Summary of PSD Permits Issued To Electric Generating Units Addressing GHGs

Permit Seeker, Issuing Agency, & Date of Issuance	Type of Facility & Location	New or Existing Facility	GHG BACT Limits and Technologies Chosen	Technologies Eliminated	Additional Notes
Taylorville Energy Center[1] (Tenaska/Christian County Generation) Illinois Environmental Protection Agency (October 17, 2011 – Draft)	602-MW IGCC coal gasification and power plant Illinois	New	• Plant-wide CO_2e: 5,031,409 tpy (CO_2: 4,990,000 tpy) • Combined cycle units: – 2,307,110 tpy CO_2e on 12 month rolling basis; – 1200 lbs CO_2 per MWh on 12-month rolling basis • Acid Gas Recovery Unit: 2,510,326 tpy CO_2e (includes limit for CO_2 vent of 111.4 tons/million SCF SNG) • High efficiency CTGs • Additional BACT limits for auxiliary boilers, etc. • Tailgas recycling	• CCS technically infeasible (need to further develop technology, unresolved issues on sequestration, etc.) • Not sequester CO_2 at beginning because prerequisites not present (lack of pipeline, etc.) • Use of biomass as feedstock	• Will produce SNG • Developer anticipates CO_2 will be geologically sequestered "at some point" and would preferably be used for EOR (Project Summary) • Developer intends to build CCS facility in future but does not want it required in permit. May accept adjustable limit in final permit. • Use of Illinois Basin coal critical for feasibility, meeting Clean Coal Portfolio Standard • "CCS using EOR cannot be required as BACT since no CO_2 pipeline exists"
Cricket Valley Energy Center[2] New York Department of Environmental Conservation (May 25, 2011 – Draft)	1,000-MW NGCC power plant New York	New	• 7,605 Btu/kWh annual net heat rate limit and thermal efficiency of 57.4% with no duct firing • Combined cycle units: 3,576,943 tons CO_2e per rolling 12-month period • Auxiliary boiler: 15,887 tons CO_2e/rolling 12-mo. period • Fire pump: 114 tons CO_2e per rolling 12-month period • High efficiency CTGs and HRSG • Black start generator: 4,822 tons CO_2e per rolling 12-month period	• CCS (not commercially available or economically feasible) – No NGCC CO_2 absorption systems – Compression: increase CO_2 emissions, large parasitic load • Lower emitting alternative technologies (not feasible)	• Draft permit contained no GHG BACT limits or efficiency design parameters; conditions listed were suggested by EPA Region 2 • EPA Region 2 submitted comments on July 29, 2011; noted that was unaware of issuance of draft permit and had limited time to conduct review • Total potential CO_2e emissions: 3,630,484 tpy • CO_2 main source of GHGs; LAER used to address for CH_4 and N_2O emissions
Abengoa Bioenergy Biomass of Kansas[3] Kansas Department of Environment and Health (March 2, 2011 – Draft)	120-MW biomass cogeneration facility Kansas	New	• BFB boilers: 0.40 lb CO_2e/lb steam produced based on 30-day rolling average • Fermentation scrubber: 13,197 lb CO_2e/hr based on 30-day rolling average • Distillation vent scrubber: 318 lb CO_2e/hr based on 30-day rolling average • State-of-the-art SF_6 circuit breakers: 80.5 lb CO_2e/day • Energy-efficient design	• Alternative emerging SF_6 technology (technically infeasible) • Dielectric oil or compressed air circuit breaker (not feasible) • CCS (not feasible or cost-effective)	• Uses biomass and natural gas for start up • Potential to emit of 1,797,693 tons/yr CO_2e; total estimated CO_2e emissions of 1,731,399 • BACT requirements exclude periods of startup, shutdown or malfunction • Carbon capture, drying and compression projected to cost $71/short ton avoided (compared to a value of $41/short ton based on NETL report) • 4 BFB boilers emit over 96% of total facility-wide CO_2e (CO_2, CH_4 and N_2O)
Lower Colorado River Authority[4] EPA Region VI (TX) (November 10, 2011 – Final)	590-MW NGCC power plan (Thomas Ferguson plant)	New (replacing existing plant)	• 7,720 Btu/kWh annual net heat rate limit based on 365-day rolling average • 0.459 tons CO_2/mWh (net) based on 365-day rolling average • For each turbine:	• CCS (not feasible or cost-effective) • Non-GHG substitutes for SF6	• Submitted GHG permit application to EPA in March 2011; draft permit issued on September 28, 2011 • Heat rate limit similar to Russell City permit • Use of heat rate and emissions standards required to measure efficiency of plant more accurately

