

Appendix D. Cost Analysis - Results

Appendix C sets out the inputs and methodology for the cost analysis conducted to support this Options Paper. This Appendix D provides the results of the analysis. Results are provided first for a range of single-install” scenarios assessing the impact of settings without policy intervention or with different types and variants of policy interventions for a single Large Light Water Reactor (LLWR) or Small Modular Reactor (SMR) that would be undertaken as the first advanced nuclear project in New York. The policy options tested include Advanced Nuclear Zero Emission Credits (ANZECs), a government cost overrun guarantee, State equity and grants. Utility ownership is not assessed quantitatively at this stage.

Across scenarios, results are provided for LLWR vs SMR and greenfield vs brownfield (including existing nuclear sites) permutations, for a total of four permutations between these parameters.

Analysis is also provided across a full pipeline of 5 gigawatt (GW), consistent with the nuclear Backbone goal (see Section 2 (Nuclear Reliability Backbone Initiative), across a range of scenarios based on the pipeline considerations in Section 6 (Technology Selection and Pipeline Considerations).

Selected scenarios are further tested under a range of sensitivities where low/high variants of key inputs replace the core settings of such inputs.

Scenarios are numbered as follows:

- "S", "P" or "Y" indicate, respectively, single install scenarios, pipeline scenarios and sensitivities;
- This is followed by "R" for reference case, "B" for base case, and/or a number for the various options tested.
- "Gf" represents greenfield siting and "Bf" represents brownfield siting permutations.
- Lower case letters (a, b, c, etc.) are used as needed to indicate further sub-scenarios.

D.1 Key Findings

The findings below summarize the primary insights from this analysis. These findings are intended to inform the design of a policy framework that can enable advanced nuclear deployment while minimizing overall public cost.

Single Install Scenarios

1. Across all permutations of technology (LLWR vs. SMR) and siting (greenfield vs. brownfield), reference scenarios demonstrate that initial nuclear projects are likely not commercially viable without any State support, even when incorporating existing federal supports such as the Investment Tax Credit and U.S Department of Energy (DOE)-backed debt. This reflects the combined effect of high upfront capital costs, long construction durations, and elevated construction-stage equity return requirements corresponding to project risk.
2. Introducing a (partial) government cost overrun guarantee materially improves project economics by reducing construction risk borne by private investors and, in turn, lowering required equity returns. Even with this risk-sharing mechanism in place, required revenues remain elevated in most scenarios, with only the most favorable cases—such as brownfield LLWR deployments—approaching required offtake revenue levels that may be achievable through merchant contracting. This underscores both that risk mitigation is a critical step, but also that it may be insufficient on its own to close the commercial viability gap.
3. ANZECs, State equity and grants all offer the opportunity to provide the state support needed to complement risk mitigation. Combinations of these can be considered to minimize the overall level of public support needed. A key observation is that greater reliance on revenue support allows greater amounts of favorable DOE Office of Energy Dominance Financing (DOE-EDF)-backed debt (until debt reaches DOE-EDF's 80% limit), and this can reduce the expected cost of State support needed. Adding State equity or upfront grants helps to reduce the amount of costly private sector equity finance needed (that would otherwise have to be supported through higher ANZEC prices). This can reduce the expected public cost but increases public exposure to construction risk.
4. The comparison between alternative forms of grant support—specifically between traditional construction grants, Provision for Revenue During Construction (PRDC)-style mechanisms and pre-Final Investment Decision (FID) grants—provides additional insight into the importance of timing of grant payments. Pre-FID grants are paid at the earliest stage of the project and thus avoid the greatest amount of carrying cost for the equity investment they displace. A PRDC structure pays funders their return throughout the construction period and therefore includes payments towards the end of construction when they avoid comparatively few equity carrying costs. As a result, dollar for dollar,

pre-FID grants achieve slightly greater reduction of total public cost, and PRDC-grants slightly lower reduction of public cost than regular construction grants.

Pipeline Scenarios

5. The pipeline analysis demonstrates how deployment strategy influences cost over time. Learning effects can reduce costs across successive projects, but these benefits are sensitive to deployment sequencing, site continuity, and the ability to maintain a consistent workforce and supply chain. Cost reductions are not smooth or automatic; they can be partially reset when projects shift across sites, are delayed, or when federal tax credits are withdrawn.
6. Technology choice matters, particularly for two reasons. Each technology may end up demonstrating a higher or lower cost relative to other technologies as the first units are deployed; and cost reductions through continued deployment are likely to occur largely limited to each individual nuclear design. As a result, technology choice needs to consider a balance – a firm commitment to pipeline deployment can unlock the greatest learning, but maintaining optionality between technologies reduces the risk of locking in a technology that may turn out to be relatively expensive and offers the opportunity to proceed with or switch to a technology later on when it may have become clearer which technology achieves a cost breakthrough.
7. Reflecting the above observations, the analysis indicates that selecting a single technology for the 5 GW pipeline likely offers the greatest cost reductions, whereas a project-by-project approach with different technologies selected for different projects and sites will likely result in less learning and fewer cost reductions. Conversely, however, the single pipeline approach offers the least amount of flexibility and optionality, and the project-by-project approach offers the greatest amount of flexibility and optionality. Flexibility can include pairing sites with smaller individual project; optionality can include opportunistically selecting technologies if and when they will have demonstrated a lowest cost approach through earlier deployments elsewhere.
8. At present and based on the central cost projection used in the analysis, SMR technologies appear to have a higher starting cost level, and even if deployed over a 5 GW pipeline of installations, SMRs would not be expected to achieve enough learning to deliver a lower cost last unit than LLWR technology. SMRs may also have a meaningfully longer timeline to complete 5 GW compared to LLWRs, unless it is feasible to achieve parallel deployment of multiple SMR units more quickly than assumed in this analysis.

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The slower deployment pace could result in other systemwide costs, as New York may need to rely on other generation resources to meet demand.

9. Given that there is uncertainty on the starting cost of advanced nuclear technologies, there is value in maintaining optionality to be able to switch from a technology chosen for near-term deployment to another design that may turn out to achieve a cost breakthrough later. The possibility of such a cost breakthrough may present itself particularly for SMRs given the relatively high levels of upward or downward cost uncertainty. A pipeline approach where the initial commitment is only to a limited pipeline, leaving the opportunity to switch to another technology if and when such cost breakthrough occurs, could realize significant cost savings.
10. The federal Investment Tax Credit (ITC) offers an important opportunity to reduce the cost to the State, and unless these tax credits are extended, this opportunity is time limited. However, the analysis indicates that maximizing deployment early on to enable as many units as possible to be eligible for the ITC is not necessarily the most cost-effective approach. Maximizing early deployment would likely mean deploying more units during the initial development stage of the technologies in question when costs are still higher. This effect appears to outweigh the benefit of more units being eligible for the ITC. However, this approach would have the additional benefit of a faster contribution to the increasing levels of power needed on the grid, which in turn offers increased system benefits as quantified by the State Energy Plan Pathways analysis.

Sensitivity Analysis

11. Extension of the ITC beyond its current phase out beginning in 2034 would be important across all scenarios to maintain momentum towards overall cost reduction. The scenario analysis indicates that the current expiration timeline of the ITCs is too near term to enable advanced nuclear technologies to deliver the cost reductions needed for truly sustainable cost levels.
12. Brownfield siting materially improves project economics relative to greenfield deployment. Lower project costs and shorter construction timelines reduce both the price at Commercial Operation Date (COD) and required revenue levels. While brownfield deployment does not eliminate the need for policy support, it can bring certain configurations—particularly LLWRs—closer to commercially viable levels.
13. Overnight capital cost (OCC) is the dominant driver of uncertainty across both single-install and pipeline scenarios, particularly for SMRs; the impact on public cost would

depend on the extent to which private sector project partners would absorb this uncertainty. Other factors subject to high impact of uncertainty in the analysis are the level of debt interest (indicating the important role EDF-backed debt plays in keeping cost of debt to a manageable level) and private sector equity hurdle rate (depending, however, how large the private sector equity share is compared to any State equity share). Fixed Operations and Maintenance (O&M) and learning rates show a moderate impact of uncertainty, and other inputs such as variable O&M, fuel cost and capacity factor show a low impact on the results of the cost analysis at the tested levels of uncertainty.

D.2 Output Metrics

For single install scenarios, the analysis provides project price at COD, the level of operational revenue needed, the public cost of support provided (if any), and components of the capital stack that add up to the OCC. OCC is the same across all the single install scenarios presented here for LLWR and SMR, respectively, and reflects the OCC for the first installation in New York as per the discussion of analysis inputs in Appendix C (Cost Analysis – Inputs and Methodology). These OCC figures (per kW) are:

Tech	Site	Base OCC
		<i>2025\$/kW</i>
LLWR	Greenfield	\$12,756
	Brownfield	\$11,385
SMR	Greenfield	\$18,655
	Brownfield	\$17,334

For pipeline scenarios, the analysis provides similar metrics; as well as outputs related to the timeline, namely construction duration, year of COD and total capacity deployed at milestone years (2040, 2045, 2050).

Further details on output metrics are provided below.

All scenario output metrics are in 2025\$.

Price at COD

The price at COD represents the expected amount needed to fully compensate construction funders for invested capital and financing costs incurred through construction if they sell the project at the start of commercial operations. In this analysis, the price at COD is calculated as

the sum of (1) the equity capital invested plus the required return on that equity consistent with the investors' hurdle rates and (2) the outstanding debt balance, including capitalized interest, assumed by the operator at COD.

Principal Investment by Source

Principal investment by source is quantified by allocating total development and construction expenditures across the project's funding sources, including, as applicable, private equity, State equity, State grants, and debt. The amounts shown represent capital contributions only and exclude any returns or capitalized interest accrued on those investments. The total of these components adds up to OCC.

Revenue

Revenue metrics are provided to reflect the fixed revenue that the operator receives in a given scenario under either a PPA or ANZEC contract in place for the first 25 years of operations, assumed under an arrangement whereby revenue increases by inflation over the contract lifetime (i.e., as constant-real price), expressed in \$/megawatt-hour (MWh). This metric represents the all-in compensation available to the project during the contracted period, including energy, capacity (converted to \$/MWh terms), and the above-market support provided by the contract. The revenue metric is provided as the amount in the first year of the contract and, based on the assumed revenue increase by inflation over the contract life, thus effectively also represents a levelized revenue metric over the contract term.

The level of contracted revenue is set such that, when combined with expected market revenue levels after the contracted term, the operator equity earns its required return on the purchase price paid at COD.

Total Public Cost

Quantification of any public cost is provided in the form of the present value (PV) of estimated public cost to New York from all public support mechanisms tested in the scenario in question. Future costs are discounted to 2026, using the New York State Department of Public Service (DPS) nominal societal discount rate of 7.62%.¹ These PV outputs are then de-escalated to 2025\$.

¹ The discount rate assumption is aligned with NYSERDA's recent Tier 1 Request for Proposals, released April 24, 2026, p. 38, which uses the same discount rate as established by the DPS Office of Accounting, Audits & Finance, revised February 23, 2026. <https://portal.nyserda.ny.gov/servlet/servlet.FileDownload?file=00Pcr00000pMkoZEAS>

Any State equity investment is not shown as a public cost since it would be repaid with return, and in addition may be funded from non-public sources (see Section 5 (Funding Sources) of the Options Paper).

As appropriate, public cost is shown as the total cost of the various policy mechanisms as well as separated into the main types: ANZECs and grants. It is important to note that in each scenario, above-market revenue could come from third party PPA or voluntary ANZEC sale arrangements, in which case the corresponding portion of ANZEC costs shown in a particular scenario could be ignored as a public cost since these costs would then be borne by the third party offtaker.

