PUGET SOUND ENERGY

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Kathy Hunter, Acting Executive Director and Secretary
Washington Utilities and Transportation Commission
621 Woodland Square Loop SE
Lacey, WA 98503

Re: Docket U-230161 – Commission-led Workshop Series on Climate Commitment Act, Comments of Puget Sound Energy

Dear Executive Director Hunter:

Puget Sound Energy ("PSE") appreciates the opportunity to respond to the questions posed in the Notice of Opportunity to Provide Comments and Agenda for Workshop #4 in Docket U-230161 issued on October 23rd, 2023 ("Notice"). The following are PSE's responses to the specific questions in the Notice.

<u>CCA Risk Sharing</u>

1) For a potential CCA risk sharing mechanism, what risks associated with the CCA are under utility control? Examples may include market risk, energy procurement, conservation levels, etc.

Most elements associated with compliance risks under the Climate Commitment Act (CCA) are outside of utility control, including, but not limited to weather, customer demand, CCA allowance prices, changes in the broader economy, and statutory and regulatory mandates.

Utilities, with approval of the Washington Utilities and Transportation Commission (the "Commission"), can design and implement customer programs that encourage or incentivize customers to change behaviors, however, gas customers are ultimately the end user of the commodity and must change their energy usage or take action to follow through with a decarbonization or electrification project. A gas utility has no authority or ability to require any customer to purchase a decarbonized product or electrify.

State law also constrains the ability of gas utilities to transition to alternative lower carbon or zero carbon fuels, such as Renewable Natural Gas (RNG). Such lower carbon or zero carbon fuels are premium products that sell at premium prices, and these premium prices have traditionally limited the ability of gas utilities from procuring them due to the state's emphasis on the lowest reasonable cost planning standard. Recent legislation has provided the Commission with additional considerations to balance with the traditional lowest reasonable cost planning standard in determining the public interest:

> In determining the public interest, the commission may consider such factors including, but not limited to, environmental health and greenhouse gas emissions reductions, health and safety concerns, economic development, and equity, to the extent such factors affect the rates, services, and practices of a gas or electrical company regulated by the commission.[1]

With this change in statute, the Commission may be able to allow gas utilities to purchase premium lower carbon or zero carbon fuels that otherwise were prohibited under the public interest standard focused on lowest reasonable cost, but it is a relatively recent statutory change and does not yet have much Commission precedent balancing the factors.

Moreover, some state statutes affirmatively limit the ability of the Commission to approve purchases of some premium lower carbon or zero carbon fuels, even if the Commission were to determine that the purchase of such products were in the public interest under RCW 80.28.425. RCW 80.28.385 affirmatively constrains the Commission's authority to include costs of RNG exceeding five percent of the amount charged the customer: "The customer charge for a renewable natural gas program may not exceed five percent of the amount charged to retail customers for natural gas." This statutory language would presumably constrain the ability of the Commission to approve RNG programs with costs more than five percent of the amount charged to retail customers even if RNG were a lower reasonable cost alternative to fossil natural gas. Currently, RNG is not a lower reasonable cost alternative to fossil natural gas (even with the addition of the social cost of greenhouse gases as required by RCW 80.28.395), but this language is illustrative of the constraints imposed by state law on the Commission and the gas utilities it regulates in moving forward with decarbonization efforts.

Utilities must also ensure that by the end of the four year period they have purchased enough CCA allowances to comply with the legal requirements for each compliance period. If they do not, utilities already bear the risk of non-compliance with the CCA through penalties, pursuant to RCW 70A.65.200.

In summary, there are very few elements that are within the control of the utility, and utilities already bear significant risk of non-compliance with the CCA through established penalties in the statute.

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[1] RCW 80.28.425(1).

2) How should a potential CCA risk sharing mechanism be structured?

As previously discussed in this proceeding and in Docket UG-230470, PSE remains concerned with both the legality and feasibility of developing a risk-sharing mechanism for the CCA. These concerns are discussed in PSE's Compliance Filing in UG-230470 filed on October 31, 2023.

To summarize these concerns, the CCA is mandated by state law, and the legislature affirmatively assigned associated risks to utilities, not customers. Specifically, gas utilities already bear the risk of non-compliance with the CCA through penalties, pursuant to RCW 70A.65.200. Additionally, CCA compliance investments are subject to prudence review by the Commission, so utilities further bear risks in the form of potential disallowances. More fundamentally, a risk-sharing mechanism diminishes price signals to customers, which are necessary to encourage the transition away from emitting resources.