	Texas		– CO_2: 908,957.6 tons/year – CH_4: 16.8 tons/year (353.3 tpy CO2e) – N_2O: 1.7 tons/year (521.6 tpy CO2e) • High efficiency CTGs and HRSG • Plant-wide energy efficiency practices and designs • Includes limits for fugitive emissions, emergency generator, fire water pump, circuit breakers, etc.		• Replace 440-MW unit with new plant • CCS could increase cost of project ~42% (~$230 million) • CCS can be considered "available" for purpose of BACT analysis (Statement of Basis) • Will increase emissions by 2 million tpy
Palmdale Hybrid Power Project[5] EPA Region IX (CA) (October 18, 2011 – Final)	570-MW NGCC power plant + 50 MW solar plant California	New	• CO2: 774 lb/MWH source-wide net output based on 365-day rolling average (for each CTG) • 7,319 Btu/kWh source-wide net heat rate based on 365-day rolling average (for each CTG) • CO_2e: 1,913,000 tpy • Solar component required part of facility	• CCS (economically infeasible) – would cost twice as much as the facility's annual capital coasts • Lower emitting alternative technologies (determined to be infeasible)	• First permit to incorporate CO2 lbs/MWH limit • Solar component is considered to be part of the GHG BACT determination for the combustion turbines and associated heat recovery system • No GHG BACT analysis performed for CH_4, N_2O or SF_6, since emissions are negligible (< 0.3% of facility GHG CO_2e emissions); CO_2 main source of GHGs • GHG limits based on operation at maximum permitted level; use of solar array will reduce GHG emissions below estimated rate
Robinson Power Company Pennsylvania Department of Environmental Protection (June 30, 2011 – Final)	148-MW NGCC power plant Pennsylvania	New	• CO_2e: 619,360 tpy based on 12-month rolling average and 70.7 tons/hr based on 60-minute average • No BACT analysis required (not a major source of attainment pollutants other than GHGs)		• GE 7EA natural gas-fired CTGs • Plant will use fuel from Marcellus shale • Permit issued 1 day before Phase II CAA GHG permit requirements took effect, which would require GHG PSD permit and BACT analysis • Plant will emit 620,000 tpy of CO_2
Wolverine Power Supply Cooperative[6] Michigan Department of Environmental Quality (June 29, 2011 – Final)	600-MW coal- and biomass-fired power plant (Wolverine Clean Energy Venture) Michigan	New	• CO_2e emissions limit of 6,024,107 tons/year based on 12-month rolling average • CO_2e emissions limit for each CFB boiler of 2.1 lb/KWH gross output based on 12-month rolling average • Energy efficiency for CFB boilers and ancillary fuel burning equipment • Minimum of 5% biomass in the feedstock (20% max); Biomass Fuel Management and Procurement Plan • Energy-efficient variable speed motors • Design specifications that maximize thermal performance of plant • Energy Efficiency Management Plan	• CCGT (redefine source) • Pulverized coal (redefine project) • IGCC (cost prohibitive; no clear advantage) • Biomass gasification (infeasible – limited available fuel source) • CCS (not feasible or cost effective) • Supercritical CFB (beyond BACT scope) • Use of design technologies other than CFB boiler not justified	• Uses CFB boilers – more feasible and cost-effective • Potential to emit of 6,050,090 tpy CO_2e • "Most GHG emission reduction technologies remain highly developmental and are not suitable at this time to be…BACT" • Many technologies eliminated because did not take advantage of site-specific criteria • CCGT would substantially increase consumer rates • Permit initially denied in 2010 based on lack of need. Denial reversed by county court in early 2011. • Sierra Club and NRDC filed challenge in MI state court on 09/26/11
MidAmerican Energy Company[7] Iowa Department of Natural Resources	644-MW coal-fired power plant (George Neal South)	Existing (Unit 4)	• CO_2 emissions limit: 2,588 lb/MWH-net based on a 30-day rolling average • CO_2e emissions limit: 6,807,782 tpy based on 12-month rolling average • Efficiency improvements	• Catalytic oxidation and thermal oxidation (technically infeasible) • CCS (not technically or financially feasible) • Thermodynamic cycle design and	• GHG emissions (CO_2, CH_4 and N_2O) expected to increase ~2 million tons/year CO_2e • CO_2 limit established as surrogate to demonstrate compliance with CO_2e standard (CO_2 expected to be 99% of unit's global warming potential)

