CES Appendix A – Specific facility law and Rule applicability

Commenter W-7 Kimberley-Clarke and Snohomish PUD

Facility description

Kimberly-Clark's Everett Mill and the Snohomish Public Utility District #1 jointly developed and permitted a biomass cogeneration project in 1995. Under a long-term operating agreement signed by the parties, the District owns the facility, including the 37 megawatts of base-load, topping cycle, electric cogeneration, while Kimberly-Clark operates and maintains the facility and has rights to the residual steam to support a pulp manufacturing operation in conjunction with its tissue mill operations. The operating agreement includes terms specifically addressing capital investment obligations and facility ownership.

The facility is limited to 10% or less fossil fuel usage on an annual basis. Non-fossil fuel used is spent pulping liquor, and wood wastes. In addition to the mixed fuel/wood fired boiler owned by Snohomish PUD, Kimberley-Clarke also operates a sulfite chemical recovery boiler and a wood fired boiler. These other boilers feed steam to the steam turbine/generator owned by Snohomish PUD and produce steam used in the industrial processes. Thermal energy remaining in the waste steam from the steam turbine is recovered and used in the industrial process.

Rule and law applicability

Ecology views this facility as a baseload cogeneration facility utilizing renewable fuels for at least 90% of its annual heat input.

As a result of the at least 90% renewable fuel usage, this facility is automatically in compliance with the greenhouse emission performance standard per WAC 173-407-120(2). As long as the design and intended operation of the facility maintains the 90% or greater renewable fuel usage, it will continue to meet this automatic compliance criterion.

If the facility was only a cogeneration facility that did not meeting the renewable fuel criterion, then it would still be in compliance with the greenhouse gas emission performance standard until one of these actions take place:

1. The facility is upgraded
2. There is an ownership in the electrical generation portion of the facility of 5% or greater.

The definition of upgrade in the law is copied into the rule. First an upgrade is defined as any modification that is made for the primary purpose of increasing electrical generation capacity. As examples, an upgrade might be any of the following:

1. Taking the existing steam turbine/generator, and;
    a. Replacing it with a larger capacity steam turbine/generator unit,
    b. Replacing it with a more efficient turbine unit allowing more electricity to be generated by the existing generator,
    c. Rebuilding the existing steam turbine with more efficient turbine blades installed allowing more electricity to be generated by the existing generator; or
2. Replacement of the generator section with a more efficient generator with a higher nameplate rating, or

3. Replacement or modifications to the boilers that increase the amount of steam available to generate electricity (assuming the steam turbine/generator output has been limited by the amount or quality of the steam available).
4. Modifications to the boiler system to produce additional steam to generate electricity through an increase in the heat input (fuel used) in the boiler.

We would view examples 1-3 as changes that that do not also require an increase to the amount of fuel used. As such examples 1-3 would be exempt upgrades; changes that improve the heat rate of the facility. However, if an increase in fuel use is required to accomplish examples 1-3, and which is an explicit part of example 4, then the upgrades would not be exempt from triggering the need to demonstrate compliance with the greenhouse gas emission performance standard.

The definition then lists a number of routine and non-routine actions that are not upgrades. These include projects to install emission control equipment, perform routine maintenance to the facility, or changes that improve the heat rate (usually expressed as Btu/1000 lb steam or Btu/Kwh) of the facility. The final exemption contains its own exemption. It exempts actions to maintain reliable system operation unless these changes also increase the amount of fuel used above rates in air quality permits as of July 22, 2007.

Ecology does not see process modifications to boilers that simply increase the amount of process steam available as upgrades that would trigger compliance with the greenhouse gas emission performance standard. This is because the electrical generation capacity would remain unchanged – the existing steam turbine generators are still the same ones with the same electrical output limitation.

We currently understand the Snohomish PUD owns a boiler and the electric generating unit (the steam turbine/generator) at the Kimberley-Clarke facility and Kimberley-Clarke operates the boiler and steam turbine/generator on the PUD's behalf. We understand that Snohomish PUD owns the electricity generated by the system. For cogeneration facilities, the duration or nature of power sales contracts do not affect applicability of the greenhouse gas emission performance standard.

