

Public Service Enterprise Group: Sequencing the Grid Investment Plan

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Decision scope: PSE&G's regulated investment priorities and sequencing

Case convention: This is an author-created management decision exercise. The review assignment and alternatives are hypothetical; company disclosures are historical. No private deliberations are represented.

The decision

On 25 February 2025, Public Service Enterprise Group (PSEG) reported a five-year capital plan of \$22.5-\$26 billion for 2025-2029, of which \$21-\$24 billion was expected to be regulated investment. Management projected 6%-7.5% annual growth in regulated rate base over the period. The upper end included potential additional demand-growth and infrastructure investment; it was not a list of approved projects. [S1], printed p. 40; [S2], 2025 outlook.

PSEG's regulated utility, Public Service Electric and Gas Company (PSE&G), separately projected \$3.72 billion of capital expenditures in 2025, \$3.99 billion in 2026, and \$4.23 billion in 2027. Its 2025 estimate covered transmission, electric distribution, gas distribution, and clean energy. Some work replaces aging equipment or supports reliability; other additions depend on program extensions, demand, or further infrastructure needs. [S1], printed pp. 55-56.

The investment opportunity arrived as customers faced two distinct rate pressures. New distribution base rates took effect in October 2024. In February 2025, the New Jersey Board of Public Utilities (BPU) estimated a separate increase in the average PSE&G residential electric supply bill from the annual Basic Generation Service (BGS) auction, effective June 2025. The auction cost is passed through by electric distribution companies (EDCs); it is not PSE&G earnings. [S1], printed pp. 41-42; [S3]; [S4].

Assignment: Imagine you are preparing a portfolio review for PSEG's senior leadership. Recommend how PSE&G should prioritize and sequence its regulated investment. Explain what work should proceed on schedule, what incremental options should be gated, and what evidence would change your recommendation. Address reliability and safety, load growth, regulatory recovery, execution risk, and customer affordability. Use only information publicly available by 26 February 2025.

The businesses and their recovery channels

PSEG is the holding company. PSE&G owns and operates regulated electric and gas delivery networks in New Jersey and also administers approved energy-efficiency and related programs. PSEG Power & Other includes nuclear generation. PSE&G's network investment should not be treated as interchangeable with PSEG's generation activity or consolidated earnings.

Three customer and regulatory channels matter to this decision:

1. **Electric and gas distribution base rates.** PSE&G's October 2024 settlement established a \$17.8 billion distribution rate base, a 9.6% allowed return on equity, and a 55% equity component. New rates became effective on 15 October 2024. These are approved regulatory parameters, not a guarantee of realized return on every project. PSE&G described the settlement as its first electric and gas distribution base-rate increase since 2018. [S1], printed pp. 41-42; [S2]; [S3].
2. **FERC-regulated transmission.** Transmission investment follows a separate federal recovery framework, including formula-rate mechanisms described in PSEG's filing. The transmission category should therefore be assessed on its own approvals, cost allocation, in-service timing, and recovery exposure. The public packet does not provide project-level economics or establish that transmission dollars can be shifted freely to distribution or clean energy. [S1], regulatory discussion and printed p. 55.
3. **BGS commodity and capacity supply.** The BGS auction procures electricity supply for customers, with costs passed through by EDCs without profit. The BPU estimated that the average PSE&G residential supply bill at 650 kWh per month would rise from \$155.84 to \$182.71, a \$26.87 or 17.24% increase, effective 1 June 2025. This is not a distribution-rate increase, a PSE&G capital return, or a measure of the bill effect of the investment plan. [S4].

PSE&G also offers bill-assistance programs for eligible customers. Assistance can reduce hardship for recipients, but it does not establish that a portfolio is affordable to every household. The public sources do not show the proposed plan's bill impact by customer class or income.

What is in the investment plan?

PSE&G's 2025-2027 capital requirements table is management's forward estimate. The category estimates add arithmetically to the reported annual totals. Amounts include an allowance for funds used during construction (AFUDC) for PSE&G. Projects within a category can have different drivers, approvals, and flexibility. [S1], printed p. 55.

