-term financial commitments between the COU and a joint operating entity recognized under federal law where the COU had an ownership interest prior to July 1, 2010.[20]

In addition, an exemption for an individual generating facility from the EPS may be considered to address unanticipated electricity system reliability needs or catastrophic events or threat of significant financial harm that may arise from unforeseen circumstances.

### *Level of the Emissions Performance Standard*

The performance standard is also set at the same level of the California and Washington EPS (1,100 pounds of $CO_2$ per megawatt-hour) and emissions from combined heat and power are determined using an output-based methodology. SB 101 defines "total emissions" as excluding emissions associated with transportation, fuel extraction or other life-cycle emissions associated with obtaining the fuel for the facility.

### *Treatment of Renewables*

As indicated above, a facility that is powered exclusively by renewable energy sources is exempt from Oregon's EPS requirement. "Renewable energy sources" include wind energy; solar photovoltaic and solar thermal energy; wave, tidal and ocean thermal energy, as well as geothermal energy.[21]

### *Consideration of Carbon Capture and Storage*

The Oregon EPS does not apply to emissions from a generating facility that has "in place a plan, as determined by the Public Utility Commission, to be a low-carbon emissions resource, pursuant to sufficient technical documentation, within seven years of commencing plant operations." An OPUC staff person familiar with SB 101 indicated that this language is intended to include coal plants with a plan to capture and sequester carbon emissions within a designated period of time. However, there are no explicit references to CCS in SB 101.

### *Improvements to Existing Plants that Trigger EPS Compliance*

The Oregon statute describes what improvements to existing plants will trigger the EPS in the form of "exclusions" to covered procurements, as follows:[22]

(a) Routine or necessary maintenance;
(b) Installation of emission control equipment;
(c) Installation, replacement or modification of equipment that improves the heat rate of the facility or reduces a generating facility's pounds of greenhouse gases per MWh of electricity;
(d) Installation, replacement or modification of equipment where the primary purpose is to maintain reliable generation output capability and not to extend the life of the generating facility, and that does not increase the heat input or fuel usage as specified in existing generation air quality permits, but that may result in incidental increases in generation capacity;
(e) Repairs necessitated by sudden and unexpected equipment failure; or
(f) An acquisition of an additional interest.

### *Other Information*

SB 101directs the Oregon Public Utilities Commission (OPUC) to review the EPS once every three years. After review, the OPUC may modify the EPS by rule and may also modify the GHGs included under the EPS.[23]

OPUC is also required to revoke the certificate of an electricity service supplier if it serves customers in the state with baseload electricity from a facility that does not comply with the EPS. It does not include specific enforcement language relating to COUs.

***Citations***

***SB 101:***
http://www.leg.state.or.us/09reg/measpdf/sb0100.dir/sb0101.en.pdf

## Montana

Montana's law regarding constraints on unabated coal plants, House Bill 25, was passed in May 2007. HB 25 prohibits the utility from acquiring an equity interest or leasing/contracting with a new coal plant (constructed after January 1, 2007), unless the facility or equipment captures and sequesters a minimum of 50% of the carbon dioxide produced by the facility. It permits sequestration offsite from the facility.

HB 25 only applies to formerly restructured utilities in Montana, which by definition is a single utility (Northwest Energy). The provisions of HB 25 apply when Northwest Energy seeks pre-approval of an electricity supply resource that it has not previously procured. The law does not apply to entities that are outside the Commission's jurisdiction, such as rural electric cooperatives which serve about 1/3 of the state.[24]

HB 25 is currently untested. The Commission updated existing rules to adopt the law, but the rules simply refer to the law.[25]

***Citations***

Montana Code Annotated 69-8-421:
http://data.opi.mt.gov/bills/mca/69/8/69-8-421.htm;
HB 25:
http://data.opi.mt.gov/bills/2007/billhtml/HB0025.htm

## New Mexico

New Mexico has adopted what can be characterized as a "first mover" incentive for carbon capture and storage at coal-fired plants by authorizing tax credits and cost recovery incentives for qualifying investments. The New Mexico statute, SB 994, was signed into law on April 3, 2007 and took effect on July 1, 2007.

SB 994 provides that a taxpayer holding an interest in a qualified generating facility located in New Mexico is eligible for an "advanced energy combined reporting tax credit."[26] A "qualified generating facility" is defined as a facility that begins construction no later than December 31, 2015 and is either a solar thermal generating facility, solar photovoltaic generating facility, geothermal generating facility, recycled energy project[27] or a new or re-powered coal-based electric generating facility and associated coal gasification facility.[28] The tax credit equals six percent of the eligible generation plant costs of the qualified generating facility up to a maximum amount of $60,000,000.[29] The new and re-powered coal-based and association coal gasification facilities are also eligible for the cost recovery incentives, described later in this section.