Requiring natural gas companies to bear some of the costs of compliance for natural gas sales stifles the price mechanism that encourages customer transition and undermines the legislative intent of the CCA. Additionally, if the Commission ultimately imposes a risk sharing mechanism on utilities, it potentially penalizes the gas utilities for fulfilling statutory obligations as public service companies.

The Commission could consider whether performance based regulatory concepts could be used to inform the design for a risk-sharing mechanism. In 2021, the Washington state Legislature passed Engrossed Substitute Senate Bill 5295 (ESSB 5295), codified in RCW 80.28.425, an act relating to transforming the regulation of gas and electrical companies toward multi-year rate plans and performance-based ratemaking. Since the passage of ESSB 5295, the Commission has been considering performance-based approaches through Docket U-210590. PSE outlines one such potential risk-sharing mechanism in its recent Compliance Filing in UG-230470 filed on October 31, 2023.

3) What should the Commission consider when assessing utility actions for prudency as they relate to the CCA?

Utilities should be required to demonstrate that they adequately studied CCA compliance needs and made reasonable investment decisions at the time the decisions were made. PSE's understanding of the Commission's prudence standard is informed by language in the Commission's order in PSE's Power Cost Only Rate Case proceeding, Docket UE-031725:

> The test the Commission applies to measure prudence is what a reasonable board of directors and company management would have decided given what they knew or reasonably should have known to be true at the time they made a decision. This test applies both to the question of need and the appropriateness of the expenditures. The company must establish that it adequately studied the question of whether to

purchase these resources and made a reasonable decision, using the data and methods that a reasonable management would have used at the time the decisions were made.[2]

4) When should the risk sharing mechanism allow for prudency determination? Every auction, yearly, every four-year compliance period, or another frequency?

PSE views the risk-sharing mechanism as separate from and not necessary for a prudency determination for CCA compliance costs. Depending upon the design and scope of any risk sharing mechanism there may be a connection, however, the risk sharing mechanism may not be the direct determining or "allowing" element for prudency determination timing.

In general, prudency could be reviewed on an annual basis, but due to the four year compliance periods established in the CCA, final costs and compliance actions will not be known until the October following the four-year compliance period. PSE currently has a separate gas tariff schedule to collect CCA costs and pass back CCA auction proceeds. Maintaining a separate tariff schedule outside of base rates is beneficial because it allows for annual filings to true-up prior periods for actual amounts and to update prior estimates as well as set the rate for the next rate period with expected costs and proceeds. If desired, the Commission could conduct interim prudency reviews in each annual filing with a final prudency determination within the annual filing that would need to occur almost one year following the end of the four year compliance period. The Commission could also conduct interim reviews of projects on which CCA auction proceeds are spent in annual filings, or in a general rate case.

<u>CCA Dispatch Cost Modeling</u>

The responses to the questions in this section pertain only to dispatch modeling for operational-level planning such as forecasting power costs for rates and for purposes of forecasting loads and resources for CCA purposes. The responses to these questions do not address modeling for long-term planning and acquisition processes.

5) Should the Commission require utilities to include GHG costs in their dispatch modeling?

A utility's modeling of resource dispatch should reflect as closely as possible the resource dispatch criteria a utility uses or intends to use in actual operations. Actual resource dispatch decisions should seek to minimize the total net cost of electric power delivered to retail customers given the utility's existing resource portfolio and best information available to the utility. A utility should therefore consider GHG costs in both its dispatch modeling and actual resource dispatch decisions – at least to the extent such GHG costs are expected to actually be

[2] WUTC v. Puget Sound Energy, Docket UE-031725, Order 12 at ¶ 19 (Apr. 7, 2004).

paid by the utility and/or be recoverable in customer rates.[3]

The Commission need not specifically require utilities to include GHG costs in their dispatch models (or actual dispatch decisions). A utility seeking to minimize the cost of electric supply to retail customers will necessarily consider any such relevant costs when making resource dispatch decisions. Further, the Commission has not previously established any requirements for how utilities make or model dispatch decisions. Potential GHG costs are just one of many variables that affect resource dispatch—fuel costs, plant heat rates, variable operations and maintenance expenses, major maintenance costs, start-up and shut-down costs, plant operating limits, and market power prices are among the variables that must also be considered. PSE does not see a reason that GHG costs should be viewed differently by the Commission.