In contrast though, a new ownership interest in the owner of the electrical generation equipment would trigger the need to demonstrate compliance with the greenhouse gas emissions performance standard (see RCW 80.80.040(4) and WAC 173-407-110 "New ownership interest" and (120)(4)(c)). Since the Snohomish PUD owns the generating equipment, a sale of 5% or greater interest in the generating equipment, the output of the generating equipment, or the PUD would trigger the need to comply with the greenhouse gas emission performance standard.

Commenter W-8 Georgia-Pacific and PacifiCorp

Facility description
Georgia-Pacific Consumer Products (Camas) LLC (GP) owns and operates a pulp and paper mill in Camas, Washington. The pulp and paper mill includes a unique cogeneration facility which does not appear to be contemplated by the statute or proposed rule.

GP owns two of the three boilers that provide steam to the cogeneration turbine. The third boiler is owned by NRG Energy, Inc. and is leased to Georgia-Pacific. There is a single 56 MW (nameplate rating) turbine owned by PacifiCorp. PacifiCorp owns all of the electricity generated by the turbine, and all the electricity is sent to the Oregon grid. All three boilers provide steam to the cogeneration turbine through common high and medium pressure steam headers. Steam not used in the turbine and low pressure waste steam from the turbine is used within the GP mill for process needs.

The Camas cogeneration system turbine is provided steam by three boilers feeding a common headers; the vast majority (over 80%) of the steam results from combustion of renewable biomass fuels. However, we are unsure whether use of a small amount of fossil fuel (as much as 15 to 20%) makes us a "fossil-fueled thermal electric facility".

Rule and law applicability
In this situation the commenter is looking at both the older Part I regulation and the proposed Part II language. The Part I language is based on RCW 80.70 while ten Part II language is based on RCW 80.80. As noted in the response to comments section, these 2 laws regulate different things and in different ways. Their commonality is that they regulate emissions from power plants.

First under Part I, the original portion of the rule, your mixture of boilers and steam turbine/generator would be subject to requirements for mitigation if a qualifying modification were to occur. The legislature set a clear de minimis generator size, but did not establish a minimum fossil fuel usage to be subject to the law. We have subsequently interpreted this to mean there is no minimum fossil fuel usage criterion. Instead we have clarified that only fossil fuels (not biomass fuels such as wood or pulp mill sludge) have CO_2 emissions for purposes of Part I (and RCW 80.70.

<u>In Part I of this rule</u>, a qualifying modification is limited changes resulting in the greater of an increase in electrical output of 25 MW or more, or an increase in CO_2 emissions of 15% or more to mitigation of CO_2 emissions resulting from only the fossil fuel used in the boilers. For facilities using a mixture of fossil fuels and biomass fuels, the biomass contributes no CO_2 emissions. Cogeneration facilities are allowed to subtract the CO_2 equivalence of emissions attributable to steam energy used within the process or used for other useful purpose. Most cogeneration facilities are anticipated to comply with the part I mitigation requirements through their use of biomass fuel and the cogeneration credit.

A facility configuration such as yours was not contemplated by the drafters of RCW 80.70. At this time we would look at a boiler modification that increases fossil fuel usage to satisfy your industrial process needs but does not increase electrical output, as not being a modification under RCW 80.70 that would trigger the need to mitigate the increase in CO_2 emissions.

Under Part II, this facility may be entirely exempt from its requirements. This is due to the definition of power plant and its use within the definition of baseload electrical generation. A power plant is a facility for the generation of electricity that is permitted as a single plant.

Assuming that the electric generator at your plant was added sometime after the installation and permitting of some of the boilers and other boilers were permitted after installation of the electric generator, then this cogeneration system would not have been permitted as a single plant/facility/unit. However, if the electric generation was installed after a permitting evaluation that looked at the effects of the inclusion of the electrical generation within the context of the plant's steam generation system, including fuels and emissions, then it may have been permitted as a single plant. In either case we would prefer to look at actual details of the steam turbine/generator's installation and consult with the Attorney General's office before being more definitive.

In any case, this applicability analysis would need to occur prior to your company implementing any project that would increase the electrical capability of your plant.

If the facility is determined to be subject to the Part II requirements, (permitted as a single plant), your description indicates that it would not be able to be classed as a facility utilizing at least 90% renewable fuels since it is not limited by design or intent to use less than 10% fossil fuel. However your facility appears to be a cogeneration facility (assuming that you are a Qualified Facility under the FERC cogeneration rules) then you would be able to utilize the cogeneration compliance demonstration process in Part II of the rule.

