Boundary for accounting emissions from generation

Ecology proposes to limit the sources of emissions evaluated for compliance with the performance standard. The greenhouse gases and emission sources proposed to use for compliance are:

- CO_2 emissions
- Emissions from the stack or stacks. This will include emissions resulting from flue gas cleaning (i.e. SO_2 scrubbing with limestone).

What is not included in determining compliance?

- emissions from transporting the fuel to the site,
- removal from the ground, and
- processing to make it useable.
- Fugitive emissions from leaks of CO_2 from any sequestration equipment or CO_2 pipelines and compressors.
- Emissions of nitrous oxide (N_2O), methane, hydrofluorocarbons, perfluorocarbons, or sodium hexafluoride whether from the stack or fugitive.

Why these limits

First the California CEC rule proposal, the source of the performance standard, seems to be based solely on CO_2 from the stack. Their original proposal of 1000 lb/MWh was based on existing natural gas combined cycle power plants. The final proposal included an upward modification to account for other types of plants. The support document for the proposed California standard does not include emissions from transportation and processing of the fuel. Since a natural gas power plant would not need a sulfur oxides control system it is unclear to what extent the emissions of CO_2 from use of a limestone based flue gas desulphurization system were included.

We have estimated and compared direct fuel combustion emissions from coal and natural gas based power plants.

The following table shows our estimates of direct plant emissions based on operation of a 1000 MW facility located in Longview WA.

Plant	CO_{2e} tonnes/yr	CO_2 tonnes/yr	N_2O[1] tonnes/yr	CH_4[1] tonnes/yr	N2O + CH4 in CO_{2e} tonnes/yr	N2O + CH4 % of performance standard	N2O + CH4 % of uncontrolled CO_2
Performance standard limit (1100 lb/MWh)	4,372,051						
Pulverized coal boiler	11,057,536	10,996,000	192	96	61,536	1.4	0.56
Natural gas boiler	5,050,564	5,022,844	83.5	87.4	27,720	0.60	0.55
Natural gas CC turbine	2,729,047	2,715,342	37	106	13,705	0.31	0.50

[1] Based on emission factors published in EPA's AP42 emission factor document.

As can be seen, from the table, the emissions of N20 and CH4 from these units are predicted to be very low compared to the CO_2 emission rate. Thus the contribution of these chemicals to the total GHG emissions from a power plant is small and could be safely ignored for the time being.

Conversely what would the CO_2 emissions be for a 100 MW plant?

Plant	CO_{2e} tonnes/yr
Performance standard limit (1100 lb/MWh)	437,205
Pulverized coal boiler	1,096,622
Natural gas boiler	502,284
Natural gas simple cycle turbines	443,000

The N_2O and CH_4 emissions are based on fuel usage factors and would be about a tenth of the emissions estimated for the 1000 MW plant. This is not entirely true for the combustion turbine as current designs are less efficient for smaller size units (more CO_2 per MW)

For the coal example, the actual stack monitoring will include the quantity of CO_2 generated from burning the coal and the CO_2 that is generated from using a limestone or sodium carbonate based sulfur dioxide control system. If we assume that the coal contains 1% sulfur by weight and that the pulverized coal power plant requires 5.3 million tons of coal per year, the annual amount of CO_2 released by a control system that removes 95% of the sulfur dioxide will produce 69,230 tons/year. This is also a small quantity and could be disregarded if desired. However, the location of the emissions monitoring probes used for emissions tracking for the federal Acid Rain and mercury control programs is in the stack after any FGD system. Because of this the CO_2 from the FGD system will be monitored and reported along with the CO_2 from combustion. As a result we choose to include this CO_2 to simplify the routine emissions monitoring process.

Transportation emissions

The law implies that all emissions from generation are to be included. This could mean emissions from extraction of the fuel from the ground transporting it and rendering it into a form suitable for use. No attempt has been made to quantify the emissions that may come from extraction of the fuel form the ground or cleaning it up enough to use as fuel for power generation. We have looked into the emissions from rail transportation of coal but not pipeline transportation of natural gas or oil. Oil product pipeline emissions are relatively small since these pipelines usually employ electric pumps.