Cost of potential public exposure to any cost overruns is not quantified at this stage. As noted in Section 4.1 (Cost Overrun Guarantee) of the Options Paper, once more clarity in this respect emerges on the specifics of risk allocation between nuclear project partners sector project partners, analysis reflecting such specifics can be made available. Any opportunity cost of funds reserved for any government cost overrun guarantee is also not quantified in this analysis.

D.3 Single Install Scenarios

Reference Case Scenarios

As a point of comparison for the remainder of the analysis, three reference cases are provided, one without any government support (either federal or state), one with only the ITC (no federal loan guarantee or DOE-EDF debt), and one with current levels of federal support but no State support. These reference case scenarios are provided as benchmarks for the scale of revenue that a project would require in the absence of federal and/or state support mechanisms.

In the first two of these three cases – without access to federally-supported debt – this analysis does not offer an assessment whether private sector debt would be available, but for the purposes of these scenarios assumes such debt at a lower level of leverage (70%) and a higher cost of debt (10%) compared to the EDF-backed debt included throughout other scenarios.

Scenarios solve for the revenue required through a bundled 25-year PPA contract structure.

Table D-1. Reference Scenario: No Federal Support

		Price at COD	Required Revenue
		2025 \$B	2025 \$/MWh
S-R0a	LLWR Gf (1 GW)	\$31.2	\$408
S-R0b	LLWR Bf (1 GW)	\$22.6	\$301
S-R0c	SMR Gf (250 MW)	\$13.8	\$700
S-R0d	SMR Bf (250 MW)	\$9.9	\$499

Table D-2. Reference Scenario: Federal Support ITC Only

		Price at COD	Required Revenue
		2025 \$B	2025 \$/MWh
S-R1a	LLWR Gf (1 GW)	\$31.2	\$364
S-R1b	LLWR Bf (1 GW)	\$22.6	\$261
S-R1c	SMR Gf (250 MW)	\$13.8	\$635
S-R1d	SMR Bf (250 MW)	\$9.9	\$437

Table D-3. Reference Scenario: Federal ITC and Debt Support

		Price at COD	Revenue Level
		2025 \$B	2025 \$/MWh
S-R2a	LLWR Gf (1 GW)	\$25.8	\$252
S-R2b	LLWR Bf (1 GW)	\$19.4	\$183
S-R2c	SMR Gf (250 MW)	\$11.4	\$452
S-R2d	SMR Bf (250 MW)	\$8.4	\$309

The estimated required revenue to make the first project feasible in the absence of federal support is well above levels that are likely to be commercially achievable. As shown in Table D-1, required revenue levels range from approximately \$301/MWh for a brownfield LLWR to \$700/MWh for a greenfield SMR (in 2025\$) without federal support, with even the most favorable cases significantly exceeding prevailing market benchmarks for long-term PPAs. Similarly, with the inclusion of only the ITC, the PPA required revenue levels still exceed commercially viable levels. As shown in Table D-2, required revenue levels range from approximately \$261/MWh for a brownfield LLWR to \$635/MWh for a greenfield SMR (in 2025\$).

The third reference scenario, in comparison, clearly illustrates the value of federal support available through tax credits and DOE-EDF debt in reducing required revenue levels; but it still

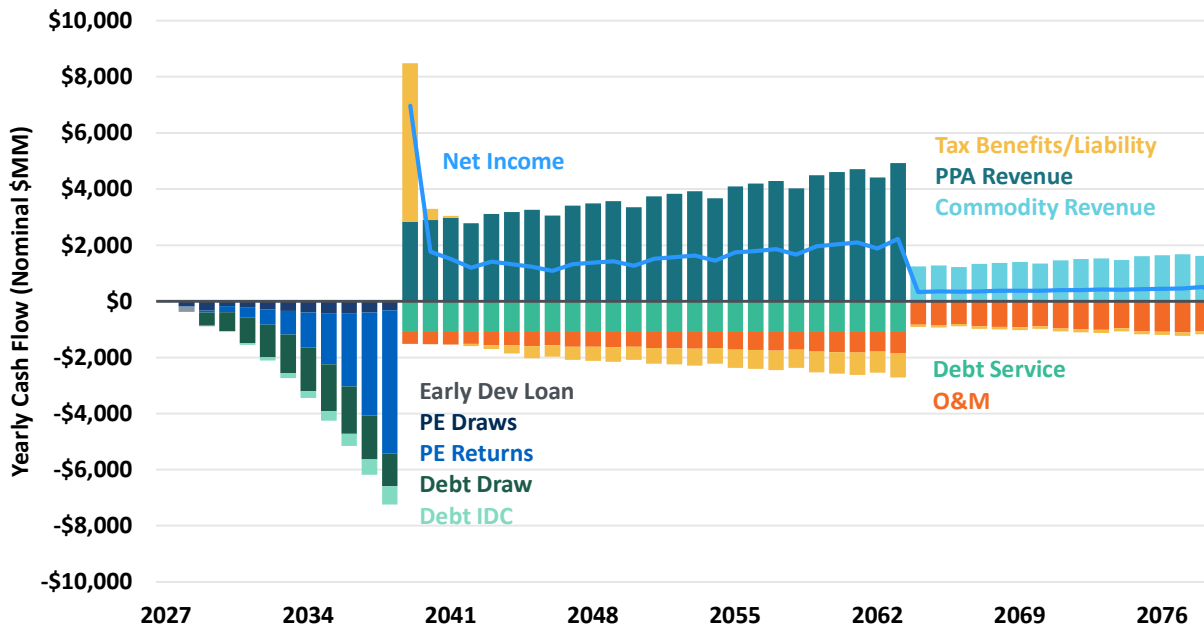
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produces estimated required offtake prices ranging from \$183/MWh for a brownfield LLWR to \$452/MWh for a greenfield SMR. While lower than in the first two scenarios, these revenue levels still appear materially higher than private sector offtakers are likely willing to pay.

Revenue could be made available through private sector offtake PPA contracts or through a State revenue support program (referred to here as an ANZEC program). At the levels quantified this would result in high ANZEC program costs; and in addition, as discussed in Section 3 (Barriers to Commercial Viability) of the Options Paper, it is considered highly uncertain whether private sector financing would be available at all absent state support for cost overruns. Accordingly, this scenario is not considered realistic as an approach to a government revenue support program, and public costs thereof are not quantified.

Figure D-1 below, which shows the cashflows for the third reference scenario, further illustrates these challenges. 80% of the OCC is paid by debt, and this incurs relatively low interest cost, reflecting the federal loan guarantee. The remaining 20% of OCC is funded by private sector equity. Because the equity is fully exposed to project risk in this scenario, its high equity hurdle rate leads to high carrying costs (shown as "PE Draws" in the figure) that compound to exceed the principal funded by the equity capital. Altogether, the expected debt and equity contributions and their associated carrying costs add up to the price at COD that construction funders need to receive to achieve their required returns. The figure also shows both the significant amount of federal tax credit received at COD that contributes to the price paid to construction funders, as well as the ongoing costs and revenues over the project life. The "PPA/ANZEC" revenue shown illustrates the revenue over time that is represented in Tables D-1-3 as the required revenue level for the scenario in question to support the price paid to construction funders as well as the debt service and operator return costs.

Figure D-1. Cashflow Diagram for S-R2a



Base Case Scenario

Based on the observations on the challenge of high finance costs and consistent with the discussions in Section 4.1 (Cost Overrun Guarantee) in the Options Paper, the analysis next estimates the role of a (partial) State cost overrun guarantee that shifts some of the construction cost risk away from private sector project partners to the public sector. The details of a government cost overrun guarantee are not specified in this analysis; however, the cost overrun guarantee is assumed to sufficiently de-risk the project to reduce the risk premium embedded in the construction equity hurdle rate such that equity hurdle rates broadly equate to those expected in other large energy or infrastructure projects, as discussed in Appendix C (Cost Analysis – Inputs and Methodology).

Such cost overrun guarantee lowers financing costs, resulting in lower project price at COD and correspondingly lower required revenue levels. While the resulting revenue levels are still high, some permutations – particularly the LLWR Brownfield scenario – suggest revenue levels that could be achievable without additional government support beyond the cost overrun guarantee, through PPA arrangements with counterparties willing to pay a premium, such as observed in announcements by some hyperscalers. As shown in Table D-4, the lowest-price LLWR Brownfield scenario produces a revenue need of \$132/MWh (2025\$), which is estimated to be comparable

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to some PPAs for nuclear facility restart projects.² However, as discussed in Section 4.2 (Advanced Nuclear Zero Emission Credits) of the Options paper, any involvement of hyperscalers would raise broader issues for consideration.

Alternatively, this level of revenue could be provided in the form of an ANZEC program. The estimated costs of such program are quantified below.

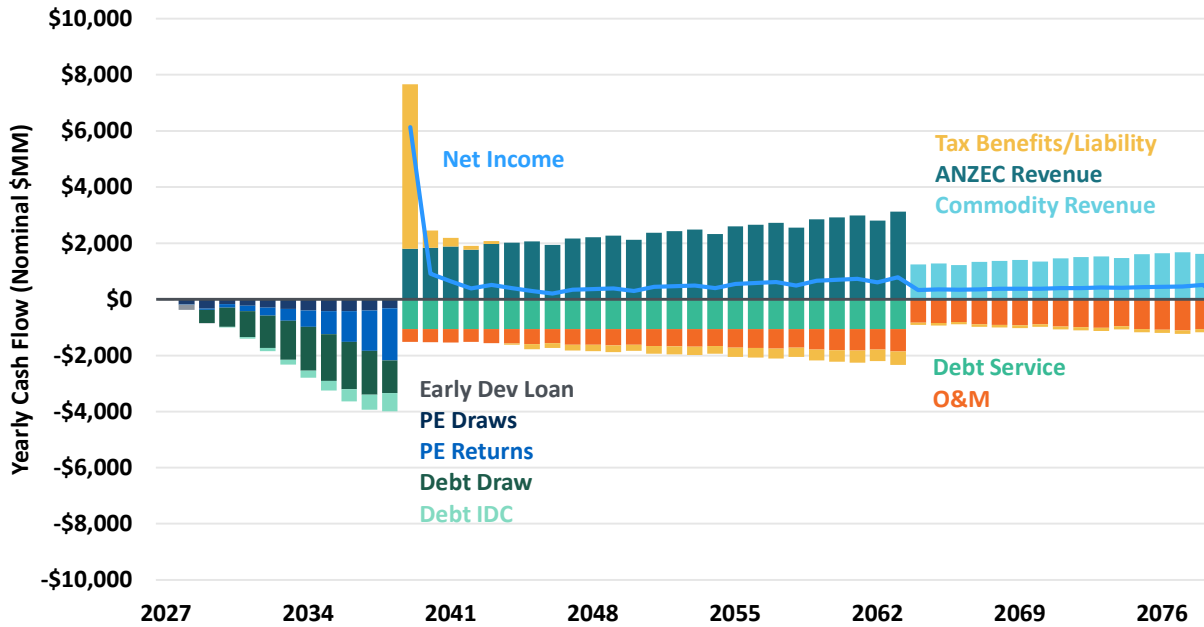
Table D-4. Base Case Scenario

		Price at COD	Revenue Level	ANZECs	Principal Investment by Source	
					Debt	Priv. Eq.
2025\$		\$B	\$/MWh	\$B PV	\$B	\$B
S-B1	LLWR Gf (1 GW)	\$18.7	\$160	\$5.97	\$9.91	\$2.86
S-B2	LLWR Bf (1 GW)	\$15.4	\$132	\$4.71	\$8.63	\$2.77
S-B3	SMR Gf (250 MW)	\$7.3	\$238	\$2.68	\$3.61	\$1.06
S-B4	SMR Bf (250 MW)	\$6.2	\$192	\$2.18	\$3.32	\$1.02

Figure D-2 below shows a similar cashflow representation for the base case as shown further above for the reference case, and illustrates the significant impact of lower funder risk translating to lower cost of finance during the development and construction phase.