Commenter W-7 Weyerhaeuser, Longview Mill complex

Facility description

Weyerhaeuser operates a topping-cycle cogeneration system which is fully integrated with the set of manufacturing facilities. Five steam generating units burning six fuel types (wood, coal, pulping wastes, oil, natural gas, pulp mill sludge), supply steam at two header pressures (1200 psi from one boiler and 600 psi from 5 boilers) to four turbine generators rated at 62 MW electricity production (total), and process steam to support the manufacturing activities. The electricity is sold to Eugene Water and Electric Board through a short-term contract. Weyerhaeuser has submitted FERC Form No. 556 "*Self-Certification of Qualifying Status for an Existing Cogeneration Facility*" on this Longview system. Four independent companies are located on or adjacent to the Weyerhaeuser mill site and are dependent upon utility support provided by Weyerhaeuser to varying degrees; i.e. process steam, process water and wastewater treatment services.

Weyerhaeuser's fuel usage does not meet the criteria in the proposed rule to qualify as a baseload electric generation facility utilizing renewable fuel.

Rule and law applicability

Ecology views this facility as a cogeneration facility. As such it will be in compliance with the greenhouse gas emission performance standard until one of these actions take place:

1. The facility is upgraded.
2. There is an ownership in the electrical generation portion of the facility of 5% or greater.

The definition of upgrade in the law is copied into the rule. First an upgrade is defined as any modification that is made for the primary purpose of increasing electrical generation capacity. As examples, an upgrade might be any of the following:

1. Taking one of the 4 existing steam turbine/generators, and;
    a. Replacing it with a larger capacity steam turbine/generator unit,
    b. Replacing it with a more efficient turbine unit allowing more electricity to be generated by the existing generator,
    c. Rebuilding the existing steam turbine with more efficient turbine blades installed allowing more electricity to be generated by the existing generator; or
2. Replacement of the generator section with a more efficient generator with a higher nameplate rating, or
3. Replacement or modifications to the boilers that increase the amount of steam available to generate electricity (assuming the steam turbine/generator output has been limited by the amount or quality of the steam available).
4. Modifications to the boiler system to produce additional steam to generate electricity through an increase in the heat input (fuel used) in the boiler.

We would view examples 1-3 as changes that that do not also require an increase to the amount of fuel used. As such examples 1-3 would be exempt upgrades; changes that improve the heat rate of the facility. However, if an increase in fuel use is required to accomplish examples 1 -3, and which is an explicit part of example 4, then the upgrades would not be exempt from triggering the need to demonstrate compliance with the greenhouse gas emission performance standard.

Ecology does not see process modifications to boilers that simply increase the amount of process steam available as upgrades that would trigger compliance with the greenhouse gas emission performance standard. This is because the electrical generation capacity would remain unchanged – the existing steam turbine generators are still the same ones with the same electrical output limitation.

As an example, if Weyerhaeuser proposes a project that would increase the pressure of the steam from the superheater of one boiler from 600 psi to 1200 psi. This increase in steam pressure is accomplished through replacement of portions or all of the existing superheater in that boiler. No additional heat input is required to accomplish the pressure increase since it will come at the expense of producing less low pressure steam in the boiler. The existing steam turbines do not require upgrades or replacement in order to generate more electricity from the additional high pressure steam to be fed to them (the turbine output has been limited by the amount of steam available). This change would not trigger the need to comply with the greenhouse gas emission performance standard since no fuel use increase is required to accomplish it.

However in the above example, if the heat input rate (fuel use) in the boiler must go up to increase the electrical output, then the cogeneration facility would need to demonstrate compliance with the greenhouse gas emission performance standard.

However, if Weyerhaeuser were to install an additional steam turbine/generator, replace all existing steam turbine/generators with larger units, and increase fuel usage (above currently permitted levels) in order to provide steam to the expanded capacity to generate electricity would trigger the need to demonstrate compliance with the greenhouse gas emission performance standard.

We currently understand that Weyerhaeuser owns and operates the electric generating units (the steam turbine/generators) at the Longview Mill Complex. Sale of electricity from those units is governed by terms of short-term contracts. For cogeneration facilities, the duration of power sales contracts do not affect applicability of the greenhouse gas emission performance standard.

