Data Request 1 – GHE Responses

DR1-1 Request letter Section II
Please provide data to support projections for expected increase in gas-based generation. Please include in this data, how the retirement of coal-based generation aligns with these projections.

Please see below for consolidated response to questions DR1-1 Request letter Section II and DR1-2 Request letter Section II 2.

DR1-2 Request letter Section II 2
The request letter states, "Consequently, the increase in CO_2 emissions from the Grays Harbor Energy Center is offset by emissions avoided at less efficient facilities that would otherwise operate to meet power and demand needs." Please provide supporting data for this statement, including, but not limited to, any documentation that supports the stipulation that GHEC is operated in priority over less efficient gas-based generation facilities.

In the Northwest Power Pool subregion of the Western Interconnection (WECC) (which includes states such as WA, OR, ID, and MT), power is bought and sold bilaterally between load serving entities (buyers) and generators (sellers). One of the most traded hubs for power in the Pacific NW is Mid-Columbia (Mid-C). Traditionally, power is bought and sold using the Mid-C power price +/- the cost to transmit power and deliver to that main hub. Hydro, wind, and solar generators can sell first since they effectively have zero marginal cost of power production and as a result are price takers, meaning they are willing to produce power at almost any cost. Coal and natural gas-fired power plants require the procurement of fuel to produce power and therefore are considered higher on the supply stack because they incur higher marginal costs.

Plants that can burn coal or natural gas more efficiently have lower heat rates, which means that they require less coal/gas to generate the same amount of power. The heat rate is the amount of energy used by a generator to generate one kilowatt-hour (kWh) of electricity. Heat rate and emission rates are inversely correlated: the lower a unit's heat rate, the more efficiently (less emissions and cost) the unit can convert fuel to power. A market that consists of more efficient coal/natural gas plants can supply consumers power at a lower cost than one with less efficient plants. There are also environmental benefits since less carbon dioxide is emitted when plants are more efficient. Another benefit of natural gas generation is that the plants are dispatchable, meaning they can be turned on or off and their output increased or decreased quickly depending on the demand for power. This flexibility enables additional renewable and other intermittent capacity to be added in the region without impacting the reliability of the grid.

When looking specifically at the Northwest Power Pool, as shown in the supply curve below sourced from ABB's Velocity Suite software, Grays Harbor Energy Center is one of the most efficient gas-powered units. Any additional capacity added to GHE would displace capacity that would otherwise be produced by less efficient units shown to the right of the "X" mark on the below graph when it is needed.