Exhibit 1. PSE&G projected capital expenditures

USD millions; PSE&G utility; forward estimates as disclosed.

Category	2025	2026	2027
Transmission	735	890	920
Electric distribution	1,190	1,235	1,325
Gas distribution	1,050	1,025	1,050
Clean energy	745	840	935
Total	3,720	3,990	4,230

The category estimates sum to \$3.720 billion in 2025, \$3.990 billion in 2026, and \$4.230 billion in 2027. Management described transmission work as supporting growth, reliability, and aging-asset replacement; distribution work as supporting new business and demand, reliability, modernization, and equipment replacement; and clean energy as including efficiency, electric-vehicle infrastructure, and grid-connected solar. [S1], printed pp. 55-56.

At the five-year level, management's low case assumed extensions of the Gas System Modernization Program (GSMP) and Clean Energy Future-Energy Efficiency (CEF-EE) at current annual investment levels plus inflation. Its high case included potential added demand-growth and other infrastructure investment. These are management scenarios, not a probability-weighted forecast or approved project register. The CEF-EE II program had an approximately \$2.9 billion authorized envelope, described as about \$1.9 billion of program investment net of administration and \$1 billion of continued on-bill repayment. The commitment period ran from 1 January 2025 through 30 June 2027, while completion was expected over six years. Authorization and commitment timing do not prove realized savings or net benefits. [S1], printed p. 40; [S2].

The different historical and forward measures also require care. PSE&G reported \$2.921 billion of 2024 capital expenditures. It separately reported \$170 million of net cost of removal associated with capital replacements and approximately \$544 million of energy-efficiency program expenditures included in operating cash flows. PSEG's results exhibit presented a rounded approximately \$3.6 billion PSE&G investment measure. The filing does not provide a formal reconciliation among these measures. Do not add them together as though they were one comparable capex total. [S1], printed p. 56; [S2], exhibit 99.1, slide 12.

A portfolio under competing demands

PSE&G's investment categories combine several different needs:

- **Replacement and safety:** equipment reaching end of life, system integrity, and work required to maintain safe and reliable service. The public plan does not identify each asset, condition score, mandatory date, or cost of delay.
- **Reliability and resilience:** network upgrades intended to reduce outages or improve restoration. The packet provides no project-level outage reduction, avoided customer cost, or reliability benefit-cost analysis.
- **Demand and new connections:** transmission and distribution work for load growth, new business, electrification, and other connections. The public plan does not disclose location-specific peak forecasts, committed load, or interconnection probabilities.
- **Clean energy and efficiency:** customer efficiency, EV infrastructure, and solar-related grid investment. The approved program has a multi-year envelope, but the packet does not report program-specific realized savings, persistence, or avoided system costs.

These categories are a useful starting point for a review, not a menu of freely interchangeable dollars. Regulatory approval, engineering scope, customer commitments, program terms, and construction lead times can constrain sequencing. Leaders can still ask which uncommitted additions should be accelerated, staged, or subjected to evidence gates.

Customer affordability and investment recovery

The distribution settlement's customer effects and the BGS supply estimate have different scopes. PSE&G said the distribution base-rate change represented about 1% annually, or approximately \$15 per month (7%) for a typical combined electric-and-gas residential customer before an offsetting gas-rate reduction; the company described the combined effect as about \$11 per month (5%). These are company estimates for a typical account, not impacts for all customers. [S3].

The BPU's \$26.87 monthly estimate is for the electric supply component of a PSE&G residential account using 650 kWh per month. It reflects auction supply costs rather than delivery

investment. The two monthly figures cannot be added as if they shared the same baseline, timing, customer population, or mechanism. Nor does either quantify the bill impact of an incremental project under review. [S3]-[S4].

The investment plan's value to customers depends on execution and recovery. A project may enter rate base only after being placed in service and found recoverable under applicable rules; some transmission costs follow FERC formula rates. Financing costs, construction delays, cost overruns, and recovery lag can affect customer and shareholder outcomes. The company's rate-base growth projection is not itself an earnings forecast or proof that a particular project creates value.

What should govern the sequence?