In contrast though, a new ownership interest in the owner of the electrical generation equipment would trigger the need to demonstrate compliance with the greenhouse gas emissions performance standard (see RCW 80.80.040(4) and WAC 173-407-110 "New ownership interest" and (120)(4)(c)). Since Weyerhaeuser owns the generating equipment, a sale of 5% or greater interest in the generating equipment, of the Weyerhaeuser-Longview Mill, the Weyerhaeuser-Longview mill power house operations (including the electric generators), or even the larger company would trigger the need to comply with the greenhouse gas emission performance standard.

Commenter W-11 United Power – Wallula Energy Resource Center (proposed project)

Facility description

The WERC is proposed to be an Integrated Gasification Combined Cycle turbine power plant utilizing a Mitsubishi gasifier and combustion turbines with heat recovery steam generators and a steam turbine/generator. Powder River Basin sub-bituminous coal is proposed to be the primary fuel source, though other fuels such as petroleum coke and biomass could be added to the coal. The combustion turbines, steam generators and steam turbine/generators constitute the "power island". The power island is proposed to have a gross output of 886 megawatts ("MW"). A parasitic load of approximately 180 MW is part of the overall facility. This parasitic load is associated with operating the power island (such as turbine and steam cooling) and to separate, clean, and compress CO_2 in the gasifier gas. The project proponent has set a 65% CO_2 reduction in potential greenhouse gas emissions as its goal, an emission rate that is substantially lower than that which would result from meeting the greenhouse gas emission performance standard in RCW 80.80.

Rule and law applicability

The following assumes that Ecology is the local jurisdiction issuing the Notice of Construction Order of Approval to the commenter's project. We acknowledge that EFSEC may have a differing interpretation and the commenter's project is in the end governed by EFSEC's permitting process and requirements.

Ecology's interpretation of how the 2 laws would work together as outlined in our proposed WAC 173-407-005 is as follows:

1. Emissions of total greenhouse gases would be limited by a condition of the Order of Approval.[1]
2. Costs over the lifetime of the project to sequester greenhouse gasses in excess of the performance standard are determined.
3. The dollar value (per requirements of RCW 80.70 and WAC 173-407, Part I) of the CO_2 that is proposed to be allowed to be emitted to the atmosphere is determined.
4. The sequestration is considered under WAC 173-407, Part I, as a self directed mitigation program.
5. As self directed mitigation program, if the dollar value of the costs to sequester greenhouse gas emissions is greater than the value of the mitigation requirement of RCW 80.70, then both laws have been complied with.
6. If the value of the self directed mitigation program is greater than the costs to sequester then additional mitigation is required as either a self directed mitigation program, payment to an independent qualified organization, or through purchase of greenhouse gas credits.

[1] Inclusion of the greenhouse gas emission performance standard or a lower emission limitation in the Order of Approval is the method that would be used to assure the ability of ecology to enforce non-compliance with the standard. Inclusion of the limitation in an Order of Approval makes it an enforceable limitation that is looked at when determining the quantity of emissions subject to mitigation under RCW 80.70.

In the commenter's case, they state that they would operate their coal based IGCC project to meet a greenhouse gas emission rate of about 765 – 810 lb/MWh (about 65 % reduction in GHG emissions from an IGCC systems 1700 – 1800 lb/MWh uncontrolled rate). The mitigation requirement would be based on the emissions actually anticipated/permitted in an air quality permit to occur. If we assume the emissions will be 765 lb/MWh and the facility produces 710 net MWh, the quantity of CO_2 to be mitigated under RCW 80.70 and WAC 173-407, Part I would be 7,769,915 tonnes which equates to $12,431,860.[2]

If the costs, over the lifetime of the project, to sequester CO_2 in excess of the performance standard would exceed this $12 million dollar value, then the mitigation requirement of RCW 80.70 will be met.

Note that if the plant sequesters to meet an allowable emission rate of 756 lb/MWh, then over the course of one year, it would 'over-sequester' 335 lb/MWhr (1100 – 765). Over the course of one year, the project would 'over-sequester' 945,142 tonnes/year. If the plant owner were to convert this 'over-sequestration' to permanent carbon credits, the owner could then use those credits to meet the carbon credit option of RCW 80.70. It would take approximately 8¼ years worth of these carbon credits to meet the mitigation quantity requirement of RCW 80.70 when carbon credits are used for compliance.

[2] This contrasts to the commenter's proposal that the RCW 80.70 emissions would be the emission performance standard. This is could occur if the permitting agency only limits the greenhouse gas emissions to the performance standard, rather than the lower proposed emissions.