July 15, 2022

Attention: Joshua Grice
Department of Ecology
Air Quality Program
P.O. Box 47600
Olympia, WA 98504-7600

RE: Rulemaking – Chapter 173-446 WAC, Climate Commitment Act Program Rule

On May 16, 2022, the Washington Department of Ecology (Ecology) issued form CR-102 (WSR 22-11-067) soliciting formal comments on its proposed new rule, Chapter 173-446 WAC, Climate Commitment Act Program. The following comments are submitted jointly by Avista, Northwest Requirements Utilities, PacifiCorp, the Public Generating Pool, Puget Sound Energy, and the Washington Public Utility Districts Association, referred to throughout these comments as the "Joint Utilities."

GENERAL COMMENTS

In addition to the specific comments provided here, the Joint Utilities would like to reiterate the clear statutory direction given to Ecology throughout the Climate Commitment Act (CCA) to develop a cap and invest program that facilitates linkage with other jurisdictions. We appreciate the efforts made by the agency to prioritize mechanisms like the price floor and price ceiling in the latest iteration of the rules. The Joint Utilities encourage Ecology to continue work to align the program with an emphasis on equivalent market integrity and stringency so as to preserve the ability to link with other jurisdictions, such as California and Quebec. It is in the collective interests of our customers that a robust set of rules be adopted that allows for Washington's program to link with external cap-and-trade programs as soon as is practicable.

We would also like to highlight our joint perspective that the CCA Program Rule should be designed and implemented to ensure that electric utilities' cost burdens associated with the program will be addressed through the provision of sufficient no-cost allowances. In contrast with other sectors, the electric utility sector is already subject to the requirements of the Washington Clean Energy Transformation Act (CETA). The CCA recognizes this difference by allocating no-cost allowances to mitigate the cost burden of electric utilities. Indeed, in order to decarbonize the economy, the state has forecasted significant electrification of buildings, transportation, and industrial processes that will increase utility loads. Any resulting cost burden for electric utility customers associated with the program must be recognized and reflected in the allowance allocation schedule adopted by Ecology by October 1, 2022, and subsequent allowance allocation schedules.

In the comments that follow, specific policy or programmatic elements of the proposed rule on which the Joint Utilities have comments or recommendations are grouped under the following three categories:

- Electric utility cost burden and no-cost allowances;
- Electric sector baseline; and
- Other programmatic concerns.

<u>ELECTRIC UTILITY COST BURDEN & NO-COST ALLOWANCES</u>

Electric utilities and their appropriate governing board or utility regulator are the entities best situated for determining the cost burden effect of the CCA cap and invest program on electricity customers. Ecology's proposed cost burden effect formula does not capture the full cost burden of the CCA on electric customers, which will lead to insufficient allowance allocation in conflict with the intent of the CCA.

In enacting the CCA, the Legislature specified its intent to allow all consumer-owned and investor-owned utilities subject to the requirements of CETA to be eligible for an allocation of no-cost allowances in order to mitigate the cost burden of the cap and invest program on electricity customers. This provision recognizes the duplicative nature of CETA and the CCA as it pertains to the electric sector and ensures that customers are not burdened with the costs of decarbonizing the electric sector under two separate policy regimes. Indeed, under both statute and the proposed rule, the definition of "cost burden" is provided as follows:

> "*'Cost burden' means the* ***impact on rates or charges to customers of electric utilities*** *in Washington state for the incremental cost of electricity service to serve load due to the compliance cost for greenhouse gas emissions caused by the program. Cost burden includes administrative costs from the utility's participation in the program* [**emphasis added**]."

The definition of cost burden is focused on the impact of the cap and invest program on utility rates on electricity customers—an impact that can only be properly assessed by the utilities and their appropriate governing board or utility regulator. This fact was recognized by the Legislature in its articulation of the methods by which Ecology is to allocate no-cost allowances to electric utilities in RCW 70A.65.120(2)(a) and (b):

> "*(2)(a) By October 1, 2022, the department shall adopt rules, in consultation with the department of commerce and the utilities and transportation commission, establishing the methods and procedures for allocating allowances for consumer-owned and investor-owned electric utilities. The rules must take into account the cost burden of the program on electricity customers.*
>
> *(b) By October 1, 2022, the department shall adopt an allocation schedule by rule, in consultation with the department of commerce and the utilities and transportation commission, for the first compliance period for the provision of allowances at no cost to consumer-owned and investor-owned electric utilities. This allocation must be consistent with a forecast, that is approved by the appropriate governing board or the utilities and transportation commission, of each utility's supply and demand, and the cost burden resulting from the inclusion of the covered entities in the first compliance period.*"

Importantly, allowance allocation hinges on a forecast process that informs the nature and extent of the program's cost burden on customers, information on which Ecology must rely when "establishing the methods and procedures for allocating allowances." Based on the statute, the Joint Utilities believe that Ecology's role is to adopt an allocation schedule consistent with utility-developed forecasts of supply, demand, *and* cost burden. The utility-developed forecast of cost burden should be inclusive of all CCA costs, including impacts to dispatch, federal power marketing administration elections, and administrative costs arising "from the utility's participation in the program" beginning in the first compliance period. After these forecasts are developed by utilities, they are then to be approved by the appropriate governing board or the Utilities and Transportation Commission (UTC) before being transmitted to Ecology for incorporation into the allowance allocation schedule.

Despite the articulation of these points by the Joint Utilities in our January 26th comments and in an additional letter sent to Ecology in April 2022, the proposed rule currently states that Ecology will be the entity to "determine how cost burden and its effect will be used to allocate allowances to each electric utility for each emissions year"[1]. At each step of the cost burden methodology articulated by Ecology in proposed WAC 173-446-230(1)(a) through (d), input by utilities and their governing board or regulator is secondary to Ecology's discretion, in contradiction to the plain language of the approach specified in RCW 70A.65.120(2)(a) and (b).

