EXH. BTC-1T
DOCKETS NOS. UE-260005 & UG-260006
2026 PSE GENERAL RATE CASE
WITNESS: Bradley T. Cebulko

BEFORE THE WASHINGTON
UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION, Complainant, v. PUGET SOUND ENERGY, Respondent.	DOCKET NOS. UE-260005 and UG-260006 (*Consolidated*)

RESPONSE TESTIMONY (NONCONFIDENTIAL)

OF BRADLEY T. CEBULKO

ON BEHALF OF JOINT ENVIRONMENTAL ADVOCATES

July 28, 2026

JOINT ENVIRONMENTAL ADVOCATES

RESPONSE TESTIMONY (NONCONFIDENTIAL) OF
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I. INTRODUCTION AND SUMMARY.

Q. Please state your name and position.

A. My name is Bradley Cebulko and I am a Partner at Current Energy Group. My business address is 4764 E. Sunrise Dr. Unit #508 Tucson, Arizona, 85718.

Q. Please describe your employment and education background.

A. I am co-founder and Partner at Current Energy Group (CEG), where I lead the team focused on gas utility regulation. Our team works on a wide array of issues including cost-of-service modeling, cost of gas, long-term planning, alternative fuels analysis, capital investment prudence review, and new regulatory business models. Before founding CEG, I briefly worked for my own sole proprietorship and, before that, was a Senior Manager at Strategen Consulting from 2021 to 2024. Before Strategen, I worked at the Washington Utilities and Transportation Commission (UTC) for eight years. From 2013 to 2016, I was an analyst with the UTC Commission Staff focused on electric and natural gas integrated resource planning (IRP), electric and natural gas energy efficiency programs, and new program design and implementation. From 2016 to 2021, I was an advisor to the UTC Commissioners, where I led the Commissioners' review of general rate cases and rulemakings, and worked on legislation.

I have a master's in public administration from the University of Washington Evans School of Public Policy and Governance, and a Bachelor of Arts in Political Science from Colorado State University. My CV is attached as Exhibit BTC-2.

Q. Have you previously testified in Washington?

A. Yes, I have testified in several proceedings before the Washington Utilities and Transportation Commission, including in Puget Sound Energy's 2022 and 2024 general rate cases, amongst other proceedings.

Q. What is the purpose of your testimony, and how is your testimony organized?

A. The purpose of my testimony is to evaluate whether PSE's proposals for its natural gas system are consistent with Washington's decarbonization statutes and with lowest reasonable cost planning principles, and to recommend measures the Commission should require where they are not. My testimony is organized in four sections. First, I review the regulatory and state policy context governing PSE's gas operations and the trend in PSE's gas capital expenditures. Second, I evaluate PSE's electrification efforts and the need for a General Building Electrification Program. Third, I evaluate PSE's response to the non-pipeline alternatives directive in Final Order 09/07 of its 2024 General Rate Case. Finally, I evaluate PSE's Gas Decarbonization Depreciation Study (the Study) and its accelerated depreciation proposal.

Q. Please summarize your key findings.

A. This is PSE's third general rate case since the Climate Commitment Act was enacted in 2021, and PSE's capital plan still reflects a business-as-usual approach to gas system investment. PSE is requesting $862 million in new gas capital investment over the multiyear rate plan, an increase over its actual spending in the preceding three years. While PSE has taken initial steps toward evaluating non-pipeline alternatives (NPAs), its efforts fall short of the Commission's directive in its 2024 general rate case to evaluate NPAs for non-emergency gas investments. PSE's proposed Climate Commitment Act (CCA) compliance strategy relies on purchased allowances, supplemented by Renewable Natural Gas (RNG) and hydrogen investments that PSE's own analysis indicates cannot drive compliance at scale. The risks and costs of continued allowance reliance are addressed in the testimony of JEA Witness Megan Larkin (MEL-1T). If PSE's proposals are approved, the Company will not invest at scale in emissions reductions until 2030 at the earliest, nearly a decade after the CCA was enacted. At the same time, PSE proposes to shorten the depreciable lives of its gas assets in anticipation of decarbonization without committing to the capital restraints, alternatives analysis, and electrification necessary to reduce emissions. To ensure PSE complies with existing requirements and that cost recovery does not run ahead of decarbonization effort, I recommend that the Commission approve a general space heating electrification program, approve an NPAs framework with supporting planning requirements, decline to rely on PSE's Gas Decarbonization Depreciation Study as a basis for comparing decarbonization pathways, and condition any accelerated depreciation on a demonstrated commitment to capital restraint.

Q. What are your recommendations to the Commission?

A. My recommendations fall into three categories.

General Building Electrification Program. I recommend the Commission:

1) require PSE to offer a general space heating electrification program, open to all gas customers regardless of electric service provider, implemented without delay. In Section III, I recommend specific incentive levels and program parameters; or
2) in the alternative, direct PSE to develop the program through a stakeholder process consistent with the design recommendations in my testimony.

Non-Pipeline Alternatives. I recommend the Commission:

3) adopt the six-step NPAs framework proposed in my testimony or, in the alternative, direct PSE to convene a working group to file a framework for Commission approval within 180 days of the Final Order;
4) order PSE to pursue all cost-effective, programmatic NPAs. To facilitate the development of the programmatic NPAs, require the Company to develop,

through its energy efficiency stakeholder group, at least three programmatic NPA pilots, including standardized non-replacement solutions such as repair, relining, and pressure modification;

5) require a gas capital planning horizon of no less than five years for investments subject to NPA review, presented in the integrated system plan and reviewed by the Commission before PSE seeks cost recovery, supported by publicly accessible system maps; and

6) clarify that PSE may propose a shared savings mechanism allowing it to retain a share of verified net benefits from successful non-pipeline alternatives.

Gas System Decarbonization Depreciation Study. I recommend the Commission:

7) find that decommissioning costs are a consequence of the original decision to install the pipe and are not attributable to electrification;

8) find that the Study's inconsistent cost accounting across scenarios, including its treatment of the Hybrid Heat Pump scenario, renders its scenario comparison unreliable as a basis for concluding that accelerated electrification is more capital-intensive than continued pipeline replacement;

9) require future iterations of the Study to include sensitivity analysis on decommissioning unit costs and full tracking of decommissioning costs for mains and services; and

10) require PSE to adopt gas capital restraint measures commensurate with the amount of any approved accelerated depreciation, including my proposed programmatic NPA program and JEA Witness Danielle A. Velez's proposed Service Line NPA Program as conditions of approval.

II. REGULATORY POLICY CONTEXT.

Q. Please summarize the relevant statutes that govern PSE's gas utility operations and planning.

A. Washington State has enacted a series of statutes targeting economy-wide greenhouse gas reductions of 45 percent below 1990 levels by 2030, 70 percent by 2040, and 95 percent by 2050.[1] The Clean Energy Transformation Act (CETA), enacted in 2019, requires electric utilities to achieve 100 percent clean electricity by 2045 and net-zero equivalent by January 1, 2030. In 2021, the state passed the Climate Commitment Act (CCA), which established an economy-wide cap-and-invest program to achieve those targets. PSE's gas operations are a covered entity under the program.[2] Then in 2024, the state passed Engrossed Substitute House Bill 1589, directing PSE to develop an Integrated System Plan (ISP) that coordinates its electric and gas resource planning to achieve CETA and the CCA, and required the Commission to approve depreciation schedules retiring all gas plant in service as of July 1, 2024, by no later than January 1, 2050.[3]

Q. How has the Commission responded to these statutory requirements in its oversight of PSE?

A. This Commission has a longstanding history of emphasizing the importance of selecting the lowest reasonable cost investment or resource that satisfies the utility's needs while complying with policies and regulations. This Commission has also consistently

[1] RCW 70A.45.020.
[2] RCW 70A.65.260
[3] Initiative 2066 (2024) would have repealed portions of HB 1589. On March 21, 2025, the King County Superior Court held I-2066 unconstitutional in its entirety. *Climate Solutions v. Washington*, No. 24-2-26580-2 SEA (King Cnty. Super. Ct.). The Washington Supreme Court granted direct review and heard oral argument on January 22, 2026. No. 104240-0. HB 1589 accordingly remains in effect, and its directives govern PSE's planning obligations unless and until a court holds otherwise.

recognized that demand-side investments and resources should be considered on par with supply-side investments and resources.

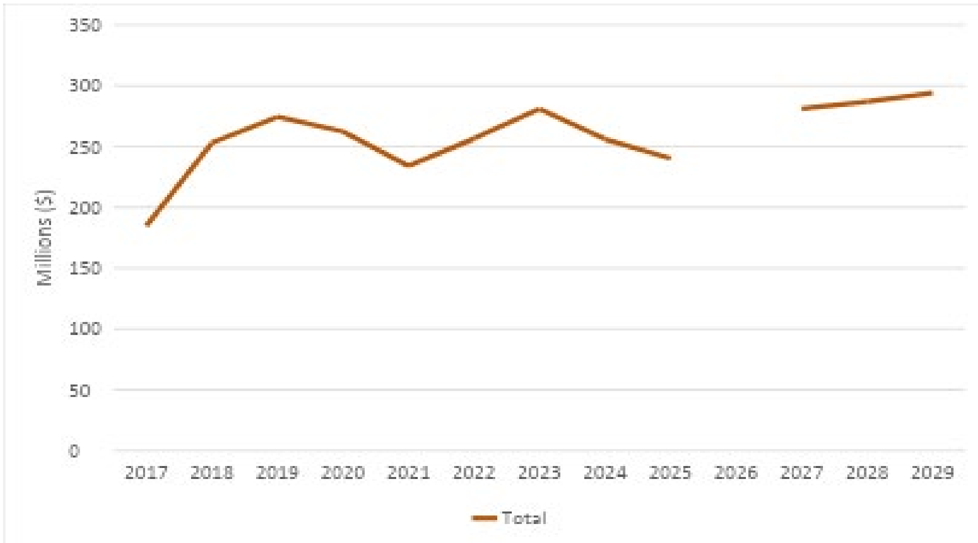
In its Final Order 09/07 in Puget Sound Energy's 2024 General Rate Case, the Commission accepted JEA's proposal and directed PSE to evaluate NPAs for all capital additions to the natural gas system, with a narrow exception for emergency and maintenance repairs.[4] The Commission found that PSE has a duty to acquire the lowest-risk resources consistent with state policy, including the CCA and HB 1589. The Commission grounded the NPA requirement in distributional equity: as customers exit the gas system, remaining customers bear a disproportionately higher share of fixed infrastructure costs, and requiring NPA evaluation of non-emergency gas capital investments is a mechanism for minimizing those costs before they are locked into rate base.

Q. Please describe the trend in PSE's natural gas capital expenditure from 2017 through 2025 and PSE's proposed expenditures for the 2027-2029 rate plan period.

A. As shown in Figure 1, PSE's actual gas capital expenditures grew from $184.7 million in 2017 to a peak of $281.0 million in 2023, before declining to $240.3 million in 2025.[5] In this rate case, PSE proposes to increase spending again in the rate plan period, to $282.7 million in Rate Year 1, $288.7 million in Rate Year 2, and $290.7 million in Rate Year 3.[6] PSE's proposed three-year natural gas system capital expenditure total of $862 million is $84.7 million, or 10.9 percent, above actual spending in the prior three years of $777.3 million.

[4] UTC, Docket Nos. UE-240004/UG-240005, Final Order 09/07 at ¶¶ 329–330.
[5] Exh. BTC-3 (PSE Response to JEA DR 41_Attachment A).
[6] PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) at 72, tbl. 30; 76, tbl. 32.

***Figure 1**: PSE Historic (2017–2025) and Proposed (2027–2029) Annual Gas System Capital Expenditures*[7]



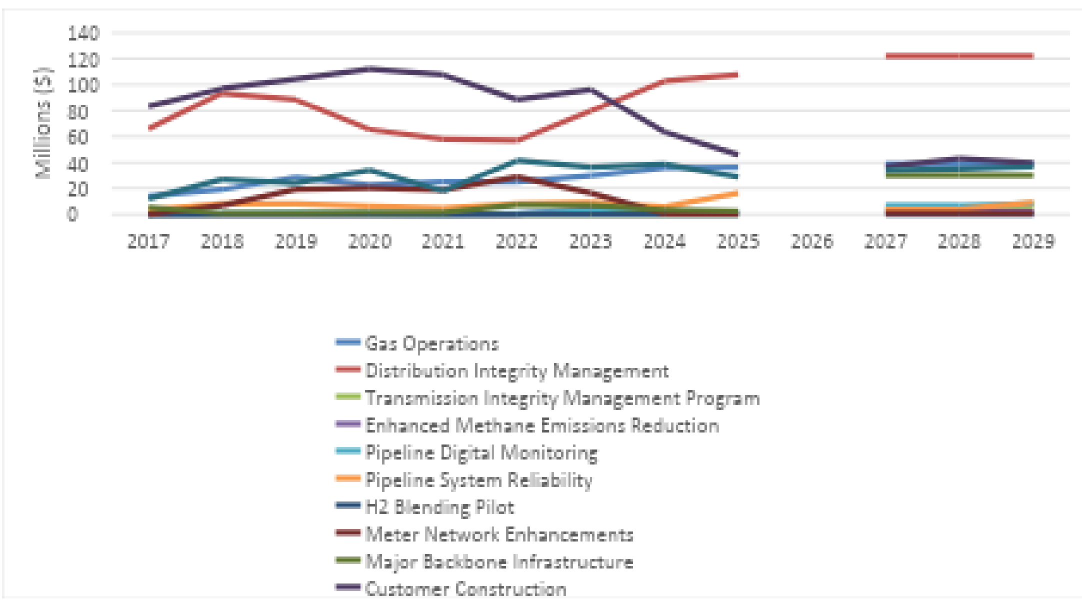
Q. How has the composition of PSE's gas capital expenditure program changed since 2017?

A. There are two categories of gas capital expenditure spending driving in opposite directions. The net effect, however, is that PSE has continued to grow its investment in its gas system since 2017 and throughout the proposed rate period. First, Customer Construction (capital expenditures associated with connecting new customers to the gas system) peaked at $112M in 2020 and has declined steadily to $46M in 2025, with PSE projecting $37M to $43M per year in the rate plan period. PSE's forecasted decline in customer construction is consistent with the direction of state policy emissions reduction policy. We should expect to see fewer customer connections. However, despite the declining trend in spending on new customer connections, PSE's is rapidly accelerating its investments in two other categories: the Distribution Integrity Management Program

[7] Exh. BTC-4 (PSE Response to JEA DR 41_Attachment A, CEG Analysis); PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) tbls. 30 & 32.

and PSE's relatively new program, Major Gas Backbone Infrastructure. PSE's spending on Distribution Integrity Management Program (DIMP) has increased from $66M in 2017 to a forecast of $122M annually during the rate plan.[8] PSE's annual investment in overhauling its distribution system will double from a low in 2022 of under $60M to $122M just five years later in 2027. DIMP, PSE's program for replacing pipeline segments, is now the dominant capital category accounting for 42 percent of the proposed $862 million gas capital program. PSE's spending on the Major Gas Backbone Infrastructure will increase from $7M in 2025 to $30M annually during the proposed rate period.

***Figure 2**: PSE Actual and Proposed Annual Gas System Capital Expenditure by Cost Category*[9]



[8] Exh. BTC-3 (PSE Response to JEA DR 41_Attachment A), PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) at 88, tbl. 35.

[9] Exh. BTC-4 (PSE Response to JEA DR 41_Attachment A, CEG Analysis); PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) tbls. 30 & 32.

Q. What does the trend in gas capital expenditures tell you about the alignment between PSE's capital program and Washington State's decarbonization requirements?

