NET ZERO WORLD INITIATIVE

Accelerating Global Energy System Decarbonization

INL/RPT-24-80552

Nuclear Energy Cost Estimates for Net Zero World Initiative – 2024 Update

Levi M. Larsen[1], Nahuel Guaita[1], Iza Lantgios[1], Jia Zhou[2], Abdalla Abou-Jaoude[1], and Nicolas Stauff[2]

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DISCLAIMER

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[1] Idaho National Laboratory
[2] Argonne National Laboratory

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EXECUTIVE SUMMARY

Understanding and managing the costs of constructing new nuclear reactors across the world is a continued challenge for modeling nuclear energy. Effective modeling requires a comprehensive understanding of the costs involved in building, operating, and decommissioning a reactor. In addition to cost considerations, capacity expansion models must also incorporate operational factors like construction time, reactor lifespan, and the expected capacity factor. However, uncertainties persist due to a lack of data for those countries that either have or have not yet developed a nuclear industry. Factors such as varied designs, sizes, supply chain maturity, and limited construction experience among vendors also create additional challenges in predicting country-specific costs. Therefore, this analysis develops a methodology using U.S. overnight capital costs as a reference to estimate cost projections for nuclear energy in different countries, such as Chile, Indonesia, Egypt, Nigeria, Argentina, Thailand, India, Ukraine, and South Africa. Costs are adjusted into country-specific values by disaggregating the primary cost drivers in nuclear projects. This includes labor costs, concrete and steel costs, equipment costs, and costs associated with import tariffs. This disaggregation allows one to better understand the relationship between nuclear costs and the impacts of localization in the countries of interest. The estimates provided can be used for modelers in each country, or modelers can adjust the methodology with different country-specific factors.

The results of this report provide recommended parameters for incorporating nuclear energy systems into decarbonization modeling scenarios. The values are primarily intended for countries in the NZW Initiative but are expected to prove useful to other related efforts. Both costs and operational metrics are provided in the study for large reactors and small modular reactors (SMR); they are summarized in Table ES-1. Several cost factors, namely overnight capital costs (OCC) and operational costs, are taken to be country specific. OCC is defined as the value of building the reactor in one night considering all costs prior to the start of operations including fuel for the initial core load. The value assumes the build is neither a first nor an "nth" of a kind but somewhere in between and used for a short-term deployment following successful demonstration. All costs are presented in 2022 USD (U.S. dollar) terms.

Table ES-1. Summary of nuclear energy cost and operational parameters. Values shown in 2022 USD terms.

Parameter	Optimistic	Base	Conservative
Capital Costs			
OCC [$/kWe]	See Table 10	See Table 10	See Table 10
Fixed Operating Costs			
Large Reactor [$/kWe-yr]	See Table 11	See Table 11	See Table 11
SMR [$/kWe-yr]	See Table 12	See Table 12	See Table 12
Variable Operating Costs			
Large Reactor [$/MWh]	$11.00	$13.00	$14.75
SMR [$/MWh]	$12.25	$13.50	$14.75
Retirement Costs			
Decommissioning costs [$/kWe-year]	$10		
Adjustment Factors			

FOAK premium	1.5		
Learning rate [%]	8%		
Multi-unit factor	See Table 14		
Construction Duration			
Large reactor [years]	5	6.8	10.4
SMR [years]	3.6	4.6	5.9
Operational Parameters			
Capacity factor [%]	95%	90%	80%
Reactor lifetime [years]	100	80	60
Maneuverability	See Table 18		

Taking the United States as a reference, these values were adjusted for the nine additional countries. The new OCC values for NZW countries were found to range between $3,000–$5,250/kWe for large reactors and $2,750–$6,250 for SMRs. Operating and maintenance costs were separated into fixed and variable costs. Fixed operation and maintenance costs were between $4–$42/kWe per year for large reactors and $4–$44/kWe per year for SMRs (the range is driven by labor cost differences). Variable operating costs for capital and fuel were between $11/MWh–$14.75/MWh for large reactors and between $12.25/MWh–$14.75/MWh for SMRs. For reference, baseline U.S. decommissioning costs were determined to be $10/kWe-year irrespective of reactor size; however, these costs were captured within the fixed O&M category and not broken out specifically. Finally, it is important to note that the learning rate is a percent reduction for each new unit built and not for each year. This report also provides recommendations and data for modeling non-grid applications such as district heating and hydrogen cogeneration. Discussion on these topics can be found in Section 5.