Further, given statutory direction, the Joint Utilities are quite concerned about the "cost burden effect" formula articulated under proposed WAC 173-446-230(1)(d) (Equation 230-1). The formula as written does not adequately estimate the impacts of the CCA and will lead to insufficient allowance allocations and higher costs for electric customers, contrary to legislative and public policy intent. An accurate electric forecast and cost burden calculation should account for the following elements to capture the full "impact on rates or charges to customers of electric utilities. . .caused by the program":

- **Increased power costs:** The inclusion of carbon prices into the dispatch of generation used to serve Washington loads is expected to result in higher operating costs and/or lower wholesale market sales.
- **Allowance allocation based on anticipated carbon emissions using facility-specific emissions factors:** Ecology should allow utilities to replace default emissions factors with facility-specific emissions factors, which more closely reflect utilities' expected compliance obligations when the utility's forecasted coal and natural gas generation is from a specified source.
- **Administrative costs of program participation in all compliance periods:** Under the proposed rule, Ecology does not account for the administrative costs associated with utilities' participation in the cap and invest program until the second compliance period, despite the fact that initial, upfront capital and operational costs associated with program participation will be most significant in the first compliance period. This is inconsistent with the statutory definition of cost burden, which does not include an exception for administrative costs incurred during the first compliance period. Ecology should allow utilities to develop forecasts of administrative cost burden subject to approval by the appropriate governing board or the UTC.
- **Variability of hydroelectric, wind, and solar resources:** Generation from variable resources may not be normalized within a four-year compliance period, resulting in a risk that utilities will face higher cost burden via either increased direct compliance obligations or embedded carbon costs in market purchases.
- **Consideration of BPA power purchases either through preference contracts or specified source sales:** Specified power purchased from BPA, including power purchased by public power utilities

[1] Proposed WAC 173-446-230(1)

under Block, Slice, and load-following contracts, will be subject to a compliance obligation based on BPA's asset-controlling supplier (ACS) emissions factor. BPA's ACS emissions factor is therefore an appropriate emissions factor to apply to such purchases for the purposes of determining cost burden. However, Ecology's cost burden effect formula only includes emissions factors for coal, natural gas, and non-emitting as well as unspecified resources, but does not address ACS purchases. If BPA decides to voluntarily participate in the cap and invest program as the FJD for the power it markets to Washington utilities, the compliance costs associated with BPA specified-source purchases will be passed on to BPA's utility customers through rates. If BPA does not decide to participate as the FJD, the compliance costs associated with BPA specified-source purchases will be incurred by the utility directly.

- **Consideration of wholesale purchases scheduled from BPA:** In the event that BPA decides not to voluntarily participate in Washington's cap and invest program as the FJD, utilities purchasing BPA's surplus power sold in the wholesale market as standard Schedule C energy would face two distinct cost burdens associated with such purchases: (1) As with any other wholesale unspecified purchase, the cost of carbon would be embedded in the prevailing wholesale market energy price; and (2) the compliance obligation for that power, which would be assumed by the subsequent purchasing-selling entity in the physical path on the e-tag. This obligation is not known until the energy is scheduled and is assigned the default unspecified emissions factor. The carbon obligation is only incurred if an entity is scheduled energy from BPA, and is additional to the embedded cost of carbon in energy prices.
- **Costs associated with balancing transactions:** Ecology's cost burden effect formula is based on annual load and generation forecasts that do not fully take into account the balancing and hedging purchases utilities make to account for the variability of load and resources across the four-year compliance period. These transactions are generally unspecified purchases that would be expected to either directly carry CCA compliance obligations or have the cost of carbon embedded in the price.

For these reasons, the Joint Utilities request that Ecology substantively revise proposed WAC 173-446-230 to align with the statutory requirements of the CCA and capture the full costs of the CCA on electricity customers. Considering the nature of long-term utility planning, the forecast process must, consistent with statute, lead to certainty regarding adequate allowances for electric utilities' upcoming four-year compliance period. The Joint Utilities understand the complexity of this request, made in the interest of our customers, and the constrained timetable under which Ecology is operating. The Joint Utilities are fully prepared to meet with Ecology as often and as frequently as necessary to help craft an acceptable and equitable methodology that minimizes administrative and procedural burden upon Ecology staff. Given the impact of this methodology on customers, the Joint Utilities request that the Washington Utilities and Transportation Commission (UTC) and the Department of Commerce (Commerce) be involved in these discussions per their consultative roles in the CCA.

Finally, the Joint Utilities respectfully request an allowance allocation adjustment mechanism to ensure the intent of the legislation is met and that electric customers, who are already incurring CETA costs, do not incur additional cost burden due to the CCA. As requested in our January 26th comments, Ecology should add a provision to the rule that grants electric utilities additional no-cost allowances from the allowance price containment reserve in order to account for unforeseen circumstances. Such circumstances can include, but are not limited to, unforeseen load growth associated with electrification, leading to unmitigated cost burden. Doing so would achieve the objectives of the CCA without slowing emissions reductions from the electric sector, as CETA already requires electric utilities to produce electricity 100 percent carbon neutral by 2030 and 100 percent free from greenhouse gas emissions by 2045.

The Joint Utilities respectfully submit an alternative to Ecology's proposed approach for the calculation of electric utility cost burden and the subsequent distribution of no-cost allowances.

To address the concerns with Ecology's proposed approach for the calculation of electric utility cost burden and the subsequent distribution of no-cost allowances, articulated above, the Joint Utilities respectfully submit for consideration a proposed alternative approach to calculating the allowances needed to cover electric utilities' cost burden in **Attachment A – CCA Cost Burden Template**. This template attempts to arrive at an approach that:

- Expands upon the simple framework provided by Ecology's cost burden effect formula and incorporates the three statutorily dictated elements of electric utilities' no-cost allowance allocation: forecasts of supply, demand, and cost burden across the four-year compliance period[2];
- Provides simplicity, transparency, and consistency across electric utilities that utilize the template, while still preserving flexibility and adaptability to utilities' idiosyncratic load and resource contexts; and
- Closely aligns with the concepts adopted in the California cap and trade program, to help better facilitate potential program linkage.

About the Template

In developing the proposed CCA Cost Burden Template, the Joint Utilities wanted to avoid "reinventing the wheel" where possible—so we looked to California, the jurisdiction with which Washington is looking to link its cap and invest program. Like the CCA, the California Air Resources Board (CARB) allocates allowances to electrical distribution utilities (EDU) and natural gas suppliers on behalf of their ratepayers. The number of allowances allocated to each EDU is based on its anticipated cap-and-trade program compliance costs. California's EDU allocation calculation methodology uses each utility's demand forecast, supply forecast, and additional information to calculate its expected annual program compliance costs.

The Joint Utilities' template is based loosely on CARB's Post-2020 EDU Allocation Table and 2021-2030 Allowance Allocation to EDUs, with the following key variations that reflect differences between the respective programs and state policy frameworks:

> **Data Sources**: While California's cap and trade program can make use of a statewide electricity demand forecast conducted by the California Energy Commission, in Washington resource planning is conducted on an individual utility basis.
>
> **Transmission Losses**: Rather than assume default transmission losses, as CARB does, the Joint Utilities' template addresses transmission losses in the Energy to Serve Load (MWh) field, which is the utility's forecasted annual energy demand including transmission and other losses.