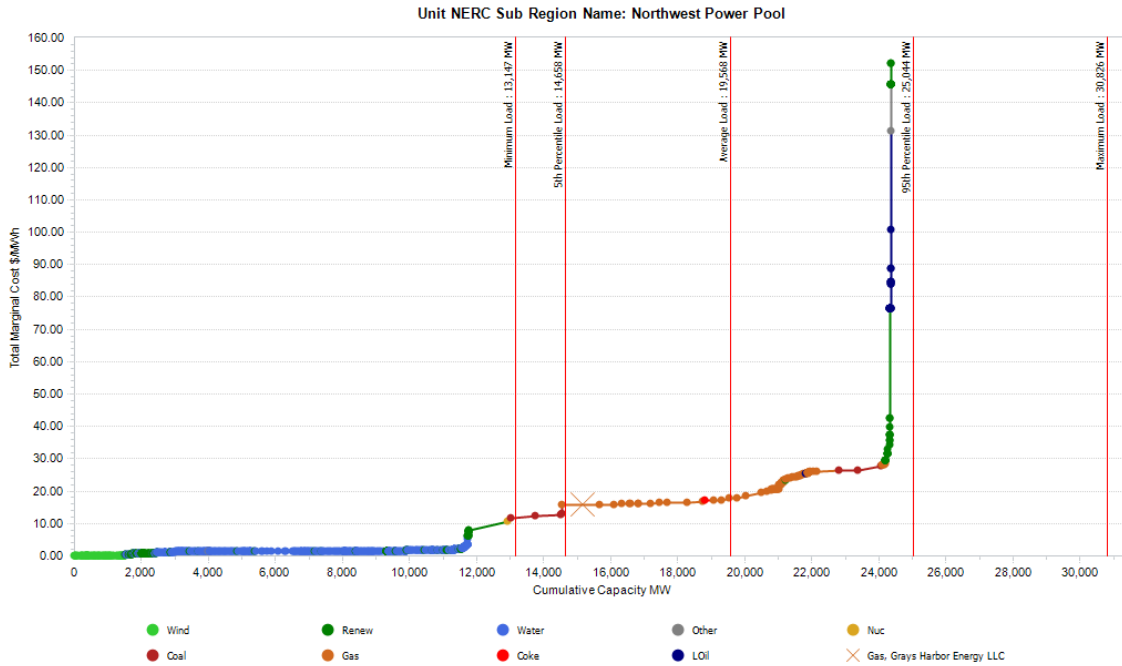

Figure 1

Furthermore, below is a table of operating natural gas generators in Washington state sorted by heat rate that indicates GHE is the most efficient plant in the state.[1]

Plant Name	Plant State	Unit	Configuration	Primary Fuel Category	Heat Rate Btu/kWh
Grays Harbor Energy	WA	CC1	CC	Gas	6,934
Chehalis Generating Facility	WA	CC1	CC	Gas	6,997
Goldendale Energy Center	WA	CC1	CC	Gas	7,004
Frederickson I	WA	CC	CC	Gas	7,143
River Road Generating Plant	WA	1	CC	Gas	7,363
Mint Farm Energy Center	WA	CC	CC	Gas	7,449
Tenaska Ferndale Cogeneration Station	WA	CC1	CC	Gas	7,852
Encogen	WA	CC	CC	Gas	8,203
Sumas Cogeneration Co LP	WA	CC	CC	Gas	8,433
Fredonia (WA)	WA	4	GT	Gas	10,489
Fredonia (WA)	WA	3	GT	Gas	10,501
Fredonia (WA)	WA	1	GT	Gas	11,468
March Point Cogeneration Co	WA	GTG1	GT	Gas	12,404
March Point Cogeneration Co	WA	GTG2	GT	Gas	12,404
March Point Cogeneration Co	WA	GTG3	GT	Gas	12,404

Figure 2

As identified in the amendment request and below table, projected plant retirements in the Northwest Power Pool (NWPP) are expected to total over 4,450 MW, resulting in tighter reserve margins, or less excess capacity after meeting demand.

[1] Source: ABB's Velocity Suite

NWPP Projected Plant Retirements				
Plant Name	Summer Capacity (MW)	Type	Approx. Distance to Grays Harbor (mi)	Retirement Year
Centralia 1	670	Coal	30	2020
Centralia 2	670	Coal	30	2025
Colstrip (1-2)	614	Coal	800	2019
Colstrip (3-4)	1480	Coal	800	2027
Boardman	585	Coal	200	2020
North Valmy 1	254	Coal	520	2019
Copco	62	Hydro	350	2021
John C Boyle	98	Hydro	340	2020
Iron Gate	19	Hydro	350	2020
Total Projected Retired Production: 4,452 MW				

Figure 3

The NWPP is a sub-region of WECC. Expected coal retirement capacity between 2019 and 2030 in WECC is around 18,000 MW.[2] Additionally, according to NERC's 2019 reliability assessment report, peak power demand in the NWPP is expected to grow annually by 0.6%.[3]