(May 16, 2011 – Final)	Iowa			IGCC (redefine source) • Coal rank utilized (would not decrease CO_2e emissions)	• Compliance determined by summing CO_2 CEMS data with CH_4 and N_2O mass emissions calculations
PacifiCorp[8] Utah Department of Environmental Quality (May 4, 2011 – Final)	629-MW NGCC power plant (Lakeside) Utah	New (co-located with existing facility)	• CO_2e emissions limit of 950 lb/MWH based on a 12-month rolling average • High efficiency CTGs and HRSG • Use of low-NO_x controls	• CCS (not technically or financially feasible at this time)	• Adding new unit (2 turbines) expected to increase power plant GHG emissions by 1.8 million tons/year CO_2e • "All BACT reviews for GHGs have focused on energy efficiency"
We Energies[9] Wisconsin Department of Natural Resources (March 28, 2011 – Final)	50-MW biomass cogeneration facility (Domtar Paper Mill-Rothschild) Wisconsin	New	• CO_2 emission limit of 3,050 lb/MWH based on a 12-month rolling average • Efficient boiler operation/good combustion practices • Use of biomass/renewable fuels • Use of NO_x controls • Use of natural gas boiler	• CCS (not feasible) • Methane oxidation (not required due to cost) • Natural gas would redefine project	• No suitable CO_2 storage near site • No examples of large-scale commercially available CCS • CFB is most efficient boiler design for biomass boiler
Russell City Energy Center (Calpine) Bay Area Air Quality Management District (February 3, 2010 – Final)	600-MW natural gas power plant (Russell City) California	New facility	• CO_2e emission limit for turbines: 1.928 MMT/yr • Heat rate limit for each turbine: 7,730 Btu/KWH • State-of-the-art SF_6 circuit breakers: 39.3 metric tons CO_2e based on 12-month rolling average • Use of most efficient fire pump engine: 7.6 metric tons CO_2e based on 12-month rolling average • Use of most efficient generating technology (natural gas)	• Non-fossil fired generation (not feasible) • CCS (not feasible) • Dielectric oil or compressed air circuit breaker (not feasible)	• Based on voluntary GHG BACT requirements • At present there are no feasible post-combustion add-on controls for such facilities • Statement of Basis notes that BACT limit "needs to be 'output-based' instead of just an absolute limit on [GHG] emissions"; permit requires both absolute mass emissions limits and heat rate limits

BACT – Best Available Control Technology
BFB – bubbling fluidized bed
CCGT – combined-cycle gas turbine
CCS – carbon capture and storage
CFB – circulating fluidized bed
CO_2e – carbon dioxide (CO_2) equivalent
CTG – combustion turbine generator
ESP – Electrostatic precipitator
FGD – flue gas desulfurization
GHG – greenhouse gas
HRSG – Heat Recovery Steam Generators
MMT – million metric tons
NGCC – natural gas-fired combined-cycle
PSD – Prevention of Significant Deterioration
SNCR – selective non-catalytic reduction
SNG – Substitute natural gas
TPY – tons per year

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1 Includes GHG BACT limits for: cold, warm and hot start and shutdown; coal bunker vents (8,217 tpy); coal dryers (78,523 tpy); auxiliary boiler (74,013 tpy and energy efficient boiler design); oxidizer/sulfur recovery unit (4,937 tpy); equipment leaks (good work practices and 1,255 tpy); emergency engines; flares (Flare Minimization Plan); use of good operating practices, etc. Project Summary notes that "carbon capture has not been commercially demonstrated in the power generation sector in baseload or full stream applications" and that "post-combustion capture has only been demonstrated on small slip streams for limited periods." Other reasons cited why CCS not feasible included that geologic formations are not being used to sequester CO_2 in absence of EOR, that demo projects are needed to further develop and refine CCS technology, and the lack of a national CO_2 control program.

2 Lower emitting alternative technologies that were analyzed and eliminated included wind, additional solar, geothermal, hydro, nuclear, biomass and simple cycle combustion turbines. Reasons given why sequestration was not technically feasible included: no access to suitable sequestration site; gov't funding needed for CCS infrastructure; and, lack of transportation infrastructure