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LIST OF ACRONYMS

CPI	Consumer Price Index
DOE	Department of Energy
EEDB	Energy Economic Data Base
ETI	Energy Technology Institute
FOAK	First-of-a-kind
HTGR	High-temperature Gas Cooled Reactor
HTSE	High-temperature Steam Electrolysis
IAEA	International Atomic Energy Agency
ILOSTAT	International Labor Organization Statistics
INL	Idaho National Laboratory
KEPCO	Korea Electric Power Corporation
LFR	Lead-cooled fast reactor
MIT	Massachusetts Institute of Technology
MITEI	MIT Energy Initiative
NEI	Nuclear Energy Institute
NOAK	Nth-of-a kind
NPP	Nuclear Power Plant
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NZW	Net Zero World
OCC	Overnight Capital Cost
O&M	Operation & Maintenance
PRIS	Power Reactor Information System
PWR	Pressurized Water Reactor
ROW	Rest of World
SFR	Sodium-Cooled Fast Reactor
SMR	Small Modular Reactor
UAE	United Arab Emirates
WACC	Weighted Average Cost of Capital

1. INTRODUCTION

The Net Zero World Initiative (NZW) aims to accelerate decarbonization of global energy systems by enabling partner countries to harness the power and technical expertise of the United States and international industry, think tanks, and universities. Participant countries include Chile, Indonesia, Egypt, Nigeria, Argentina, Thailand, and Ukraine. The NZW also has cooperation agreements with India and South Africa. One key technical pillar of the initiative is an energy system-wide (ESW) decarbonization and investment analysis of climate-neutral pathways. These require key technology inputs (for variable renewable, battery storage, nuclear energy, etc.) to be used in the employed ESW models.

Due to the lack of nuclear energy adoption in certain participant states, modeling costs and operational inputs of nuclear reactors can prove difficult to quantify. Additionally, even in regions where nuclear power has been deployed, data is limited, and estimates can be difficult to obtain. Effective modeling requires an understanding of costs associated with building, operating, and decommissioning the reactor. Beyond cost, capacity expansion models also must account for operational parameters such as construction time, reactor lifetime, and expected capacity factor.

ESW modeling performed under NZW may also account for using nuclear energy in non-grid energy applications. This would include using nuclear energy for applications such as district heating and hydrogen production. The inclusion of these two applications warrants the need for additional cost and operation data.

This report aims to provide ranges of ESW inputs across countries for the cost and performance of nuclear energy with a corresponding justification for each variable. Values are provided separately for large reactors and small modular reactors (SMRs) but are presented as reactor technology agnostic estimates. A combination of literature review and data processing is conducted on nuclear construction and operation costs, operational parameters, and non-grid application factors. Country-specific data is provided developing a cost adjustment methodology that considers country-specific differences in larger cost areas such as equipment, labor, and materials. A range is provided of potential outcomes for each variable in the form of optimistic, expected, and conservative values, as summarized in Table ES-1. All cost estimates in this report are provided in 2022 USD (U.S. dollar) terms.

This initiative was started in 2023 with a report issued that provided cost estimates using a different methodology. This report provides the 2024 updates with several major improvements:

- Base costs come from the latest nuclear cost estimates from a recent detailed study [1].
- Costs are broken into two categories with SMRs and large reactors having separate recommended values. For the sake of this report, large reactors are defined as >400 MWe and SMRs as <400 MWe to match the methodology used in Reference [1].
- Several improvements were made to refine localization amounts by further disaggregating costs using the generalized nuclear code of account (GN-COA) method.
- Costs are provided in heat-only terms to enable modelers to accurately project costs associated with non-electric applications.
- More detail is presented on nuclear coupling for heat applications (hydrogen and district heating).

2. METHODOLOGY

2.1. Overnight Cost and Operation and Maintenance Cost Assumptions

Nuclear cost estimation is an inherently challenging task. Even in countries where multiple reactors have been built, cost estimation can be relatively imprecise. This is partly because nuclear costs depend on a myriad of factors from regulatory process, commodity costs, contractor experience, and construction technologies. In the United States, various efforts have attempted to produce cost range targets [2] [3] [4] [5] [6] [7]. One of the more recent efforts consisted of a comprehensive literature survey of bottom-up cost estimates coupled with specific recommendations for large reactor and SMR builds between a first- and nth-of-a-kind (BOAK) [1]. Because grid modelers can safely assume that a first-of-a-kind demonstration has already occurred elsewhere, BOAK values are directly applicable as they would correspond to near-term follow-on units (not the ultimate "nth" cost after dozens of units are built). The recommended BOAK values from Reference [1] will be used as the foundation of this report for overnight nuclear costs. Operational cost estimates also rely on data from the same INL report. Table 1 provides the estimated nuclear cost ranges for OCC and O&M costs for both large reactors and SMRs.

Table 1. Recommended nuclear cost ranges for reactors in the United States. Values in 2022 USD.