² For example, Microsoft is estimated to pay Constellation approximately up to \$115/MWh as part of a 20-year PPA for restarting Unit 1 at the Three Mile Island nuclear facility. See Reuters, "Microsoft may pay Constellation premium in Three Mile Island power agreement, Jefferies says". September 24, 2024.
<https://www.reuters.com/markets/deals/microsoft-may-pay-constellation-premium-three-mile-island-power-agreement-2024-09-23/>

Figure D-2. Cashflow Diagram for S-B (Core scenario) for LLWR Greenfield



As discussed in Section 4 (Options Assessment), a number of other intervention options or variants of the above approach can be considered both to overcome barriers to project development and reduce public cost of interventions. These are considered below.

Single Install Policy Options

The following scenarios each build upon the base case approach assumed above, including a cost overrun guarantee and ANZEC offtake, and are presented for the same four permutations (LLWR vs. SMR and greenfield vs. brownfield siting). The discussion in this section focuses on the LLWR greenfield site permutation; however, observations apply to each of the four use cases.

Note that in each scenario, any public cost shown for ANZECs might be avoided to the extent part or all of the energy offtake would be contracted through a third-party PPA or voluntary ANZEC sale contract.

Each scenario either adds or changes components of the intervention approach during construction and operation to test the following aspects:

- **Scenarios S-B, S-1, and S-2: comparison between revenue support (ANZECs), State equity, and State construction grants.** These three intervention types represent the key available alternatives to provide government support to projects, and scenarios provided here assess differences between them including on public

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cost impact. Scenarios S-1 and S-2, respectively, assume an equal percentage of annual capital expenditures funded from State equity or a grant, to test the extent to which this allows ANZEC support levels to be reduced while maintaining commercial viability of the project. The comparison between S-1 and S-2 also enables conclusions on the relative cost differences between grant and equity support.

- **Scenario S-3: the level of State equity investment.** While Scenario S-1 tests a minority State shareholding (providing 40% of capital that is not covered by debt), Scenario S-3 assumes a majority State shareholding of 80% of costs after debt.
- **Scenario S-4: a fixed (capped) level of ANZEC revenue support.** While the above scenarios solve for the ANZEC revenue level needed, in Scenario S-4 a capped level of ANZEC revenue is assumed to solve for levels of State equity and grants needed. The grant amount required is tested for a State minority equity stake of 40% of costs after debt. The capped level of ANZEC revenue is set at \$100/MWh (2025\$).
- **Scenarios S-5 and S-6: pre-FID grant.** While grant options listed above are analyzed in the form of construction grants, these scenarios test pre-FID grants. 50% of pre-FID project costs are assumed to be made available in the form of grants rather than in the form of bridge loans as assumed in other scenarios. Scenario S-5 combines this with the features of the base case (cost overrun guarantee and ANZECs); Scenario S-6 combines this with the features of S-1 (adding a 40% State equity share).
- **Scenario S-7: PRDC.** The grant in Scenario S-2 is applied as a "standard" construction grant (capital injection provided for any and all types of project expenditure). Scenario S-7 tests an alternative grant structure referred to as Provision for Revenue during Construction (PRDC). The PRDC is designed to function similarly to Construction Work in Progress (CWIP) treatment in regulated jurisdictions or a Regulated Asset Base (RAB) framework, under which investors are compensated for financing costs during construction rather than capitalizing those costs until commercial operation. Under the PRDC structure, the project receives annual payments during construction equal to both the required return on equity (both private and state) and interest on debt during construction. This effectively eliminates the compounding of capitalized interest and capitalized equity returns over the multi-year construction period, reducing the financing burden embedded in the price at COD.

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- **Scenario S-8: continued State equity stake during operation.** This variant takes Scenario S-1 (with a 40% State equity share) as a starting point, but tests retention of the State ownership interest beyond COD rather than transferring the project to full ownership by a private-sector operator.

Table D-5. Single Install Policy Options: Greenfield LLWR

Scen	Policy Support	Price at COD	Revenue Level	PV of Public Support			Principal Investment by Source			
				Grant	ANZECs	Total	Debt	Grant	State Eq.	Priv. Eq.
2025\$		\$B	\$/MWh	\$B	\$B	\$B	\$B	\$B	\$B	\$B
S-B	Base case	\$18.7	\$160	\$-	\$5.97	\$5.97	\$9.91	\$-	\$-	\$2.86
S-1	40% State	\$17.3	\$143	\$-	\$4.96	\$4.96	\$9.53	\$-	\$1.22	\$2.02
S-2	40% grant	\$15.3	\$127	\$1.20	\$3.97	\$5.17	\$7.84	\$1.90	\$-	\$3.02
S-3	80% State	\$15.9	\$131	\$-	\$4.24	\$4.24	\$8.29	\$-	\$3.43	\$1.04
S-4	Capped ANZEC	\$12.2	\$100	\$2.34	\$2.34	\$4.68	\$5.20	\$3.56	\$1.53	\$2.48
S-5	Pre-FID Grant	\$17.7	\$147	\$0.17	\$5.19	\$5.36	\$9.91	\$0.19	\$-	\$2.66
S-6	Pre-FID Gr + Eq	\$16.6	\$137	\$0.17	\$4.61	\$4.78	\$8.92	\$0.19	\$1.39	\$2.26
S-7	PRDC	\$12.6	\$104	\$2.94	\$2.57	\$5.51	\$7.22	\$-	\$-	\$5.55
S-8	State Eq. in Ops.	\$17.3	\$139	\$-	\$4.69	\$4.69	\$9.06	\$-	\$1.41	\$2.30

Table D-6. Single Install Policy Options: Brownfield LLWR

Scen	Policy Support	Price at COD	Revenue Level	PV of Public Support			Principal Investment by Source			
				Grant	ANZECs	Total	Debt	Grant	State. Eq.	Priv. Eq.
2025\$		\$B	\$/MWh	\$B	\$B	\$B	\$B	\$B	\$B	\$B
S-B	Base case	\$15.4	\$132	\$-	\$4.71	\$4.71	\$8.63	\$-	\$-	\$2.77
S-1	40% State	\$14.5	\$124	\$-	\$4.19	\$4.19	\$7.81	\$-	\$1.34	\$2.24
S-2	40% grant	\$12.6	\$107	\$1.36	\$3.09	\$4.45	\$6.13	\$2.02	\$-	\$3.24
S-3	80% State	\$13.6	\$116	\$-	\$3.68	\$3.68	\$7.03	\$-	\$3.31	\$1.06
S-4	Capped ANZEC	\$11.7	\$100	\$1.44	\$2.60	\$4.04	\$5.40	\$2.02	\$1.50	\$2.47
S-5	Pre-FID Grant	\$14.6	\$124	\$0.21	\$4.23	\$4.44	\$7.87	\$0.23	\$-	\$3.29
S-6	Pre-FID Gr + Eq	\$13.9	\$119	\$0.21	\$3.86	\$4.07	\$7.30	\$0.23	\$1.45	\$2.40
S-7	PRDC	\$11.4	\$97	\$2.30	\$2.40	\$4.70	\$6.29	\$-	\$-	\$5.11
S-8	State Eq. in Ops.	\$14.5	\$120	\$-	\$3.93	\$3.93	\$7.41	\$-	\$1.51	\$2.49

Notes: The "Capped ANZEC" scenario includes 40% state equity participation and a grant, sized to make the project feasible. "Pre-FID Gr + Ep" includes a pre-FID grant and 40% state equity participation during construction. PRDC payments are not included in "Principal Investment by Source" because they pay financing costs rather than capital expenditures.

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Table D-7. Single Install Policy Options: Greenfield SMR

Scen	Policy Support	Price at COD	Revenue Level	PV of Public Support			Principal Investment by Source			
				Grant	ANZECs	Total	Debt	Grant	State. Eq.	Priv. Eq.
2025\$		\$B	\$/MWh	\$B	\$B	\$B	\$B	\$B	\$B	\$B
S-B	Base case	\$7.3	\$238	\$-	\$2.68	\$2.68	\$3.61	\$-	\$-	\$1.06
S-1	40% State	\$6.7	\$204	\$-	\$2.16	\$2.16	\$3.61	\$-	\$0.39	\$0.67
S-2	40% grant	\$6.1	\$181	\$0.33	\$1.81	\$2.14	\$3.33	\$0.51	\$-	\$0.83
S-3	80% State	\$6.0	\$177	\$-	\$1.76	\$1.76	\$3.25	\$-	\$1.08	\$0.34
S-4	Capped ANZEC	\$3.8	\$100	\$1.36	\$0.59	\$1.95	\$1.35	\$2.08	\$0.46	\$0.77
S-5	Pre-FID Grant	\$6.8	\$213	\$0.07	\$2.29	\$2.36	\$3.61	\$0.08	\$-	\$0.98
S-6	Pre-FID Gr + Eq	\$6.3	\$188	\$0.07	\$1.92	\$1.99	\$3.53	\$0.08	\$0.39	\$0.66
S-7	PRDC	\$4.8	\$135	\$1.11	\$1.12	\$2.23	\$2.82	\$-	\$-	\$1.85
S-8	State Eq. in Ops.	\$6.7	\$196	\$-	\$2.03	\$2.03	\$3.61	\$-	\$0.39	\$0.67

Table D-8. Single Install Policy Options: Brownfield SMR

Scen	Policy Support	Price at COD	Revenue Level	PV of Public Support			Principal Investment by Source			
				Grant	ANZECs	Total	Debt	Grant	State. Eq.	Priv. Eq.
2025\$		\$B	\$/MWh	\$B	\$B	\$B	\$B	\$B	\$B	\$B
S-B	Base case	\$6.2	\$192	\$-	\$2.18	\$2.18	\$3.32	\$-	\$-	\$1.02
S-1	40% State	\$5.7	\$172	\$-	\$1.85	\$1.85	\$3.20	\$-	\$0.42	\$0.72
S-2	40% grant	\$5.1	\$149	\$0.44	\$1.48	\$1.92	\$2.62	\$0.65	\$-	\$1.06
S-3	80% State	\$5.3	\$157	\$-	\$1.61	\$1.61	\$2.83	\$-	\$1.13	\$0.38
S-4	Capped ANZEC	\$3.6	\$100	\$1.13	\$0.65	\$1.78	\$1.40	\$1.62	\$0.49	\$0.83
S-5	Pre-FID Grant	\$5.8	\$173	\$0.09	\$1.86	\$1.95	\$3.22	\$0.09	\$-	\$1.02
S-6	Pre-FID Gr + Eq	\$5.5	\$162	\$0.09	\$1.68	\$1.77	\$2.94	\$0.09	\$0.48	\$0.82
S-7	PRDC	\$4.4	\$127	\$0.91	\$1.10	\$2.02	\$2.52	\$-	\$-	\$1.82
S-8	State Eq. in Ops.	\$5.7	\$166	\$-	\$1.76	\$1.76	\$3.06	\$-	\$0.47	\$0.81

Notes: The “Capped ANZEC” scenario includes 40% state equity participation and a grant, sized to make the project feasible. “Pre-FID Gr + Ep” includes a pre-FID grant and 40% state equity participation during construction. PRDC payments are not included in “Principal Investment by Source” because they pay financing costs rather than capital expenditures.