[2] RCW 70A.65.120(2)(b)

Natural Gas Power/Balancing Purchases: California's EDU allocation assumes that natural gas is the "backstop resources"—that is, any power not supplied by coal, nuclear, hydroelectric, or RPS-eligible resources would be generated with natural gas. CARB assumes that the EDU would require a minimum quantity of natural gas power equivalent to 5% of energy to serve load, consistent with the expectation that EDUs will need some natural gas power to support variable renewable resources. In contrast, and consistent with Ecology's formula, the Joint Utilities' template includes natural gas as a declared, specified resource category and treats unspecified purchases as the backstop resource for supplying energy to serve load after all declared resources are forecast. An "operational adjustment" of 5% unspecified energy to account for balancing purchases that carry CCA compliance obligations is included for all electric utilities, similar to California's assumption of a minimum of 5% natural gas for balancing, to cover short-term purchases not otherwise captured in the annual forecasting framework. These balancing purchases are needed to balance supply and demand, as well as to maintain system reliability when resources and loads do not perform as forecasted.

Wholesale Purchases Scheduled from BPA: Compared to California, BPA power has a significantly greater role in Washington's resource context and market. Specified-source BPA power purchases, to which BPA's asset-controlling supplier (ACS) emissions rate is applied (consistent with the associated compliance obligation), are isolated and captured as a declared resource category in the Joint Utilities' template.

However, in the event that BPA decides not to voluntarily participate in Washington's cap and invest program as the first jurisdictional deliverer (FJD) for its surplus power sold in the wholesale market as standard Schedule C energy, then the carbon obligation for that power is assumed by the subsequent purchasing-selling entity in the physical path on the e-tag. This obligation is not known until the energy is scheduled and is assigned the default unspecified emissions factor. The carbon obligation is only incurred if an entity is scheduled energy from BPA, and is additional to the embedded carbon cost in prevailing wholesale energy prices.

A simple example helps illustrate how this cost is in addition to carbon costs already captured elsewhere in the cost burden template. Assume the price of energy before the CCA is $40/MWh, but after the CCA is effective the energy price is $55/MWh. A utility pays $55/MWh for the energy and the associated embedded carbon cost of $15/MWh is accounted for in the utility's unspecified purchases and/or balancing purchases in the template. However, if the energy ends up being scheduled from BPA—and if BPA is not jurisdictional under the CCA--then the utility is subject to an additional carbon obligation for that MWh equal to the default unspecified emissions factor multiplied by the cost of an allowance. If the energy is sourced and scheduled from any other entity, then that entity is the FJD and the cost of carbon is captured in the market price, and the utility has no additional cost under the CCA. If BPA was the FJD, then electric utilities would not need to be allocated allowances to cover this cost.

Administrative Costs: Under the CCA, the definition of "cost burden" is inclusive of administrative costs associated with a utility's participation in the cap and invest program. The Joint Utilities' template includes consideration of administrative costs beginning the first compliance period.

Increased Power Costs Due to Redispatch: Implementation of the CCA will result in higher operating costs for, and lower wholesale market sales from, Washington-based thermal generation that has been planned for in utility portfolios and customer rates. Even if utilities receive no-cost allowances for direct compliance costs (i.e. emissions), these changes will increase the cost of electricity for Washington ratepayers. The text and intent of the CCA counsels Ecology to allocate sufficient no-cost allowances to mitigate these impacts.

These impacts are not accounted for in other variables of the template, which measure emissions by volume associated with declared resources or unspecified purchases. In the template, the "power cost adjustment" variable attempts to capture the cost impact of decreased resource utilization and resulting decreases in third-party sales revenue (which is used to reduce net power costs). More simply, the "power cost adjustment" variable reflects the diminished value of the thermal generation that Washington utilities and ratepayers already own and helps to quantify that cost burden impact.

Using the Template

In using and filling out the template, electric utilities have discretion as to the sources of information needed to complete each field for each year of the first four-year compliance period (2023 through 2026). In forecasting demand (represented in the template by the "Energy to Serve Load" field), utilities may use their most recent IRP or another board-approved forecast, or a more up-to-date forecast adapted as needed to account for the CCA. Generation forecasts are informed by a utility's IRP or other resource planning analysis and are intended to be inclusive of specific actions identified in the utility's 2022 Clean Energy Implementation Plan (CEIP). The Joint Utilities recommend that utilities use "average," "P50," or "base case" load and generation forecasts, to maintain consistency among utilities and align with the assumptions embedded in the CEIP. It should be noted that utilities have flexibility to choose the source of information from their available options; no one source of data is prioritized over another, as different utilities have varying levels of data in their published documents. Once the sources of information have been identified by the utility, the template can be used as follows:

Forecasting Retail Electric Load

Enter the appropriate forecast of energy to serve load (MWh) for each year of the four-year compliance period, including transmission and distribution losses.

Forecasting Resources Used to Serve Retail Electric Load

Specified, Declared Sources

- **BPA Specified-Source Purchases (MWh)**: Enter estimate of annual energy generation provided by the Bonneville Power Administration, e.g. specified-source purchases including Block, Slice, and load-following products or other specified ACS purchases.
- **Coal (MWh):** Enter total forecasted generation from owned or long-term contracted specified-source coal resources through 2025, after which coal is not allowed to be used to serve retail load under CETA. The template provides the option of disaggregating specified coal resources so that facility-specific emissions factors can be applied.
- **Natural Gas (MWh):** Enter total forecasted generation from owned or long-term contracted specified-source natural gas resources. The template provides the option of disaggregating specified natural gas resources so that facility-specific emissions factors can be applied.
- **Hydro (MWh):** Enter total forecasted generation from owned or long-term contracted specified-source hydro resources. Assume "average," "P50," or "base case" hydro conditions.

- **Other Renewables & Non-Emitting Resources (MWh):** Enter total forecasted generation from owned or long-term contracted specified-source non-hydro renewables and other non-emitting resources.

Unspecified Sources

- **Unspecified Purchases (MWh):** Enter estimate of generation to be acquired through unspecified wholesale market purchases. Unspecified purchases are assumed to be the backstop resource. In the template, this estimate is equal to Energy to Serve Load (MWh) minus the sum of all specified sources.
- **Operational Adjustment (MWh):** Enter estimate of shorter-term balancing transactions that carry CCA compliance obligations. In the template, this estimate is equal to Energy to Serve Load (MWh) multiplied by 5%[3].
- **Wholesale Purchases Scheduled from BPA, if BPA is not FJD (MWh)**: In the event that BPA decides not to participate in the cap and invest program as an FJD, utilities will need to be able to recover the costs associated with energy scheduled from BPA and treated as unspecified for the purposes of the CCA. The template provides the option for a utility to forecast energy scheduled from BPA unspecified imports.