For natural gas pipelines, the gas is moved primarily with natural gas fired engines (reciprocating engines and turbines). There are a number of difficulties with the apportioning the emissions from natural gas pipelines, primarily as a result of the pipeline transporting billions of cubic feet per year from gas fields to users in Washington and Oregon, while a power plant uses only a fraction to what the pipeline transports. An added complication for Washington and Oregon sources is that the primary pipeline delivering natural gas for retail uses is supplied from its ends. One supply area is in central and northern

British Columbia, the other is from Wyoming and NW Colorado. Any apportionment of emissions will have to account for the plant location, which indicates the number of compressor stations between the gas collection and the power plant. A complicating factor results from the model plant location at Longview, WA. At that location the natural gas delivered to a user may have originated in Wyoming, British Columbia or both, and may change on an almost daily basis based on many factors including operating levels of industrial users and weather.

If oil is the fuel being evaluated, every thing associated with natural gas outlined above is repeated, plus the difficulty of allocating the small percentage f the GHG emissions from an oil refinery to the power plant. An additional complicating factor is that the crude oil from each field has differing quantities of the desirable fuel fractions (#2, #4 or even #6 distillate) and that each crude source varies in these fractions over time. The emissions from the oil refinery will be exceeded many times by the emissions directly from the power plant.

However to get a scale of what might come from the transportation of coal by rail we have estimated of the emissions from moving coal by rail from Wyoming to Washington.

Locomotive emissions were estimated based on a 115 car unit train using 5 SD70 locomotives. The estimate of locomotive to power a 1000 MW power plant would be 108,360 tonnes CO_2 per year. For the 100 MW example plant the locomotive emissions would be 8334 tonnes CO_2 /year. In both cases, these emissions are less than 1% of the uncontrolled CO_2 emissions

Calculation support information

Boiler and turbine emissions

Emissions for these generation station designs are estimated in a spreadsheet that can be supplied upon request.

The spreadsheet is conservative in its treatment of boiler based electric generation emissions. Boiler based steam electric unit emissions are based on a 35 % efficient electric generating system to estimate fuel quantities needed. CO_2 emissions are estimated -using published emission factors for various fuels.

The information for turbines is derived from manufacturer's literature on heat rates for simple cycle and combined cycle operation.

Calculation of locomotive emissions

Assumptions:

SD70 locomotive
Loaded operation at notch 6, fuel consumption 130 gal/hr[2]
Idle operation fuel consumption at 4 gal/hr.
4 engines required to pull loaded train
2 engines required to pull empty cars
Mine at Gillette Wyoming, point of use Longview WA, Distance 1294 rail miles[3]
Assume average speed of 45 mph
No idling time included
1000 MW coal plant uses 5,300,000 tons coal/year
100 MW coal plant uses 502,485 tons coal/year

Given information

#2 diesel produces 22300 lb CO_2 / 1000 gallons

Calculations

Hours to make one round trip	57.5 hours
Average fuel use per hour for round trip	398 gal/hour
Total fuel used per trip	22889 gallons
CO_2 emitted	231.5 tonnes/round trip

Number of trips per year

1000 MW plant	468
100 MW plant	36

CO_2 emitted per year by locomotives

1000 MW plant	108,360 tonnes CO_2 per year
100 MW plant	8,334 tonnes CO_2 per year

A current BNSF radio advertisement indicates their trains can move one ton of freight 400 miles for each gallon of fuel used. This equates to a fuel usage of a loaded 115 car train of coal of about 5200 gallons per one way trip, and

[2] SD70 fuel data from www.alkrug.ven.com/rrfacts/fueluse.htm, viewed on Oct. 16, 2007
[3] Gillette, WY to Longview, WA, using the BNSF rail miles inquiry calculator

less on the return, empty trip. This would result in even lower direct CO_2 emissions from the locomotives than estimated above.

Wet Scrubber CO_2 emission calculation

5300000	ton coal
1%	% sulfur by weight
95%	% removal
32	mw S
	mw
44	CO2

Chemical assumptions, 1 mole weight of sulfur will release 1 mole weight of CO2 from the carbonate scrubbing chemicals

53000	Ton sulfur in coal
	Ton Sulfur
50350	removed
	Ton
69231.25	CO2