Observations

- **Scenarios S-B, S-1 and S-2: comparison between revenue support (ANZECs), State equity and construction grants.** These scenarios test the dynamic between the three available key support mechanisms: revenue support during operation in the form of an ANZEC program, upfront intervention in the form of a State equity stake,

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and/or upfront support in the form of construction grants. Between these, the key observation is that either State equity or construction grants can materially reduce the estimated public cost compared to the approach of only cost overrun guarantee and ANZEC in Scenario S-B on a present value basis:

- In Scenario S-1, State equity has a lower cost of finance than the private sector construction equity it displaces, which reduces overall cost of financing from the project perspective and translates to a lower purchase price at COD. This lower purchase price results in a lower revenue requirement (ANZEC payment) during operation. However, this reduction in public cost is accompanied by an increase in public risk exposure to any overruns during construction.
- In Scenario S-2, a construction grant reduces overall project cost and the associated revenue need. The grant itself, though, shows up as a public cost because those funds provided to the project are not paid back.
- Note that the analysis does not account for any difference between State equity and grants in terms of any State exposure to cost overruns that either instrument might imply. As noted in Section 4.1 (Cost Overrun Guarantee), a State equity investment likely implies a State commitment to back a corresponding share of project cost overrun risk. However, it would need to be determined whether the same applies in the case of a State grant. Impacts in this regard on cost of private equity are not reflected in this analysis.
- **Scenario S-3: the level of State equity investment.** Increasing State construction equity share from 40% to 80% of costs after debt further reduces the required ANZEC offtake price and total public cost, reflecting the same dynamic that was already identified further above when comparing the 40% State equity scenario with the scenario without any State equity, but more pronounced as a result of the higher State equity share. Again, as discussed above, this would also mean that public exposure to cost overruns could increase compared to the earlier scenarios.
- **Scenario S-4: a fixed (capped) level of ANZEC revenue support.** In this scenario, the ANZEC offtake price is capped at \$100/MWh (2025\$) in combination with 40% State equity, to test how much additional grant support would be needed if the priority is to keep the level of ANZEC payments low. While both State equity and grants have been shown to reduce overall public cost compared to an ANZEC-only approach, this scenario shows the limitations of continuing to increase the scale of

these interventions in order to further reduce ANZEC support. In this scenario, the lower level of project revenue results in a lower amount of DOE-EDF debt compared to other scenarios, since debt is limited by the debt service coverage ratio during operations. Since debt is a relatively low-cost source of finance, a reduction in the amount of debt is not favorable to the overall project cost. As a result, it can be observed that once the dynamic of reducing debt is triggered, further reduction in ANZEC and further shift towards more grant support no longer delivers meaningful additional reduction in total public cost, but as noted above, any such increase in grant support compared to other scenarios does entail increasing levels of upfront public risk exposure. This illustrates the value of fine-tuning the mix of interventions to maximize the availability of debt.

- **Scenarios S-5 and S-6: pre-FID grant.** These scenarios show similar dynamics as those identified for scenarios with construction grants tested above. Grants can help to reduce total expected public cost, especially when provided early in project development. Compared to the total project cost, a grant of 50% of pre-FID costs represents a relatively modest amount, and accordingly the overall cost reduction shown is modest. The key benefit of pre-FID grants may be in helping projects to overcome the pre-FID barriers identified in Section 3.1 (Reaching FID), subject to availability of grant funding sources.
- **Scenarios S-7: PRDC.** Compared to Scenario S-2, Scenario S-7 provides a construction-period payment that is much larger than the grant payment amount in S-2 since it covers the full cost of finance during construction. However, support in the form of PRDC is not necessarily more economically efficient than a traditional construction grant. Generally, the earlier during the development and construction period a grant is made available to the project, the more it avoids carrying cost accumulating for the private sector equity it displaces. A PRDC structure pays funders their return throughout the construction period and therefore includes payments towards the end of construction when they avoid comparatively few equity carrying costs. There are other second order effect differences between PRDC and regular grant that could, for instance, affect the DSCR calculation for debt and thus total available debt that the project can accommodate, but these effects are small, and where grants would be used, a choice between a PRDC or more traditional structure may therefore primarily reflect design preferences rather than cost difference.
- **Scenario S-8: continued State equity investment during operation.** In Scenario S-8, the State continues an equity ownership share during the operations phase of the

project. As part of this scenario, it is assumed that the State maintains a 5% required return on equity. This lowers the effective cost of capital during operations and lower total public support cost. The reduction in total public cost is relatively small, however, which may not be significant enough to consider maintaining a public equity stake during operations.

Selection of the optimal policy mix going forward from the concepts put forward above requires careful balancing of the dynamics identified in this analysis.

D.4 Pipeline Scenarios

The scenarios presented for this pipeline analysis are a subset of those described qualitatively in Section 6 (Technology Selection and Pipeline Considerations), to show a range of structures, including dedicated pipelines, parallel development, sequential buildouts, and project-by-project procurement approaches.

- Scenario P-1a: Single pipeline of 5 LLWRs
- Scenario P-1b: Single pipeline of 20 SMRs
- Scenario P-2: Multiple pipelines in parallel (2 LLWRs and 12 SMRs)
- Scenario P-3a: Multiple sequential pipelines (5 LLWRs)
- Scenario P-3b: Multiple sequential pipelines (2 LLWRs and 12 low-cost SMRs)
- Scenario P-4: Project-by-project procurements (2 LLWRs and 12 SMRs)

All pipeline scenarios presented in this analysis reflect the policy support structure of the above **base case scenario** S-B, i.e., include an assumed state government support framework consisting of ANZECs and a (partial) government cost overrun guarantee. Accordingly, the pipeline analysis does not incorporate the opportunities for cost reduction through combination with various other policy options (such as State equity or grants) demonstrated in the single install analysis further above. Where such opportunities would be incorporated into a broader suite of policy interventions, the pipeline cost results shown below could be expected to reduce accordingly.

Across the scenarios, deployment is subject to a common set of structural assumptions:

- Except in the “project-by-project” approach of scenario P-4, each site is assumed to accommodate 2 GW of installed capacity, corresponding to either two LLWRs or

eight SMRs.³ Units constructed at the same site benefit from additional learning effects, particularly reductions in owner's costs (see Appendix C (Inputs and Methodology)).

- In the project-by-project scenario, co-location is only assumed for each GW (one LLWR or four SMRs).
- Units are assumed to be developed at greenfield sites. Brownfield sites are tested further below in the sensitivity analysis section.

The below discussion for the range of scenarios in each case offers a description and visual representation of the scenarios, a graph with the OCC per unit across the pipeline (reflecting learning effects and cost reductions), and tables with cost and other output metrics.

Scenario 1: Single Pipeline

Scenarios P-1a and P-1b consist of a dedicated 5 GW pipeline of a single technology deployed sequentially, assessed as either of five LLWRs or twenty SMRs (based on an assumed size of 250 MW per unit), respectively. Development of the first unit begins in 2027.

Within a given site, LLWR units are constructed with a two-year stagger in Scenario P-1a, reflecting overlapping development and construction activities and enabling strong realization of site-level learning. In Scenario P-1b, SMR units are initially constructed with a one-year stagger between units at the same site. Parallel deployment of two or four SMR units at the same time is introduced later in the pipeline process once sufficient experience has been gained.

When transitioning between sites, longer stagger intervals (three years) are assumed, reflecting the time required to initiate development at a new location and relocate the necessary workforce. This sequencing results in alternating short and long staggers across the pipeline.

³ While the 5 GW backbone goal is not fully divisible into 2 GW portions, for consistency a similar level of co-location cost reduction is nevertheless also assumed for the 5th gigawatt as if it was part of a 2 GW colocation arrangement. This reflects an assumption that all installs across the 5 GW pipeline would on average be subject to a similar level of colocation, without stipulating any specificity in the analysis on which part of the pipeline would be collocated with which other part. As a result, OCC for units comprising the 5th GW (except in scenario 4) is presented as an average across co-located units.

Figure D-3. P-1a: Single Pipeline (5 LLWRs)

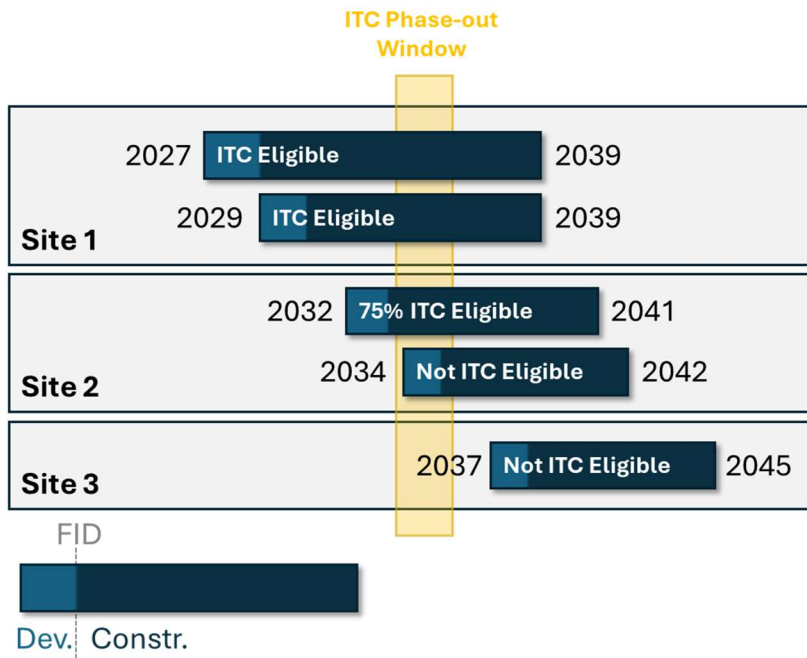


Figure D-4. P-1B: Single Pipeline (20 SMRs)

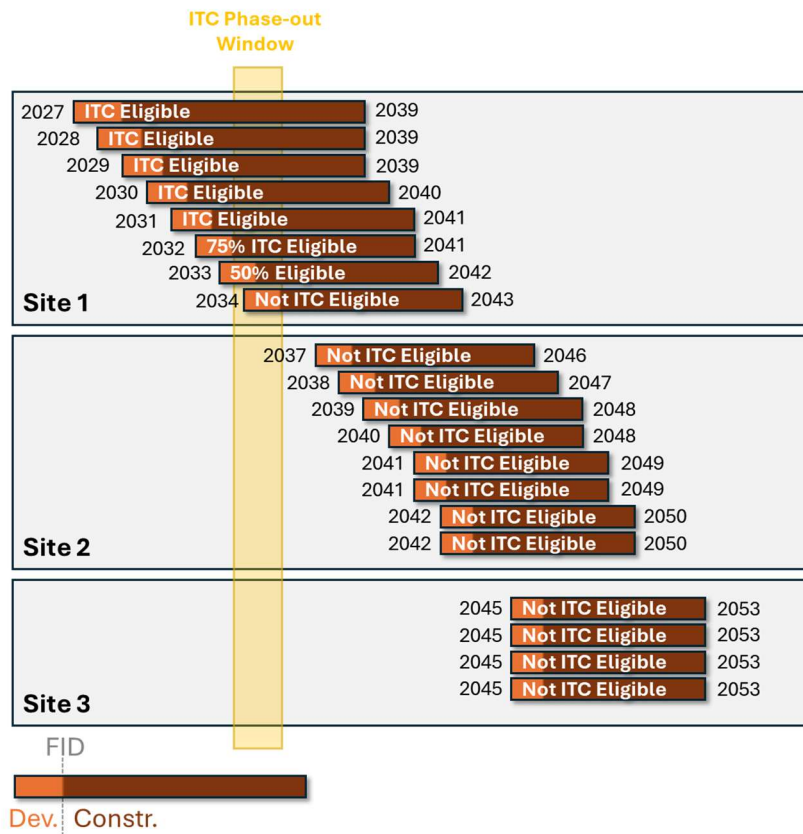
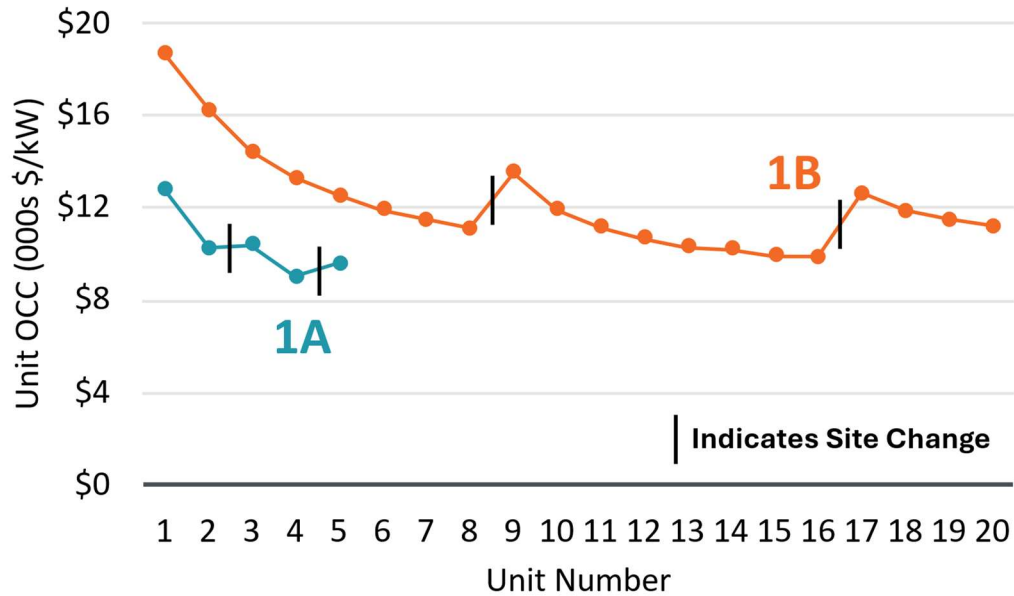