SB 994 requires the "qualified generating facility" to meet the following specifications:[30]

(a) Emits the lesser of: i) what is achievable with the best available control technology; or ii) thirty-five thousandths pound per million Btu's of $SO_2$, twenty-five thousandths pound per million Btu's of $NO_X$ and one hundredth pound per million Btu's of total particulates in the flue gas;

(b) Removes the greater of: i) what is achievable with the best available control technology; or ii) 90% or more of the mercury from the input fuel;

(c) Captures and sequesters or controls $CO_2$ emissions such that by the later of January 1, 2017, or eighteen months after the commercial operation date, no more than 1,100 lbs per MWh of $CO_2$ is emitted into the atmosphere;

(d) All infrastructure required for

sequestration is in place by the later of January 1, 2017, or eighteen months after the commercial operation date of the qualified generating facility;

(e) Includes methods and procedures to monitor the disposition of the $CO_2$ captured and sequestered from the facility; and

(f) Does not exceed 700 net MW nameplate capacity.

SB 994 also directs the New Mexico Public Regulation Commission to adopt rules to allow the utility a reasonable opportunity to recover costs incurred for the development and ongoing construction of a "clean energy project."[31] The law defines a "clean energy project" as the construction or modification of a new or existing electric generation facility in a manner that employs a technology that has additional financial risk because it is not commercially established or because it employs an established technology that is not commercially proven under the altitude, geographic or resource availability conditions under which it is proposed to operate. This may include associated renewable energy storage facilities, recycled energy and advanced coal technology, or other technology as deemed appropriate by the commission.

In addition, the "clean energy project" should achieve emission levels no greater than those specified for advanced coal technology and cannot include nuclear power. SB 994 defines "advanced coal technology" as new coal-based generation, coal gasification or other technology using coal as a fuel source that is certified by the department of environment to meet the same specifications as listed for the qualified generating facility.[32]

***Citations***

***SB 994:***

http://legis.state.nm.us/lcs/_session.aspx?Chamber=S&LegType=B&LegNo=994&year=07

3.13.8.7 NMAC – Definitions: Advanced Energy Tax Credit Defined

http://www.tax.newmexico.gov/SiteCollectionDocuments/Tax-Library/Statutes-and-Department-Directives/Recent-Regulation-Changes/Other_Tax_Credits.pdf

## Illinois

Illinois recently passed a law that implements a clean coal portfolio standard. While this law does not limit coal power, it does create a preference for coal resources that utilize CCS. The Illinois statute, SB 1987, was signed into law on January 12, 2009 and took effect on June 1, 2009.

SB 1987 requires each Illinois electric utility to enter into one or more sourcing agreements with an "initial clean coal facility" that represents at least 5% of each utility's total supply to serve the load of eligible retail customers in 2015.[33] An "initial clean coal facility" is defined as a proposed facility with a nameplate capacity of at least 500 MW when commercial operation commences, having a final Clean Air Act permit on the effective date of the act, and meeting the definition of "clean coal facility" described below.

The new law further provides that "[i]t is the goal of the State that by January 1, 2025, 25% of the electricity used in the State shall be generated by cost-effective clean coal facilities."[34] The provisions limit the total amount paid under the clean coal sourcing agreements, however, in order to keep annual average cost increases to customers due to the cost of these resources to under 0.5%.

Eligible clean coal procurement under this portfolio standard is defined by the level of emission reductions achieved through carbon capture and sequestration. A clean coal facility scheduled to commence operation before 2016 must capture and sequester at least 50% of the total carbon emissions that the facility would emit. If the facility is scheduled to commence operation during 2016 or 2017, at least 70% of the total carbon emissions that the facility would emit must be captured and sequestered. The applicable percentage for facilities scheduled to commence operations after 2017 is 90%. For the purpose of establishing these thresholds, the scheduled commencement date is established at the time that construction commences.[35]

SB 1987 includes provisions for repowering and retrofitting coal-fired plants previously owned by Illinois utilities to qualify as clean coal facilities. No specific definitions of these terms are provided in the statute and rules have not been adopted to date to clarify how the Commission intends to define them.[36]

The state Attorney General may specifically enforce the initial clean coal facility's sequestration requirement.[37] The Commission may reduce the allowable return-on-equity for the facility reflected in the sourcing agreement if the facility willfully fails to comply with its capture and sequestration requirements.[38]

***Citations***

SB 1987: www.ilga.gov/legislation/publicacts/95/PDF/095-1027.pdf.