[3] Includes GHG BACT limits for: Ash pelletizer dryer (1,124 lb CO_2e/hr based on 30-day rolling average); NFPA-20 certified firewater pump engine (24 tons CO_2e/yr during any 12-month consecutive period); biogas flare (248 tons CO_2e/yr during any 12-month consecutive period). BACT for energy-efficient design incorporates cogeneration, process integration, combustion of co-products, heat recovery, and operational and maintenance monitoring, and applies to the BFB boilers, ash pelletizer dryer, and fermentation and distillation bent scrubbers. GHG BACT for BFB boilers also includes use of low-carbon and carbon-neutral fuels, restricted to those with low to no economic value, or lower impacting crops, and the use of natural gas for startup. GHG BACT for ash pelletizer dryer and biogas flare also includes restricting fuel type to pipeline-grade natural gas (and to biogas for flare). GHG BACT options eliminated included: for SF6 circuit breakers – emerging alternative technology, use of dielectric oil (technically infeasible) and oil/air-blast breakers (adverse environmental impacts); CCS – precombustion, oxygen-fired and various post-combustion capture processes (technically infeasible), post-combustion capture with chemical absorption (not cost-effective), carbon storage and beneficial use (not evaluated since capture not found to be cost-effective).

[4] Includes GHG BACT limits for: Fugitive emissions – 16.2 tpy of CH_4 (327.2 tpy CO2e); emergency generator – 15,314 lbs/hr CO_2 (766 tpy CO_2e); fire water pump – 7,052 lb/hr CO_2 (352.6 tpy CO_2e); State-of-the-art SF_6 circuit breakers – 131 tpy CO_2e. Includes work practice and operational requirements for fire pump and emergency generator, and separate standards for startup and shutdown emissions

[5] Includes GHG BACT limits for SF_6 circuit breakers (9.56 tpy CO_2e based on 12-month rolling average) and requirements for annual boiler tune-ups, and the use of high efficiency CTGs and HRSG. Lower emitting alternative technologies that were analyzed and eliminated included wind, additional solar, geothermal, hydro, nuclear and biomass. GHG BACT options eliminated as part of CCS included solvent-, sorbent- and membrane-based capture processes, geologic sequestration, ocean storage and mineral carbonation (all determined to be technically infeasible). CO2 transportation was found to be commercially available.

[6] Plant will consist of two 300-MW CFB boilers using sub-bituminous coal and biomass. GHG BACT selected also included use of proper management of renewable resources (e.g., biomass). BACT analysis found that pulverized coal, IGCC and biomass gasification technologies would increase CO_2 emissions over CFB design. CCS BACT analysis examines and eliminates the following capture technologies as not being demonstrated on the scale needed: chemical, physical and hybrid technologies for absorption (including amine and ammonia-based); adsorption; physical separation; biological uptake; and oxyfiring. CCS BACT analysis also examines and eliminates geologic (in part due to unresolved liability issues) and terrestrial sequestration technologies. GHG sources listed: CFB boilers, auxiliary boiler, emergency firewater pump engine and emergency generator, and black start generator. Lawsuit by environmental groups claims that GHG BACT analysis is flawed because it failed to require use of cleaner fuels.

[7] Permit required as a result of installation of SNCR, FGD, baghouse and other controls on Unit 4, which began operating in 1979. BACT requirements include workplace manual detailing efficiency improvements identified as BACT (replacement of low-pressure turbine components, reduced ESP use, etc.). Plant efficiency improvements eliminated as BACT included (reason why in parenthesis): cooling system heat loss recovery (would redefine the source), flue gas heat recovery (additional recovery technically infeasible), low-rank coal drying (technically infeasible for coal currently being used) and combined heat and power plant (not technically feasible). Pollution control device improvements that were eliminated as BACT: switching to a wet FGD system (no impact on net GHG emissions) and use of ammonia in SNCR system (safety aspects of using urea outweigh small possible CO_2 reduction). CCS BACT analysis examines and eliminates the following capture technologies: pre-combustion (not technically feasible), oxygen-combustion (would redefine the source) and post-combustion (no system applied to large power plant yet). CCS BACT analysis also examines and eliminates the following sequestration technologies: mineral, hydrodynamic and solubility trapping.

[8] Utah DEQ notes that using a GHG emission limit, which would represent the potential to emit, for BACT "adds no value to the resulting permit." However, CO2e emissions limit added "in this instance" at request of PacifiCorp. The Intent To Approve (ITA) issued by Utah DEQ did not set a CO_2 emissions standard or limit, though it noted that the plant would surpass the California GHG emissions standard of 1,100 lbs/ per MWH of gross output for baseload power plants. The acceptance in the ITA of high efficiency CT natural gas boiler as BACT for GHGs had suggested the use of a design standard in lieu of emissions standard.

[9] We Energies permit emissions limits based on CO_2e emissions per 1,000 pounds of steam produced for natural gas boiler of 190 lb/1,000 lb steam produced, and 3,050 lb per MWH of gross output for biomass boiler.