One challenge currently facing electric utilities is determining which GHG emissions will incur an actual cost obligation so that such costs can be appropriately included in dispatch decisions and models. At issue is the CCA and, more specifically, the allocation of no-cost allowances to electric utilities. Although the Department of Ecology has established rules for its initial allocation of no-cost allowances to utilities and provided that the initial allocation will be adjusted after the fact, there remains uncertainty as to exactly how such adjustment will be calculated. Clear rules and a full understanding of how the no-cost allowance adjustment will be applied are key to determining the actual allowance costs an electric utility can expect to incur and, therefore, when and to what extent such costs should be reflected in resource dispatch decisions.

According to its current understanding of the Department of Ecology's no-cost allowance allocation and adjustment process, PSE receives no-cost allowances only for emissions from PSE's in-state generation and market purchases used to serve its retail electric load. PSE must purchase allowances for any emissions from emitting resources that generate electricity sold in the wholesale market or delivered to other utilities, in some cases for purposes of providing important balancing services for the electricity grid. This means that PSE would not incur actual GHG costs for emissions associated with serving retail load but would incur actual GHG costs for emissions associated with wholesale market sales. Such actual costs should be accordingly included in dispatch decisions in order to minimize net electric supply costs. Put simply, if an electric utility dispatches an emitting generator to serve retail load, then there are no GHG costs to include in the dispatch decision. If an electric utility dispatches an emitting resource to sell the output in the wholesale market, then the electric utility should include GHG costs in the dispatch decision.

[3] Included in the distinction here is that between actual direct costs such as those associated with compliance under the CCA and external social costs not borne directly by the utility or its retail customers. These comments refer to "GHG costs" to mean those direct costs associated with the CCA, as these are the costs relevant to resource dispatch decisions. External social costs are relevant to longer-term decisions regarding how a resource portfolio will evolve over time, including retirements of existing resources and acquisitions of new ones. CETA explicitly instructs utilities to consider the external social cost of greenhouse gases when evaluating conservation efforts, developing integrated resource plans, and evaluating resource acquisition options.

6) What information is needed/readily available to effectively model GHG costs in dispatch, and what assumptions can be made to navigate any potential data limitations?

As discussed in response to question #5 above, clarity regarding the no-cost allowance allocation and adjustment process is critical for effectively modeling GHG costs in resource dispatch. Even with clear rules, incorporating such costs in actual dispatch decisions may remain complicated and difficult to implement with precision. Given PSE's current understanding of the rules, an electric utility must differentiate between the dispatch of emitting resources to serve retail loads from the dispatch of emitting resources to support wholesale market or balancing transactions to properly include GHG costs in those dispatch decisions. In a model that includes perfect foresight of load, variable resource output, and market prices, this is possible. In actual operations, however, these variables are constantly changing and often difficult to forecast a day, or even an hour, in advance. Dispatch decisions made in the day-ahead time-frame (when most electric energy transfers are planned and scheduled) based on a forecast of which resources will be used to serve retail load may appear sub-optimal after the fact as actual load, variable resource output, and market power prices differ from forecast. This does not mean a utility cannot or should not include a reasonable estimate of GHG costs in dispatch decisions. Rather, such decisions will reflect an electric utility's reasonable judgement at the time in light of the imperfect forecasts and information available.

A utility also must have an estimate of the applicable cost per unit of GHG emissions, which, in practice is the price of a CCA allowance. To date, these prices have been highly volatile, thereby making it difficult for utilities determine what would be an appropriate price to include in dispatch decisions. Additionally, the prices for CCA allowances are largely determined by infrequent auctions that occur long before or long after the utility must make its dispatch decisions. This mismatch between the timing of dispatch decisions and price signals from quarterly auctions makes alignment of price assumed for dispatch and actual CCA price very difficult. Although data from secondary CCA market prices are available to mitigate this mismatch, the "right" price will likely depend on a utility's specific circumstances and may change over time.

Some of the other data required to include GHG costs in dispatch decisions is relatively straight-forward and available. For example, a utility must know the emissions rates of the generators in its portfolio – these are effectively just measures of efficiency which are already used to calculate fuel costs.

7) What effect would the inclusion of GHG costs in dispatch modeling have on customers?