Figure D-5. Pipeline Scenarios P-1a and p-1b Unit OCCs (2025\$)



Scenario 2: Multiple Pipelines in Parallel

This scenario represents parallel deployment tracks of two different advanced nuclear technologies. The analysis provided here illustrates this as parallel deployment of LLWRs and SMRs; other variants not quantified here could include two different LLWR designs or two different SMR designs in parallel. The start of project development between the two pipelines is shown in this scenario as truly parallel, with both pipelines starting in 2027; in practice the project currently being pursued by NYPA would still be expected to progress sooner than any other parallel effort, but as a simplification this nuance is ignored in this scenario.

Figure D-6. P-2: Multiple Pipelines in Parallel (2 LLWRs and 12 SMRs)

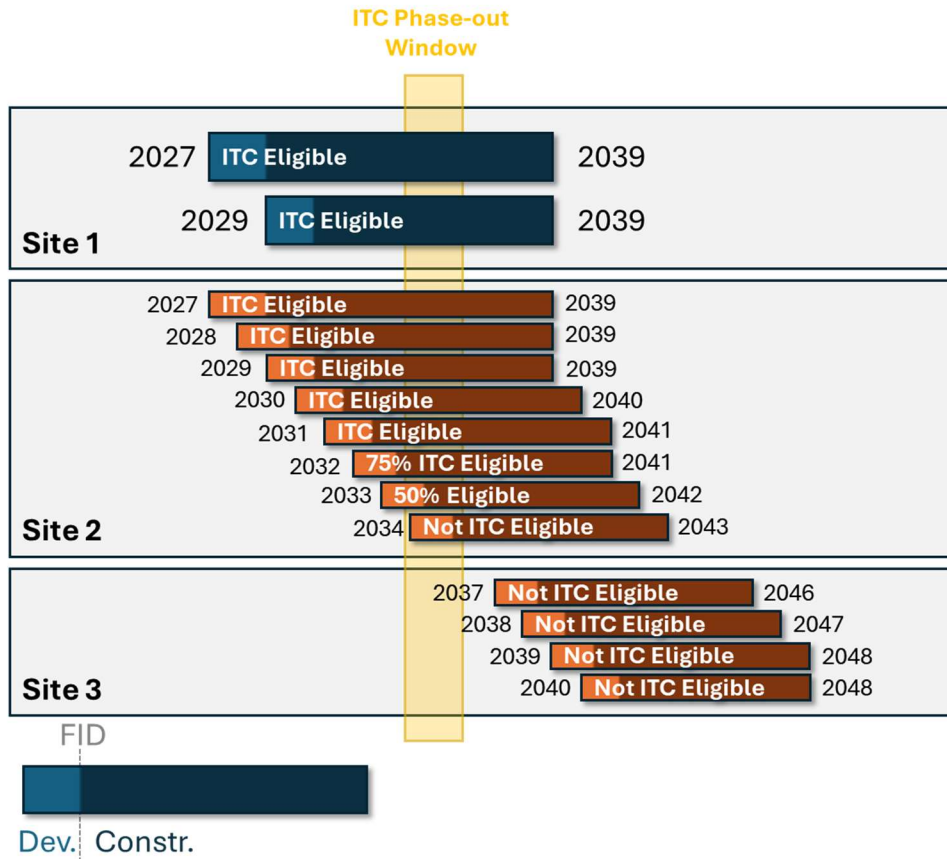
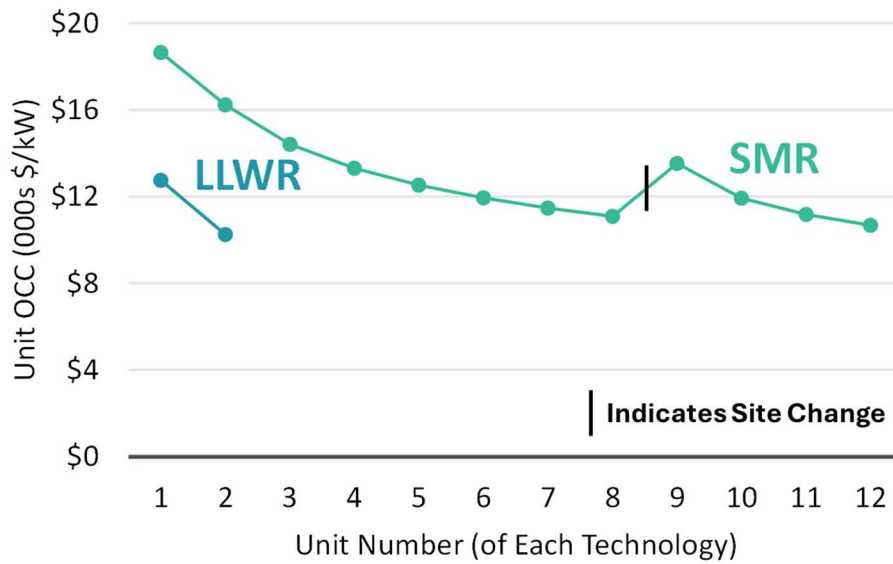


Figure D-7. Pipeline 2 Unit OCC (2025\$)



Scenario 3: Multiple Sequential Pipelines

This scenario also allows for the possibility of two different advanced nuclear designs being pursued but sequentially rather than in parallel. After an assumed initial pipeline of 2 GW (shown in this scenario as 2 GW of LLWR though this could instead be a pipeline of SMRs), a pause is assumed, allowing New York to evaluate progress both the in-state efforts and those in other states. Depending on the assessment, the State would then proceed with the same technology for the remaining 3 GW, or switch to a different technology.

Scenario 3 assumes that a switch to a different technology would only occur if, at this later point in time, at least one other design would have achieved a more significant cost breakthrough than what is represented in the base case cost decline trajectories that otherwise underpin the analysis. Scenario P-3b captures this switch to a different cheaper technology in the form SMRs following the low end of the SMR cost range shown in Table C-1 of Appendix C (Cost Analysis – Inputs and Methodology).

Key features of this scenario impact learning and cost reductions. While the gap between the first and second pipeline unlocks the opportunity for review, some time-sensitive learning within the State can be lost partially. Furthermore, when switching to another technology later on, that technology would have achieved its cost reductions out of state, and not all of those learnings carry over into New York. See the discussion of these aspects in Appendix C (Cost Analysis – Inputs and Methodology). The analysis assumes that, during the gap, 2 GW of the technology in question is advanced out of state such that additional learning from those 2 GW in respect of equipment and indirect cost components is available for New York's subsequent deployment of the second pipeline of LLWRs (Scenario P-3a) or SMRs (Scenario P-3b).

Figure D-8. P-3a: Multiple Sequential Pipelines (5 LLWRs)

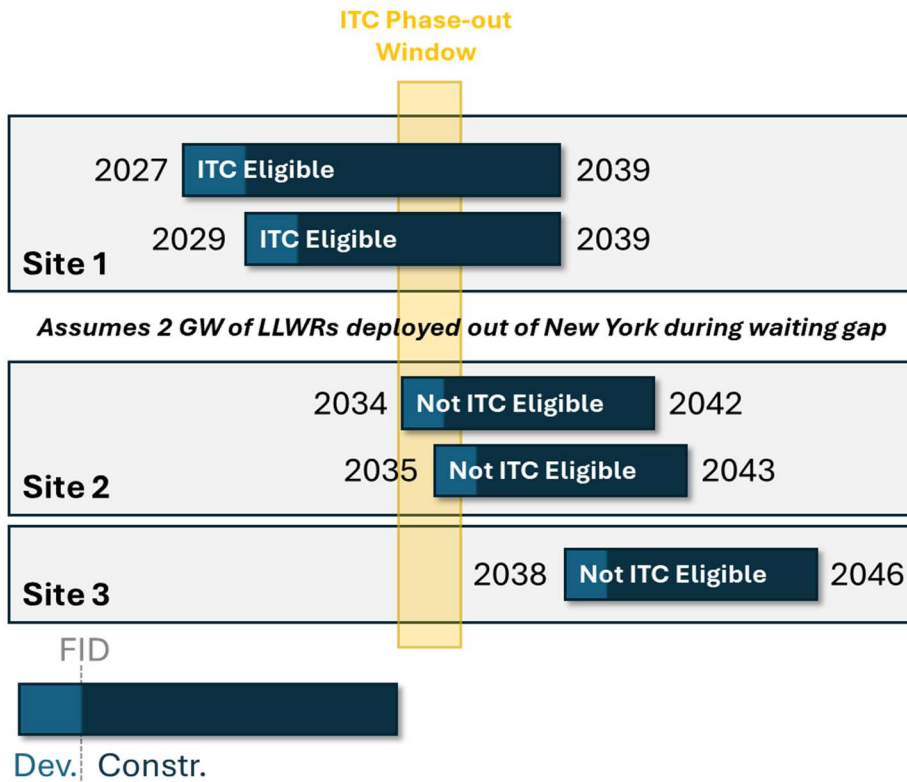


Figure D-9. P-3b: Multiple Sequential Pipelines (2 LLWRs and 12 Low-Cost SMRs)