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[1] Both the California Legislature and the California Public Utilities Commission (CPUC) concluded that if utilities or other load-serving entities were allowed to enter into new long-term commitments with high-greenhouse gas (GHG) emitting power plants, California ratepayers would be exposed to high costs of retrofits (or the need to purchase expensive offsets) under future emission control regulations. California ratepayers would also be exposed to potential supply disruptions when these high-emitting facilities are taken off line for retrofits, or retired early, in order to comply with future regulations.
SB 1368, Section 1(f)-(m) at http://www.leginfo.ca.gov/pub/05-06/bill/sen/sb_1351-1400/sb_1368_bill_20060929_chaptered.pdf
CPUC Decision 07-01-039 issued on January 25, 2007 in Rulemaking 06-04-009, at page 3.
http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

[2] "Capacity factor" is defined as the ratio of the annual amount of electricity produced by the power plant divided by the annual amount of electricity the plant could have produced based on maximum rated capacity (or maximum "permitted" capacity, if the permit limits maximum plant operation below the facility's rated capacity.)

[3] The California EPS is codified at Public Utilities Code section 8340-8341. "Long-term financial commitment" is defined at subsection 8340(j).

[4] "Baseload generation" is defined at subsection 8340(a).

[5] CPUC Decision 07-01-039 at page 6.

[6] Subsection 8341(d).

[7] CPUC Decision 07-01-039 at page 6.

[8] CPUC Decision 07-01-039 at page 10.

[9] We use these terms interchangeably here.

[10] Subsection 8341 (d)(3).

[11] CPUC Decision 07-01-039, Attachment 7, page 5.
http://www.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/64072.htm

[12] D.10-07-046, issued July 29, 2010.

[13] http://www.energy.ca.gov/emission_standards/index.html

[14] "Renewable resources" are defined below under the heading "Treatment of Renewable Resources."

[15] E-mail with Dick Byers, Senior Policy Advisor, Washington Utilities and Transportation Commission, 10-10-08.

[16] In RCW 19.280.020 of SB 6001

[17] Section 5, Subsections (11)-(13) of SB 6001

[18] Chapter 463-85 WAC

[19] Section 13 of SB 101. Since the implementing rules have not been developed yet, our description of OPUC's EPS necessarily relies on the plain reading of the statute.

[20] SB 101, Section 5(2)(b) and (3)(c)

[21] These are listed in ORS 469A.025 which can be found at http://www.leg.state.or.us/ors/469a.html

[22] Section 1(10)(b) of SB 101

[23] Subsection 2(4)(b) provides that the OPUC may "[m]odify the emissions standard based upon current information on the rate of greenhouse gas emissions from a commercially available combined-cycle natural gas generating facility that:
(A) Employs a combination of one or more gas turbines and one or more steam turbines and produces electricity in the steam turbines from waste heat produced by the gas turbines;
(B) Has a heat rate at high elevation within the boundaries of the Western Electricity Coordinating Council; and
(C) Has a heat rate at ambient temperatures when operating during the hottest day of the year."

[24] Interview with Will Rosquist, Rate Analyst, MT PSC, 10-10-08.

[25] Ibid.

[26] Section 7-9G-2 (A) of 3.13.8.7 NMAC

[27] The statute defines a "recycled energy project" as energy produced by a generation unit with a name-plate capacity of not more than fifteen megawatts that converts the otherwise lost energy from exhaust stacks or pipes to electricity without combustion of additional fossil fuel.

[28] Section 7-9G-2 (B) (10) (e) of 3.13.8.7 NMAC

[29] Section 7-9G-2 (J) of 3.13.8.7 NMAC

[30] Section 7-9G-2 (B) (2) (a-f) of 3.13.8.7 NMAC

[31] Section 2 (D) (2) of SB 994

[32] Section 2 (D) (1) (a-f) of SB 994

[33] 20 ILCS 3855/1-75 (d) (1) of SB 1987

[34] 20 ILCS 3855/1-75 (d) (1) of SB 1987

[35] 20 ILCS 3855/1-10) Sec. 1-10 of SB 1987

[36] 20 ILCS 3855/1-75 (d) (5) of SB 1987

[37] 20 ILCS 3855/1-75 (d) (3) (D) (v) of SB 1987

[38] 20 ILCS 3855/1-75 (d) (3) (D) (vi) of SB 1987