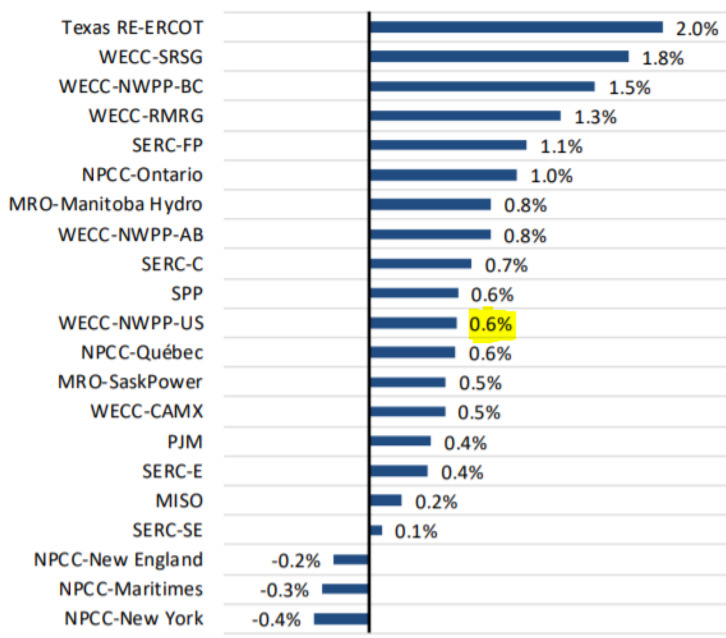

Figure 27: Annual Peak Demand Growth Rate for 10-Year Period by Assessment Area

Figure 4

With fewer coal generating units operating to meet growing power demand, the region will need increased production from existing natural gas generators. In summary, gas-based generation will be needed to help "fill the gap" between supply and demand left from the retired coal capacity.

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[2] Kujala, B. (2019, August 19). A Pile of Retirements: The Next 10 Years for Western Coal Plants. Retrieved October 05, 2020, from https://www.nwcouncil.org/news/coal-retirements.

[3] (Rep.). (n.d.). NERC. Retrieved October 05, 2020, from https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2019.pdf.

The below graph sourced from S&P Global Platts shows a comparison of GHE's peak heat rate vs. the market implied peak heat rate forecasted for the next 10 years.[4] The market implied heat rate is calculated by dividing the forecasted average on peak and off peak power prices by the gas prices. The green line represents the generator with the highest marginal cost which would ultimately set the market clearing price and the blue line represents the average heat rate at GHE. In other words, if the GHE heat rate (the blue line) is below the market peak heat rate (the green line), the GHE will be dispatched.

Figure 5

The graph illustrates that the implied market heat rate for a gas power plant in the region is expected to exceed GHE's heat rate in every month but one for the next ten years. In other words, GHE is projected to procure gas and sell power at a lower cost than other units in the region for almost the entire period. Because market dispatch is based on efficiency, GHE is expected to operate in priority to other gas generating units 99% of the time over the next ten years.

DR1-3 Request letter Section II 3
Please provide any available measurements or documentation that supports the statement, "Accordingly, no increase in noise is expected."

The equipment changes involved in the Advanced Gas Path package all take place inside the existing equipment. The upgrade will not add any new equipment or create any new noise sources. Existing components of the turbine will be replaced with components nearly identical in shape and size, only made from more advanced materials capable of withstanding higher temperatures. As a result, GHE expects no change to sound levels during operation. GHE and Invenergy do not have any empirical sound level measurement data for facilities operating with the Advanced Gas Path packaged installed. However, Invenergy has installed the Advanced Gas Path package at its Nelson Energy Center, located west of

[4] Source: S&P Global Platts Natural Gas Services; S&P Global Platts Electric Power Services

Chicago in Rock Falls, Illinois and the operators have not noticed any change in sound levels; nor have they received any complaints about noise from neighbors.

The Site Certification Agreement already includes numeric noise limits (Art. V.E.2.). GHE is not requesting any changes in those limits. GHE is confident that the facility will continue to comply with those limits after the Advanced Gas Path is installed, and GHE will remain responsible for ensuring compliance with those limits. GHE recognizes that it is in our best interest to proactively maintain noise levels and mitigate the possibility of any noise-related issues.