Large Reactors	Optimistic	Base	Conservative
BOAK Overnight Capital Costs (USD/kWe)	$5,250	$5,750	$7,750
Total O&M (USD/MWh)	$26.5	$34.6	$39.75
Small Modular Reactors	**Optimistic**	**Base**	**Conservative**
BOAK Overnight Capital Costs (USD/kWe)	$5,500	$8,000	$10,000
Total O&M (USD/MWh)	$26.75	$30.00	$41.25

It is important to note that Reference [1] recommends the cost ranges above irrespective of the reactor technology; these ranges are intended to represent costs of baseload reactors in commercial electricity markets including reactors with hydrogen production capacity. Reactors (especially microreactors) deployed specifically for other applications would need to be considered separately as higher costs are expected, which may still be acceptable for the type of applications where these reactors are needed. In essence, the study did not have enough data to reasonably determine cost ranges for specific reactor types (water, sodium, gas, or salt cooled). As a result of this uncertainty, the recommendation is assumed to be reactor technology agnostic at this time, and estimates are not provided for separate technologies such as high-temperature gas reactors, light-water reactors, sodium-fast reactors, etc.

Additionally, these values consider single nuclear power plant (NPP) unit sites and do not account for multi-unit adjustments where costs may be lower because multiple reactors are sited together and reap OCC and O&M cost synergies. Discussion of NPP siting strategy is typically beyond the scope of ESW models, but if modelers choose to account for multi-unit factors, a methodology for cost adjustment is provided in Section 3.5.1.

Last, as previously highlighted, these overnight costs are for a non-first-of-a-kind (non-FOAK) reactor, referred to in Reference [1] as “BOAK.” They assume a demonstration has already been built somewhere in the globe and corresponds to the expected price for near-term following units. The costs are also distinct from a nth-of-a kind (NOAK) estimate which assumes a long-term plateauing of costs after dozens of units have been built (in that sense, the BOAK costs may still observe cost reductions from the effects of learning). O&M costs are presented in a different manner. For large reactors, values are based on existing data for the U.S. light-water reactor fleet. For SMRs, which have not yet been deployed, values are based off estimates.

The high-level methodology used in the modeling behind this report allows for leveraging U.S. nuclear cost ranges and adjusting them on a country-by-country basis to provide local cost estimates, in USD terms, for each NZW participant. To do so for OCC, costs were divided into four primary cost categories—labor, materials, equipment, and other—and country-specific adjustment factors were defined for each category. Said adjustment factors were applied to their respective categories and aggregated to produce new country-specific OCC ranges. For O&M costs, the same approach was used. Total O&M values were divided into three primary cost categories including fuel, capital, and labor. Again, country-specific adjustment factors were defined and applied to produce new, country-specific O&M ranges. To verify the usefulness of this approach, the method was compared against realized overnight and operational costs in China and the United Arab Emirates (UAE). As noted previously, all monetary units are in 2022 USD terms, for easier comparison, and not converted to country-specific currencies.

The cost adjustment approach used for a given OCC value is represented in more detail in Equation 1 below.

$$OCC_x = OCC_{US}(\gamma LF_x + \alpha MF_x + \sigma EF_x + \theta OF_x)$$

Equation 1. OCC adjustment equation.

Where,

- X represents a given country
- OCC represents total nuclear overnight costs, represented in USD/kWe
- γ represents the percentage of labor costs of total OCC
- α represents the percentage of material costs of total OCC
- σ represents the percentage of equipment costs of total OCC
- θ represents the percentage of other costs of total OCC
- $\gamma + \alpha + \sigma + \theta = 1$
- LF represents the labor adjustment factor for a given country
- MF represents the material adjustment factor for a given country
- EF represents the equipment adjustment factor for a given country
- OF represents the “other” adjustment factor for a given country.

A similar method was used to adjust O&M costs and is shown in Equation 2 below.

$$O\&M_x = O\&M_{US}(\gamma LF_x + \lambda CF_x + \phi FF_x)$$

Equation 2. Operational cost adjustment equation.

Where,

- X represents a given country
- O&M represents nuclear operational costs, represented in USD/MWh
- γ represents the percentage of labor costs of total O&M
- λ represents the percentage of capital costs of total O&M
- ϕ represents the percentage of fuel cost of total O&M
- $\gamma + \lambda + \phi = 1$
- LF represents the labor adjustment factor for a given country
- CF represents the capital adjustment factor for a given country
- FF represents the fuel adjustment factor for a given country.

For both OCC and O&M costs, this process was repeated for optimistic, base, and conservative costs to produce an expected range for each country. A detailed description of how each adjustment factor was built for a given country can be found in Section 2.2.3.

2.2. OCC Cost Adjustment

To properly adjust OCC costs, high-level values had to be separated into individual cost accounts following a GN-COA structure from Reference [8]. This account structure breaks total OCC into broad categories such as preconstruction costs, direct costs, indirect costs, and supplementary costs. These accounts are also separated into subaccounts, which have varying levels of granularity. For this application, broad categories and their immediate subcategories were used as they were considered granular enough to provide the level of specificity. Costs within each account could then be separated into equipment, material, labor, and other categories. This enables one to determine the account-level amount of localization and percent of total OCC that could be applied to a given account.