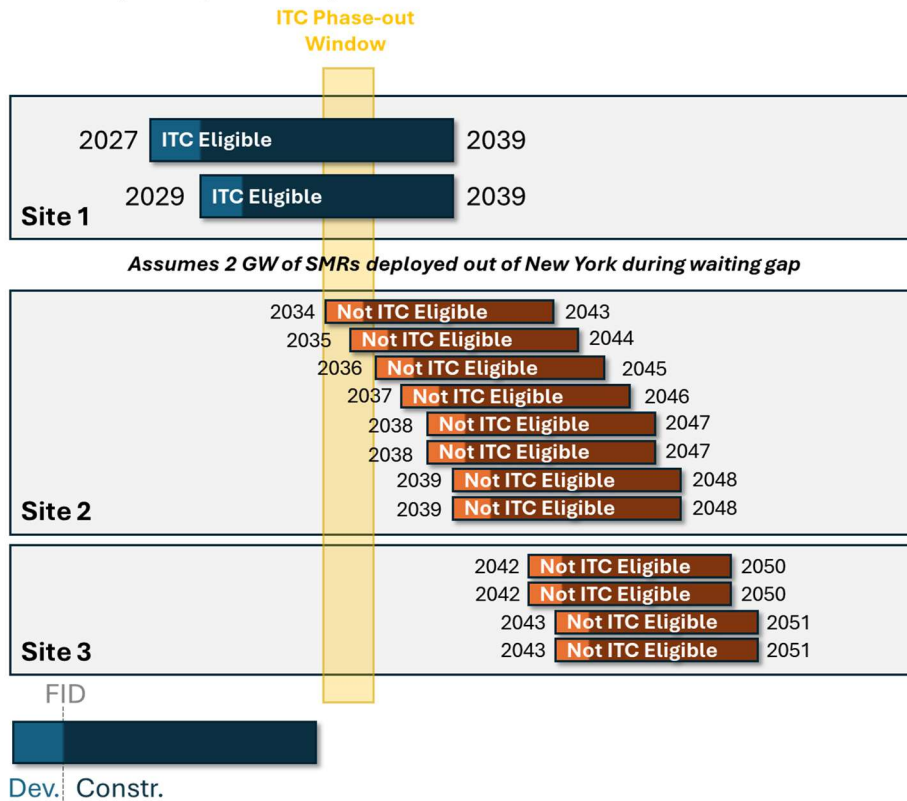
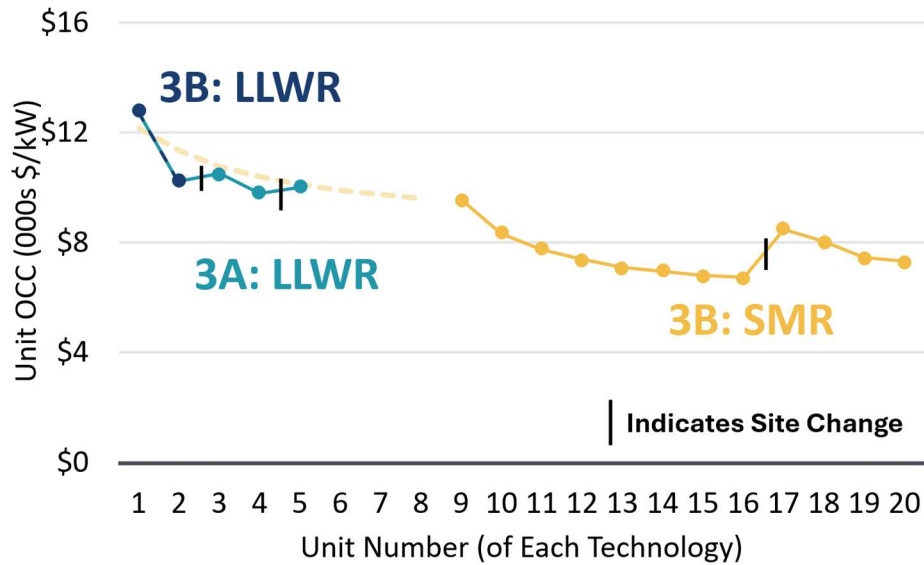


Figure D-10. Pipelines 3a & 3b Unit OCCs (2025\$)



Note: Dashed yellow line represents out of state deployment for the SMR technology deployed.

Scenario 4: Project-by-Project Procurements

This scenario assumes that the first two GW are deployed in the same fashion as Scenario P-1a (2 LLWRs that begin 2 years apart). However, the following three GW are assumed to be three separate SMR technologies that are all procured in a “project-by-project” manner, meaning that they are all assumed to be of different technologies that share no learning. Each of the final three GW are procured two years apart starting after the LLWRs. While these “project-by-project” deployments share no in-state learning with each other, they can still benefit from assumed deployment-related learning of each technology outside New York.

For the first SMR technology (3rd GW in the pipeline) it is assumed that 1 GW has been deployed outside New York before it begins deployment in New York. For the second SMR technology (4th GW in the pipeline) this increases to 2 GW and for the third SMR technology (5th GW in the pipeline) to 4 GW deployed outside New York before being deployed in New York.

Figure D-11. P-4: Project-by-Project Procurements (2 LLWRs and 12 SMRs)

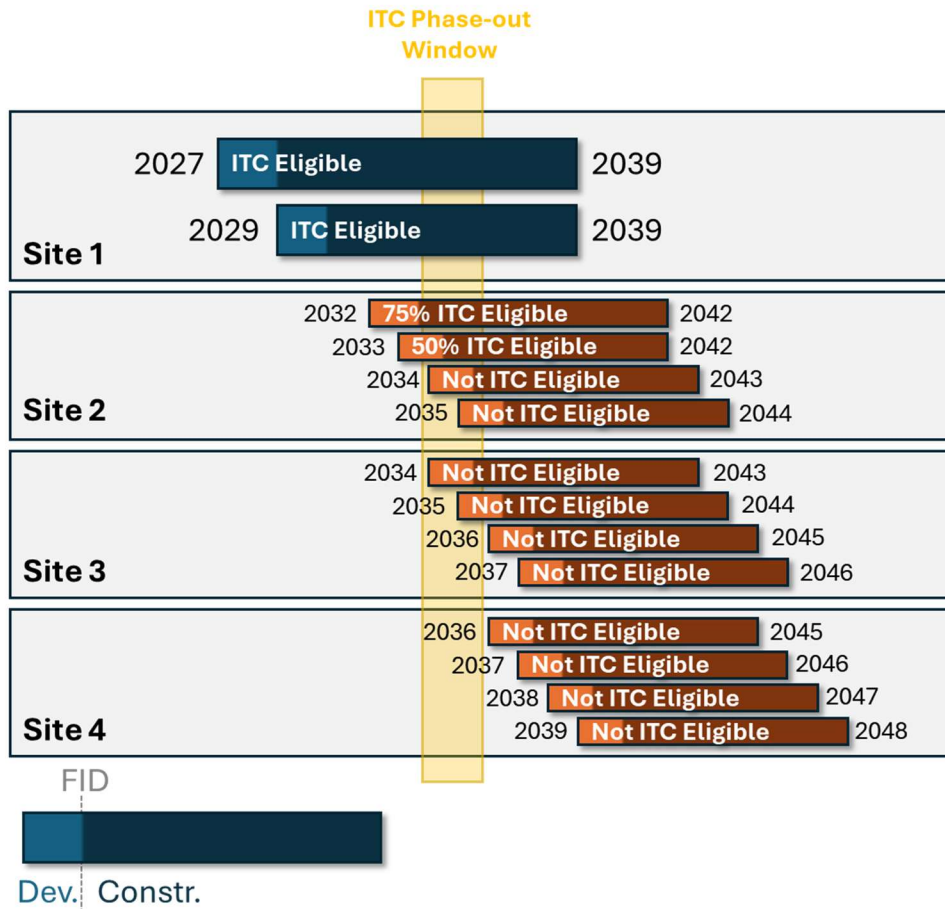
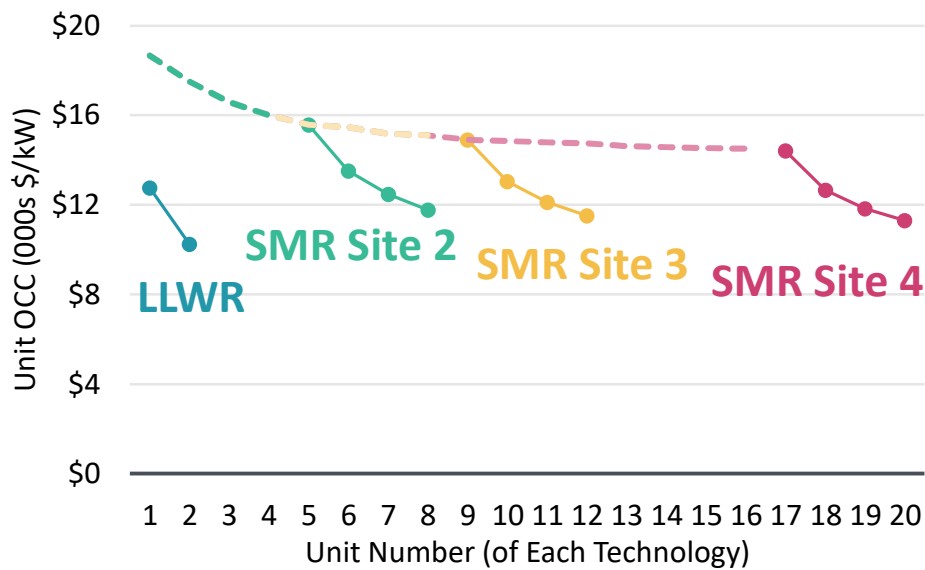


Figure D-12. Pipeline 4 Unit OCCs (2025\$)



Note: Dashed lines represent out-of-state deployments for technologies at sites 2, 3, and 4. The out-of-state reduction in overnight costs shown for these technologies only reflects the decreases in cost components for which learnings transfer across sites and states (equipment and indirect costs).

Results and Discussion

Table D-9. Summary Pipeline Scenario Comparison

Pipeline	Price At COD	PV of Public Support	GWs Online by 2040	GWs Online by 2045	GWs Online by 2050
	<i>2025 \$B</i>	<i>2025 \$B</i>			
P-1a	\$66.9	\$19.0	2.00	5.00	5.00
P-1b	\$77.8	\$19.8	1.00	2.00	4.00
P-2	\$83.2	\$23.9	3.00	4.00	5.00
P-3a	\$68.7	\$20.1	2.00	4.00	5.00
P-3b	\$60.0	\$15.4	2.00	2.75	4.50
P-4	\$80.7	\$23.5	2.00	4.00	5.00

Table D-10. P-1a: Single Pipeline (5 LLWRs)

	Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
LLWR Unit 3	9	2041	\$10,398	\$13.0	\$120	\$3.22
LLWR Unit 4	8	2042	\$9,038	\$10.8	\$127	\$3.39
LLWR Unit 5	8	2045	\$9,019	\$10.8	\$127	\$2.89
Total for Pipeline				\$66.9		\$19.0

Table D-11. P-1B: Single Pipeline (20 SMRs)

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
SMR GW 1	11	2039-2040	\$15,656	\$22.6	\$162 - \$207	\$7.10
SMR GW 2	9	2041-2043	\$11,758	\$15.0	\$129 - \$155	\$3.97
SMR GW 3	9	2046-2048	\$11,831	\$14.5	\$152 - \$156	\$3.69
SMR GW 4	8	2049-2050	\$10,080	\$12.2	\$135	\$2.57
SMR GW 5	8	2053	\$11,186	\$13.5	\$146	\$2.47
Total for Pipeline				\$77.8		\$19.8

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Table D-12. P-2: Multiple Pipelines in Parallel (2 LLWRs and 12 SMRs)

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
SMR GW 1	11	2039-2040	\$15,656	\$22.6	\$162 - \$207	\$7.10
SMR GW 2	9	2041-2043	\$11,758	\$15.0	\$129 - \$155	\$3.97
SMR GW 3	9	2046-2048	\$10,881	\$13.4	\$143 - \$146	\$3.31
Total for Pipeline				\$83.2		\$23.9

Table D-13. P-3a: Multiple Sequential Pipelines (5 LLWRs)

	Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
LLWR Unit 3	9	2043	\$10,467	\$12.8	\$144	\$4.06
LLWR Unit 4	9	2044	\$9,792	\$12.0	\$137	\$3.54
LLWR Unit 5	8	2046	\$9,707	\$11.6	\$133	\$2.99
Total for Pipeline				\$68.7		\$20.1