A. The state has set aggressive economy-wide greenhouse gas reductions of 45 percent by 2030, 70 percent by 2040, and 95 percent by 2050 relative to 1990 levels, and the Climate Commitment Act obligates PSE to cover its share of those emissions. Separately, ESHB 1589 directs PSE to achieve all cost-effective electrification, assess the potential for geographically targeted electrification, and assess non-pipeline alternatives, and establishes an Integrated System Planning process to implement these requirements. To mitigate the risk that ratepayers bear stranded costs from gas assets rendered uneconomic by this transition, ESHB 1589 also directs the Commission to approve a depreciation schedule retiring all gas plant in service as of July 1, 2024, no later than January 1, 2050

PSE's capital program does not reflect these requirements. PSE is requesting $862 million in new gas capital investment over the MYRP, a 10.9 percent increase over actual spending in the preceding three years, on mains and services with proposed average service lives of 45 to 55 years and meters with a proposed average service life of 35 years.[10] At the same time, it is also seeking accelerated depreciation of gas assets installed prior to July 1, 2024, on the grounds that those assets face early retirement due to the energy transition. PSE is proposing accelerated depreciation, in part, because "customer-connected distribution assets face heightened early retirement risk due to electrification trends."[11] Figure 1 shows that PSE's gas investment program is not contracting in response to these requirements; it is growing.

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[10] PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 39, tbl. 1.
[11] *Id*. at 11:4–11.

PSE also continues to defer a General Building Electrification Program, arguing in this proceeding that its 2027 ISP is the appropriate vehicle for determining whether and how such a program should be designed.[12] Yet PSE requests rate recovery for investments in alternative fuel technologies that, by its own characterization, are not available at scale,[13] and did not go through the ISP process. The result is an inconsistent standard for capital review: new gas investment and alternative fuels investment proceed outside the ISP process while a General Building Electrification Program is deferred to it.

It is concerning that PSE continues to grow its gas system expenditures when its own analysis shows that total gas throughput (i.e., customer demand) will significantly decrease and compliance with Washington's emissions limits requires widespread electrification of gas end uses and, over time, a smaller gas system.[14] Every dollar of a new long-lived gas plant added today increases the cost and stranded asset risk of the transition the Company's own modeling says is coming.

III. GENERAL BUILDING ELECTRIFICATION PROGRAM.

Q. Is PSE proposing an expansion of these efforts into a General Building Electrification Program?

A. No. PSE continues to not propose a general building electrification program. This is the third consecutive rate case in which PSE has deferred a general building electrification program.

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[12] PSE Exh. MS-1T (Matt Steuerwalt Opening Testimony) at 21:20–22.
[13] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 19.
[14] *Id*. at 6–7. Hybrid Heat Pump scenario: approximately 67 percent decline in gas throughput by 2050; Cold Climate Heat Pump scenario: approximately 59 percent decline in gas customers and 76 percent decline in throughput by 2050. *See also* Exh. JDT-1T (John D. Taylor Opening Testimony) at 47, fig. 6.

Q. What is a General Building Electrification Program, and how does it differ from the Targeted Building Electrification Program PSE has piloted?

A. A Targeted Building Electrification Program is designed to test whether electrifying a specific, defined set of customers is a cost-effective substitute for a specific, planned gas infrastructure investment. A targeted program answers the question "can electrification avoid this particular pipeline project?" A General Building Electrification Program answers a different question: "how does PSE meet the CCA's emissions limits at the lowest reasonable cost?" A general program reduces system-wide gas throughput and CCA-covered emissions by making heat pump incentives available to all customers, regardless of whether any individual conversion avoids a specific infrastructure project. Because the two programs answer different questions, they are evaluated against different cost-effectiveness tests and do not require the same data to design. Both can proceed at once, but neither is a substitute for the other.

Q. Is a General Building Electrification Program needed today?

A. Yes. A General Building Electrification Program is both necessary and feasible, and none of PSE's stated reasons for deferring one withstands scrutiny. It is necessary because PSE's own analysis demonstrates that widespread electrification is required to comply with Washington's emissions limits, and each year of delay compounds the deployment gap that must be closed. It is feasible because heat pumps are mature, widely deployed technology, because PSE has administered operationally analogous incentive programs for years, and because program design can directly manage electric peak impacts. I first present the need for and feasibility of a general program, and then address PSE's stated reasons for deferral.

Q. How does PSE's own analysis demonstrate a need for a general electrification program?

A. The CCA requires economy-wide GHG reductions of 45 percent by 2030, 70 percent by 2040, and 95 percent by 2050. As discussed more thoroughly in Section V, PSE conducted a Gas Decarbonization Depreciation Study for this rate case that examined three hypothetical business futures: a Reference scenario, a Hybrid Heat Pump Scenario, and a Cold Climate Heat Pump (CCHP) Scenario. The Hybrid Heat Pump (HHP) Scenario projects a 67 percent decline in gas throughput by 2050 with only an approximately 3 percent customer decline.[15] This is the conservative policy scenario as it preserves most of the gas customer base, retaining gas for peak and backup use only. The more aggressive CCHP scenario projects a 76 percent throughput decline and a 59 percent customer decline by 2050. The Company's witness characterizes these scenarios as illustrative rather than forecasts.[16] That characterization does not diminish their significance here. PSE considered these scenarios sufficiently reliable to inform its proposed depreciation rates. Indeed, PSE witness Taylor presents the customer forecast, throughput forecast, and bill impacts of the Company's proposed depreciation approach under the Hybrid Heat Pump scenario specifically.[17] PSE thus treats the HHP scenario as sufficiently reliable to present to the Commission the customer bill impacts of its depreciation proposal, even as it declines to propose the electrification program that scenario assumes. Notably, PSE's official F25 Final Gas Load Forecast corresponds to the Reference scenario, which the depreciation study describes as the outcome that would persist absent additional policies and measures to achieve state climate goals.[18] Every scenario consistent with CCA compliance entails substantial electrification.

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[15] PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 24:14–23.
[16] *Id*. at 24:2–4.
[17] PSE Exh. JDT-1T (John D. Taylor Opening Testimony) at 44–46, 51.
[18] PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 24:5–13.

Q. What does PSE's own scenario data imply about the pace of heat pump deployment needed?

A. Illustratively, PSE serves approximately 820,000 residential gas customers. Under the HHP Scenario, PSE retains approximately 97 percent of those customers on the system through 2050 while still achieving a 67 percent throughput decline, meaning nearly all of the decline must come from heat pump adoption by customers who remain on the system.[19] The scenario assumes full hybrid heat pump adoption for new furnaces by 2045, with existing furnaces converting over time. If substantially all remaining residential customers adopt a heat pump by 2050, the implied pace is roughly 30,000 households per year on average, and higher than that going forward, because adoption in the years since the scenario window opened has run far below this rate. Each year of delay compounds the gap that must be closed before the 2030 CCA target.

Q. Are heat pumps an unproven technology and are their impacts not well understood?

A. No. Millions of heat pumps are sold every year, and tens of millions are currently in service around the United States. Nationally, heat pumps outsold gas furnaces in the United States for the fourth consecutive year in 2025, and outsold gas furnaces by their widest-ever margin (32 percent) in 2024, according to shipment data compiled by an industry trade association.[20] Further, increasing levels of heat pump deployment and decreasing levels of gas appliance deployment appears to be a structural trend, persisting over years and accelerating, as shown by research from the Building Decarbonization Coalition.[21] Washington State mirrors that

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[19] *Id*. at 24:14–23.
[20] Alison F. Takemura, Canary Media, "Heat pump sales dipped in 2025. They still beat gas furnaces" (Feb. 2026), available at https://www.canarymedia.com/articles/heat-pumps/heating-cooling-sales-us-gas-furnaces.
[21] Building Decarbonization Coalition, "Q2 2026 Momentum Report" (July 14, 2026), available at https://buildingdecarb.org/momentum-q2-2026.

trend, where the state building code strongly incentivizes most new residential buildings to install heat pumps.[22]

Q. Would designing a general building electrification program be a novel undertaking for PSE?

A. No. Building electrification incentive programs, including heat pump rebates, are operationally analogous to energy efficiency rebate programs, which PSE has administered for years. PSE already runs several rebate programs, including an income-qualified gas-to-electric heat pump program. A general building electrification program does not require new administrative infrastructure, new contractor networks, or new customer outreach channels.

Q. PSE identifies electric peak impacts as a key uncertainty it wants its electrification pilots to examine.[23] Would winter peak concerns prevent a General Building Electrification Program from proceeding?

A. No. PSE is already investing $784 million in electric customer growth driven by electrification of end uses and changing building codes.[24] A general building electrification program adds incremental load to a trajectory PSE has already incorporated into its capital program, and a voluntary incentive program adds that load gradually, as customers replace equipment at the natural end of life over many years, giving PSE's planning processes ample visibility. Program design can also directly manage peak impacts. The HHP Scenario, which PSE presents as the conservative decarbonization case and under which it presents the bill impacts of its depreciation proposal, explicitly retains gas as backup fuel on peak winter days, limiting

[22] BetterBuiltNW, "Washington State Energy Code Updates: What to Know" (March 26, 2024), available at https://betterbuiltnw.com/news/washington-state-energy-code-updates-what-to-know.
[23] PSE Exh. AAA-1 (Aaron A. August Opening Testimony) at 77:18–20.
[24] PSE Exh. MS-1T (Matt Steuerwalt Opening Testimony) at 10:11–13.

electric peak impacts by design.[25] PSE cannot simultaneously rely on the HHP scenario in its depreciation case and argue that hybrid electrification creates unacceptable electric peak stress. A 2025 dual-fuel heat pump analysis using PSE's 2023 hourly emissions data found that dual-fuel systems are typically sized to a 30°F balance point with gas backup engaging at a 35°F switchover, meaning hybrid equipment adds limited load, if any, during peak winter conditions. [26]

Q. Some participating customers will fully electrify rather than install hybrid systems. Does full electrification change your conclusion?

A. No. Full conversions add winter load, which coincides with PSE's peak demand, but the addition is gradual, small, and controllable. Under the program I recommend, the Commission sets the pace through the program budget and annual targets, giving PSE multi-year forecast visibility. A program whose load additions are capped, gradual, and forecastable cannot reasonably be the load growth PSE finds unmanageable. Further, PSE can require customers to enroll in time-of-use rates and demand response programs as a condition of the incentive. If anything, PSE will have better information about electrification that occurs through a planned program than electrification that occurs naturally without PSE receiving any notice.

Q. What reasons does PSE offer for deferring a General Building Electrification Program, and do they withstand scrutiny?

A. PSE offers three principal reasons: that its Targeted Electrification Program is still generating results, that the 2027 ISP is the appropriate venue for program design, and that cost-effectiveness and electric peak impacts remain uncertain. None withstand scrutiny. The

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[25] PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 24:14–19.
[26] NEEA, *Dual-Fuel Heat Pump Systems Analysis, Report #E25-347* (Sept. 2025), available at https://neea.org/wp-content/uploads/2025/09/Dual-Fuel-Heat-Pump-Systems-Analysis.pdf.

targeted program answers a different question than a general program and is not a substitute for one. The ISP deferral is inconsistent with PSE's treatment of its alternative fuels investments, which proceed in this case without ISP review and without the analysis PSE demands of electrification. And the peak and cost-effectiveness uncertainties are overstated, as discussed above. I address each in turn.

Q. What has PSE attempted to date?

A. PSE's Targeted Electrification Pilot - Phase 2 is approved and running through December 2026 per Order 11.[27] Its six components are low-income direct installation, multifamily rebates in named communities, a small business heat pump pilot, the Duvall gas-constrained area pilot, income-qualified heat pump rebates, and commercial and industrial (C&I) decarbonization grants.[28] Although PSE presents these components under the Targeted Building Electrification Program label, only the Duvall pilot is a targeted electrification proposal deployed to avoid a specific, identified gas infrastructure investment. The remaining five components are heat pump incentive offerings defined by customer segment rather than by avoided infrastructure. In design and operation, they resemble a General Building Electrification Program but only at a pilot scale.

Q. Why does that program not substitute for a General Building Electrification Program?

A. As discussed above, targeted and general programs serve fundamentally different purposes, are evaluated against different cost-effectiveness tests, and are not substitutes for one another. PSE's continued piloting of targeted electrification therefore cannot justify the continued absence of a general program. PSE has been deploying "pilot" projects since 2023 and has not made any proposals to scale those projects despite their success. If PSE's new targeted

[27] UTC, Docket Nos. UE-240004/UG-240005, Order 11 (March 17, 2025).
[28] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 80.

electrification proposal is approved as proposed, it will have completed seven years of pilots on the same decarbonization strategy by the end of this MYRP, without any movement toward deploying the strategy at scale.

Q. Does PSE apply the same standard to its other proposed decarbonization investments that it applies to a General Building Electrification Program?

A. No. PSE is deferring a General Building Electrification Program to the 2027 ISP,[29] yet it requests rate recovery in this case for alternative fuels investments that satisfy neither cost-effectiveness analysis nor demonstrated scalability, and that did not go through the ISP process. PSE requests rate recovery for a hydrogen blending project that will serve up to 500 customers at 5 percent hydrogen by volume, with blending not beginning until Q3 2029.[30] PSE contracted for 3.5 MMBtu of RNG in 2025, a negligible fraction of PSE's approximately 900 million therm annual throughput.[31] Measured against the customers it serves, the hydrogen pilot's combined $1.4 million capital and $2 million operations and maintenance (O&M) budget works out to roughly $6,800 per participating customer, more than double the top of the heat pump rebate range I recommend below ($1,500 to $3,000), for a fuel PSE concedes is not available at scale. This asymmetry undermines the credibility of PSE's stated basis for deferral and directs decarbonization spending toward pathways that PSE's own analysis shows cannot scale to meet its CCA obligations.[32]

Q. Are RNG and hydrogen better positioned to drive CCA compliance than electrification?

A. No. While PSE is not seeking cost recovery for alternative fuels broadly, its proposed hydrogen

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[29] PSE Exh. MS-1T (Matt Steuerwalt Opening Testimony) at 21:20.
[30] PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) at 107:3–6, and PSE Exh. MLV-12 (Natural Gas Reliability and Resiliency Investments) at 23.
[31] PSE Exh. MS-1T (Matt Steuerwalt Opening Testimony) at 21:15.
[32] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 20.

investments proceed without the cost-effectiveness analysis and demonstrated scalability that PSE contends must precede a General Building Electrification Program. PSE has not justified applying a more demanding standard to electrification than to hydrogen. As discussed in the testimony of JEA Witness Danielle A. Velez (DAV-1T), Washington does not have a broadly available commercial supply of hydrogen, and direct use of hydrogen as a residential heating fuel is widely understood to be not cost effective.[33] Further, the amount of usable energy able to be extracted from hydrogen blending is limited, with PSE's own estimates stating the gas distribution system is limited to roughly 15 percent hydrogen blending by volume (~5 percent energy content).[34,35] PSE's filing does not present evidence of how their proposal avoids these challenges. Furthermore, unlike heat pumps, I am not aware of any evidence of demonstrated emission reductions at scale from hydrogen blending in the residential sector. In other words, not only does the hydrogen proposal not meet PSE's own requested evidentiary standards, the proposal does not appear to have evidence it will successfully reduce emissions. Even under favorable assumptions, blending hydrogen into the existing gas system has limited emissions value. Research on hydrogen blending finds that blending as much hydrogen as most pipelines can handle before degrading (roughly 20 percent by volume) achieves only about a 7 percent emissions reduction, because hydrogen carries less energy per unit volume than methane.[36]

Q. Does PSE present analysis supporting the cost-effectiveness or decarbonization role of its alternative fuels investments in this case?