Forecasting Emissions Associated with Resources Used to Serve Retail Electric Load

- **BPA Specified-Source Purchases (MTCO2e):** Total BPA specified-source purchases multiplied by ACS emissions factor. In the template, the ACS factor is the average of the ACS factors used in the previous four years (2019-2022), which is 0.0154 MTCO2e/MWh.
- **Coal (MTCO2e):** Total forecasted generation from owned or long-term contracted specified-source coal resources multiplied by the relevant coal emissions factor(s). In the template, a utility can use facility-specific emissions factors if known or the default coal emissions factor of 1.0614 MTCO2e/MWh.
- **Natural Gas (MTCO2e):** Total forecasted generation from owned or long-term contracted specified-source natural gas resources multiplied by the relevant natural gas emissions factor(s). In the template, a utility can use facility-specific emissions factors if known or the default natural gas emissions factor of 0.4354 MTCO2e/MWh.
- **Unspecified Purchases (MTCO2e):** Total generation estimated to be acquired through unspecified purchases multiplied by the unspecified emissions factor established pursuant to WAC 173-444-040, which is 0.437 MTCO2e/MWh.
- **Operational Adjustment (MTCO2e):** Operational Adjustment value multiplied by the unspecified emissions factor.
- **Wholesale Purchases Scheduled From BPA, if BPA is not FJD (MTCO2e):** Total estimated BPA imports multiplied by the unspecified emissions factor.
- **Energy supplied to EITEs (MWh):** Energy supplied to EITEs by the utility. Fill out this field ONLY IF EITEs are receiving allowances for energy consumption directly. Otherwise, assume inclusion of energy supplied to EITEs in utility-specific emissions.

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[3] The "Operational Adjustment" variable accounts for those shorter-term resource purchases that are needed for balancing and hedging against the variability of load and resource conditions across the four-year compliance period, but which are additional to the Unspecified Purchases backstop resource estimate provided for in the template. These short-term balancing purchases will be reported under the GHG Reporting Rule and will thus carry a corresponding CCA compliance obligation. In developing this variable, some utilities were able to review their historical trading practices in view of the CCA to assess whether the California-derived 5% factor was a reasonable representation. Utilities that were able to conduct this analysis reported balancing transactions ranging from 4% to 10% of energy to serve load each year.

- **EITE Emissions (MTCO2e):** Calculated as the energy supplied to industrial covered entities divided by Energy to Serve Load, then multiplied by the sum of all emissions associated with declared resources, including the unspecified source categories.
- **Utility-Specific Emissions (MTCO2e):** Total metric tons of carbon dioxide equivalent associated with energy to serve load. In the template, calculated as the sum of all emissions associated with declared resources subtracted by emissions associated with industrial covered entities.

Calculating Cost Burden

- **Utility-Specific Emissions (MTCO2e):** See above
- **Administrative Costs Allowance Adjustment:** Projected administrative costs associated with participation in the CCA program and allowance market/auction. Calculated as projected administrative cost per year divided by the estimated floor price for one emissions allowance.
- **Power Cost Adjustment:** Projected power cost impacts due to redispatch—the cost of carbon in thermal dispatch decreases wholesale market sales and increases average production cost. Increased power costs associated with redispatch can be determined by modeling a portfolio without a price on carbon and then modeling the same portfolio with a price on carbon. The redispatch cost is the difference between the net power costs in these two scenarios. Net power costs for this purpose include only the variable costs of generation and purchased power net of wholesale market sales revenue; they do not include the cost of any emissions allowances. In the template, calculated as the projected increased power costs per year divided by the assumed price of emissions allowance equal to the forecast in Appendix H.1 of Ecology's Preliminary Regulatory Analysis for Chapter 173-446.
- **Allowance Allocation (allowances):** Utility-specific emissions allowances + Administrative costs allowance adjustment + Power cost adjustment

The Joint Utilities believe that the cost burden calculation produced by the proposed template will provide a more accurate forecast of utilities' actual cost exposure as required by the CCA relative to Ecology's proposal. The Joint Utilities look forward to walking through this template approach with Ecology staff, with the understanding that the UTC, Commerce, and appropriate governing boards will need to be involved to ensure that cost burden impacts are adequately captured in the interest of customers.

The rules for the allocation of no-cost allowances to electric utilities must explicitly consider the impact of economy-wide electrification, as required by statute.

RCW 70A.65.120(7) requires that "rules establishing the allocation of allowances to consumer-owned utilities and investor-owned utilities […] consider the impact of electrification of buildings, transportation, and industry on the electricity sector." The proposed rules do not currently reflect any consideration of economy-wide electrification in the allocation of allowances to electric utilities and should be amended in order to reflect this statutory requirement. One means by which Ecology could take electrification into consideration is to account for this in an allowance allocation adjustment mechanism described above if it can be demonstrated that the electrification results in a lower net lifecycle decrease in emissions.

Vintage 2023 no-cost allowances should be distributed to utilities before auctions begin in 2023.

As currently drafted, proposed WAC 173-446-260(1) states that, "By September 1, 2023, Ecology will distribute vintage 2023 no-cost allowances to mass-based EITE facilities, natural gas utilities, and electric utilities that have authorized accounts in the electronic compliance instrument tracking system."

The Joint Utilities strongly recommend that Ecology distribute vintage 2023 no-cost allowances before auctions begin in 2023. As previously noted, each utility's no-cost allowance allocation is intended to offset the costs associated with participating in the cap and invest program—costs that utilities will begin to incur *before* January 2023. Delaying the distribution of allowances delays utilities' ability to consign their no-cost allowances to auction; indeed, by September 2023 at least two auctions are expected to occur, representing two missed consignment opportunities. This creates a high level of uncertainty for utilities and customers in the first nine months of the program. To date, Ecology has not provided an explanation as to why vintage 2023 no-cost allowances cannot be distributed well in advance of Fall 2023. The Joint Utilities request further dialogue, expectation-setting, and clarification from Ecology on this matter, with the preferred outcome of distribution of no-cost allowances before auctions begin in 2023.

Ecology does not have the authority to specify in rule what electric utilities can and cannot do with the revenues of no-cost allowances consigned to auction beyond what is provided in statute.