As discussed in response to question #5 above, appropriate inclusion of GHG costs in dispatch decisions minimizes net electric supply costs for retail customers. Including GHG costs in the dispatch decision for an emitting generator makes that generator appear less economic to operate which, all other things equal, causes it to run less. This in turn reduces emissions and fuel consumption but decreases wholesale market sales, which are used to lower power costs paid by retail customers. Accordingly, inclusion of GHG costs in dispatch decisions necessarily increases net power supply costs paid by retail customers. However, if the GHG costs included in dispatch are an accurate reflection of the actual costs that would be incurred for emissions, then the avoided cost from reduced emissions will more than offset the net cost increase from changes in fuel consumption and wholesale market transactions.

To illustrate, first consider a simple example dispatch decision where the GHG cost included in the dispatch decision represents the cost of an actual CCA allowance cost(e.g., dispatch to support a wholesale market sale for which the utility would not receive a no-cost allowance):

Table 1. *Example 1 MW dispatch decision, to support wholesale market sale, and resulting customer cost with GHG properly included in dispatch cost vs not including*

	All values in $ per MWh	**Include GHG cost in dispatch**	Do not include GHG cost in dispatch
	Dispatch decision		
1	Fuel and other (non-GHG) variable costs	**$50**	$50
2	GHG cost	**$20**	$0
3	Total dispatch cost	**$70**	$50
4	Market power price	**$60**	$60
5	Is plant dispatched?	**No**	Yes
	Customer costs		
6	Fuel and other (non-GHG) variable costs	**$0**	$50
7	Market sales revenue	**$0**	$60
8	Cost to retail customers before GHG cost	**$0**	($10)
9	Cost of actual GHG allowance purchase	**$0**	$20
10	Net cost to retail customers	**$0**	$10

The example in Table 1 illustrates that when a utility expects to incur an actual compliance cost for GHG emissions including such cost in the dispatch decision minimizes net cost to retail customers. In this example, proper inclusion of GHG cost in the dispatch decision prevents the sample plant from being dispatched and results in net customer cost of $0 vs a $10 net cost if GHG costs are not considered (row 10). Without GHG cost in the dispatch decision the plant would have been dispatched and customers would have received the net benefit of the wholesale sale ($10, row 8), but that benefit would not have been sufficient to offset the cost of the emissions allowance that would also need to be purchased ($20, row 9). Note also that loss of the $10 benefit from the wholesale sale that would have been made absent any actual GHG costs represents an increased cost to retail customers that is not mitigated by Department of Ecology's no-cost allowance allocation methodology.

In contrast with the example above, consider a scenario wherein actual GHG costs will not be incurred if a plant is dispatched (as in dispatch to serve retail load for which the utility would receive a no-cost allowance). In this case inclusion of GHG cost in the dispatch decision results in higher net cost for retail customers, as illustrated in Table 2.

Table 2. *Example 1 MW dispatch decision, to serve retail load, and resulting customer cost with GHG improperly included in dispatch decision vs not including*

	All values in $ per MWh	Include GHG cost in dispatch	**Do not include GHG cost in dispatch**
	<u>*Dispatch decision*</u>		
1	Fuel and other (non-GHG) variable costs	$50	**$50**
2	GHG cost	$20	**$0**
3	Total dispatch cost	$70	**$50**
4	Market power price	$60	**$60**
5	Is plant dispatched?	No	**Yes**
	<u>*Customer costs*</u>		
6	Fuel and other (non-GHG) variable costs	$0	**$50**
7	Market purchase cost	$60	**$0**
8	Cost to retail customers before GHG cost	$60	**$50**
9	Cost of actual GHG allowance purchase	$0	**$0**
10	Net cost to retail customers	$60	**$50**

The example in Table 2 illustrates that when a utility does not expect to incur an actual compliance cost for GHG emissions including any GHG cost in the dispatch decision will only increase net costs for retail customers. In this example, improper inclusion of GHG costs in dispatch prevented the sample plant from being dispatched and required a market purchase to serve load at a cost of $60 compared to a net total cost of only $50 had the plant been dispatched for the same 1 MWh of retail load.

Thank you for the opportunity to provide comments on the questions of CCA risk sharing and CCA dispatch cost modeling. Please contact Brennan Mueller, Manager of Energy Analysis, at Brennan.Mueller@pse.com, or Kelima Yakupova, State and Regional Policy Consultant, at Kelima.Yakupova@pse.com for additional information about these comments. If you have other questions, please contact me.

Sincerely,

/s/ Wendy Gerlitz

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