A. It does not. PSE presents no quantitative benefits for the hydrogen blending program and

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[33] Jan Rosenow, *Is Heating Homes with Hydrogen All but a Pipe Dream? An Evidence Review*, 6 Joule Commentary 2225 (Oct. 19, 2022), available at https://www.sciencedirect.com/science/article/pii/S2542435122004160.
[34] UTC, Docket No. UE-240004, Exh. BTC-1T (Bradley T. Cebulko Opening Testimony) at 38:1–6.
[35] RMI, "We Need Hydrogen — But Not for Everything," available at https://rmi.org/we-need-hydrogen-but-not-for-everything/.
[36] Energy Innovation Policy and Technology, LLC, "Blending Hydrogen with Natural Gas" (2022), available at https://energyinnovation.org/wp-content/uploads/2022/03/Hydrogen-Blending-One-Pager.pdf.

justifies it entirely by qualitative operational learning objectives.

Q. What is your recommendation regarding a General Building Electrification Program?

A. My recommendation is that the Commission requires PSE to offer a general space heating electrification program. The program should offer electrification incentives to all gas customers regardless of whether that customer is also a PSE electric customer. Specifically, I recommend a rebate program, funded up to a $78 million cumulative cap through 2030, offering $1,500-$3,000 per converted system, and paired with a Performance Incentive Mechanism tied to annual electrification targets. I describe the basis for each of these design elements below.

Q. Why is it appropriate to require PSE to adopt such a program?

A. PSE's current proposal to continue relying on CCA allowance purchases and invest in alternative fuels is not consistent with lowest reasonable cost planning principles or applicable decarbonization requirements, and it shifts cost and risk to customers, as discussed above. Additionally, my proposed General Building Electrification Program is cost-effective compared to PSE's current CCA compliance strategy, as I discuss below. It is therefore reasonable to require PSE to adopt the program as a condition of, or an alternative to, approving PSE's requested spending on its gas system and CCA compliance.

Requiring PSE to adopt such a program would not amount to preapproving investments or acquisitions, for at least three reasons. First, PSE would not acquire, own, or operate any of the equipment its customers voluntarily adopt through the program; PSE would merely provide incentives shown to be cost-effective. Second, PSE retains the option of proposing a different reasonable and cost-effective CCA compliance strategy on rebuttal, or of continuing to purchase allowances funded by a source other than the customer funds whose approval would be conditioned on adopting a General Building Electrification Program. Third, under my proposal PSE would retain significant discretion over program design, incentive levels, and implementation, so long as its final program satisfies the criteria I set forth below. Nor would requiring the program undermine the Commission's review of PSE's expenditures; it would give effect to that review by directing an approach demonstrated to be more reasonable and cost-effective than PSE's proposal.

Q. Please explain how you arrived at an incentive level of between $1,500 and $3,000?

A. The range is a starting point for program design. Under my recommendation, PSE's compliance filing must include a total resource cost analysis, and the final incentive levels should be set and adjusted based on that analysis. The range I recommend bounds PSE's initial proposal, and I derived it from incentive levels PSE itself already offers. PSE currently provides $1,500 for conversion of electric resistance heating to a heat pump,[37] $1,500 for hybrid heat pump installation,[38] and up to $4,000 for gas-to-heat-pump fuel switching for income-qualified customers.[39] Each of these incentives was developed through PSE's existing program processes. PSE has therefore already represented, through its own program design, that incentives of this magnitude are reasonable for heat pump adoption, including fuel switching specifically. My recommended range sits within the band PSE has established.

Q. Is your recommended incentive range based on cost-effectiveness analysis?

A. Yes, in two respects. The range is anchored to incentive levels PSE itself developed and offers through its existing programs, each of which passed through PSE's own program design and

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[37] PSE, "Electric resistance to air-source heat pump conversion rebate," available at https://www.pse.com/en/rebates/heating/electric-resistance-to-air-source-heat-pump-conversion-rebate.
[38] PSE, "Hybrid Heat Pump," available at https://www.pse.com/en/rebates/heating/hybrid-heat-pump.
[39] PSE, "Moderate-Income Fuel-Switching Heat Pump Program," available at https://www.pse.com/en/rebates/heating/mi-heatpump.

cost-effectiveness processes. And as I describe below, a screening-level comparison against PSE's CCA allowance costs indicates rebates in this range reduce covered emissions at a cost comparable to or below what PSE pays for allowances. What I have not done is conduct a formal total resource cost study to support a single, specific incentive amount.

Q. Is the absence of a formal cost-effectiveness study a problem for your proposal?

A. No, for two reasons. First, the inputs required for a program-level cost-effectiveness analysis, including avoided gas infrastructure costs, allowance cost forecasts, program delivery costs, and expected participation response, are in PSE's possession. That is why my recommendation takes the form of a required filing containing that analysis rather than a specific incentive amount for adoption in this order. The Commission need not order rebates of $1,500 to $3,000; it need only find it reasonable to require PSE to justify its proposed incentive levels with analysis. A full residential conversion avoids roughly 700 therms per year,[40] or approximately 3.7 metric tons of CO_2 annually,[41] which at recent Climate Commitment Act allowance prices represents approximately $245 per heat pump per year in avoided compliance cost alone,[42] before accounting for avoided gas infrastructure investment.[43] Over a 20-year measure life, avoided allowance costs alone are of the same order of magnitude as the recommended incentive.

Q. Why do you recommend the program be available to all customers rather than limited to income-qualified customers, as PSE's existing fuel-switching incentive is?

A. Because the program's purpose is to reduce emissions. CCA-covered emissions do not vary

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[40] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study), fig. 7.
[41] EPA, *GHG Emission Factors Hub* (2025), tbl. 1 (Natural Gas, 53.06 kg CO_2/mmBtu), available at https://www.epa.gov/system/files/documents/2025-01/ghg-emission-factors-hub-2025.pdf.
[42] Using the average price of the last four auctions, $66.25 per allowance.
[43] Heat pump deployments providing additional benefits such as avoided gas infrastructure investment should be eligible for stacked incentives (e.g., from a non-pipeline alternative or Targeted Building Electrification program).

with the income of the household producing them. Every conversion reduces throughput and PSE's compliance obligation by roughly the same amount, so restricting eligibility caps the program's emissions impact at a fraction of its potential. There is a reasonable justification for providing a larger incentive for income-qualified customers than other customers. I therefore recommend a program open to all gas customers, with an enhanced tier for income-qualified customers consistent with PSE's existing $4,000 level.

Q. Is there precedent for offering both general electrification incentives and higher incentives for low- and moderate-income households?

A. Yes. This two-tier structure is standard among established electrification programs. Efficiency Maine, although its rebate is directed at oil, propane, and electric-resistance heated homes rather than gas customers, offers heat pump rebates of $1,000 per outdoor unit for any-income households, $2,000 per unit for moderate-income households, and $3,000 per unit for low-income households, up to a lifetime cap of three units per housing unit (maximum household totals of $3,000, $6,000, and $9,000, respectively).[44] Mass Save offers whole-home heat pump rebates of up to $8,500 for general customers and up to $16,000 for income-qualified customers.[45] Colorado utilities offer income-qualified rebates at roughly four times the base rebate available to all customers.[46]

A review of other states shows that general-eligibility incentives in these programs range from $3,000 to $8,500 per home, so my recommended range of $1,500 to $3,000 is conservative relative to established practice. Furthermore, none of the other state's programs

[44] Efficiency Maine, *Residential Heat Pump Rebates*, available at https://www.efficiencymaine.com/at-home/residential-heat-pump-rebates/ (last visited July 22, 2026).
[45] Mass Save, *Heating and Cooling Rebates and Incentives*, available at https://www.masssave.com/residential/rebates-offers-services/heating-and-cooling/
[46] *See* Colo. Pub. Util. Comm'n, Proceeding No. 23A-0392EG (*In the Matter of the Investigation and Consideration of the Clean Heat Plan Filed by Public Service Company of Colorado*).

treat income qualification as an eligibility wall as does PSE. Rather, the states offer incentives based on relative income.

Q. Are there ways to further limit programmatic risk if uptake is greater than expected?

A. Yes. The simplest mechanism is a ceiling on total program expenditures, on an annual or cumulative basis. I recommend a cumulative budget of between $39 million and $77 million (depending on the incentive level chosen) by 2030. This would incentivize roughly 31,000 heat pumps by 2030.

Q. How did you arrive at your recommended budget cap?

A. The cap is anchored to PSE's own Hybrid Heat Pump scenario. That scenario assumes new gas furnaces convert to hybrid heat pumps starting in 2024, and that all furnace sales are hybrids by 2045.[47] PSE has approximately 820,000 residential gas customers. Under the HHP scenario, about 97 percent stay on the gas system, so approximately 795,000 homes eventually install a heat pump. A furnace lasts about 20 years, so approximately 40,000 furnaces reach end of life each year. If the hybrid share of those replacements grows steadily from zero in 2024 to 100 percent in 2045, the scenario implies about 5,700 conversions in 2027, 7,600 in 2028, and 9,500 in 2029. That is about 22,800 conversions over the rate plan.[48] I then multiplied those conversions by the incentive range of $1,500 to $3,000 and added 13 percent for administrative costs. The 13 percent administrative assumption is conservative; PSE's actual residential conservation programs run at 10 to 13 percent.[49] This produces a recommended ceiling of approximately $39 million to $77 million for the rate plan period, or $13 million to $26 million annually.

[47] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 40.
[48] Exhibit BTC-6 (GBEP Budget Estimate Workpapers).
[49] UTC, Docket Nos. UE-230892/UG-230893, *PSE 2024-2025 Biennial Conservation Report* (June 1, 2026), exh. 2.

My proposed cap is conservative. It counts only conversions at natural equipment end of life, using a 20-year furnace life. It also remains far below the scenario's average pace of roughly 30,000 conversions per year through 2050. The cap bounds ratepayer exposure during program startup and should be revisited in PSE's next general rate case. For scale, the program's average annual cost of roughly $13 to $26 million is approximately one-tenth of PSE's current annual conservation portfolio spending. PSE spent approximately $366 million on energy efficiency programs in the 2024-2025 biennium, $293 million on electric and $73 million on gas.[50] A program of this size is well within PSE's demonstrated administrative capability and the bounds of program spending the Commission routinely oversees.

Q. Have you completed a Cost Benefit Analysis of offering rebates at this level?

A. Yes. While I did not conduct a formal total resource cost test, my analysis indicates that offering rebates at this level would cost less than purchasing CCA allowances. As shown below, the average settlement price of the last 4 auctions (representing one calendar year) was $66.25, ranging between $64.30 and $70.86 per allowance.[51] One metric of cost-effectiveness, therefore, is whether the rebate cost per metric ton of emissions avoided by transitioning a natural gas appliance to a heat pump is less than approximately $66; if so, the rebate is cost-effective because it avoids allowances PSE would otherwise need to purchase.

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[50] *Id.*, exhs. 1 & 2.

[51] Wash. Dep't of Ecology, *Washington Cap-and-Invest Program, Auction #14 June 2026 Summary Report*, Publ'n No. 26-14-039 (issued June 10, 2026), available at https://apps.ecology.wa.gov/publications/documents/2614039.pdf.

***Figure 3**: Four Most Recent CCA Auction Allowance Prices*

Auction	Date	Allowance Settlement Price
11[52]	September 2025	$64.30
12[53]	December 2025	$70.86
13[54]	March 2026	$65.26
14[55]	June 2026	$64.56

Adopting the range of the National Laboratory of the Rockies of 2.9–3.8 tons of carbon avoided per household heat per year pump deployed in Washington,[56] and assuming a heat pump lifespan of 20 years, the utility cost ranges between $19.74 and $51.72 per ton as shown in Figure 4, generally below recent auction prices as shown in Figure 5.

***Figure 4**: Estimated cost per ton of Electrification*

Rebate Level	Emissions Avoided (high)	Emissions Avoided (low)
$1,500	$19.74	$25.86
$3,000	$39.47	$51.72

***Figure 5**: Comparison of Allowance Price vs. Estimated Cost of avoided emissions via Electrification*

	Allowance Price	Electrification Estimate	Difference
Max	$70.86	$51.72	($19.14)
Average	$66.25	$33.58[57]	($32.67)
Min	$64.30	$19.74	($44.56)

[52] Wash. Dep't of Ecology, *Washington Cap-and-Invest Program, Auction #11 September 2025 Summary Report*, Publ'n No. 25-14-051 (September 2025), available at https://apps.ecology.wa.gov/publications/documents/2514051.pdf.

[53] Wash. Dep't of Ecology, *Washington Cap-and-Invest Program, Auction #12 December 2025 Summary Report*, Publ'n No. 25-14-083 (December 2025), available at https://apps.ecology.wa.gov/publications/documents/2514083.pdf.

[54] Wash. Dep't of Ecology, *Washington Cap-and-Invest Program, Auction #13 March 2026 Summary Report*, Publ'n No. 26-14-003 (March 2026), available at https://apps.ecology.wa.gov/publications/documents/2614003.pdf.

[55] Wash. Dep't of Ecology, *Washington Cap-and-Invest Program, Auction #14 June 2026 Summary Report*, Publ'n No. 26-14-039 (June 2026), available at https://apps.ecology.wa.gov/publications/SummaryPages/2614039.html.

[56] Wilson et al., *Heat pumps for all? Distributions of the costs and benefits of residential air-source heat pumps in the United States*, Joule 8 (April 17, 2024) at 1000–1035, available at https://doi.org/10.1016/j.joule.2024.01.022.

[57] At an assumed $2,250 rebate level and 3.35 avoided tons per heat pump per year.

In other words, even without a formal total resource cost test, the rebate program appears to reduce covered emissions at a cost comparable to or lower than what PSE already pays to simply purchase allowances and pass the costs through to customers. This approach is also conservative because it considers only avoided CCA compliance costs. The other benefits of heat pump adoption, including indoor air quality, comfort, avoided gas infrastructure investment, and avoided gas equipment replacement costs, are excluded, meaning the cost-effectiveness of accelerated heat pump adoption is likely more favorable than this streamlined analysis shows.

Q. Does this program structure need to be permanent?

A. No. I have structured this program such that it can be relatively unmanaged while heat pump market penetration is still so low. As most beneficiaries will be homeowners whose heating equipment approaches its end of life, the program will inherently have a degree of randomness. This reduces both near term complexity and risk, as the inherent randomness will reduce the likelihood of major localized effects on the gas or electricity systems. In essence, a General Building Electrification Program will be analogous to early rooftop solar incentive programs. As PSE considers what programs it should implement as a result of the conclusions of its forthcoming ISP, PSE can propose revisions to the program.

Q. Does this approach lock the Commission into a particular decarbonization pathway?

A. No. This approach deliberately allows the economic, market, and policy environment to continue unfolding and enables PSE to conduct its analysis through the integrated system planning process. However, regardless of whether the future is full electrification or a hybrid pathway, heat pump deployment will be dramatically higher. A General Building

Electrification Program is adaptable to both cases, as medium- and long-term pathways are determined without wasting critical near-term time.

Q. What timeframe should this program be implemented.

A. The Commission should require this program to be implemented immediately given the urgency of CCA compliance. If the Commission's seeks alternatives or believes that further development is needed, it should direct PSE to develop a General Building Electrification Program through a stakeholder group and file a proposal within 180 days of this order.