PSEG's public disclosures describe a large program but not a project-level ranking. To make a recommendation, leadership would need to distinguish baseline obligations from optional additions and define a repeatable screen. Candidate criteria include:

Review question	Evidence to request
Is the work required now?	Asset condition, safety risk, replacement deadlines, regulatory commitments, customer connection obligations, and cost/risk of deferral
What need does it address?	Territory or substation load forecasts, interconnection queue, peak demand, reliability history, storm exposure, and service-quality objectives
What benefit follows?	Expected outage reduction, avoided operating cost, customer impacts, efficiency savings, and downside if load or participation is lower
How is it recovered?	Applicable BPU or FERC mechanism, prudence and approval status, in-service timing, allocation, and expected recovery lag
Who pays and when?	Customer-class bill impact, assistance eligibility, supply-versus-delivery distinction, and cumulative rate effects
How reversible is it?	Design maturity, procurement commitments, cancellation cost, construction lead time, and opportunities to stage capacity

An academic study of U.S. utilities found that transmission investment was positively associated with market size and negatively associated with competitor generation after controlling for

market size. Its historical open-access transmission results do not estimate PSE&G's distribution needs or the returns on this plan. Research on regulatory incentives and service quality also suggests that recovery rules and operating resources may affect investment timing and outcomes, but the studies in the dossier use other institutions and do not supply PSE&G-specific coefficients. [A1]-[A5].

The choice

The management team can consider three broad approaches:

1. **Execute the announced portfolio envelope.** Maintain planned delivery across the categories, with operational control of cost and schedule. This could prepare for demand and reliability needs, but the high case includes contingent additions and public evidence does not quantify their marginal value or customer-bill effects.
2. **Protect baseline work and gate incremental additions.** Proceed with safety, replacement, approved commitments, and justified reliability work; stage optional demand-growth or program expansions against location-specific load, customer benefit, affordability, approval, and execution milestones. This preserves flexibility, but waiting can raise future costs or leave capacity short if demand arrives quickly.
3. **Reprioritize within feasible project boundaries.** Compare projects by reliability, asset condition, demand, customer value, and recovery readiness, then shift timing where approvals, engineering, and commitments permit. This may improve portfolio quality, but the public record does not show that dollars can be transferred freely among regulated categories or business lines.

There is no project-level dataset in the public packet to rank the actual investments. A defensible recommendation should specify which work is protected, what additions remain conditional, who validates the gates, and what evidence would trigger acceleration or delay.

Discussion questions

1. Which parts of the announced program appear necessary to maintain safe, reliable service, and what additional evidence would you need to classify them?
2. What evidence should PSE&G require before accelerating an incremental project for expected load growth?
3. How should the company compare distribution, FERC-regulated transmission, gas modernization, and clean-energy investments when they have different benefits and recovery rules?
4. How should the BGS supply-cost increase affect the timing and communication of delivery investments, if at all?
5. What customer-affordability and project-execution triggers belong in a portfolio review? What would cause you to revisit your recommendation?

Sources and scope

The case draws on PSEG/PSE&G's combined 2024 Form 10-K filed 25 February 2025, PSEG's 2024 results release and exhibit, PSE&G's October 2024 rate-settlement release, and the New Jersey BPU's February 2025 BGS auction release. Exact links, printed-page locators, academic citations, version details, and reading-depth limits appear in the accompanying source register. [S1]-[S4] identify primary evidence; [A1]-[A5] identify academic sources.

All material is limited to information available by 26 February 2025. Figures are shown in nominal U.S. dollars as reported. Forward capital amounts and rate-base growth are management estimates. No project-level return, reliability benefit, customer elasticity, or probability of load growth is estimated in this case.

Source key: [S1] PSEG/PSE&G 2024 Form 10-K; [S2] PSEG 2024 results release and SEC exhibit; [S3] PSE&G October 2024 rate-settlement release; [S4] New Jersey BPU February 2025 BGS auction release. [A1] Klumpp and Su (2015); [A2] Cambini and Rondi (2010); [A3] Cullmann and Nieswand (2016); [A4] Guthrie (2006); [A5] Cambini, Fumagalli, and Rondi (2016). Full bibliographic records and direct links are in the source register.