During the first compliance period, allowances allocated at no cost to consumer-owned and investor-owned utilities may be consigned to auction for the benefit of ratepayers, deposited for compliance, or a combination of both. In specifying what electric utilities can and cannot do with revenues from voluntary consignment of no-cost allowances, the statute in RCW 70A.65.120(4) simply states that, "The benefits of all allowances consigned to auction under this section must be used by consumer-owned and investor-owned electric utilities for the benefit of ratepayers, with the first priority the mitigation of any rate impacts to low-income customers."

As proposed, the rule does not recognize that the Legislature established different requirements for how proceeds from no-cost allowances consigned by electric utilities must be spent compared to how proceeds from no-cost allowances allocated to natural gas utilities must be spent. Ecology's proposed rule language in WAC 173-446-300(2)(b)(iv) goes a step further by stating that, "Revenues from allowances sold at auction must be returned by providing nonvolumetric credits on ratepayer utility bills, prioritizing low-income customers, or used to minimize cost impacts on low-income, residential, and small business customers through actions that include, but are not limited to, weatherization, decarbonization, conservation and efficiency services, and bill assistance." The verbiage in the proposed rule is drawn from the section addressing allocation of allowances to natural gas utilities, but is structured such that it applies to both electric and natural gas utilities. The rules of statutory construction apply here and dictate that the CCA implementing rules establish different requirements for gas and electric utilities. As Ecology is not a utility regulator, the agency cannot specify additional requirements on the use of revenues from no-cost allowances, nor can the agency enforce these provisions.

To respect the law and clear legislative intent, the Joint Utilities recommend that Ecology revise proposed WAC 173-446-300(2)(b)(iv) as follows:

> "*(iv) Revenues from allowances sold at auction <u>by natural gas utilities</u> must be returned by providing nonvolumetric credits on ratepayer utility bills, prioritizing low-income customers, or used to minimize cost impacts on low-income, residential, and small business customers through actions that include, but are not limited to, weatherization, decarbonization, conservation and efficiency services, and bill assistance. <u>The benefits of all allowances consigned to auction by electric utilities must be used for the benefit of ratepayers, with the first priority the mitigation of any rate impacts to low-income customers.</u>*"

<u>ELECTRIC SECTOR BASELINE</u>

Ecology's proposed data source for imported electricity in the baseline does not align with the point of regulation. At minimum, Ecology should publish the results of its subtotal baseline calculations for public review and feedback before final rules are adopted.

As previously stated in the Joint Utility comments on the draft CCA Program rule submitted January 26th, establishing an accurate baseline for the cap and invest program is critical to determining the magnitude of emissions reductions necessary to meet the state's 2030 emissions limit, which then defines the annual program allowance budgets set by Ecology. Further, the integrity of the baseline is important for the ability to link with other jurisdictions. The proposed approach to establishing a baseline for imported electricity is inconsistent with the FJD point of regulation under the CCA and, therefore, is not an accurate representation of the baseline.

Proposed WAC 173-446-200(2)(f) states that Ecology will use fuel mix disclosure reports generated by the Department of Commerce in accordance with RCW 19.29A.060 to identify and catalog all contracted power, and methods from WAC 173-444-040 to estimate GHG emissions associated with electricity imports to arrive at the "electric power entity subtotal baseline." Issues with this approach include:

- The fuel mix disclosure report methodology is not aligned with the methodology that will be used by electric power entities to report emissions going forward under Chapter 173-441 WAC;
- The fuel mix disclosure reports do not "identify and catalog all contracted power," as anticipated by the proposed rule;
- Fuel mix disclosure reports are only provided by electric utilities serving retail load in the state, not electricity importers who are otherwise treated as FJDs under the CCA;
- Fuel mix disclosure reports attribute certain emissions based on the presence or absence of renewable energy certificates and attribute actual emissions reductions to renewable energy instruments;
- The methodology for accounting and disclosing unspecified purchases changed in 2019, making comparison across all baseline years difficult using the fuel mix approach;
- The fuel mix disclosure methodology does not distinguish between in-state unspecified purchases and unspecified imports; and
- The fuel mix disclosure enabling statute provides a statement of legislative intent that "the fuel characteristics disclosed under this chapter represent reasonable approximations that are suitable only for informational or disclosure purposes" (RCW 19.29A.130).

At the time of this writing, Ecology has not provided an approximate value for the electric power entity subtotal baseline based on the fuel mix approach. At minimum, Ecology should publish the results of its subtotal baseline calculations for public review and feedback before final rules are adopted.

The Joint Utilities believe the methodology for establishing the subtotal baseline should attempt to align with the point at which a compliance obligation is applied (i.e., at the level of imports, rather than retail sales) and with the methodology that determines compliance with the requirements of the cap and invest program. Failure to align the baseline and Ecology's compliance obligation determination will result in an inaccurate picture of the state's historical emissions and impact the state's ability to accurately represent progress toward emission reduction targets.

Open Access Technology International, Inc. (OATI) possesses e-tag data for electricity imports into Washington balancing authority areas (BAAs) during the 2015-2019 baseline years. The Joint Utilities have verified the existence of the data and the ability of OATI to produce aggregated summary values in MWh for imports, exports, and wheels relative to the physical border of Washington for each of the baseline years. The value for electricity imports into the state provided by OATI can then be multiplied by the default, unspecified emissions factor to arrive at a more accurate assessment of the electric power entity subtotal baseline rather than relying on fuel mix disclosure reports. Preliminary analysis of import data from OATI suggests that the fuel mix approach may be grossly undercounting historical emissions associated with electricity imports. However, direct comparison of the two methodologies is infeasible until Ecology publishes the results of its proposed approach for public review.

In addition to e-tag data for electricity imports, OATI provides a product for entities that must report to the California Air Resources Board (CARB) called webCARB, which uses customer-specified source data and OATI e-tag data to create GHG Emissions Reports that can then be filed to CARB. A similar product could be developed for Washington reporting entities. The Joint Utilities strongly recommend that Ecology do the due diligence of the state in acquiring and verifying the relevant data from OATI directly, as is done in California.

OTHER PROGRAMMATIC CONCERNS

Ecology should ensure that emissions are not double counted for the same unit of energy.

Ecology's proposed rules extend the CCA to emissions from both in-state entities as well as from out-of-state entities whose emissions are imported to the state of Washington (proposed WAC 173-446-030). However, there are no offsetting provisions either in the Department's emissions reporting rules (Chapter WAC 173-441), or proposed CCA rules (Chapter WAC 173-446), that account for sales—specified or unspecified—of electricity that are exported out of Washington.