Q. If the Commission opts for a stakeholder approach, what constraints should be placed on it?

A. PSE should convene a stakeholder group no fewer than three times before filing a program with the Commission. At least one of the required stakeholder meetings must be convened for the purpose of presenting and receiving feedback on PSE's draft program proposal, and must occur no fewer than 45 days prior to the filing deadline. PSE must circulate the draft program materials to stakeholder meeting participants at least 7 days before that meeting and accept written feedback on its draft program proposal for at least 14 days after the meeting.

Q. What should PSE's filing include?

A. The filing must include all elements for stakeholders to evaluate the proposal and have the key information necessary for PSE to implement the program immediately after Commission approval. This should include supporting analysis, budgetary and rate recovery information, eligibility criteria and participation targets, and evaluation and performance measures.

Q. What supporting analysis should PSE's proposal provide?

A. First, it should have a cost-effectiveness analysis applying a total resource cost test that accounts for, at a minimum, program costs, avoided gas system infrastructure investment, avoided CCA allowance purchases, customers' avoided gas equipment replacement costs,[58] and incremental electric system costs attributable to the program.

Q. What budgetary and rate recovery information should PSE's filing include?

A. The proposal should also have a proposed program budget for the remainder of the MYRP period, broken out by measure type (space heating, water heating) and customer segment (residential, commercial/industrial, income-qualified). The filing should also include the proposed rate recovery mechanism, including identification of the appropriate allocation between gas and electric customers and the proposed tracker or rate schedule.

Q. What eligibility and participation targets should PSE's filing include?

A. The filing should include program eligibility criteria, including explicit confirmation that gas-only customers are eligible, and participation targets for each year of the MYRP period, by customer segment.

Q. What evaluation and performance metrics should PSE's filing include?

A. The filing should include proposed measurement and verification methodology sufficient to allow the Commission to evaluate program cost-effectiveness at the end of the MYRP period. The filing may include a proposal for a performance incentive or performance incentive mechanism for achieving certain targets.

Q. Do the avoided CCA allowance costs offset the program costs?

A. Yes, over the life of the measures, though not in the same year the incentive is paid. Each conversion requires a one-time incentive of $1,500 to $3,000 and avoids roughly $190 to $250 per year in allowance costs at recent auction prices, or approximately $3,800 to $5,000 over a

[58] E3, "Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California," (Dec. 2023) at 35, fig. 7 (finding avoided equipment replacement costs equal to almost half of the NPV cost for electric appliances), available at https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California_u.pdf.

20-year measure life at current prices, before any escalation in allowance prices and before counting avoided gas infrastructure investment and avoided equipment replacement costs.

Allowance purchases are a recurring expense that PSE passes through to customers, and they produce no durable emissions reduction or risk reduction. Each dollar spent on allowances this year must be spent again next year. A conversion incentive is a one-time expenditure that reduces the compliance obligation, and customer bills, every year thereafter. The program converts a perpetual pass-through expense into a declining one.

IV. NON-PIPELINE ALTERNATIVES.

Q. In its 2024 Final Order, the Commission instructed PSE to assess all capital expenditures, with limited exception, for nonpipelined alternatives. How has PSE responded to the Commission's NPA directive in this proceeding?

A. PSE developed an NPA framework document titled "Suitability Criteria for Non-Pipeline Alternatives," attached as Appendix A to Exhibit MLV-3. The document was finalized and approved internally by PSE staff on August 22, 2025.[59] Since Final Order 09/07, the Company states that it has reviewed 503 capital projects for NPA suitability, determined an NPA suitable for 29, and implemented or begun implementing 27.[60] Of the 27, only four are complete. Eighteen are recorded at "identified" or "initial evaluation" status.[61] The selected alternatives are confined to retirements, O&M solutions, and six targeted electrification projects serving one to two customers each. Where PSE estimated the displaced investment, the 27 alternatives displace approximately $6 million in traditional capital,[62] less than 1 percent of the $862 million in gas capital investment PSE requests in

[59] PSE Exh. MLV-3 (Delivery System Planning and Project Delivery), Appendix A at 3.
[60] Exh. BTC-7 (PSE Response to JEA DR 139).
[61] Exh. BTC-8 (PSE Response to JEA DR 139_Attachment A).
[62] *Id*. This figure sums the estimated cost of the displaced traditional investment for the rows in which PSE provided

this case. Of the 474 projects PSE screened out, 86 percent were rejected on one of two bases, cost-effectiveness or adoption feasibility, and PSE acknowledges its screening "generally identifies the first constraining factor and concludes the evaluation at that point," meaning the remaining criteria were not evaluated or documented for those projects.[63]

Q. How do you define non-pipeline alternatives?

A. I define "non-pipeline alternatives" broadly, including both investments or actions that respond to an identified system need without full pipeline replacement (sometimes referred to as "non-replacement alternatives") as well as typical NPA measures. My definition includes non-pipeline alternatives such as targeted electrification and demand response, and it also includes solutions that involve work on the pipeline itself, such as repair, relining, and pressure modification. I define NPA broadly because solutions performed *on the pipe* could avoid replacement capital just as effectively as non-pipeline alternatives do, but could be read out of a literal interpretation of "non-pipeline." The purpose of the Commission's directive is to ensure lower-cost alternatives are evaluated before ratepayers fund full replacement, and that purpose does not turn on whether the alternative touches the pipe.

Q. Please describe PSE's NPA framework.

A. PSE's framework document contains a list of suitability criteria, an asset-type documentation table, threshold criteria for integrity and retirement projects, and a

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an estimate. For projects where PSE selected a retirement, abandonment, or O&M alternative, PSE stated that it "did not develop an estimated capital replacement cost" and reported the displaced investment as "N/A." Exh. BTC-7 (PSE Response to JEA DR 139) at § (d). The total displaced investment is therefore understated by an unknown amount.

[63] Exh. BTC-7 (PSE Response to JEA DR 139) at § (e).

compliance phase-in timeline.[64] Cost-effectiveness appears among the suitability criteria, described as "a relative cost comparison between options."[65] The framework does not, however, contain a cost-benefit methodology: no model, calculation procedure, or specification of which costs and benefits are compared. I return to this omission below. The document is not a clearly sequenced, step-by-step review process and does not contain a defined process flow with explicit decision points. The steps PSE describes in testimony, and discovery responses, are distributed across multiple exhibits and responses and are not assembled into a single coherent, documented procedure.[66]

PSE states that it applies a hybrid NPA screening process: programmatic-level screening for investment categories it characterizes as consisting of standardized, repeatable activities, and project-level analysis for site-specific projects such as Major Gas Backbone Infrastructure.[67] The criterion for determining which tier applies is not expressly defined in the framework document. PSE's distinction appears to turn on whether projects are internally characterized as "standardized" or "heterogeneous," without defined thresholds or documentation requirements for that classification.[68] The lack of definition is just one of several deficiencies with the framework.

Q. Let's walk through the key deficiencies in the NPA framework.

A. For the vast majority of its proposed gas system spending, PSE is not performing a substantive evaluation of alternatives. The framework produces the appearance of compliance, a documented review of 503 projects, but the reviews themselves are single-

[64] PSE Exh. MLV-3 (Delivery System Planning and Project Delivery) at Appendix A.
[65] *Id.*, Appendix A at 9–10.
[66] *Id.*, Appendix A; PSE Resp. Exh. BTC-9 (PSE Response to JEA DR 11); Exh. BTC-10 (PSE Response to JEA DR 13).
[67] Exh. BTC-10 (PSE Response to JEA DR 13).
[68] *Id.*

factor rejections under a cost-effectiveness methodology that exists nowhere in documented form. The deficiencies fall into three categories: first, the screening is not a substantive alternatives evaluation, and its outputs cannot be independently verified or replicated; second, the cost-effectiveness determinations that drive most rejections are not supported by any documented methodology and do not reflect PSE's own stated approach; and third, the framework was self-designed and self-applied, with no Commission review of its criteria or thresholds prior to this proceeding. I address each in turn.

Q. Why do you conclude that the framework has not led to meaningful evaluation of alternatives for the majority of PSE's proposed gas system spending?

A. The core issue at hand is that PSE has neglected to complete a thorough, fair, and transparent alternatives analysis for the vast majority of projects "reviewed." PSE's programmatic screening is described solely at a categorical level: asked to identify, by program, the NPA types evaluated and whether each was suitable, PSE provided a summary table of conclusions with no underlying analysis, workbooks, or project-specific documentation.[69] When asked directly for examples demonstrating application of its suitability criteria, PSE objected in part that the request "seeks information or analysis that does not exist," and stated that its programmatic screening is applied "holistically" and "may conclude once a key constraint or limiting factor is identified."[70] PSE's subsequent project-level accounting confirms the pattern. Of 503 documented reviews, the programmatic screenings produced zero suitable NPAs, every suitability finding came

[69] *Id*., tbl. 1.
[70] Exh. BTC-11 (PSE Response to JEA DR 73) §§ (a), (b).

from project-level review, and the reported bases for rejection are single-factor determinations that PSE acknowledges did not evaluate the remaining criteria.[71]

The record does show that PSE can perform genuine alternatives analysis when it chooses to. The North Lacey and Bonney Lake Needs Assessment and Solutions Reports compare pipeline and non-pipeline alternatives against defined criteria with supporting scoring[72] and PSE identified the Duvall Reliability Study and the Olympia MAOP alternatives comparison as further examples.[73] In discovery, PSE produced the Duvall Reliability Study and identified the Olympia MAOP alternatives comparison as further examples.[74] I note that the existence of these documents does not establish that the analyses in them were sound; I address deficiencies in the Bonney Lake evaluation below. Each is a discrete, site-specific project. Olympia, moreover, reflects standard federal practice rather than an NPA innovation: Pipeline and Hazardous Materials Safety Administration regulations identify six MAOP reconfirmation methods, most of which are non-replacement approaches.

No comparable documentation exists for the programmatically screened categories, and those categories are where the money is. The Distribution Integrity Management Program alone represents $365 million over the rate plan, or 42 percent of the proposed $862 million program.[75] In short, the projects with the most spending receive the least scrutiny. Documented, project-level analysis applies to a handful of site-

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[71] Exh. BTC-7 (PSE Response to JEA DR 139) §§ (a)–(c), Exh. BTC-8 (PSE Response to JEA DR 139_Attachment A). Of the 474 projects determined not suitable, 49 were screened programmatically and 425 at the project level; none of the 29 suitability determinations resulted from programmatic screening. *Id*.
[72] PSE Exh. MLV-4 (Major Backbone and Expedited Substation Projects), Appendix I.
[73] *Id*., Appendix J.
[74] Exh. BTC-12 (PSE Response to JEA DR 73_Attachment A (R)), Exh. BTC-13 (PSE Response to JEA DR 73_Attachment B); Exh. BTC-14 (PSE Resp. JEA DR-036); Exh. BTC-15 (PSE Response to JEA DR 38).
[75] PSE Exh. MLV-1T (Michelle L. Vargo Opening Testimony) at 72, tbl. 30.

specific projects, while the categories carrying the majority of proposed capital receive only undocumented categorical screening.

Q. Does PSE apply its cost-effectiveness analysis transparently and consistently?

A. No. PSE states that where a suitable non-pipeline alternative is identified, it evaluates cost-effectiveness by comparing the pipeline investment cost against the cost of the alternative, including repair and retirement costs, associated electric system upgrade costs, and the social cost of carbon.[76] The applied comparisons that appear in the record do not reflect that methodology, and PSE does not provide an explanation as to why it was not consistent with its stated methods. PSE's evaluation of candidate areas for its targeted building electrification pilot compares only the upfront infrastructure cost against the upfront incentive cost for each area.[77] PSE's cost-effectiveness comparison for the North Lacey project is similarly described as a comparison of pipeline cost against non-pipeline alternative cost.[78] PSE's analysis appears to leave out important costs and benefits, such as ongoing operations and maintenance costs, retirement or decommissioning costs, electric system upgrade costs, cost of compliance with state policies, and the social cost of carbon.

Q. Does PSE's flawed cost-benefit analysis affect the outcome evenly between traditional pipeline replacement and NPA activities?

A. No. Omitting the pipeline's eventual retirement and decommissioning costs understates the true lifecycle cost, and the relative risk, of the pipeline replacement option. Omitting the social cost of carbon omits a benefit that would accrue specifically to the

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[76] PSE Exh. MLV-3 (Delivery System Planning and Project Delivery) at 20:5–11.
[77] Exh. BTC-13 (PSE Response to JEA DR 73_Attachment B), tbl. 2.
[78] Exh. BTC-11 (PSE Response to JEA DR 11).

electrification option, since it avoids the emissions associated with continued gas combustion. Both omissions understate the case for the NPA relative to the pipeline. It does seem that PSE, at times, separately evaluates electric system capacity as a qualifying feasibility criterion, distinct from its cost-effectiveness comparison. For example, PSE lists "electric system capacity" as its own evaluation criterion, separate from "cost-effectiveness," when selecting among Bonney Lake, Duvall, and North Lacey as candidate areas for its targeted electrification pilot,[79] and separately states that recent housing growth in the Bonney Lake area created electric system constraints that rendered the area not viable for targeted electrification.[80]

Q. Did PSE evaluate the electric system impacts of electrifying Bonney Lake customers?

A. Partially, but the analysis is not thorough. PSE stated that converting approximately 4,480 Bonney Lake customers would add approximately 9,634 kW of winter peak, or roughly 2.15 kW per customer, and PSE concluded the existing distribution circuits could not accommodate 80 to 90 percent of that load.[81] However, there are three things are absent from that analysis. First, PSE did not quantify the cost. PSE's stated methodology requires electric upgrade costs to be quantified and compared. PSE instead quantified the load and treated the constraint as disqualifying, without pricing the upgrades or comparing them to the cost of the gas solution. Second, PSE did not consider a partial or hybrid case. By PSE's own figures the existing circuits could accommodate the conversion of roughly 450 to 900 customers, approximately the scale of the targeted

[79] Exh. BTC-13 (PSE Response to JEA DR 73_Attachment B).
[80] PSE Exh. MLV-4 (Major Backbone and Expedited Substation Projects), Appendix J at 23; Exh. BTC-16 (PSE Response to JEA DR 40).
[81] Exh. BTC-16 (PSE Response to JEA DR 40).

electrification pilot PSE itself designed, and hybrid heat pumps retaining gas backup at design conditions would add materially less than the 2.15 kW per customer assumed. Neither configuration appears to have been evaluated. Third, the analysis is inconsistent with PSE's own electric system planning. In this same proceeding, PSE proposes a battery energy storage system at the Bonney Lake substation to defer electric capacity upgrades in the same area.[82] When the electric system constraint arose in the gas NPA evaluation, PSE treated it as disqualifying. PSE did not evaluate whether the electrification load, particularly in the hybrid or partial configurations discussed above, which would add load well within the 1 to 5 MW size PSE itself uses to screen storage solutions, could be accommodated through the non-wires or more conventional distribution options PSE routinely applies to load growth.

Q. Why do you conclude it is problematic that PSE's NPA framework was self-designed and self-applied with no Commission review prior to this proceeding?

A. Final Order 09/07 did not prescribe a process for developing the framework, so the absence of a stakeholder process was not itself a violation of the order. The problem is structural, and it explains why the deficiencies described above cannot be remedied simply by directing PSE to improve its screening under the existing framework. PSE bears the burden of demonstrating that it evaluated alternatives, and PSE is the sole author of the framework used to make that demonstration. PSE designed the suitability criteria, set the thresholds that determine which projects are exempt, and decided which cost components its cost-effectiveness comparison would include, all without external review. PSE also has a financial interest in the outcome of the NPA results. Traditional

[82] PSE Exh. AAA-1T (Aaron A. August Opening Testimony) at 28.

pipeline replacement grows rate base and earns a return, while a successful NPA necessarily costs less and is often expensed rather than capitalized. The results of PSE's NPA analysis are consistent with PSE's financial incentives. This is why I recommend that the framework's criteria, thresholds, and cost-effectiveness methodology be established through a Commission-approved process with stakeholder input, rather than left to PSE's discretion, as I describe in Recommendation 2.