OCC was broken down between equipment, material, and labor as shown in Figure 1 (top). O&M costs were broken between fuel and variable costs (both assumed 100% imported) and fixed costs (assumed 100% local), as shown in Figure 1 (bottom). This analysis does not make a specific inference of where foreign investments are sourced but essentially assumes the imported inputs of the investment would be equivalent to those sourced for U.S.-based estimates. For simplicity, foreign-based estimates could be viewed as being sourced from similar countries as the United States does. The local portion of the investment intends to show the cost savings (relative to the United States) that could happen if inputs are produced locally.

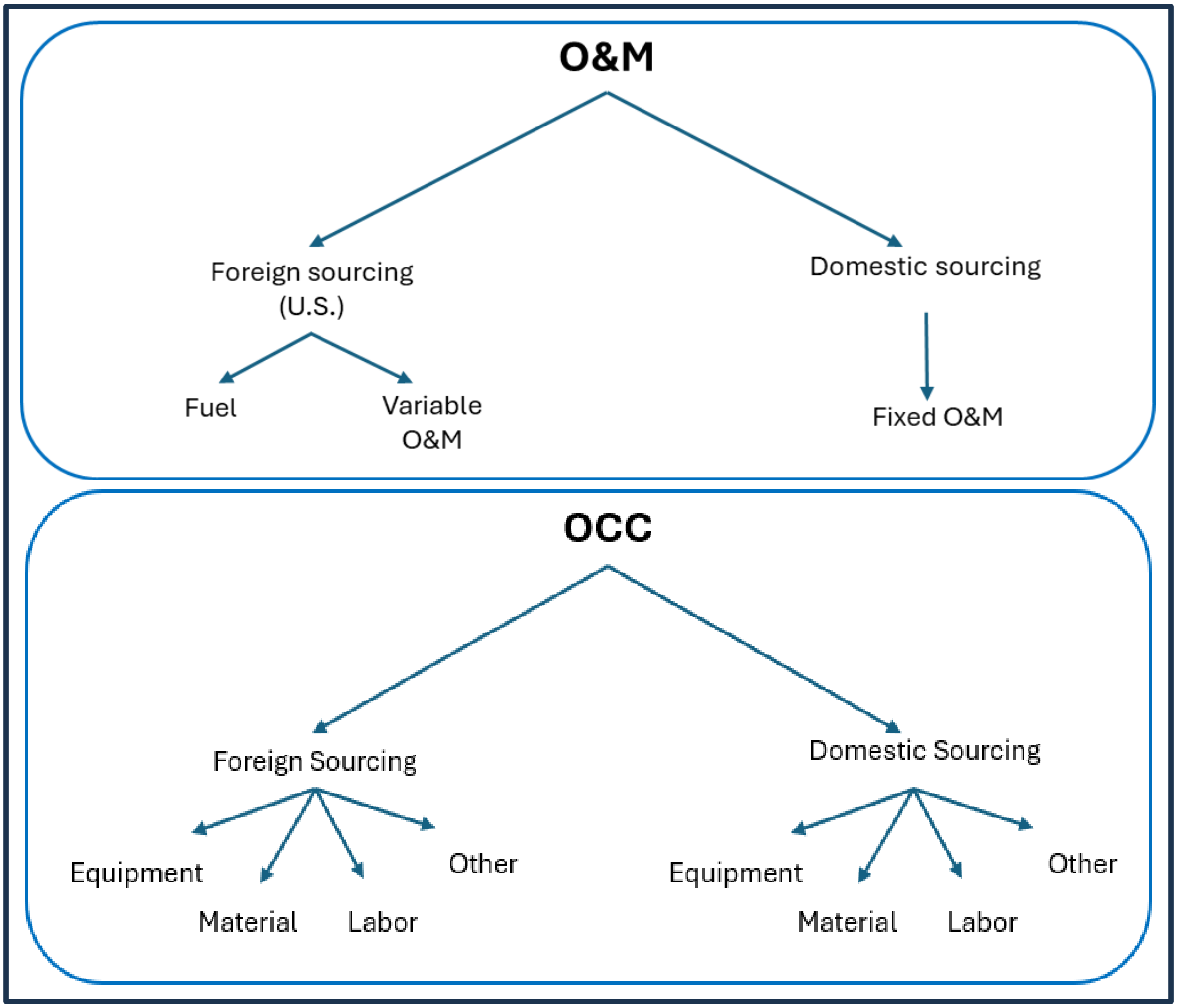


Figure 1. OCC (top) and O&M (bottom) cost breakout by foreign versus domestic sourcing.