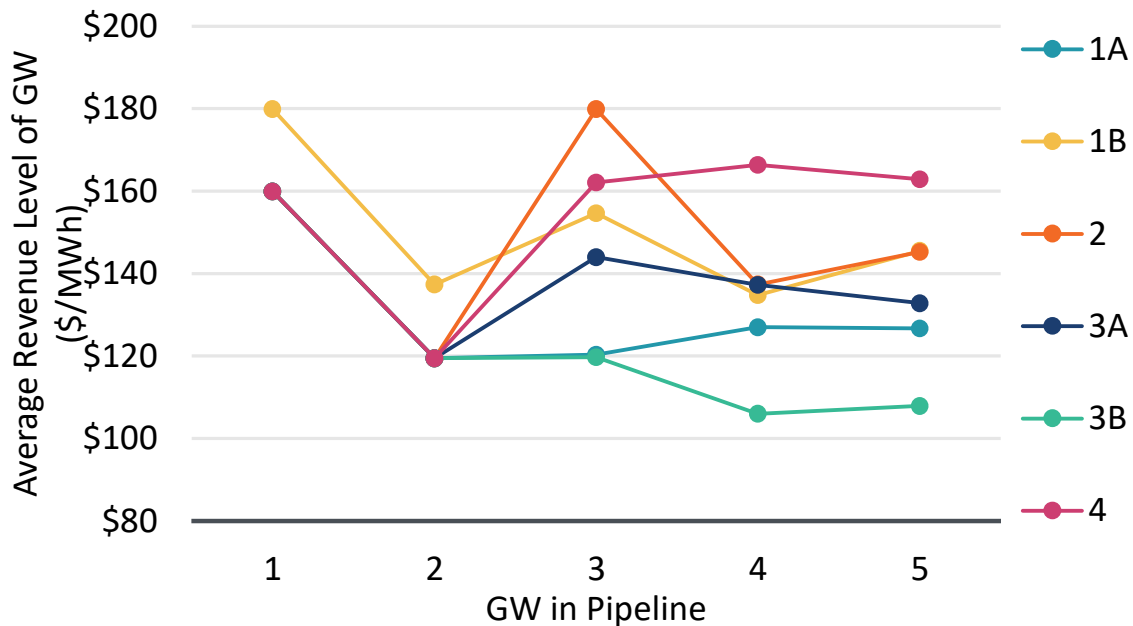
Table D-14. P-3b: Multiple Sequential Pipelines (2 LLWRs and 12 Low-Cost SMRs)

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
Low-Cost SMR GW 3	9	2043-2046	\$8,250	\$10.3	\$120	\$2.65
Low-Cost SMR GW 4	9	2047-2048	\$6,890	\$8.6	\$106	\$1.72
Low-Cost SMR GW 5	8	2050-2051	\$7,326	\$8.9	\$108	\$1.53
Total for Pipeline				\$60.0		\$15.4

Table D-15. P-4: Project-by-Project Procurements (Significant SMR Activity Outside NY)

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	Years	Year	2025 \$/kW	2025 \$B	2025 \$/MWh	2025 \$B
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
SMR GW 3	9	2042-2044	\$13,333	\$17.0	\$151 - \$174	\$5.01
SMR GW 4	9	2043-2046	\$12,897	\$15.9	\$166	\$4.79
SMR GW 5	9	2045-2048	\$12,555	\$15.5	\$163	\$4.17
Total for Pipeline				\$80.7		\$23.5

Figure D-13. Average Revenue Level per GW by Pipeline 2025\$/MWh



Observations

- Scenario P-1: a single pipeline.** Across the pipeline approaches assessed here, the single technology approach of Scenario 1 shows the lowest projected cost, with the exception of Scenario 3b. This reflects maximizing the learning effects within a single technology; however, this approach also entails the highest amount of commitment to a single technology and therefore the lowest level of optionality. When comparing the LLWR and SMR pipelines under this approach, under the base cost assumptions used in this analysis, SMR cost reductions do not overtake LLWR costs within the 5 GW deployment horizon.

- **Scenario P-2: multiple pipelines in parallel.** The parallel deployment of LLWR and SMR pipelines illustrates the tradeoffs where pursuing “speed-to-power” may entail fewer opportunities for learning-based cost reductions. This parallel deployment approach achieves faster deployment than a fully sequential SMR pipeline.⁴ As a result of learning being split across technologies, learning is divided rather than concentrated within a single standardized pipeline, resulting in less learning. This scenario does allow more units to benefit from the ITC, but the analysis indicates this is insufficient to offset the reduced learning. The resulting cost estimate for this scenario is relatively high. However, this should be considered within the broader context of system benefits from greater “speed to power”. As noted in Section 2 (Nuclear Reliability Backbone Initiative) of the Options Paper, analysis carried out for the 2025 State Energy Plan assessed scenarios with a higher amount of 3.3 GW of new nuclear deployed by 2040 vs a lower amount of 2.2 GW by 2040, roughly matching the difference between this Scenario 2 with 3 GW deployed by 2040 and most of the other pipeline scenarios presented here that would achieve 2 GW by 2040. The SEP analysis quantified an increased system benefit of \$31 billion under the 3.3 GW scenario compared to \$28 billion under the 2.2 GW approach, suggesting an incremental \$3 billion benefit from faster deployment. These considerations indicate that parallel deployment may be valuable where speed and technology diversification are prioritized, but that these benefits come at a higher overall support cost.
- **Scenario P-3: sequential pipelines.** The sequential pipeline scenarios further highlight the interaction between learning and deployment timing. Introducing a gap between initial and subsequent deployments results in some loss of time-sensitive learning, reflected in higher costs for the first units following the pause. However, these effects are partially offset as learning is re-established in later units, resulting in total pipeline cost under Scenario P-3a that remains broadly comparable to Scenario P-1a, while offering significantly more optionality to switch to any other technology that may emerge as a lower cost option. However, the analysis does not quantify the “wait and see” cost of the full 5 GW not coming online as quickly as under Scenarios 1 or 2.

⁴ Note, however, that under the scenario assumptions applied here, Scenario 1a (single pipeline of LLWRs) still achieves deployment of the full 5 GW earlier. This is because the SMR portion of Scenario 2 does not assume parallel deployment of multiple SMRs.

- Scenario P-3b further illustrates the potential value of optionality. Although there is no certainty that any of the current candidate technologies will achieve lower cost than projected under the base case cost assumptions, if a particular technology does achieve such a cost breakthrough, the "wait and see" approach represented by Scenario 3 would allow New York to switch to that technology, and the projections provided here suggest that in that case a significant overall cost reduction could be captured, with Scenario P-3b showing the lowest total public cost of all the scenarios assessed here.
- **Scenario P-4: project-by-project procurement.** Finally, the scenario with less coordinated deployment (project-by-project procurement approach) shows weaker cost reductions. In these cases, learning effects are less consistently realized due to reduced continuity in technology. This assumption could be conservative given that it is possible that some general learnings could be realized across technologies.

D.5 Sensitivities

Sensitivity analysis tests uncertainty factors in the analysis and (potential) developments that may be currently unknown, or wholly or significantly outside the control of State policy.

This analysis is provided firstly for two specific variables: (i) whether federal tax credits may continue beyond their current expiry dates, and (ii) whether nuclear deployment in New York will take place at greenfield or brownfield sites.

Secondly and more generally, for a wide range of key inputs, sensitivity analysis is provided that uses higher or lower input assumptions than those described in Appendix C (Cost Analysis – Inputs and Methodology) for the analysis results provided above. This reflects that there is uncertainty around many of the input assumptions necessary to perform this analysis. This uncertainty will reduce in future as increased experience in advanced nuclear deployment is gained. The uncertainty ranges tested for OCC, fixed O&M, variable O&M, and fuel costs reflect the Zero by 40 Technoeconomic Assessment (0x40 Assessment).⁵ The remaining variables—such as financing assumptions (including equity hurdle rates and debt terms), capacity factor, and other operational parameters—are informed by industry benchmarks, observed variation across

⁵ NYSERDA & EPRI, "Zero by 40 Technoeconomic Assessment". September, 2025. <https://www.nysERDA.ny.gov/-/media/Project/Nyserda/Files/Publications/Energy-Analysis/Zero-x-40-Technoeconomic-Assessment.pdf>

comparable infrastructure projects, and the judgment of the study team regarding plausible outcomes for initial deployments.

All sensitivity analysis is conducted under the same policy settings as the base case scenario.

Continuation of ITC

In the base pipeline scenarios, the ITC is assumed to phase out according to current law, resulting in later units receiving reduced or no tax credit support. Because the ITC is a front-loaded incentive tied to capital investment, its availability has a direct impact on project economics, particularly for early-stage projects with high capital intensity. Historically, similar tax credits for renewable energy technologies have been extended multiple times, often in response to deployment challenges and policy priorities, making continued availability a plausible scenario for analysis.

To isolate the impact of ITC availability over time, the analysis includes sensitivity scenarios in which the ITC is assumed to remain available at full value for all units in the pipeline. The ITC sensitivity is applied to Scenarios P-1a and P-1b.

Table D-16. P-Y1a: LLWRs with ITC Maintained Throughout Pipeline

	Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	12	2039	\$12,756	\$18.7	\$160	\$5.97
LLWR Unit 2	10	2039	\$10,246	\$13.5	\$119	\$3.52
LLWR Unit 3	9	2041	\$10,398	\$13.0	\$114	\$2.88
LLWR Unit 4	8	2042	\$9,038	\$10.8	\$100	\$2.00
LLWR Unit 5	8	2045	\$9,019	\$10.8	\$100	\$1.69
Total for Pipeline				\$66.9		\$16.1

Table D-17. P-Y1b: SMRs with ITC Maintained Throughout Pipeline

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
SMR GW 1	11	2039-2040	\$15,656	\$22.6	\$162 - \$207	\$7.10
SMR GW 2	9	2041-2043	\$11,758	\$15.0	\$119 - \$129	\$3.22
SMR GW 3	9	2046-2048	\$11,831	\$14.5	\$116 - \$119	\$2.24
SMR GW 4	8	2049-2050	\$10,080	\$12.2	\$104	\$1.48
SMR GW 5	8	2053	\$11,186	\$13.5	\$112	\$1.45
Total for Pipeline				\$77.8		\$15.5

From the ITC sensitivity, the following is observed:

- The first 2 GW of the LLWR pipeline are unchanged, as these qualified for the ITC to begin with. The first GW of the SMR pipeline is also unchanged. However, for the GW in which the ITC would phase out, the required Revenue Level and corresponding public cost are materially reduced if the ITC continues. In the LLWR case, total public support declines from approximately \$19.0 billion to \$16.1 billion (about a 15.3% reduction), while in the SMR case it declines from approximately \$19.8 billion to \$15.5 billion (about a 22% reduction).
- The relative impact of maintaining the ITC is more pronounced for SMRs, reflecting the additional portion of the 2nd GW that is assumed to be impacted by the ITC phase out in Scenario P-1b.

Brownfield vs Greenfield

The pipeline sensitivity analysis also evaluates the impact of siting assumptions by testing scenarios in which units are deployed at brownfield sites rather than greenfield locations. In the base pipeline scenarios, all units are assumed to be developed at greenfield sites, reflecting a conservative assumption that does not rely on the availability or suitability of existing infrastructure. To assess the potential benefit of leveraging existing sites, the sensitivity scenarios assume that the units are instead deployed at brownfield locations. Brownfield sites are assumed to benefit from lower initial capital costs and shorter development and construction timelines, reflecting reduced site preparation requirements, existing infrastructure, and potentially streamlined permitting processes. These sensitivities are provided for comparative

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purposes but do not reflect an expectation on the amount of capacity that could actually be deployed at New York brownfield sites.