A. NPA Framework Steps

Q. What are you proposing in this section?

A. PSE's self-designed framework has not resulted in a reasonable evaluation of alternatives. PSE's NPA evaluation results show it as well. In this section, I am proposing an NPA framework for the Commission's consideration. The framework consists of six steps that apply at the level of individual capital projects: when PSE identifies a system need that would otherwise be met with pipeline replacement or new pipeline investment, the framework governs how alternatives to that investment are identified, evaluated, and documented. It is distinct from the programmatic NPA offerings I recommend separately below, which are standardized solutions that PSE would develop once and deploy across many similar projects rather than evaluate case by case. The project-level framework and the programmatic offerings are complimentary and aimed at different investments.

Q. What are the six steps of your proposed NPA framework?

A. The six steps are:

1. Project Identification,
2. Initial Viability Test,
3. Non-Pipeline Alternative Portfolio Development,
4. Gas and Electric System Viability,

5. Cost-Benefit Analysis, and
6. Monitoring and Evaluation.

Q. Please describe the first step, project identification.

A. All gas capital projects should be subject to non-pipeline alternative review, with one narrowly defined exception as recognized by this Commission: Grade 1 emergency leaks that must be addressed immediately. Every other planned capital investment should enter the screening process. If PSE excludes a project from review, it must document the excluded project to prevent inappropriate bypass of the analysis.

Q. Please describe the second step, the Initial Viability Test.

A. The Initial Viability Test (IVT) should assess three things: timing, scale, and programmatic potential. On timing, the question is whether an alternative can be designed and implemented before the need must be addressed, which is why the minimum five-year planning horizon I described above is critical. If this planning horizon is correctly applied, the timing criterion should only screen out NPAs that cannot be designed and implemented within a five-year timeframe. A determination that an NPA cannot be implemented on this timeframe should be documented and supported by transparent, consistent, concrete, and data-based assumptions (for example, about the time required to plan and launch a program, the number of participants a program can attract per year, etc.). As with timing, scale-based viability determinations should be contemporaneously documented based on transparent, consistent, concrete, and data-based assumptions about the ability of demand-side and supply-side alternatives to address system needs. On programmatic potential, the question is whether the project can be bundled with similar projects into a programmatic offering rather than being evaluated on a bespoke basis.

The IVT should not automatically exclude large categories of projects based on its risk criteria. Pipe age, leak history, and risk score describe why a segment needs remediation, but do not answer whether a NPA could address that need.

Q. Please discuss the third step, NPA Portfolio Development.

A. As PSE appropriately recognizes, both demand-side and supply-side resources must be considered, and on equal footing. Demand-side resources include demand response, energy efficiency, electrification, and behavioral programs, among other potential opportunities to reduce or eliminate customer demand. Supply-side resources include operational measures like bypassing regulator stations, liquefied natural gas injection, compressed natural gas trucking, and propane-air. The portfolio must be aligned with state climate policies, which means zero- or low-carbon resources should be prioritized.

Q. How should the fourth step, Gas and Electric System Viability, be assessed?

A. For programmatic NPAs, PSE will not need to conduct a gas system viability test for each project. For project-specific alternatives, a gas system viability assessment should quantitatively and objectively determine whether the proposed alternative can reliably meet the system's need, accounting for hydraulic impacts, pressure support, redundancy, and interactions with adjacent infrastructure.

The electric system viability assessment, if necessary, should quantitatively and objectively consider the cost and feasibility of serving additional electric load from a non-pipeline alternative. However, this step must include a materiality threshold. Small, customer-level alternatives involving only a handful of customers should not require a detailed electrical feasibility study. The cost of the study should not serve as a barrier to small projects.

The electric system viability assessment will be most accurate if an overlapping consumer-owned electric utility shares relevant information with PSE. However, where coordination with the consumer-owned electric utility is not feasible within the required timeline, PSE should be permitted to use proxy assumptions for electric system costs, so that the electric feasibility step does not become a de facto veto on non-pipeline alternative consideration.

Q. Please discuss the fifth step, the Cost Benefit Analysis.

A. The Commission should require that non-pipeline alternatives be evaluated using the modified-Total Resource Cost (TRC) test that it uses for energy efficiency portfolios. The modified-TRC measures whether the overall benefits of a resource, including both energy and quantifiable non-energy benefits, exceed the total costs incurred by the utility and participating customers, in addition to social costs like the social cost of GHGs (which represents a different set of costs than CCA compliance costs). The cost of the non-pipeline alternative must be assessed against the full lifetime cost of the displaced gas investment, including return on investment, ongoing operations and maintenance, and stranded asset risk.

Q. Finally, please discuss the sixth step, Monitoring and Evaluation.

A. The Commission should require standardized, publicly available reporting on all implemented non-pipeline alternatives, tracking actual costs, timelines, reliability outcomes, and customer participation against the assumptions used at approval. Equally important, the Commission should require tracking of the actual costs and project execution for pipeline investments in which a non-pipeline alternative was considered but not selected. Without that feedback loop, the Commission has no way to evaluate whether the screening and viability assumptions embedded in the framework are accurate over time. Observed outcomes from both approved and rejected alternatives should be used to refine planning assumptions.

Q. Your testimony notes that PSE has a financial disincentive to pursue NPAs. Should the Commission address that disincentive?

A. It can. If PSE believes a financial incentive is warranted, it may propose a shared savings mechanism that allows it to retain a share of the verified net benefits of successful alternatives. Any such proposal should calculate benefits using the documented cost-benefit methodology in the framework I propose, should leave the majority of net benefits with customers, and should be verified against actual costs.

Q. Do you have a recommended NPA framework for how PSE should conduct that project-specific analysis?

A. Yes. I recommend the Commission either adopt the framework I propose in this section of testimony, or, in the alternative, direct PSE to convene a new (or use an existing stakeholder) working group, using the framework I propose as the starting point. The group should meet no fewer than three times, and file for Commission approval of the framework within 180 days of the Final Order in this docket.

B. Supporting Planning and Transparency Requirements

Q. Are planning and transparency requirements foundational to the framework?

A. Yes. The framework's steps cannot function without two preconditions. First, PSE must adopt an adequate capital investment planning horizon, and second, PSE must share sufficient system data to identify where alternatives are feasible. Without these, the subsequent screening and evaluation steps will not result in appropriate alternatives actually being selected, regardless of how well the steps themselves are designed.

Q. What planning horizon do you recommend, and why does it matter?

A. I recommend a planning horizon of no shorter than five years for capital investments subject to NPA review. PSE's current framework applies a timing threshold before a non-pipeline alternative is deemed infeasible; for constrained area system needs specifically, PSE's suitability criteria require that the timing of the need be greater than three years, or that current mitigations be acceptable, for a non-pipeline alternative to be considered feasible.[83] A short planning horizon functions as a de facto exclusion criterion: it screens out NPAs that require lead time to design, permit, and implement, before those alternatives are ever evaluated on their merits. A viable non-pipeline alternative or targeted electrification effort frequently needs several years to identify participants, secure funding, and construct any necessary electric system upgrades. By failing to pair its lead-time screening criterion with an adequate planning horizon, PSE is effectively screening many projects out of consideration simply by virtue of its framework's design.

Q. Should capital investment planning be reviewed before a rate case, rather than concurrently with it?

A. Yes. PSE's capital expenditure and NPA planning should be presented in the ISP that is reviewed by the Commission before PSE seeks cost recovery for the resulting investments in a general rate case. Reviewing these decisions for the first time in a rate case, after the capital has already been spent or committed, limits the Commission's ability to influence the outcome. A longer-term planning review allows PSE's planning assumptions and alternative-selection decisions to be tested before the costs are locked in. Importantly, PSE should be required to show that investments have undergone

[83] PSE Exh. MLV-3 (Delivery System Planning and Project Delivery), Appendix A at 21–22.

appropriate capital expenditure planning and NPA analysis in the ISP process when establishing their prudence in a rate case.

Q. What data access do you recommend the Commission require?

A. I recommend the Commission require PSE to make available publicly accessible distribution system maps identifying pipeline diameter, vintage, and material. Washington's electric utilities are already required to publish hosting capacity maps identifying where the electric distribution system has available capacity for new load or generation. A gas-system analog serves the same purpose: it allows stakeholders and potential program participants to identify where NPAs are most likely to be viable, rather than relying entirely on PSE's internal planning process to surface those opportunities. I do not expect that this information would require disclosing confidential customer information, nor do I expect that the vast majority of this information, such as the general location, diameter, vintage, or material of a distribution main, would be considered confidential critical infrastructure information.

Q. Why is public access to system data helpful?

A. It allows stakeholders and the public to independently identify where NPAs may be viable, rather than depending entirely on PSE's internal planning process to surface those opportunities. For example, a publicly available map showing pipeline vintage would let a stakeholder identify segments likely to need replacement in the next decade, well before PSE brings a specific project forward, creating an opportunity to raise a NPA earlier in the planning process. Similarly, that data could reveal clusters of opportunity, such as a concentration of aging, low-customer-count segments in a particular area, that might justify a targeted programmatic offering even if no single segment would independently justify one.

Q. What is your recommendation regarding capital planning and data transparency requirements?

A. I recommend the Commission require that PSE adopt a capital investment planning horizon of no less than five years for investments subject to NPA review, presented in the ISP reviewed before the associated rate case, and that PSE publish distribution system maps identifying diameter, vintage, and material.

C. Programmatic NPAs

Q. What is a programmatic NPA activity?

A. A programmatic NPA is an activity or investment offered under a standardized set of terms, rather than a bespoke individual analysis for a single project. A programmatic approach applies common eligibility criteria, a standardized incentive level or solution, and a deemed cost-effectiveness value across every instance that meets those criteria, so that a customer or project can access the offering without a separate, project-specific analysis. This is the same structure used for utility energy efficiency programs: the utility does an analysis once, at the program level, to establish eligibility rules and incentive levels, and every subsequent participant is evaluated against those pre-established terms rather than through a new analysis each time. JEA Witness Velez's recommendation to adopt a service line NPA is an example of a programmatic NPA.

Q. Does PSE's programmatic NPA screening constitute a programmatic NPA offering?

A. No. PSE's programmatic screening, as described in its discovery responses, is a project identification filter used to determine whether PSE believes a given investment category warrants project-level analysis. The first step of an NPA framework should screen whether a need is suitable for an NPA (albeit using more granular and well-supported criteria than PSE's framework uses), but PSE's programmatic screen is not a standing program in which customers or projects can be enrolled.[84] Under PSE's framework, every project that makes it through the programmatic screening would still need to be resolved through project-specific analysis.[85]

Q. Why is programmatic NPA analysis necessary, in addition to project-specific analysis?

A. Project-by-project NPA analysis is resource-intensive, both for the utility conducting it and for the parties reviewing it. At the scale of a utility's full capital program, requiring bespoke analysis for every individual project creates a timing and administrative barrier that limits how many non-pipeline alternatives actually get evaluated and deployed, regardless of how good the analytical framework is. Some categories of investment recur frequently enough, and share enough common characteristics, that they do not require project-by-project analysis to identify where a non-pipeline alternative is likely to be viable. These include, but are not limited to, service line replacements, dead-end mains, and low-customer-count mains.

Q. How does PSE justify resolving every outcome through project-specific analysis rather than a programmatic offering?

A. PSE states that project-level analysis is necessary because location-specific system constraints, customer demand characteristics and service requirements, permitting and

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[84] Exh. BTC-10 (PSE Response to JEA DR 13), tbl 1.
[85] *Id*.

constructability considerations, and operational impacts on the broader system vary too much to be captured by programmatic screening alone.[86]

Q. Does that justification support PSE's continued reliance on project-by-project analysis instead of a programmatic offering?

A. No. Energy efficiency programs address exactly this kind of variation through programmatic design: common eligibility criteria, standardized incentive levels, and deemed cost-effectiveness values that apply across a customer population without requiring a bespoke engineering analysis for each participant. The existence of site-specific variation is a reason to design a programmatic offering that accounts for that variation through eligibility criteria and deemed values, not a reason to forgo programmatic design altogether.

Q. What programmatic NPA offering do you recommend as the priority for the Commission to require?

A. First, the commission should adopt the recommendation proposed by JEA Witness Velez which recommends adoption of a service line replacement program. Second, the Commission should order PSE to investigate, through its energy efficiency stakeholder group, three to four additional programmatic offerings. The stakeholder group should not limit itself to electrification; it should also consider whether other non-replacement solutions, such as repair, relining, and pressure modification, can be standardized and deployed across the high-volume project categories for which case-by-case evaluation is impractical. For example, PSE shows that for Buried Meter Set Assembly (MSA) remediation, repair has been determined suitable and is applied to 75 percent of buried

[86] *Id*.

MSAs in lieu of capital investment.[87] That is precisely the model to replicate: a standardized NPA solution, developed once, applied programmatically. Another example could be dead-end mains with five or fewer customers, where the impact to the electric and gas systems from decommissioning the segment could be reasonably estimated without conducting detailed modeling.

Q. Are there circumstances in which project-specific analysis is still necessary, even with programmatic offerings in place?

A. Yes. Programmatic offerings address recurring, standardized investment categories where common eligibility criteria can substitute for individualized review. Many larger, more complex, or unique capital projects are site-specific, however, and will still require project-level review of the same NPAs.

V. <u>GAS SYSTEM DECARBONIZATION DEPRECIATION STUDY</u>

Q. What is the purpose of this section?

A. The purpose of this section is to provide an overview of PSE's Gas Decarbonization Depreciation study (the Study)[88] and illustrate how the Study artificially inflates the cost of the Cold Climate Heat Pump Scenario relative to other business scenarios. First, I explain the Study and relevant terms; I then walk through how the Study artificially inflates the cost of the Cold Climate Heat Pump Scenario in three ways:

(1) **Decommissioning costs are misattributed to the costs of electrification:** Costs in the Cold Climate Heat Pump Scenario are largely driven by decommissioning costs associated with obsolescence retirements, e.g. retirements due to customer attrition from the gas system. I argue that the costs of decommissioning pipe are not inherent to

[87] *Id.*
[88] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study).

any business scenario, but rather the decision to install the pipe in the first place. Decommissioning costs are not avoided in the business scenarios that involve the preservation of gas distribution infrastructure, but rather merely deferred until the future. The Commission should find that the costs of decommissioning gas infrastructure are not inherent to the costs of electrification but rather the initial decision to install the pipe.

(2) **PSE's unit costs are unsupported:** PSE's estimated costs of service line and main decommissioning are based on a narrow set of project data, rather than a larger set of historical data. Additionally, in a scenario in which there is widespread adoption of full electrification, as expected in the Cold Climate Heat Pump scenarios, PSE's decommissioning cost assumptions do not account for likely efficiencies in decommissioning of mains and services at scale that would decrease unit decommissioning costs, which would significantly reduce the cost of the scenario. Should the Company iterate on this Study, the Commission should require the Company to conduct sensitivity analysis regarding the impact of per-unit decommissioning costs on the costs of the Cold Climate Heat Pump Scenario.

(3) **Capital additions per customer should fall as the system shrinks. PSE's model holds them flat: Finally**, PSE assumes that in the Cold Climate Heat Pump scenario, gas system capital additions per customer are not declining over time. If the gas system is declining in throughput and customer count, there is no reason why per-customer capital additions should be staying static or rising into the 2050s.