2.2.1. Determining Localization Levels

In the case of localization, it was assumed the levels of foreign sourcing verses domestic sourcing were identical across all NZW countries. In practice, this simplification is expected to vary from country to country, but a generalized approach was deemed adequate for approximate estimates. Future w ld further explore individual countries capabilities to source category. Localization levels were determined based on the authors’ expert opinion and judgment of non-nuclear countries to be able to source a given category locally. Table 2 shows the breakdown that was used across for all NZW countries. Within the table, localization was categorized as none (0% localization), low (25% localization), medium (50% localization), high (75% localization), and full (100% localization). For example, account 21 (“Structures and Improvements”) has a medium level of localization for equipment, a full level for materials, and a full level for labor. Note that the estimates in Table 2 for labor and material are, on aggregate, predominantly locally sourced, while equipment has low levels of local providers. These characterizations, which are obtained from expert judgments, could be adjusted based on country- and vendor-specific expectations.

Table 2. Localization amount for net-zero world countries by cost category.

Account	Account Title	Equipment	Materials	Labor	Other
10	**Capitalized Preconstruction Costs**				
11	Land and Land Rights				Full
12	Site Permits				Full
13	Plant Licensing			Full	
14	Plant Permits				Full
15	Plant Studies			Medium	
16	Plant Reports			Medium	
17	Community Outreach and Education			Full	
18	Other Preconstruction Costs				Medium
19	Contingency on Preconstruction Costs				Medium
20	**Capitalized Direct Costs**				
21	Structures and Improvements	Low	Full	Full	
22	Reactor System	Low	Full	High	
23	Energy Conversion System	Low	Full	High	
24	Electrical Equipment	Low	Full	High	
25	Initial Fuel Inventory	None	Full	Medium	
26	Miscellaneous Equipment	Medium	Full	Full	
27	Material Requiring Special Consideration	None	Full	Medium	
28	Simulator	None	Full	Medium	
29	Contingency on Direct Costs	Full	Full	Full	
30	**Capitalized Indirect Services Cost**				
31	Factory & Field Indirect Costs	Low	Full	High	
32	Factory & Construction Supervision	Low	Full	Low	
33	Startup Costs	Low	Full	Medium	
34	Shipping and Transportation Costs	High	High	High	
35	Engineering Services	Low	Full	Low	
36	PM/CM Services	Low	Full	Medium	
37	Regulatory Inspection Support	Low	Full	Medium	
38	Spare Parts	Low	Full	Medium	
39	Contingency on Indirect Services Cost	Full	Full	Full	
50	**Capitalized Supplementary Costs**				
51	Taxes	Full	Full	Full	
52	Insurance	None	None	None	
53	Spent Fuel Storage		*Excluded*		
54	Decommissioning	Low	Full	High	
55	Other Owners' Costs				Full

Account	Account Title	Equipment	Materials	Labor	Other
56	Fees				Full
57	Management Reserve				Full
59	Supplementary Contingencies				Full

2.2.2. Cost Categorization

To separate OCC into individual accounts according to the GN-COA approach, account-level cost contributions for SMRs and large reactors were taken from Reference [1] and applied to optimist, base, and conservative estimates. Next, for each account, the percentage of equipment, labor, material, and other costs were identified using historical data from actual builds and bottom-up estimates. Much of these estimates are the same used in Reference [1] as well as data produced from Reference [9].

Breakouts for direct costs are shown in Table 3 for all subaccounts. Different values are reported for large and SMRs, due to inherent differences in design, size, and deployment strategy. Large reactors typically involve more extensive infrastructure and labor requirements, while SMRs are designed for modular construction and potentially reduced on-site labor costs. These fundamental differences in construction and operation lead to variations in cost breakdowns across categories. The SMR datasets contained no data for account 27. It was therefore assumed to be 100% equipment as is observed in large reactor datasets. Account 28, which is still likely accounted for within the high-level OCC values, could not be extrapolated from the data and is therefore ignored from a cost breakout perspective.

Table 3. Percentage breakout for large reactor direct costs.

		Equipment		Labor		Material	
Account Number	Account Description	Large Reactors	SMR	Large Reactors	SMR	Large Reactors	SMR
21	Structures and Improvements	10%	18%	61%	20%	29%	62%
22	Reactor System	77%	85%	18%	1%	5%	14%
23	Energy Conversion System	71%	81%	24%	1%	5%	18%
24	Electrical Equipment	47%	20%	37%	18%	17%	61%
25	Initial Fuel Inventory	100%	100%	0%	0%	0%	0%
26	Miscellaneous Equipment	38%	32%	51%	9%	11%	60%
27	Material Requiring Special Consideration	100%	100%[1]	0%	0%	0%	0%
28	Simulator	NA	NA	NA	NA	NA	NA

		Equipment		Labor		Material	
Account Number	**Account Description**	**Large Reactors**	**SMR**	**Large Reactors**	**SMR**	**Large Reactors**	**SMR**
29	Contingency on Direct Costs[2]	63%	62%	27%	7%	10%	31%

[1] *The data survey to determine cost breakouts did not include material requiring special consideration so SMRs were assumed to match large reactor cost breaks for account 27.*