DR1-4 Request letter Section II 4
The request letter states, "Depending on ambient conditions, the hotter firing of the combustion turbines could result in a slight increase in water used in the cooling tower, but the change is not expected to be material. No change in the quality of wastewater discharge is to be expected."
Please provide calculations or documentation that supports the "non-material" increase in cooling tower water use. Please also provide calculations or documentation to demonstrate a lack of change in wastewater discharge.

The amount of water used in the facility's cooling tower depends upon several factors, including ambient conditions (i.e. temperature, relative humidity) and the facility's operating characteristics (e.g. power production, operating hours). The SCA contains limits on the volume of water to be withdrawn annually, and those limits were developed considering various scenarios throughout the year. The AGP upgrade enables the gas turbines to fire at a higher firing temperature, and consequently improves efficiency. This results in a maximum increase of total exhaust energy, as estimated by the OEM, of roughly 3% when the turbine is at a base load operating condition. At this condition, the higher exhaust energy could increase the overall heat load in the condenser, and thus the required heat rejection (i.e. evaporation rate) in the cooling tower could theoretically increase by an amount of less than 3%. Due to the large number of variables and the several energy transfer processes between the gas turbine and cooling tower, there is a range in water consumption. However, we do not expect this increase to ever exceed 3%. It is also important to note this higher exhaust energy condition is only a factor at base load. Since the units have a higher max output and higher efficiency with AGP, the MW levels the gas turbines typically operate at now will be at a lower percent load point after the upgrade, and will actually have a lower heat rejection and evaporation rate at times when the facility is not operating at 100% load, which is much of the time.

Additionally, Invenergy has not noticed a material increase in water use at the Nelson Energy Center after AGP installation. The GHE Site Certification Agreement already includes provisions governing the withdrawal of water for use at the facility. (Art. V.A.) GHE is not requesting any change to those provisions.

As to the waste water discharge, the upgrade will not change any part of the steam cycle chemistry and no additional chemicals will need to be used to operate with the AGP parts. For this reason, we do not expect any difference in wastewater quality following installation. The NDPES permit already contains provisions governing the water quality of water discharged from the facility and GHE is not requesting any change to those provisions.

DR1-5 SCA Article II B 1. b.
Please provide rational for the suggested edits to remove facility capacity.

When the Site Certification Agreement was written, Article II.B.1.b. referred to the rated or "nominal" capacity of the GE 7FA turbines that were proposed to be used and that were, in fact, installed. The

Advanced Gas Path package involves upgrading some of the internal equipment in those turbines, and GE does not provide a rated capacity for the Advanced Gas Path package. Instead, GE guarantees a percentage change in performance across a range of different temperatures. For this reason, our request for amendment is careful to refer to the expected capacity when operated at 100% load at 59 degrees F. Rather than including these details in the SCA, we thought it made more sense to remove the reference to rated capacity and instead, clearly specify the equipment being installed, especially since it would be extremely rare for a turbine to actually be operating at a specified megawatt value. Needless to say, whether or not a megawatt rating is specified in SCA Article II.B.1.b., GHE would be required to come to the Council if it wanted to install additional or different equipment in the future to further increase the power output of these units.

DR1-6 SCA Article II B. 2.

Please provide rational, including relevant data or projections, for extending the construction window to 2028. Please include discussion on why construction has not been feasible to this point.

Like other project developers, GHE and Invenergy construct generation facilities when market conditions or contractual arrangements give them a high level of confidence that there is demand for the electricity they would generate. The long lead time involved in permitting and constructing these facilities, require developers to try to predict future market conditions, so they are prepared to deliver electricity when it is needed. To date, market conditions have not justified construction of Units 3&4. Considering market conditions and load forecasts, it is our best estimate that there will be sufficient need for electricity in the region to justify construction by 2028.