(4) **Accelerating depreciation without capital restraint is costly and risky for customers:** Finally, I argue that any form of accelerated depreciation, or any change

that has the effect of **accelerating** cost recovery, must be paired with a demonstrated reduction in new capital investment in the same assets whose depreciation is being accelerated, such that the utility is shrinking the asset base at risk of stranding rather than continuing to replace it at a business-as-usual pace. Pursuing accelerated depreciation without capital restraint shifts costs to near-term ratepayers without any corresponding reduction in stranded asset risk for future ratepayers.

A. Overview of PSE's Gas Decarbonization Depreciation Study

Q. Please provide an overview of PSE's Gas Decarbonization Depreciation Study and the context in which it was ordered.

A. As part of ESHB 1589, the Washington legislature required the Commission to approve a depreciation schedule that depreciates all gas plants in service as of July 1, 2024, by a date no later than January 1, 2050.[89] The legislation did not discuss the depreciation schedule of gas plant installed after July 1, 2024. In PSE's 2024 rate case, the Commission directed PSE to evaluate the impacts of a range of depreciation approaches.[90] To this end, PSE hired Gannett Fleming and Atrium Economics to evaluate the impacts of various depreciation methods on capital recovery, rate base, and bill impacts under a range of decarbonization business scenarios.[91] Witness Ned Allis sponsors the Gas Decarbonization Depreciation Study.

Q. What decarbonization scenarios are modeled in the Study?

A. Gannett Fleming models transition costs under three business scenarios from 2025–

[89] ESHB 1589, 68th Leg., Reg. Sess., ch. 351 (2024 Wash. Laws).
[90] UTC, Docket No. UE-240004 Order 09/07 (Jan. 15, 2025) at ¶ 108.
[91] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 20, PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 23.

2050:[92]

(1) **The Reference Case scenario:** This scenario reflects a business-as-usual approach and includes no major changes in gas system planning assumptions. The reference case serves as only a basis for comparison, as a pathway that does not substantially decrease emissions would not be lawful under existing Washington State climate law.

(2) **Hybrid Heat Pump scenario:** This scenario assumes that starting in 2024, new and existing gas furnaces convert to hybrid heat pumps.[93] Full adoption is achieved by 2045. As shown in Table 1, this scenario results in only a 3 percent decline in gas customer count, due to the fact that customers rely on the gas system for backup heating, but does result in a significant decline of 67 percent in overall throughput.

(3) **Cold Climate Heat Pump scenario**: This scenario assumes that starting in 2024, new and existing gas furnaces convert to cold climate heat pumps (without hybrid backup). Full adoption is achieved in 2045. This scenario results in a 59 percent decline in gas customers and a 76 percent gas throughput as Cold Climate Heat Pump customers disconnect from the gas system.

***Table 1**: Changes in Customer Count and Throughput by Scenario*[94]

Scenario	**Decline in gas customers**	**Decline in gas throughput**
Reference Case	1%	20%
Hybrid Heat Pump	3%	67%
Cold Climate Heat Pump	59%	76%

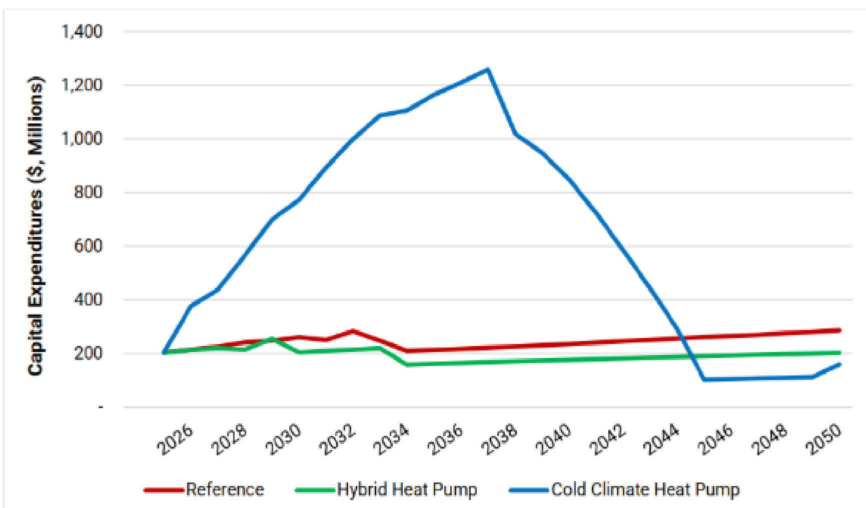
[92] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 40.
[93] Hybrid heat pumps combine electric heat pump with a gas furnace backup; hybrid heat pumps switch to gas backup when outdoor temperatures are sufficiently low, meaning that they may rely on gas heating for the coldest days of the heating season.
[94] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 5–6.

For each scenario, the Study models rate base, revenue requirement, and bill impacts under a range of depreciation approaches.

Q. What are the results of the Study pertaining to capital expenditures, depreciation expense, and bill impacts under the current depreciation approach?

A. Under the current depreciation approach, the Decarbonization Depreciation Study finds that capital expenditures in the Cold Climate Heat Pump Scenario increase significantly from 2026 through the mid 2030s, peaking at just over $1,200 million in 2037[95] (Figure 6), compared to the Reference and Hybrid Heat Pump scenarios, which comprise only a modest increase or stay static.

Figure 6*: PSE Decarbonization Depreciation Study Capex by Business Scenario, 2025–2050*[96]



Similarly, depreciation expense under the current depreciation approach increases significantly under the Cold Climate Heat Pump scenario, peaking in the early 2040s, compared to a more modest increase in the Reference and Hybrid Heat Pump scenarios.[97] Rate base and thus

[95] *Id.* at 43.
[96] *Id.* at 43.
[97] *Id.* at 50

capital revenue requirement per customer also increase substantially through the early 2040s before declining, compared to modest increases in the Reference and Hybrid Heat Pump scenarios.[98]

The Study concludes that the Cold Climate Heat Pump scenario will result in significantly higher customer bills across customer classes under the current depreciation approach compared to the Hybrid and Reference heat pump scenarios.[99]

B. The Study's Findings Depend Entirely on Decommissioning Net Salvage Assumptions.

Q. Do you agree with the Study's conclusion that the Cold Climate Heat Pump scenario will likely result in a more expensive pathway than the Hybrid and Reference scenarios?

A. No, for the reasons I explain below. The Study's cost comparison is driven almost entirely by decommissioning net salvage, which I show is calculated inconsistently across scenarios and based on unsupported unit costs. I address the mechanics of decommissioning net salvage first, and then return to why the resulting comparison cannot support the Study's conclusion.

Q. How do utilities typically collect the cost of retiring, or decommissioning, assets?

A. Utilities typically recover the cost of retiring assets through depreciation rates over the service lives of those assets. Expected net salvage is incorporated into depreciation rates as a percentage of plant, so that customers pay for the eventual cost of removal, in addition to the original cost of the asset, over the period in which they receive service from it. The underlying concept is that the responsibility for an asset's ultimate removal is part of the cost of owning it, and that customers who benefit from the asset should bear their proportional share of that cost.

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[98] *Id*. at 51.
[99] *Id*. at 10.

Q. What is Decommissioning Net Salvage, and how does the Company calculate Decommissioning Net Salvage in the Study?

A. Net Salvage is the salvage value of a retired asset less the cost of retiring it. Typically, gas utilities decommission distribution pipe by retiring it in place, and thus decommissioned gas pipes have no salvage value. PSE, like many other gas utilities, argues that there is a negative net salvage value for some gas system assets. The Study calculates Decommissioning Net Salvage, or terminal net salvage, as a function of number of obsolescence retirements of services and mains in a given year, and the unit cost of decommissioning services and mains.[100]

Q. How does the Study forecast the number of obsolescence retirements used in that calculation?

A. The Study models annual service line obsolescence retirements as directly related to the customer attrition in each scenario.[101] The Study models annual main obsolescence retirements as scaling proportionally to service obsolescence retirements, with a 3:4 main to service retirement ratio.[102] Obsolescence retirements in the Cold Climate Heat Pump Scenario are presented in Figure 7.

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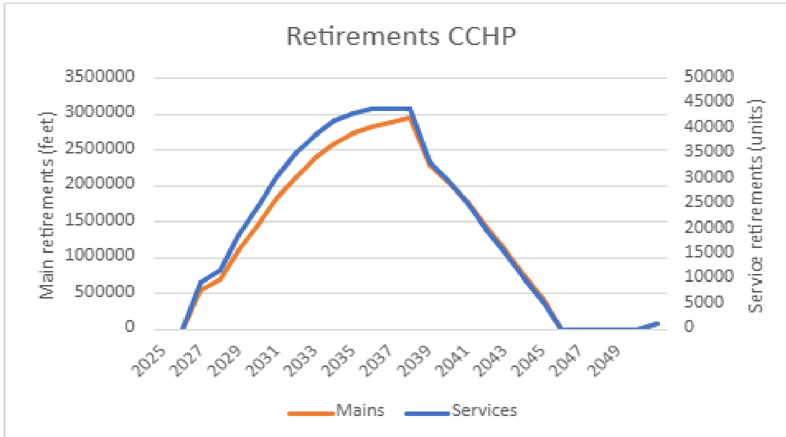
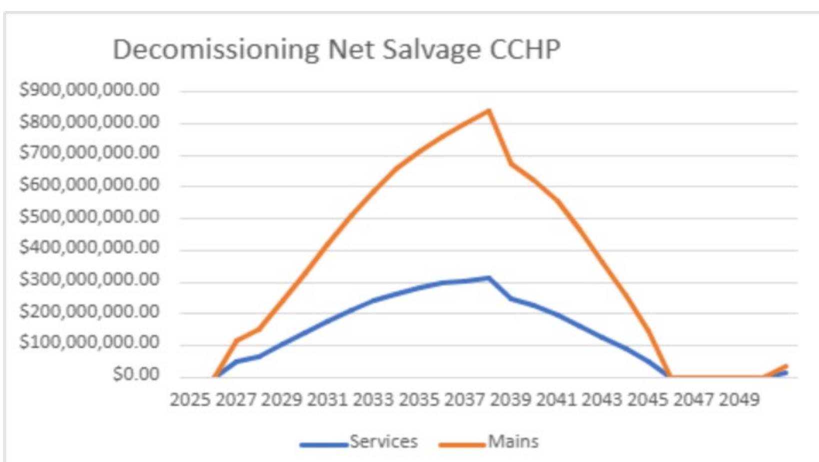
[100] *Id.*, Appendix 1 at 3.
[101] PSE Exh. NWA-4C (Gas Planning Model (C)) "Obsolescence" tab, columns AN and AP.
[102] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 69.

Figure 7: Obsolescence Retirements 2025–2050, Cold Climate Heat Pump Scenario[103]



Decommissioning net salvage is then calculated as a function of the number of retirements of services and mains times the assumed cost of retirement ($200 per foot for mains and $5,000 per service) scaled with inflation.[104] Decommissioning net salvage costs for mains and services in the Cold Climate Heat Pump scenario are shown in Figure 8.

***Figure 8**: Decommissioning Net Salvage costs, Cold Climate Heat Pump Scenario, 2025–2050*[105]



[103] Exh. BTC-17 (NWA-4C Gas Planning Model (R), CEG Analysis).
[104] Decommissioning net salvage is calculated in PSE Exh. NWA-4C (Gas Planning Model (C)), "Obsolescence tab," columns AR–AT. Decommissioning costs per foot for mains and services are provided in "Confidential Inputs" tab, cells A14 and A15.
[105] Exh. BTC-17 (NWA-4C Gas Planning Model (R), CEG Analysis).

Q. What does the Company assume regarding the relative costs of asset removal and decommissioning?

A. The Company states that the per unit decommissioning costs to retire mains and services are higher than to replace them, in part because retirement costs are "shared between the addition of the new asset and the cost of removal."[106] The Company specifies these shared costs could include permitting requirements, traffic control, and other costs, "with most of these costs assigned to the new asset."[107] By contrast, "for decommissioning projects, all project costs will be the cost of removal, leading to a higher per-unit cost to decommission when compared to replacement."[108] This accounting treatment has consequences for the scenario comparison that I discuss below.

Q. How does Decommissioning Net Salvage then impact depreciation and rate base in the Cold Climate Heat Pump scenario?

A. High Decommissioning Net Salvage drives depreciation expense sharply downward, and and potentially negative, in the Cold Climate Heat Pump Scenario under the Weighted Net Salvage approach.[109] This in turn leads to rising rate base, even as assets are being pruned from the distribution system with falling throughput and customer count.

Q. How does Decommissioning Net Salvage drive disproportionately high costs in the Cold Climate Heat Pump scenario as compared to the Reference and Hybrid Heat Pump scenarios?

A. The largest driver of costs in the Company's model of the Cold Climate Heat Pump Scenario is Decommissioning Net Salvage. Obsolescence retirements, meaning

[106] PSE Exh. NWA-1T (Ned W. Allis Opening Testimony) at 34.
[107] *Id*. at 40.
[108] *Id*.
[109] *Id*. at 39–40.

retirements of mains and services before the end of their useful life due to customers leaving the gas system, occur at a far higher rate in the Cold Climate Heat Pump scenario than in the Reference or Hybrid Heat Pump scenarios, because customer count does not decline drastically in either of those scenarios. Because decommissioning costs are a function of the number of obsolescence retirements, decommissioning costs are correspondingly lower in the Reference and Hybrid Heat Pump scenarios as well. At their relative peaks, service obsolescence retirements occur at roughly 30 times the rate in the Cold Climate Heat Pump scenario compared to the Hybrid Heat Pump scenario, and main obsolescence retirements occur at roughly 100 times the rate (Table 2).

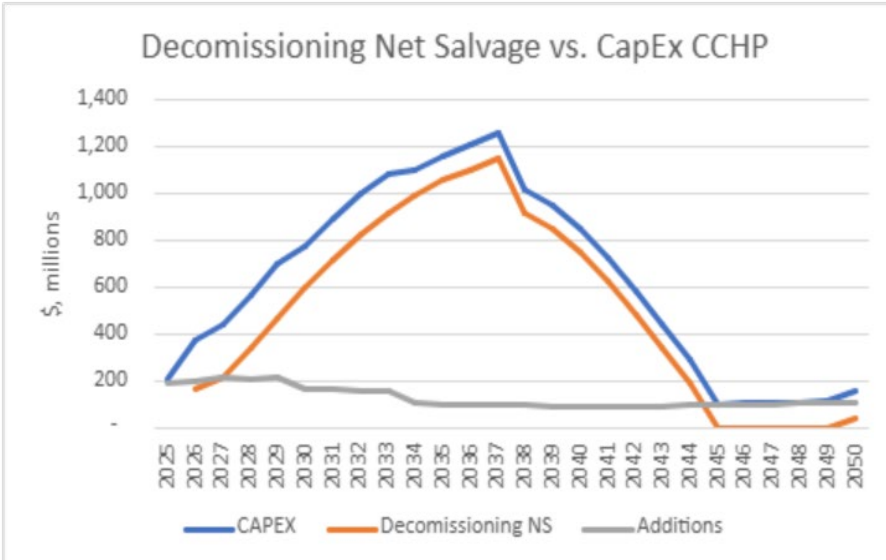
Table 2*: Peak service obsolescence retirements, main obsolescence retirements, and decommissioning net salvage by scenario*[110]

Scenario	**Peak (year)**	**Service Obsolescence Retirement (units)**	**Main Obsolescence Retirement (feet)**	**Decommissioning Net Salvage Services ($)**	**Decommissioning Net Salvage Mains ($)**
Reference Case BAU	2034	200	15,724	1,302,055	4,103,276
CCHP	2037	44,113	2,953,895	314,475,836	842,309,573
HHP	2039	1,463	29,052	11,068,050	8,788,884

In the Cold Climate Heat Pump scenario, both obsolescence retirements and Decommissioning Net Salvage costs peak at the same time as the peak capital expenditures, around the mid to late 2030s. Total Decommissioning Net Salvage (the sum of decommissioning net salvage of mains and services) makes up the lion's share of the total capital expenditures in the cold climate heat pump scenario (Figure 9).