[2] *Contingency cost category breakout was calculated by taking the total weighted average across each category (i.e., 63% of all large reactor direct costs are equipment, and therefore, 63% of the contingency is attributed to equipment)*

To break out indirect costs, a different approach was necessary due to the limited availability of detailed account-level data. While previous studies for computing indirect costs based on direct costs were considered, this analysis utilized a combination of established guidelines and cost-estimating algorithms derived from engineering-economic literature to ensure comprehensive coverage of cost categories. Data was primarily drawn from three key references [10] [11] [12]. These sources provided a comprehensive set of data for both large reactors and SMRs. The PWR12 BE example from the Energy Economic Data Base (EEDB) was used consistently across both large reactors and SMRs to ensure comparability. The data was aggregated by calculating averages across various cost components, providing representative indirect cost allocations for both reactor types.

Indirect costs mainly encompass project support labor, which can be challenging to estimate early in a research, development, and demonstration program. To address this challenge, established guidelines were employed to calculate these costs as a fraction of direct costs, utilizing cost-estimating algorithms sourced from engineering-economic literature [13].

An algorithm originally developed for Generation III+ nuclear plants was used to calculate field indirect costs. This algorithm considers factors such as plant rating, labor costs, and construction duration. The algorithm was adapted to estimate both nuclear island (NI) and balance-of-plant (BOP) field indirect costs. For instance, the formula used to estimate NI and BOP field indirect costs is as follows in Equation 3 and Equation 4:

$$NI = 6.85 \times 10^6 \left(\frac{P}{1{,}200}\right)^{0.33} + 0.48LN + 4.30 * \times \left(\frac{P}{1200}\right)^{0.5} M$$

Equation 3. NI Field Indirect Cost.

$$BOP = 6.85 \times 10^6 \left(\frac{P}{1{,}200}\right)^{0.66} + 0.34LN + 4.30 \times 10^5 \left(\frac{P}{1{,}200}\right) M$$

Equation 4. BOP Field Indirect Cost.

Where,

- P = Plant rating (MWe)
- LN = Labor cost for the NI

- *M* = Construction duration (months)
- *LF*= Labor cost for the BOP scope.

Similar algorithms were applied for other indirect cost categories, such as construction supervision, design services, and project management/construction management (PM/CM) services.

One key challenge in this analysis was mapping the capitalized indirect service costs between the EEDB COA and the GN-COA. The EEDB COA organizes these costs based on the location of offices—home office (EEDB code 92) or field office (EEDB code 93)—and further breaks them down by service type, such as quality assurance and supervision. On the other hand, the GN-COA categorizes these costs by the type of service provided with GN-COA codes 35 and 36 documenting engineering and management services, respectively [8]. To ensure accurate representation, EEDB accounts were mapped to multiple GN-COA accounts. In the absence of specific data for certain categories, assumptions were made to allocate costs accurately. Categories 34 ("Shipping and Transportation Costs"), 37 ("Startup Costs"), 38 ("Engineering Services"), and 39 ("PM/CM Services") were assigned 100% to either factory, labor, or material costs based on the nature of the services they encompass. This assumption was necessary to maintain the consistency and accuracy of the cost allocation across different reactor types.

The final cost distribution for these categories reflects this approach, ensuring that indirect costs are appropriately represented in the overall cost structure for both large reactors and SMRs. Table 4 provides the final values leveraged in this work.

Table 4. Percentage breakout for indirect costs by category for both SMRs and large reactors.

Account Number	Account Description	Equipment	Labor	Material
31	Factory & Field Indirect Costs	0%	59%	41%
32	Factory & Construction Supervision	91%	9%	0%
33	Startup Costs	100%	0%	0%
34	Shipping and Transportation Costs	100%	0%	0%
35	Engineering Services	100%	0%	0%
36	PM/CM Services	73%	27%	0%
37	Regulatory Inspection Support	0%	100%	0%
38	Spare Parts	0%	0%	100%
39	Contingency on Indirect Services Cost*	58%	24%	18%

Account Number	Account Description	Equipment	Labor	Material
** Contingency cost category breakout was calculated by taking the total weighted average across each category (i.e., 58% of all indirect costs are equipment, and therefore, 58% of the contingency is attributed to equipment).*				

Due to lack of data, additional assumptions were made for preconstruction costs (account 10 and its subaccounts) and supplementary costs (account 50 and its subaccounts). Given these two broad accounts represented on average ~10% of the OCC, these assumptions have a lesser impact on the outcomes. Accounts were categorized as either being labor driven or "other" cost driven, and in instances where no data was reported, some were ignored similarly to account 28 in Table 3. For a complete breakout of preconstruction and supplementary costs, see Appendix D – Preconstruction and Supplementary Cost Categorization.