As evidenced by Figure 5 above, the implied market heat rate in the NWPP is expected to increase throughout the decade, indicating a growing need for gas-fired generation. GHE's request to extend the construction window of Units 3&4 to 2028 is based on a projected need for gas-powered generation in the region in the latter half of the decade. The last projected coal plant retirement in the NWPP is expected to occur in 2027 when Colstrip retires Units 3&4 and capacity in the region decreases by 1,480 MW (see Figure 3). We also understand that according to NERC, power demand in the NWPP is expected to increase 0.6% annually.[5] It takes approximately two years to construct a power plant, so we would have to start construction by 2028 in order to be operational in 2030. In summary, extending the construction deadline for Units 3&4 through 2028 allows GHE to observe changing market conditions as coal plants retire and help fill a potentially large gap between dispatchable and reliable power supply and demand.

GHE considered requesting a 10-year extension because it would be a "round" number. Ultimately, however, our best guess looking at the data suggests that construction in the 2026-2028 range is most likely, so we did not want to request an extension longer than necessary.

DR1-7 SCA Article VII B.

Please provide calculations and assumptions used to determine facility Greenhouse Gas (GHG) emissions with the installed Advanced Gas Path upgrade, with respect to facility projections on future load.

The Grays Harbor Energy Center utilizes Equation G-4 in 40 CFR 75 Appendix G as the method for calculating CO2 emissions from each turbine/duct burner stack. This is the USEPA approved method for

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[5] (Rep.). (n.d.). NERC. Retrieved October 05, 2020, from https://www.nerc.com/pa/RAPA/ra/Reliability Assessments DL/NERC_LTRA_2019.pdf.

turbines/duct burners combusting natural gas. The emission factor used in this equation is 118.86 lb CO_2/mmBtu. This emission factor is used to report emissions to both Ecology and the USEPA. Because the equation relies on heat input to calculate emissions, any percentage change in heat input will result in the same percentage change in CO_2 emissions.

The change in potential CO_2 emissions can be calculated using the following assumptions:

1. Each of the duct burners has a permitted heat input rate of 505 mmBtu/hr. The rated capacity of the duct burner will not be affected with the upgrade to the turbines. Potential emissions are calculated using the USEPA factor and the heat input.

$$\frac{505\ mmBtu}{hr} \times \frac{118.86\ lb\ CO2}{mmBtu} \times \frac{8{,}760\ hr}{yr} \times \frac{ton}{2{,}000\ lb} = 262{,}906\ tons\ CO2/year$$

   Therefore, the total CO_2 potential to emit (PTE) for both duct burners is 525,812 tons CO_2/year. This value will not change due to this project.

2. Potential CO_2 emissions for a single turbine as they are currently configured are calculated using the USEPA emission factor and the currently permitted heat input rate of 1,671 mmBtu/hr.

$$\frac{1{,}671\ mmBtu}{hr} \times \frac{118.86\ lb\ CO2}{mmBtu} \times \frac{8{,}760\ hr}{yr} \times \frac{ton}{2{,}000\ lb} = 869{,}934\ tons\ CO2/year$$

   Therefore, the total CO_2 potential to emit (PTE) for both turbines is 1,739,868 tons CO_2/year.

3. Potential CO_2 emissions for a single turbine after the installation of the AGP upgrade package are calculated using the same USEPA emission factor and a heat input rate of 1,823 mmBtu/hr, which is based on GE data for operations at an ambient temperature 59F and 100% load.

$$\frac{1{,}823\ mmBtu}{hr} \times \frac{118.86\ lb\ CO2}{mmBtu} \times \frac{8{,}760\ hr}{yr} \times \frac{ton}{2{,}000\ lb} = 949{,}066\ tons\ CO2/year$$

   Therefore, the total CO_2 PTE for both turbines is 1,898,132 tons CO_2/year.

4. The CO_2 potential annual emissions from the turbines will increase by approximately 9.1%, which is directly correlated to the 9.1% increase in the nominal rated heat input.