Without appropriate accounting for specified or unspecified exports, Ecology's proposed rules will double count GHG emissions for exports into jurisdictions that have a similar state-level GHG obligation and with whom Washington does not have a linkage agreement. For example, where sales are exported to jurisdictions like California, which has a cap and trade program, covered entities will be responsible for both a Washington and a California GHG obligation unless and until the programs are linked. The rules should be amended to explicitly account for wholesale sales transactions that are exported to jurisdictions that have a GHG obligation. To remedy this disparate treatment, Ecology should amend proposed WAC 173-446-040(3)(a)(ii) as follows:

> "*(ii) The following GHG emissions are not covered emissions for facilities:*
> *(A) Emissions from the on-site combustion of any fuel product as described in WAC 173-441-122(5) except those described in (a)(i)(A), (B), or (C) of this subsection;*
> *(B) Carbon dioxide collected and supplied off-site that the facility owner or operator can demonstrate to ecology's satisfaction is part of the covered emissions of another covered entity under this chapter<u>;</u>*
> *<u>(C) Emissions from the on-site combustion of any fuel product that generates electricity that is then exported to a jurisdiction that imposes a carbon price on the electricity</u>."*

Ecology should further clarify the entity responsible for emissions associated with Bonneville Power Administration power purchases.

BPA markets hydropower from 31 federal dams in the Columbia River Basin and provides up to 28 percent of the Northwest region's electricity. Because of its status as a federal agency, BPA is not mandated to participate in Washington's cap and invest program as a covered entity, but does retain the ability to opt into the program and assume compliance obligations as the first jurisdictional deliverer (FJD) of the power it markets to Washington entities.

While BPA continues to deliberate as to whether and when it will decide to "become jurisdictional" under the cap and invest program, it is important to properly allocate responsibility for the power it markets in Washington in the event that it does not become jurisdictional—or in the event that a decision in the affirmative does not take effect before the start of the program in January 2023.

Proposed WAC 173-446-040(3)(e) provides for the allotment of covered emissions for FJDs of imported electricity. Subsection (ii) states the following:

> "*(ii) If the electricity importer is a federal power marketing administration over which the state of Washington does not have jurisdiction, and the federal power marketing administration has not voluntarily elected to comply with the program, then a utility that purchases electricity for use in the state of Washington from that federal power marketing administration is the importer and first jurisdictional deliverer of that electricity.* ***Such a utility is a covered entity under this program and has the compliance obligation for the GHG emissions associated with that electricity*** [**emphasis added**]."

The Joint Utilities recommend that Ecology further clarify the entity responsible for emissions associated with BPA power purchases. It is unclear when reading the language excerpted above that a utility must still meet the applicability conditions provided under proposed WAC 173-446-030 in order to be a covered entity—the allocation of emissions associated with BPA power purchases to an entity does not itself supersede these applicability provisions, i.e. the quantitative emissions threshold of 25,000 MTCO2e/year.

Furthermore, the above language is not consistent with the definition of "electricity importer" that is adopted in the proposed rule by reference to WAC 173-441-124(2)(c)(v). This definition states that if the electricity importer is BPA, and the agency has not voluntarily elected to comply with Ch. 173-441 WAC, then the electricity importer "is the next purchasing-selling entity in the physical path on the e-tag, or if no additional purchasing-selling entity over which Washington state has jurisdiction, then the electricity importer is the electric utility that operates the Washington state transmission or distribution system, or the generation balancing authority."

To align the allocation of emissions associated with BPA purchases for compliance purposes with the allocation provided for reporting purposes, and to remove any ambiguity as to the applicability conditions for covered entities, the Joint Utilities recommend that this subsection be amended as follows:

> "*(ii) If the electricity importer is a federal power marketing administration over which the state of Washington does not have jurisdiction, and the federal power marketing administration has not voluntarily elected to comply with the program, then the electricity importer is the next purchasing-selling entity in the physical path on the e-tag, or if no additional purchasing-selling entity over which Washington state has jurisdiction, then the electricity importer is the electric utility that operates the Washington state transmission or distribution system, or the generation balancing authority. Such an entity or utility is the first jurisdictional deliverer of that electricity and has a compliance obligation for the GHG emissions associated with that electricity, provided that the applicability conditions specified in WAC 173-446-030 are also met."*

Ecology should specify how it is going to determine which electric power entities are going to be considered covered entities as of the beginning of the 2023 emissions year.

Beginning with the first compliance period (2023 through 2026) and for all subsequent compliance periods, covered entities include:

- An FJD that generates electricity in Washington and whose covered emissions associated with this generation for any calendar year from 2015 through 2019 equal or exceed 25,000 MTCO2e per year; and
- An FJD that imports electricity into Washington, and whose cumulative annual total of covered emissions associated with this imported electricity for any calendar year from 2015 through 2019, whether from specified or unspecified sources, equal or exceed 25,000 MTCO2e per year.

Under the cap and invest program, covered emissions are GHG emissions reported under Ch. 173-441 WAC. Electric utilities that meet the electric power entity reporting threshold of 10,000 MTCO2e per year will be required to report their annual emissions to Ecology beginning with the 2022 emissions year reported by June 1, 2023.

According to proposed WAC 173-446-060(4), any facility, supplier, or FJD that was in operation between 2015 and 2019 but that was not required to report emissions during that time becomes a covered entity in the calendar year in which its covered emissions first equal or exceed 25,000 MTCO2e per year, or upon formal notice from Ecology that the facility or FJD is "expected" to exceed 25,000 MTCO2e per year for the first year the entity is required to report emissions, whichever happens first.

Ecology has not explained how it is going to make the determination that a facility, supplier, or FJD is "expected" to exceed 25,000 MTCO2e per year for the first year the entity is required to report emissions—which, for electric power entities, is 2023. Ecology should specify which data and sources of information it intends to use to make this determination for the 2023 reporting and emissions year.

Ecology should clarify the ability of electric utilities that are not covered entities to register as general market participants and consign no-cost allowances to auction.

In enacting the CCA, the Legislature specified its intent to allow all consumer-owned and investor-owned utilities subject to the requirements of CETA to be eligible for an allocation of no-cost allowances in order to mitigate the cost burden of the cap and invest program on electricity customers. Electric utilities are eligible for no-cost allowances regardless of whether or not they are covered entities with compliance obligations under the program.