2.2.3. Country-Specific Cost Adjustment Factors By Category

Once costs had been separated into their respective categories (i.e., equipment, material, labor, and other) and localization levels were determined, country-specific indexes were used to produce adjustment factors to convert the portion of localized costs into country-specific terms. The indexes selected for each category were as follows:

- **Equipment adjustment index:** Price level of gross fixed capital formation from the World Bank [14].
- **Material adjustment index:** A weighted average of concrete and steel indexes used. The concrete and steel index were calculated using export price data from the IndexBox Platform [15].
- **Labor adjustment index:** Different indexes were used for OCC and O&M to account for differences in construction verses operations labor.
    - **OCC labor index**: The high-skilled labor index created with ILOSTAT data for high-skilled workers' wage [16] was used.
    - **O&M labor index**: The average monthly earnings of employees by economic activity in the manufacturing, construction and energy sectors was used from Reference [17].
- Other: Price-level ratio of PPP conversion factors to market exchange rates [47].

Table 5 highlights the calculated adjustment factors used to adjust country-specific costs. Further details are provided in the following sections around the sources and methodology for each category. Note that in the Table 5, a factor of 0.03 for Labor O&M for Nigeria means that the cost of domestic labor in that country is only 3% of the cost from the United States. The same interpretation can be given to the other factors across all the categories.

Table 5. Adjustment factor for each component by country.

Country	Equipment	Material Combined	Labor OCC	Labor O&M	Other
United States	1.00	1.00	1.00	1.00	1.00

Chile	0.65	0.55	0.19	0.19	0.51
Indonesia	0.35	0.39	0.04	0.03	0.33
Egypt	0.43	0.58	0.03	0.04	0.28
Nigeria	0.55	0.52	0.10	0.03	0.37
Argentina	0.55	0.44	0.15	0.11	0.51
Thailand	0.40	0.42	0.11	0.10	0.33
India	0.34	0.46	0.04	0.04	0.29
Ukraine	0.31	0.40	0.08	0.10	0.36
South Africa	0.48	0.50	0.20	0.16	0.43

2.2.4. Equipment Adjustment Factor

Four price-level indexes were taken from the World Bank. The International Comparison Program (ICP) 2021 cycle provides data for 176 economies and their regions, covering 45 expenditure headings with indicators such as purchasing power parities (PPPs), national account expenditures in both PPP and nominal terms, and price-level indices. The dataset includes revised data for 2017, imputed results for economies that did not participate, and annual PPPs from 2017 to 2021. The ICP 2021 methodology maintains consistency with the 2017 cycle but introduces changes, such as linking the Commonwealth of Independent States region through a global core list and adopting the standard approach for estimating housing PPPs in the Asia and Pacific region. The results, based on data provided by participating economies and produced in accordance with ICP methodology, are not considered official national statistics and should be treated as approximations subject to potential errors [14].

The aggregated index selected from the four, the gross fixed capital formation (GFCF) index, covers expenditures for fabricated metal products, except machinery and equipment; electrical and optical equipment; general purpose machinery; special purpose machinery; road transport equipment; other transport equipment; residential buildings; non-residential buildings; civil engineering works; and other products. For a disaggregation of this index, see Appendix C – Gross Fixed Capital Formation Components Description.