Table D-18. P-Y1a: LLWRs with Brownfield Sites

	Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
LLWR Unit 1	10	2037	\$11,385	\$15.4	\$132	\$4.71
LLWR Unit 2	8	2037	\$9,145	\$11.3	\$104	\$2.87
LLWR Unit 3	7	2039	\$9,281	\$10.8	\$105	\$2.62
LLWR Unit 4	7	2041	\$8,066	\$9.4	\$114	\$2.86
LLWR Unit 5	6	2043	\$8,049	\$9.0	\$110	\$2.36
Total for Pipeline				\$56.0		\$15.4

Table D-19. P-Y1B: SMRs with Brownfield Sites

	Avg. Time to Complete	COD	Avg. OCC	Price at COD	Revenue Level	PV of Public Support
	<i>Years</i>	<i>Year</i>	<i>2025 \$/kW</i>	<i>2025 \$B</i>	<i>2025 \$/MWh</i>	<i>2025 \$B</i>
SMR GW 1	9	2037-2038	\$14,547	\$19.5	\$141 - \$167	\$5.97
SMR GW 2	8	2039-2042	\$10,925	\$13.4	\$114 - \$143	\$3.55
SMR GW 3	7	2044-2047	\$10,993	\$12.9	\$141	\$3.42
SMR GW 4	7	2048-2049	\$9,366	\$11.0	\$125	\$2.35
SMR GW 5	7	2052	\$10,394	\$12.2	\$135	\$2.27
Total for Pipeline				\$69.1		\$17.6

From the brownfield siting sensitivity, the following is observed:

- Deploying early units at brownfield sites reduces total pipeline cost across both LLWR and SMR pipelines. In the LLWR case, total public support declines from approximately \$19.0 billion to \$15.4 billion (roughly 18-19%), while in the SMR case it declines from approximately \$19.8 billion to \$17.6 billion (roughly 11-12%).
- The primary driver of this reduction is the lower initial capital cost of brownfield deployment. Because the first units in the pipeline have the highest costs and set the baseline for subsequent learning, reducing their cost has a disproportionate impact on overall pipeline economics.
- Brownfield deployment also shortens development and construction timelines for early units, enabling earlier COD and reducing interest on debt and equity returns contribution to the price at COD.

- Overall, the results indicate that leveraging brownfield sites for early deployment can meaningfully reduce total cost and improve timing, but requires site availability and room to add these additional reactors.

Input Sensitivities

The sensitivity analysis tests uncertainty for the inputs shown in Tables D-20 and D-21. As a starting point, sensitivity analysis is provided for a single install, based on a LLWR greenfield single installation, with some factors also tested for a single SMR. For the most impactful sensitivities, additional analysis is provided at the pipeline scenario level.

Table D-20. Difference Between Base Input and Alternate Values for LLWR Greenfield

Variable	Base	Low	High	Highest
Greenfield OCC (\$/W)	\$12.756	\$10.205	\$15.952	
Capacity Factor (%)	93%	90%	95%	
Fixed O&M (\$/W-yr)	\$0.201	\$0.144	\$0.233	
Variable O&M (\$/kWh)	\$0.0033	\$0.0023	\$0.0040	
Fuel Cost (\$/kWh)	\$0.0111	\$0.0095	\$0.0127	
Debt Interest Rate (%)	5%		6%	7%
Minimum Required DSCR	1.1x		1.2x	1.3x
Equity Hurdle Rate	22.5%	20%	25%	

Table D-21. Difference Between Base Input and Alternate Values for SMR Greenfield

Variable	Base	Low	High	HALEU Cost
Greenfield OCC (\$/W)	\$18.655	\$12.125	\$30.780	
Fuel Cost (\$/kWh)	\$0.0111			\$0.0158
Equity Hurdle Rate	25%	22.5%	27.5%	

Note that uncertainty on future commodity (energy and capacity) prices can affect analysis results significantly,⁶ but is not tested here. In the nuclear cost analysis conducted here, and as noted in Appendix C (Cost Analysis – Inputs and Methodology), an ANZEC revenue structure is assumed similar to that seen in for instance the Index REC program. In this structure, total revenue to the project consists of a commodity price component and a (net) ANZEC support payment component. The project would be largely hedged against commodity price fluctuation

⁶ Case 15-E-0302, NYSEDA & DPS Staff, "Petition Regarding Agreements for Procurement of Tier 4 Renewable Energy Certificates," Appendix C, pages 23-24 (submitted November 30, 2021).
<https://documents.dps.ny.gov/public/MatterManagement/CaseMaster.aspx?MatterCaseNo=15-E-0302&CaseSearch=Search>

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– the ANZEC portion of revenue would go up as commodity prices go down and vice versa. As a result, the public cost component would fluctuate inversely with commodity prices, going up where commodity prices go down and vice versa. This effect would apply similarly in a nuclear program as in the CES programs referenced above, and the current nuclear cost analysis therefore does not repeat it. As has been documented in previous such analysis, a critical and welcome effect of this dynamic is that it effectively cushions ratepayers against large swings in energy prices – where commodity prices go up, REC (or in this case ANZEC) costs to ratepayers would go down and vice versa.

Table D-22 below displays the results of the sensitivity analysis on a single install basis, as a percentage deviation of present value public cost compared to the base case single install scenario. For selected inputs, more detailed sensitivity analysis results at the pipeline level is provided further below.

Table D-22. Single Install Sensitivities

	Sensitivity	Difference in Total Public Cost
LLWR		
S-Y1	High OCC LLWR	30%
S-Y2	Low OCC LLWR	-24%
S-Y3	High CF LLWR	-1%
S-Y4	Low CF LLWR	1%
S-Y5	High Fixed O&M LLWR	5%
S-Y6	Low Fixed O&M LLWR	-8%
S-Y7	High Variable O&M LLWR	1%
S-Y8	Low Variable O&M LLWR	-1%
S-Y9	High Fuel Cost LLWR	2%
S-Y10	Low Fuel Cost LLWR	-2%
S-Y11	High Debt Interest LLWR	12%
S-Y12	Highest Debt Interest LLWR	24%
S-Y13	High DSCR LLWR	0%
S-Y14	Highest DSCR LLWR	2%
S-Y15	High Eq. Hurdle Rate LLWR	14%
S-Y16	Low Eq. Hurdle Rate LLWR	-12%
SMR		
S-Y17	High OCC SMR	72%
S-Y18	Low OCC SMR	-39%
S-Y19	HALEU Fuel Cost SMR	3%

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At the levels of uncertainty assessed here, the impacts on analysis results is most significant for OCC, fixed O&M, debt interest and equity hurdle rate. Consequently, these factors are explored below at the pipeline analysis level. In addition, the pipeline sensitivity analysis includes analysis for high/low learning rate settings, which by their nature can only be tested in the form of pipeline analysis. The high and low learning rates are assumed to be +/- 25%, as shown in Table D-23 with percentages rounded to the nearest whole.

Table D-23. Difference between Base Learning Rates and Alternative Rates for Pipeline Sensitivities

Cost Component	Base Learning Rate	Low Learning Rate	High Learning Rate
Equipment	16%	12%	20%
Materials	7%	5%	9%
Labor	5%	4%	6%
Indirect	18%	13%	22%
Owner's Cost	33%	25%	41%

Table D-24 and

Table D-25 present the results of the pipeline sensitivity analysis.

Table D-24. LLWR Pipeline Sensitivities

Uncertainty	Price At COD	PV of Public Support	Difference in Total Public Cost
	<i>2025 \$B</i>	<i>2025 \$B</i>	%
P-1a	\$66.9	\$19.0	
P-Y1 High OCC	\$83.1	\$24.9	31%
P-Y2 Low OCC	\$53.6	\$14.0	-26%
P-Y3 High FOM	\$66.9	\$20.3	7%
P-Y4 Low FOM	\$66.9	\$16.8	-12%
P-Y5 High Debt Interest Rate	\$68.1	\$21.3	12%
P-Y6 Highest Debt Interest Rate	\$69.4	\$23.8	25%
P-Y7 High Hurdle Rate	\$69.5	\$20.7	9%
P-Y8 Low Hurdle Rate	\$64.5	\$17.5	-8%
P-Y9 High Learning Rate	\$62.0	\$17.5	-8%
P-Y10 Low Learning Rate	\$71.4	\$20.2	7%

Table D-25. SMR Pipeline Sensitivities

Uncertainty	Price At COD	PV of Public Support	Difference in Total Public Cost
	2025 \$B	2025 \$B	%
P-1b	\$77.8	\$19.8	
P-Y1 High OCC	\$127.6	\$36.1	82%
P-Y2 Low OCC	\$51.0	\$11.0	-44%
P-Y3 High FOM	\$77.8	\$22.3	13%
P-Y4 Low FOM	\$77.8	\$18.8	-5%
P-Y5 High Debt Interest Rate	\$79.2	\$20.9	6%
P-Y6 Highest Debt Interest Rate	\$80.5	\$23.3	17%
P-Y7 High Hurdle Rate	\$80.7	\$20.6	4%
P-Y8 Low Hurdle Rate	\$75.2	\$17.3	-13%
P-Y9 High Learning Rate	\$69.1	\$17.4	-12%
P-Y10 Low Learning Rate	\$88.0	\$22.5	14%

The above results lead to the following observations regarding uncertainty:

- **OCC is the dominant driver of pipeline cost uncertainty.** In both LLWR and SMR pipelines, higher OCC increases total public cost significantly, while lower OCC produces similarly large reductions. High capital costs drive the need for a large debt facility and equity investments, which increase capitalized interest during construction and equity returns. Changes in OCC have no direct effect on the operating revenue potential of the plant, thus an increase requires further public support in terms of higher ANZEC contract prices and a decrease directly reduces the need for public support. This reflects the central role of capital cost in determining both financing requirements and overall project economics.
- **SMR outcomes are more sensitive to cost uncertainty than LLWR.** The wider range of potential outcomes for SMRs reflects both higher baseline costs and greater uncertainty in technology maturity. As a result, total pipeline cost for SMRs varies more significantly across high and low OCC cases than for LLWRs.
- **Operating costs (FOM) have a moderate but meaningful impact.** Higher fixed O&M costs increase total public cost by reducing available cash flow and limiting debt capacity, while lower operating costs produce corresponding increases in debt capacity. However, the magnitude of this effect is materially smaller than that of OCC.

- **Debt interest rates affect pipeline economics.** Higher debt rates increase total public cost by 12% for LLWR and 6% for SMR, while the “highest” debt rates reduce total public cost by 25% and 17%, respectively. This reflects the importance of low-cost DOE-EDF-backed debt in the financing structure. Higher debt rates increase interest during construction and ongoing debt service, while lower rates improve the operator’s ability to support the project at a lower revenue requirement.
- **Equity hurdle rates have a smaller but still relevant effect.** Higher construction equity hurdle rates increase total public cost by 9% for LLWR and 4% for SMR, while lower hurdle rates reduce total public cost by 8% and 13%, respectively. These results indicate that construction equity costs matter, but their impact is smaller than OCC and debt costs because equity represents a smaller share of the capital stack than debt. The impact of uncertainty shown here reflects the base case scenario approach where all equity is provided by private sector equity investors; in an approach where there would be a State equity share, the impact of private sector hurdle rate uncertainty would be more muted.
- **Learning rate assumptions affect total cost, but less than starting OCC.** Higher learning rates reduce total public cost by 8% for LLWR and 12% for SMR, while lower learning rates increase total public cost by 7% and 14%, respectively. The impact is larger for SMRs because the 5 GW pipeline includes more individual units, creating more opportunities for learning to affect later deployments.