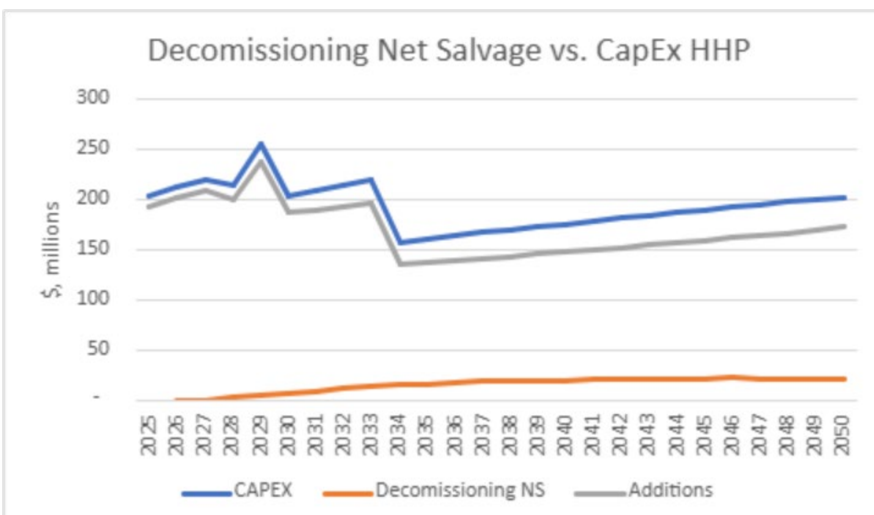
[110] PSE Exh. NWA-4C (Gas Planning Model (C)), "Obsolescence" tab.

***Figure 9**: Decommissioning Net Salvage, Additions, and Total Capital Expenditure in the Cold Climate Heat Pump Scenario*[111]



By contrast, in the Reference and Hybrid Heat Pump Scenarios, decommissioning net salvage makes up only a small fraction of overall capital expenditure (Figures 10 and 11).

***Figure 10**: Decommissioning Net Salvage, Additions, and Total Capital Expenditure in the Hybrid Heat Pump Scenario*[112]



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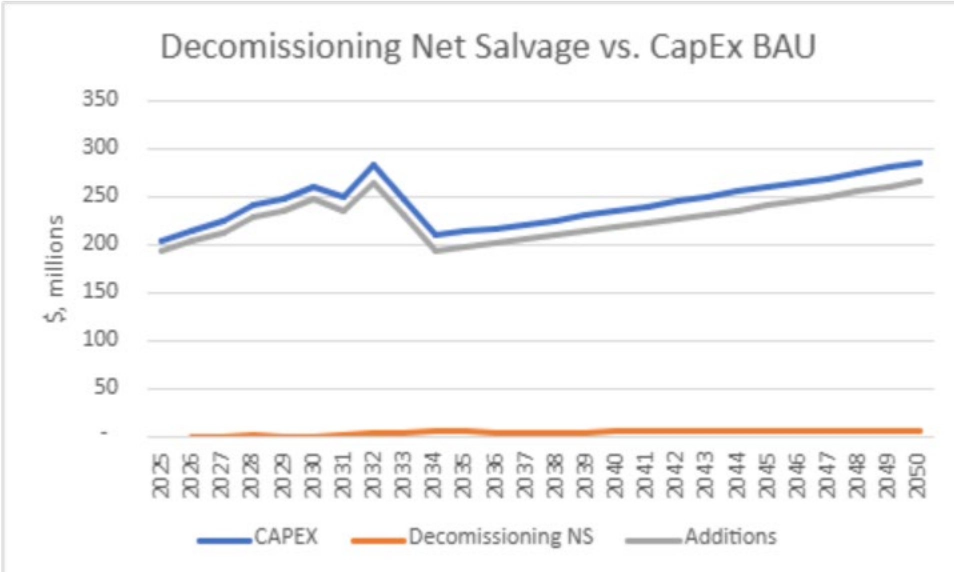
[111] Exh. BTC-17 (NWA-4C Gas Planning Model (R), CEG Analysis), "Obsolescence_BTC" tab.
[112] *Id*.

***Figure 11**: Decommissioning Net Salvage, Additions, and Total Capital Expenditure in the Reference Scenario*[113]



In other words, in the Hybrid and Reference scenarios, capital expenditures are driven predominantly by addition. In the Cold Climate heat pump scenario, capital expenditures are driven by obsolescence retirements.

Q. How does the Study handle retirements due to replacement?

A. The Study treats retirements due to replacement as interim retirements, e.g. "assets retired (often replaced) prior to the final retirement of the facility."[114] The Study models expenditures on interim retirements (interim net salvage) as a flat percentage of overall capital expenditure. The Company states that "replacement activity is represented at an aggregate level through modeled capital expenditures and associated interim net salvage," with 95 percent of overall capital expenditure treated as additions and the remaining five percent as interim replacement costs.[115]

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[113] *Id.*
[114] PSE Exh. NWA-4 (Gas Decarbonization Depreciation Study) at 32.
[115] Exh. BTC-18 (PSE Response to JEA DR 8).

Q. How can costs due to interim retirements be compared to costs due to obsolescence retirements?

A. The aggregate costs of retirements are represented in the model as decommissioning net salvage for obsolescence retirements and interim net salvage for interim retirements.[116] While these represent costs at the scenario level, they do not give a good sense for how costs to decommission relate to the original cost of the asset.

Q. How can costs to decommission an asset be compared to original asset costs for interim and obsolescence retirements? E.g., how can we understand how much more expensive an asset is to retire than to install?

A. To understand the relative costs of retirement compared to original asset costs, I calculate interim net salvage and decommissioning net salvage percentages. I define interim net salvage percentage as interim net salvage (e.g. the total removal costs of interim retirements) divided by the original value of interim retirements. Similarly, I define decommissioning net salvage percentage as the decommissioning net salvage value (e.g. total removal costs of obsolescence retirements) divided by the original value of the obsolete assets. In essence, both express the cost of removal of the asset as a percentage of the asset's original value, or the cost to install.

Q. How do interim net salvage percentage and decommissioning net salvage percentage differ in the Cold Climate Heat Pump scenario?

A. In the case of the CCHP scenario, the average interim net salvage percentage (i.e. for replacement) from 2026 to 2050 is 10 percent, meaning that assets that will be replaced are on average 1/10th as expensive to remove as to install.[117] By contrast, the average

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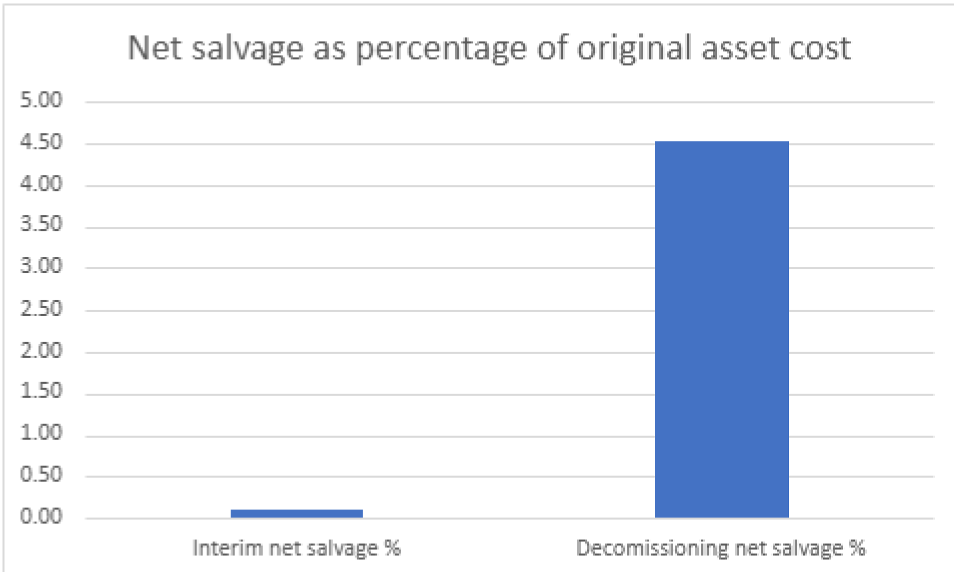
[116] *Id.*

[117] Exh. BTC-17 (NWA-4C Gas Planning Model (R), CEG Analysis).

decommissioning net salvage percentage (i.e. to remove) from 2026 to 2050 is 453 percent, meaning that assets are on average 4.5x as expensive to terminally decommission as they were to install.[118]

Figure 12*: Net salvage as a percentage of original asset cost*[119]



In essence, this means that retirements that are decommissioned due to obsolescence are vastly more expensive compared to installation costs compared to decommissioning costs for interim retirements.

Q. Does PSE's stated rationale justify a disparity of this magnitude?

A. No. As discussed above, PSE attributes the higher per-unit cost of decommissioning to an accounting convention: shared removal costs, such as permitting and traffic control, are largely assigned to the new asset in replacement cases, while the full cost is assigned to removal in decommissioning cases.[120] PSE offers no data, cost study, or quantification showing that this allocation convention alone accounts for a 45-fold difference between

[118] *Id.*
[119] *Id.*, "Base Case (C)_BTC" tab.
[120] *Id.*

the two. An accounting choice about which line item absorbs shared costs is not a demonstrated engineering or economic basis for treating decommissioning as more than four times as expensive as the asset it removes.

C. Decommissioning Costs are Misattributed to the Costs of Electrification.

Q. Does the framing of the Study distort the costs of the Cold Climate Heat Pump scenario relative to the Hybrid Heat Pump and Reference Scenarios?

A. Yes, in two respects. First, decommissioning is a real cost under every scenario, but Cold Climate Heat Pump forces most of it to occur inside the Study's 2025-2050 window, while the Reference and Hybrid Heat Pump scenarios retain most of the same assets past 2050, so the identical eventual cost is not recognized within the modeling period. Second, and independent of the timing of cost recovery, PSE's own allocation methodology assigns cost differently depending on how a retirement is classified. As described above, interim retirements, which predominate in the Reference and Hybrid Heat Pump scenarios, allow most shared removal costs to be assigned to the new asset being installed. Obsolescence retirements, which predominate in Cold Climate Heat Pump, carry the full cost as removal, with no costs allocated to the future.

Q. Are decommissioning costs a consequence of the Cold Climate Heat Pump Scenario?

A. No. Decommissioning costs are not avoidable costs; they are a consequence of the original decision to install the pipe, not the decision to remove it. Pipe must be retired at end of life regardless of the business scenario, which occurs every 30-60 years, depending on the life of the asset. Electrification determines only the timing and whether removal costs are shared with a replacement project or borne entirely by the retirement. By contrast, choosing to replace the pipe not only incurs removal costs but also locks in the cost of the new asset and that asset's eventual removal. No actual cost savings are realized by choosing to replace rather than remove pipe. By misrepresenting the costs of decommissioning in the CCHP scenario, the Study makes electrification far more costly than it truly is.

Q. Does the Study accurately represent the costs of the Reference and Hybrid Heat Pump Scenarios?

A. No. The Reference and HHP scenarios account for the upfront capital cost of new replacement pipe but exclude the eventual decommissioning cost of that pipe, thereby exacerbating the misleading difference in costs between them and the CCHP scenario. Because mains have an engineering life of several decades,[121] most of the current plant in service would be retired outside the 2050 modeling horizon. This is the case even with ESHB 1589's requirement to depreciate gas plant installed before July 1, 2024. In this sense, the Reference and HHP scenarios defer some of the costs of retirement but do not ultimately avoid the cost of decommissioning plant in service.

Q. Why not just defer these decommissioning costs indefinitely by perpetually maintaining the gas system?

A. The reference scenario is not compatible with state climate targets, and the HHP scenario assumes a level of control over customer exits from the gas system that gas utilities, in reality, do not have.

If a gas utility tries to implement a Hybrid scenario with relatively low throughput, the full cost of maintaining the gas system would be spread over the relatively few therms needed to provide heating on the coldest days of the year, putting

[121] E.g., the observed retirement from 1987–2024 for Account 376.2, Mains plastic, shows an average service life of 55 years. PSE Exh NWA-3 (Depreciation Study Report) at 39.

upward pressure on rates. Exacerbating the rate increases, the HHP scenario requires widespread use of alternative fuels with commodity costs several times that of natural gas today. As a result, customers may leave the system regardless of the utility's intentions, due to monthly costs of what will ultimately amount to a few days of annual back-up heating. In this case, the utility will be responsible for decommissioning not only the plant that exists today, but also the plant that the utility has since added in service of the Hybrid pathway. These ballooning costs will fall on fewer customers remaining on the system further increasing the likelihood that the remaining customers will leave. Worse, the customers least able to depart the system are more likely to be lower income..

Q. Does the Hybrid Heat Pump scenario exacerbate stranded asset risk?

A. Yes. Implementing the HHP scenario would exacerbate customer and possibly taxpayer risk by kicking the can of decommissioning down the road and continuing to invest in the system as usual. Meeting state decarbonization goals and ensuring an equitable energy transition requires us to grapple with the problem of decommissioning now.

D. PSE's Unit Cost Assumptions are Unsupported.

Q. Are the costs for service line and main decommissioning modeled by the Depreciation study appropriate?

A. No. PSE assumed a cost of $200 per foot of main and $5,000 per service decommissioned.[122] These assumptions are not consistent with PSE's own historical retirement data. According to historical data provided by PSE, the weighted average cost per mile for decommissioning mains with no service lines connected without replacement, weighted by miles of main, from 2017-2025 is $553,537, or $105/foot;[123] I

[122] PSE Exh NWA-4 (Gas Decarbonization Depreciation Study) at 68.
[123] Exh. BTC-19 (PSE Response to JEA DR 94) at § (a).

calculated an even lower weighted average of $87 per foot from the provided dataset. The weighted average cost per mile for decommissioning mains and associated services without replacement from 2017–2025 in this dataset was $188,971, or $36 per foot.[124] These values represent a significant decrease compared to the original estimate of $200 per foot of main.