Proposed WAC 173-446-053(1) requires all electric utilities in the state that are not required to report GHG emissions under Ch. 173-441 WAC (i.e. they are under the 10,000 MTCO2e/year reporting threshold) to register to receive no-cost allowances. The proposed rule is unclear as to whether utilities that are required to report GHG emissions but are still beneath the CCA applicability threshold of 25,000 MTCO2e/year must also use this registration process in order to receive no-cost allowances.

Electric utilities that are not covered entities retain the right to opt into the program or register as general market participants. However, proposed WAC 173-446-150(1)(b) seems to suggest that an electric utility *must* be either a covered or opt-in entity in order for Ecology to set up a limited use holding account, which then allows the utility to consign their no-cost allowances to auction:

> *"(b) For each electric utility and each natural gas utility registering in the program* ***as a covered or opt-in entity****, ecology will also set up a limited use holding account. Electric utilities and natural gas utilities must transfer their no cost allowances to the limited use holding account in order to consign them to auction for the benefit of ratepayers as described in WAC 173-446-300(2)(b)* [**emphasis added**]*."*

The restriction of a limited use holding account to only those utilities registering in the program as a covered or opt-in entity is not reflective of the Legislature's intent to allow utilities to mitigate the cost burden of the cap and invest program on electricity customers by consigning no-cost allowances to auction. The Joint Utilities recommend that Ecology amend this language by simply striking "as a covered or opt-in entity" in the language above, thereby allowing electric utilities that are not covered entities and choose to register in the cap and invest program as general market participants to obtain a limited use holding account and consign their allowances to auction for the benefit of ratepayers.

The proposed process for price ceiling unit sales extends a level of discretion to Ecology that is not supported by statute.

Market integrity is essential to a well-operating cap and invest program, which in turn necessitates clear rules and certainty on how such rules will function. To that end, the Joint Utilities appreciate that Ecology attempted to remove some discretion and uncertainty in the language around price ceiling unit sales in this iteration of its proposed rules, but there is still too much uncertainty to assure market integrity.[4] The language needs to be further strengthened to adhere to statutory intent as follows:[5]

> "*(6)* ((*~~If ecology agrees to sell price ceiling units,~~*)) <u>*In the event that no allowances remain in the allowance price containment reserve, and if the covered entity or opt-in entity shows in its request for a price ceiling unit sale under subsection (4) of this section that it has insufficient compliance instruments to meet its compliance obligations for the immediately upcoming compliance deadline, ecology must issue the number of price ceiling units for sale to the covered*</u>

[4] Proposed WAC 173-446-385(6)

[5] RCW 70A.65.160(2) – *"In the event that no allowances remain in the allowance price containment reserve, the department must issue the number of price ceiling units for sale sufficient to provide cost protection for facilities as established under subsection (1) of this section."*

<u>or opt-in entity to provide sufficient cost protection for such entities.</u> <u>E</u>cology shall instruct the financial services administrator to begin to accept cash payment for purchases from price ceiling sales no earlier than 10 business days after the previous allowance price containment reserve auction and to cease accepting payments no later than seven business days thereafter."

As currently drafted, the language of the proposed rule extends a level of discretion to Ecology that is not supported by statute. The edits suggested by the Joint Utilities are in keeping with the direct language of the CCA statute, provide certainty to covered entities and the market, and support the overall aims of market integrity and preserving the ability to link with other jurisdictions in the future.

CONCLUSION

In summary, as Ecology develops rules for the CCA program that impact electric utility operations and our customers, the agency must be guided by the direction provided in statute. The Joint Utilities are engaged together in a highly collaborative process and are committed to investing the resources needed to work with Ecology to ensure the electric sector meets its proportionate share of the state's emissions reduction objectives.

In these comments, the Joint Utilities have made substantive recommendations on key program elements, including establishing the electric sector baseline and allocation of allowances to electric utilities, and we look forward to discussing these recommendations further with you. We make these recommendations in the interest of our customers.

Thank you for the opportunity to provide comment. The Joint Utilities understand and appreciate that Ecology is working under a constrained rulemaking timeline to stand up this impactful program by January 1, 2023. We look forward to continued dialogue with Ecology as rulemaking and implementation of the CCA progresses.

Sincerely,

/s/ Bruce Howard
Bruce Howard
Senior Director of Environmental Affairs
Avista

/s/ Zepure Shahumyan
Zepure Shahumyan
Director, Energy and Environmental Policy
Pacific Power

/s/ Mary Wiencke
Mary Wiencke
Executive Director
Public Generating Pool

/s/ Lorna Luebbe
Lorna Luebbe
Vice President of Sustainability & Deputy General Counsel
Puget Sound Energy

/s/ Tashiana Wangler
Tashiana Wangler
Rates and Policies Director
Northwest Requirements Utilities

/s/ Nicolas Garcia
Nicolas Garcia
Policy Director
Washington Public Utility Districts Association

Enter Data
Formula

WA Utility (non multi-jurisdictional)		Allowance Allocation Calculation for 2023-2026					
YEAR	*Formula descriptions*	*2023*	*2024*	*2025*	*2026*	*Field description*	*Data source and calculation method*
Energy to Serve Load (MWh)	A					Forecasted annual energy demand, including transmission and other losses.	Most recent IRP or other board-approved forecast, or a more up-to-date forecast adapted as needed to account for the CCA
DECLARED RESOURCES:		Generation forecasts are informed by IRP analysis and inclusive of CEIP specific actions.					
BPA Specified-source purchases (total) (MWh)	B					Estimate of annual energy generation provided by the Bonneville Power Administration. E.g. specified-source purchases including block, slice, and load-following products or other specified ACS purchases.	
Coal - Total (MWh)	C	-	-	-	n/a - not permitted under CETA	Total forecasted generation from owned or long-term contracted specified-source coal resources.	
Aggregate Coal Generation (Less Specified Resources)	C1				n/a - not permitted under CETA	Energy acquired from aggregate coal generation (less specified resources).	
Specified Coal Resource #1	C2				n/a - not permitted under CETA	Generation from Specified Coal Resource #1, an owned or long-term contracted resource.	
Specified Coal Resource #2	C3				n/a - not permitted under CETA	Generation from Specified Coal Resource #2, an owned or long-term contracted resource.	
Natural Gas - Total (MWh)	D	-	-	-	-	Total forecasted generation from owned or long-term contracted specified-source natural gas resources.	
Aggregate Natural Gas Generation (Less Specified Resources)	D1					Energy acquired from aggregate natural gas generation (less specified resources).	
Specified Natural Gas Resource #1	D2					Generation from Specified Natural Gas Resource #1, an owned or long-term contracted resource.	
Specified Natural Gas Resource #2	D3					Generation from Specified Natural Gas Resource #2, an owned or long-term contracted resource.	
Hydro - Total (MWh)	E					Total forecasted generation from owned or long-term contracted specified-source hydro resources.	Assume "average," "P50," or "base case" hydro conditions
Other Renewables & Non-Emitting Resources - Total (MWh)	F					Total forecasted generation from owned or long-term contracted specified-source non-hydro renewables and other non-emitting resources.	
Unspecified Purchases (MWh)	G = A - (sum of B through F)	-	-	-	-	Estimate of generation to be acquired through unspecified wholesale market purchases. Unspecified purchases are assumed to be the backstop resource.	Energy to serve load minus the sum of all dspecified sources.
Operational adjustment (MWh)	H = A * 5%	-	-	-	-	Estimate of shorter-term balancing transactions that carry CCA compliance obligations	Energy to serve load multiplied by 5%. This 5% adder reflects estimated shorter term balancing transactions that carry CCA compliance obligations.
BPA Unspecified Imports, if BPA is not FJD (MWh)	I					Estimate of unspecified imports from BPA for each year, if BPA is not the FJD	Utility specific estimate