5. The CO_2 potential annual emissions from the combined turbine/duct burner stacks after the installation of AGP will be the following:

Unit	Heat Input (mmBtu/yr)	CO2 Emissions (tons/year)
Turbines	31,938,960	1,898,132
Duct Burners	8,847,600	525,812
Total	40,786,560	2,423,944

Invenergy has projected that the future actual heat input for the two turbines/duct burners at Grays Harbor after the installation of the AGP upgrade package will be 31,691,290 mmBtu/yr. This is representative of operation at different loads and under varying environmental conditions. The projected actual CO2 emissions are calculated as follows:

$$\frac{31{,}691{,}290\ mmBtu}{yr} \times \frac{118.86\ lb\ CO2}{mmBtu} \times \frac{ton}{2{,}000\ lb} = 1{,}883{,}413\ tons\ CO2/year$$

The average annual emissions per turbine/duct burner stack would be approximately 941,707 tons CO2/year.

When evaluating CO2 emissions, it is also important to consider the corresponding power generation and the rate of emissions per unit of power produced. GE conducted an analysis of the design ratings of the turbines as they are currently configured and an analysis of the design ratings after the AGP upgrade package is installed. The change in the efficiency of the turbines, also known as the heat rate, will result in a lower rate of CO2 emissions produced per MWh of power generated.

1. Currently, the turbines have a design heat rate of 9,301 Btu/kWh (59F, 100% load). CO2 emissions per MWh are calculated as follows:

$$\frac{9{,}301\ Btu}{kWh} \times \frac{1000\ kW}{MW} \times \frac{mmBtu}{1{,}000{,}000\ Btu} \times \frac{118.86\ lb\ CO2}{mmBtu} = 1{,}105\ lb\ CO2/MWh$$

2. After the AGP upgrade package is installed, the turbines will have a design heat rate of 9,086 Btu/kWh (59F, 100% load). CO2 emissions per MWh are calculated as follows:

$$\frac{9{,}086\ Btu}{kWh} \times \frac{1000\ kW}{MW} \times \frac{mmBtu}{1{,}000{,}000\ Btu} \times \frac{118.86\ lb\ CO2}{mmBtu} = 1{,}080\ lb\ CO2/MWh$$

3. The CO2 emissions per MWh will decrease by approximately 2.3%, which directly correlates with the 2.3% improvement in heat rate.

DR1-8 SCA Article VII B.

There is a discrepancy between what the facility's approved output (650 MW), the output used as an example in the GHG mitigation plan (630 MW), and the output used in the GHG mitigation funding calculations (635 MW). Please provide additional information that reconciles these numbers, and discuss how the projected shift in GHG output with the AGP could impact GHG mitigation.

The original GHG mitigation plan was executed in 2003 before the facility was constructed and before Invenergy took ownership of the facility in 2005. The mitigation plan uses 630 MW in a hypothetical example to illustrate the calculation that would be used. We understand that 630 MW may have been what the maximum generating capacity was expected to be at that time. In general, maximum output of the turbines can vary slightly from unit to unit once equipment is installed and units are tuned.

Invenergy later submitted a mitigation plan in February 2008 that became the basis for the current 635 MW input in the facility's annual GHG mitigation plan. The units did not fire for the first time under

Invenergy ownership until the following year, so we understand this 635 MW output assumption was also an estimate of the facility's maximum gross output level.

The SCA refers to the 650 MW nameplate capacity or "rated capacity" of the generating equipment from the manufacturer. This nameplate power output is the sum of the maximum rated gross outputs for the two gas turbines (175 MW each) and the steam turbine (300 MW). Because of the current configuration of the facility, however, GHE is unable to generate a gross output level near this 650 MW nameplate capacity even in the most favorable conditions.

Post installation of AGP, we expect to revise the GHG mitigation calculation to reflect the increase in the facility's capacity and the decrease in the facility's gross heat rate.