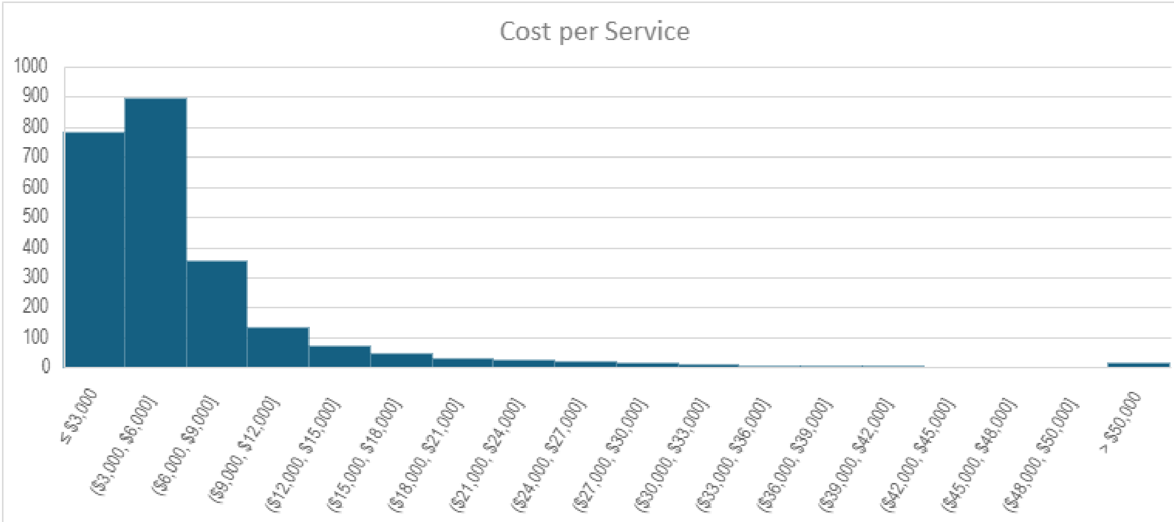
***Table 3**: Main Decommissioning Costs by Source*[125]

	Weighted average by miles of main, PSE Response to JEA 001-Rev01 Attachment A (CEG calculation)	**Weighted average by miles of main, PSE response to JEA 002-Attachment B**	**Decommissioning Study Assumptions**
Main decommissioning (no services attached)	$87/ft	$252/ft	$200/ft

While the average cost of retirement per service decommissioned without replacement from 2017–2025 of $5,994 per service[126] was closer to the assumption used in the Study, average cost of retirement per service would not be the most appropriate summary statistic for this dataset. The per-service line retirement on a cost-per-service basis from 2015-2025 provided by PSE was incredibly skewed (Figure 13), with a few very high-cost projects driving up the cost of service line decommissioning.[127]

[124] Exh. BTC-21 (PSE Response to JEA DR 1_Revised_Attachment A, CEG Analysis).
[125] *Id.*; Exh. BTC-24 (PSE Response to JEA DR 2_Attachment B, CEG Analysis).
[126] Exh. BTC-21 (PSE Response to JEA DR 1_Revised_Attachment A, CEG Analysis).
[127] *Id.*

__Figure 13__: Per-service retirement costs, 2017–2025[128]



Q. What is a more appropriate summary statistic to represent service line retirement costs?

A. In cases of highly skewed distributions, a few very expensive projects can drag up the average cost of the entire data set; representing skewed distributions with averages is therefore not an appropriate way to summarize the data. A median is a more appropriate summary statistic. Given the small number of full decommissioning projects that PSE conducts in its service territory currently, it is not clear that these very high-cost projects are representative of the types of projects that PSE would encounter with widespread decommissioning. The median project cost on a per-service basis for the data categorized as "service retirement" from 2017-2025 was $4,184; significantly lower than the $5,000 per service decommissioning cost estimated by PSE in their Gas Decarbonization Depreciation Study.[129]

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[128] *Id.*
[129] *Id.*

Q. How does the Company justify relying on the cost estimates of $200 per foot of main and $5,000 per service in the Decarbonization Decommissioning study?

A. Through discovery, I asked the Company to explain the discrepancy between the weighted average cost per mile for decommissioning mains with no service lines connected without replacement, weighted by miles of main, from 2017-2025, and the $200 per foot of main estimate used in the Study. The Company responded that the discrepancy is a result of using different data sets.[130] The Company specified that the weighted average of $105/ft was derived from a broader historical data set (I calculated a weighted average cost per mile of $87 from this data set)[131] while the $200 per linear foot assumption used in the Study was derived from a different data set.[132]

The difference between the composition of these two data sets is still unclear. The Company states only that the dataset used to calculate its weighted average value for main replacements "is derived from a broader dataset that includes all main retirement activity, including both planned and emergent work across a wider range of conditions," while the other data set used to create the estimates pertaining to PSE's depreciation study "reflects a defined set of projects, generally consisting of planned main retirement activities with relatively consistent project characteristics."[133] It is this secondary data set that was used to create the $200/ft cost estimate used in the Study.[134]

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[130] Exh. BTC-19 (PSE Response to JEA DR 94) at § (b).
[131] *Id.*
[132] Exh. BTC-23 (PSE Response to JEA DR 2_Attachment B).
[133] Exh. BTC-25 (PSE Response to JEA DR 97) at § (c).
[134] Exh. BTC-26 (PSE Response to JEA DR 120).

Q. Does the Company justify why the more limited dataset used to develop the $200/ft estimate in the Study was preferable to the larger data set that resulted in a weighted average cost of decommissioning of $87/ft?

A. No. In discovery, PSE stated only that the assumption was "derived from PSE's historical project cost experience for retired mains and services."[135] That explanation does not make sense for three reasons. First, PSE provided a more comprehensive record of historical decommissioning with cost data for approximately 220 main retirement projects completed without replacement, from 2017 through 2025, with a weighted average cost of $87 per foot for mains without connected services.[136] Second, the dataset from which the Study's assumption was apparently developed, containing only 29 projects,[137] is a small fraction of PSE's available experience. PSE has not explained why those 29 projects better represent future decommissioning work than the comprehensive record. If "historical project cost experience" is the standard PSE claims to apply, the full record of that experience indicates a cost roughly half the Study's assumption. At each step, from the comprehensive dataset to the selected subset to the final assumption, the cost moves only upward, and no step is supported by analysis in the record.

Q. How would it impact decommissioning net salvage costs if main and service line replacement costs were lower in the Cold Climate Heat Pump Scenario?

A. They would decrease dramatically. For instance, using a main decommissioning cost value of $100/foot and a service decommissioning cost value of $4000 per service (corresponding roughly with the historical weighted average from PSE's Revised

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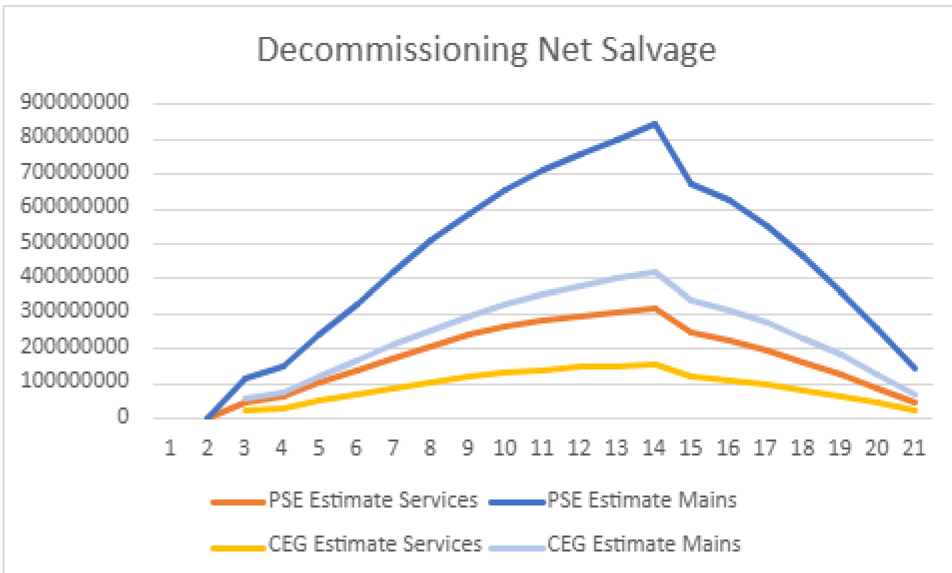
[135] Exh. BTC-22 (PSE Response to JEA DR 2).
[136] Exh. BTC-21 (PSE Response to JEA DR 1_Revised_Attachment A, CEG Analysis).
[137] Exh. BTC-24 (PSE Response to JEA DR 2_Attachment B, CEG Analysis).

Response to JEA DR 1_Attachment A for main decommissioning with no associated services, weighted by miles of main, and the median cost of service retirement from the same data set) would drive down decommissioning net salvage for mains and services alike in the Cold Climate Heat Pump scenario (fig. 14).

***Figure 14**: Comparing Decommissioning Net Salvage estimates using PSE decommissioning cost estimates and alternate CEG decommissioning cost estimates*[138]



Q. What should the commission infer from your sensitivity test with lower estimates of mains and service decommissioning costs?

A. The massive capital expenditures driven by decommissioning net salvage costs that are claimed in PSE's Cold Climate Heat Pump scenario are extremely sensitive to changes in main and service decommissioning costs. The estimates used by the Company are not appropriate because a) they come from a smaller data set of projects than the overall historical data of main and service retirements kept by the Company and b) they are being used to represent a skewed overall data set in which averages are driven up by a

[138] Exh. BTC-17 (NWA-4C Gas Planning Model (R), CEG Analysis).

small number of outliers. Additionally, there is reason to believe that in a decarbonization scenario future unit costs may be lower than historic unit costs. This is because, in a scenario in which there is widespread customer departure from the gas system, there would be opportunities to decommission large segments of main at one time, reducing the outlier projects in which small segments of main incur high per foot decommissioning costs. A targeted or zonal decarbonization program removing large segments of customers within the same area would produce lower per-unit costs through economies of scale; the Study does not reflect these efficiencies. Should the Company iterate on the Study or rely on the Study to justify other capital and operational declines, the Commission should require the Company to conduct a sensitivity analysis for lower per-unit service and main decommissioning costs. The Commission should also direct the Company to explore ways to lower the unit cost of decommissioning.

E. Capital Additions per Customer Should Fall as the System Shrinks, but PSE's Model Holds Them Flat.

Q. Are there other costs that are artificially inflated in the Cold Climate Heat Pump Scenario relative to other scenarios?

A. Yes. Even as customer count is declining and obsolescence retirements are increasing, the Study assumes static or rising levels of capital additions per customer (Figure 15). This again artificially inflates the overall cost of the Cold Climate Heat Pump scenario; if the gas system is being pruned to account for customer loss, there is no reason why capital additions per-customer should be staying static or rising into the 2050s. An efficient treatment of costs would align planned retirements with parts of the system that are set to be otherwise replaced; this strategy should lead to declining capital additions per customer over time.

Figure 15: *Capital additions per customer in the cold climate heat pump scenario*[139]

F. Accelerating Depreciation Without Capital Restraint is Costly and Risky for Customers.

Q. What is the relationship between accelerated depreciation and capital investment?

A. Washington's climate statutes effectively require gas demand to decline, which puts long-lived gas assets at risk of retiring before their costs are recovered. The purpose of accelerating depreciation on gas assets is to reduce future rate base and, with it, future stranded cost exposure in a system facing declining demand. Acceleration achieves that purpose only if the utility is simultaneously slowing the addition of new long-lived assets. If the utility accelerates recovery of existing plant while continuing to add rate base at historical rates, the stranded cost exposure is not reduced; it is rebuilt as fast as it is recovered. Customers then pay twice: higher depreciation expense today to retire the old exposure, and a return on the new investment that recreates it.

Q. Does that mean you oppose accelerated depreciation for PSE's gas system?

A. Not necessarily. Accelerated depreciation is a legitimate cost recovery tool in a system with declining demand and assets at risk of early retirement. Whether it benefits

[139] *Id.*

ratepayers depends on whether it is paired with a demonstrated reduction in new capital investment in the same assets whose depreciation is being accelerated, such that PSE is shrinking the asset base at risk of stranding rather than continuing to replace it at a business-as-usual pace. Absent that pairing, accelerating depreciation shifts costs to near-term ratepayers without any corresponding reduction in stranded asset risk for future ratepayers. Accordingly, I would support accelerated depreciation paired with the capital restraint I describe below. PSE has demonstrated no such restraint in this proceeding.

Q. How does accelerated depreciation without capital restraint increase ratepayer cost and risk?

A. If a utility accelerates depreciation of existing assets while continuing to add new long-lived assets to rate base at a business-as-usual pace, current ratepayers bear higher depreciation charges and higher rates, while future ratepayers remain exposed to a growing undepreciated asset base. The intergenerational equity benefit that justifies accelerated depreciation does not materialize. Accelerated depreciation would have to be paired with capital restraint, which requires the gas utility to aggressively invest in demand-side resources, NPAs, repair over replacement, and electrification, and crucially, targeted electrification paired with decommissioning. PSE does not even have a General Building Electrification Program nor a targeted electrification proposal outside of a pilot.

Q. Is PSE demonstrating substantial capital restraint that would justify accelerating depreciation?

A. No. As noted in the previous section of my testimony pertaining to capital expenditure, PSE's gas system investment is not shrinking, but is rather growing. PSE is requesting $862M in a three-year capital rate plan.

Q. Should the Commission condition approval of PSE's accelerated depreciation request on adoption of specific capital restraint measures?

A. Yes. Accelerated depreciation and capital restraint are two sides of the same coin. Accelerating depreciation recovers existing plant faster, which only reduces stranded asset risk to customers if the Company is not simultaneously adding new long-lived plant at the same or a greater rate. Approving accelerated depreciation without any corresponding restraint on new capital additions allows PSE to recover old investment faster while continuing to grow the asset base it will need to recover later, shifting cost and risk onto today's ratepayers without producing any offsetting reduction in the Company's long-term stranded asset exposure. This outcome is inconsistent with HB 1589 and the state's broader decarbonization policy, both of which anticipate a shrinking, not a growing, long-term role for the gas distribution system.

PSE has not proposed any capital restraint measure in this proceeding to accompany its accelerated depreciation request. Absent such a measure, the Commission has no basis to conclude that approving accelerated depreciation will reduce, rather than simply reallocate, the cost and risk borne by ratepayers.

I recommend that the Commission condition any approval of accelerated depreciation, or any proposal that effectively accelerates depreciation, on PSE's adoption of capital restraint measures commensurate with the amount of accelerated depreciation approved. Specifically, I recommend that the Commission require PSE to adopt my proposed programmatic NPA program and JEA Witness Velez's proposed Service Line NPA Program as conditions of approval. Both measures directly restrain the growth of new long-lived gas plant, which is the specific mechanism through which accelerated depreciation would otherwise increase, rather than reduce, stranded asset risk to customers.

Q. Based on your analysis, what recommendations do you have for the Commission related to the Gas System Decarbonization Depreciation Study?

A. Regarding the Company's Gas Decarbonization Depreciation Study and depreciation proposal, I have the following recommendations:

1. The Commission should not treat decommissioning costs as costs attributable to electrification. Decommissioning costs are a consequence of the original decision to install the pipe. Electrification affects only the timing of retirement and whether removal costs are shared with a replacement asset or borne solely by the retirement project.
2. The Commission should find that PSE's Gas Decarbonization Depreciation Study does not apply a consistent cost accounting treatment across business scenarios. This inconsistency inflates the projected capital expenditure of the CCHP scenario relative to the other scenarios and does not support a reliable comparison of costs across decarbonization outcomes. As a consequence, the scenario analysis in Exh. NWA-4 cannot be used to support a finding that accelerated electrification is materially more capital-intensive than continued pipeline replacement.
3. The Commission should require the Company to conduct a sensitivity analysis for unit costs of decommissioning mains and services, as well as direct the Company to look in to ways to lower these unit costs.
4. The Commission should require PSE to investigate and track the full cost of decommissioning mains and service lines, and how those costs are allocated

between the new and replacement asset, where the Company is replacing the pipe rather than only retiring it.

5. The Commission should not accept the hybrid heat pump scenario as a reliable basis for comparing decarbonization cost pathways. The scenario defers but does not avoid decommissioning costs, excludes from its modeling window the eventual retirement of new plant additions, and understates long-term stranded asset risk relative to a scenario in which customers exit the gas system more rapidly than projected.
6. The Commission should require PSE to adopt gas capital restraint measures commensurate with the amount of any approved accelerated depreciation, including my proposed NPA framework and Ms. Velez's proposed Service Line NPA Program as conditions of approval. See discussion above.

VI. CONCLUSION.

Q. Does this conclude your direct testimony?

A. Yes.