Constants Used in Calculations	
0.0154	Asset Controlling Supplier (ACS) factor for Bonneville Power Administration - Average of ACS factors used in previous four years (2019-2022) (MTCO2e/MWh)
1.0614	Default Coal Emissions Factor ($MTCO_2e/MWh$)
WW	Specified Coal Resource #1 emissions factor, if known (MT CO2e/MWh)
XX	Specified Coal Resource #2 emissions factor, if known (MT CO2e/MWh)
0.4354	Default Natural Gas Emission Factor ($MTCO_2e/MWh$)
YY	Specified Natural Gas Resource #1 emissions factor, if known(MT CO2e/MWh)
ZZ	Specified Natural Gas Resource #2 emissions factor, if known (MT CO2e/MWh)
0.437	Unspecified emissions factor established in WAC 173-444-040
5.00%	Estimated balancing purchases and sales as a percentage of total energy to serve load
0.437	Unspecified emissions factor established in WAC 173-444-040

EMISSIONS ASSOCIATED WITH DECLARED RESOURCES:							
MT CO2e BPA purchases	J = B * BPA's ACS emissions factor	-	-	-	-	Metric tons of CO2 equivalent associated with BPA purchases.	Total BPA purchases multiplied by BPA's ACS factor.
MT CO2e Coal	K = C * coal emissions factor(s)	#VALUE!	#VALUE!	#VALUE!	n/a - not permitted under CETA	Metric tons of CO2 equivalent associated with specified-source coal generation.	Total generation from owned or long-term contracted specified-source coal resources multiplied by the relevant coal emissions factor(s) (default coal emissions factor or specific emissions factors, when known).
MT CO2e Natural gas	L = D * natural gas emissions factor(s)	#VALUE!	#VALUE!	#VALUE!	#VALUE!	Metric tons of CO2 equivalent associated with specified-source natural gas generation.	Total generation from owned or long-term contracted specified-source natural gas resources multiplied by the relevant natural gas emissions factor(s) (default natural gas factor or specific natural gas factor, when known)
MT CO2e Unspecifed purchases	M = G * unspecified emissions factor	-	-	-	-	Metric tons of CO2 equivalent associated with unspecified purchases.	Total generation estimated to be acquired through unspecified purchases multiplied by the unspecified emissions factor established in WAC 173-444-040
MT CO2e Operational adjustment	N = K * unspecified emissions factor	-	-	-	-	Metric tons of CO2 equivalent associated with the operational adjustment.	Operational adjustment value multiplied by the unspecified emissions factor established in WAC 173-444-040
MT CO2e BPA unspecified imports	O = I * unspecified emissions factor	-	-	-	-	Metric tons of CO2 equivalent associated with importing unspecified BPA power if BPA chooses not to be the FJD	Total BPA imports multiplied by the unspecified emissions factor established in WAC 173-444-040
Energy supplied to EITEs (MWh)	P					Energy supplied to industrial covered entities by the utility. Fill out this field ONLY IF EITEs are receiving allowances for energy consumption directly. Otherwise, assume inclusion of energy supplied to EITEs in utility-specific emissions ("R").	
EITE Emissions (MTCO$_2$e)	Q = (P / A) * sum of J through O	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	EITE Purchased Electricity multiplied by Utility-Specific Emissions Factor	Energy provided to EITE customers divided by all energy to serve load, then multiplied by the sum of all emissions associated with declared resources.
Utility-Specific Emissions (MTCO$_2$e)	R = sum of J through O - Q	#VALUE!	#VALUE!	#VALUE!	#VALUE!	Total metric tons of CO2 equivalent associated with energy to serve load.	Sum of all emissions associated with declared resources subtracted by emissions associated with industrial covered entities.
COST BURDEN CALCULATION:							
Utility-Specific emissions allowances	S	#VALUE!	#VALUE!	#VALUE!	#VALUE!	Total metric tons of CO2 equivalent associated with energy to serve load.	Total metric tons of CO2 equivalent associated with energy to serve load.
Administrative Costs Allowance Adjustment	T = estimated annual administrative cost / allowance floor price	-	-	-	-	Projected administrative costs associated with participation in the CCA program and allowance market/auction.	Projected administrative cost per year divided by the estimated floor price for one emissions allowance.
Power Cost Adjustment	U = estimated annual power cost impacts / allowance price used to estimate power costs					Projected power cost impacts due to redispatch - CO2 cost in thermal dispatch decreases wholesale market sales, increases average production cost.	Projected increased power costs per year divided by the assumed price of emissions allowance equal to forecast in Appendix H.1 of Ecology's Preliminary Regulatory Analysis for Chapter 173-446 WAC
Annual Allocation (allowances)	**V = S+T+U**	#VALUE!	#VALUE!	#VALUE!	#VALUE!	Utility-Specific Emissions Allowances PLUS Administrative cost allowance adjustment PLUS Power Cost Adjustment	Utility-Specific Emissions less EITE Emissions PLUS Administrative cost allowance adjustment PLUS Power adjustment

	Estimated cost burden for administration each year: reporting, market participation, auction tracking, etc. In dollars.
$22.34	Estimated allowance floor price for 2023
$23.46	Estimated allowance floor price for 2024 (not adjusted for inflation)
$24.63	Estimated allowance floor price for 2025 (not adjusted for inflation)
$25.86	Estimated allowance floor price for 2026 (not adjusted for inflation)