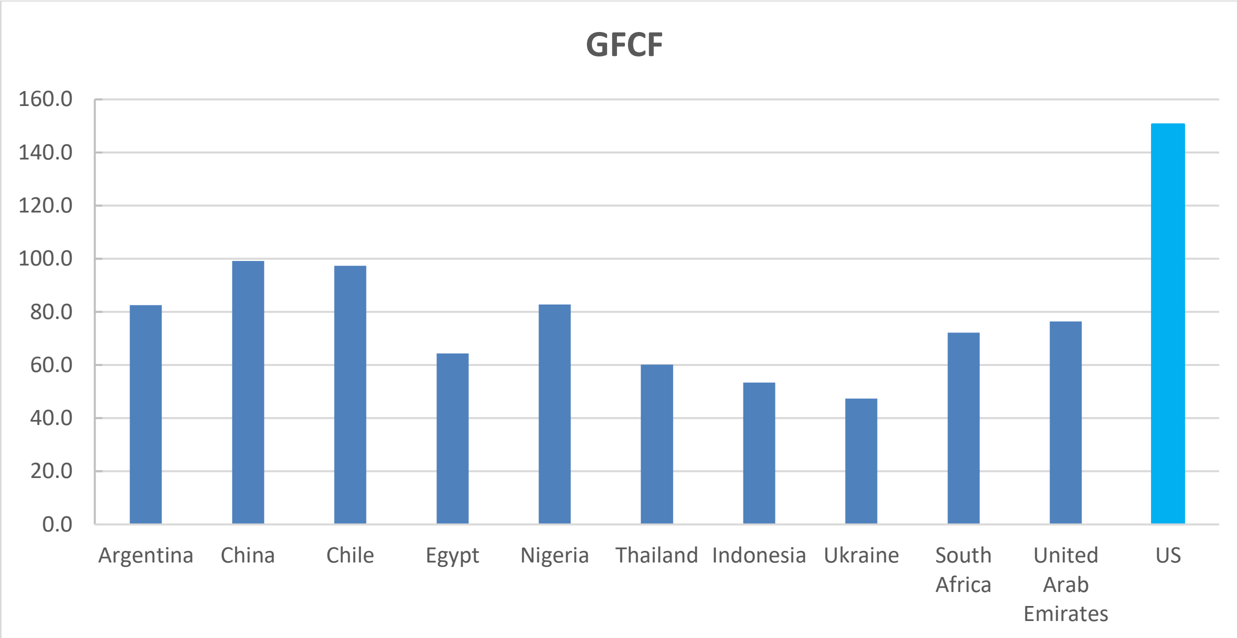


Figure 2. Price-level GFCF by country.

2.2.5. Material Adjustment Factor

It was assumed that the material cost category of overnight costs was divided into two subcategories: steel and concrete. Following Massachusetts Institute of Technology's (MIT's) observations, it was also assumed that concrete costs correspond to 24% of total material costs and steel to 76% [7]. Concrete and steel export prices were used to create adjustment factors using data from IndexBox, which has comprehensive market data categorized by region and country. Commodities are classified using the Harmonized System (HS), a global commodity classification developed by the World Customs Organization, which ensures data compatibility across over 179 countries. The export price ($Export_{price}$) is calculated as the average unit value of exported goods on a free-on-board (FOB) basis using the formula shown in Equation 5:

$$ExportPrice = \frac{Export_{value}}{Export_{quantity}}$$

Equation 5. Export price calculation.

Where,

- $Export_{value}$ represents the export value based on FOB pricing, which includes costs up to the port of departure
- $Export_{quantity}$ is the quantity of products exported in physical terms.

Note that IndexBox reported commodity costs for all countries in 2021 USD terms which were then escalated to 2022 values [18].

2.2.6. Labor Adjustment Factor

To create labor cost adjustments, the average hourly earnings of employees by occupation was sourced from the International Labour Organization Statistics (ILOSTAT)—specifically, high-skilled labor for OCC and manufacturing, construction, and energy labor for O&M. The monthly earnings relate to the gross remuneration in cash and in kind paid to employees, at regular intervals, for time worked or work done together with remuneration for time not worked, such as annual vacation, other type of paid leave, or holidays. Earnings exclude employers' contributions in respect of their employees paid to social security, pension schemes, the benefits received by employees under these schemes, severance, and termination pay [17].

According to the methodology described by ILOSTAT, the time series are harmonized. The data reported as weekly, monthly, and yearly was converted to hourly using data on average weekly hours when available. The data was converted to USD as the common currency, using exchange rates or using PPP rates for private consumption expenditures. This methodology allows for international comparisons by taking account of the differences in relative prices between countries. Data disaggregated by occupation according to the latest version of the International Standard Industrial Classification of all economic activities available for that year [17].

As MIT points out in Reference [7], this approach is relatively limited. Ideally, all construction tasks would be broken down within their respective labor categories, and multipliers would be sought for each specific bracket. However, due to the unavailability of data (both in the breakdown of labor tasks for nuclear construction and country-specific ratios), this was considered outside of the current scope. However, the approach outlined above was still deemed to be representative of potential cost variations across countries. This is because an energy construction-specific ratio of average labor rates is expected to be relatively representative for nuclear energy and incorporate, to some extent, the impact of productivity. This is discussed further in Appendix B – Labor Productivity Differences.

2.2.7. "Other" Adjustment Factor

Other costs, which did not clearly fit into the labor, material, and equipment categories, had to be adjusted using a broader approach. For example, other costs include land and land rights (account 11 with the GN-COA), plant permits (account 15), and fees (account 56) which are distinctly different from constructing buildings and manufacturing reactor parts. The approach used to adjust these costs considered the broader price differences between the considered countries and the United States.

Comparing prices across countries requires converting local currencies into a common unit of measure. One approach is to convert national gross domestic product (GDP) figures into a common currency, such as USD, using market exchange rates. However, these rates may not accurately reflect differences in price levels between countries. To address this, PPP can be used. PPP involves creating a hypothetical currency called "international dollars," which is designed to have the same purchasing power across different countries. The exchange rates used to convert local currencies into international dollars are known as PPP conversion rates.

Purchasing power refers to the amount of goods and services that can be bought with a specific amount of money in a particular country. This concept is crucial for making cross-country comparisons. For example, the same amount of money can buy more in a country with lower price levels than in one with higher prices. PPP conversion rates capture these differences in purchasing power [17]. The PPP conversion factors for each country are presented in Table 6.

Table 6. Price-level ratio of PPP conversion factors to market exchange rates [47].

Country	GDP price levels relative to the 2022 USD
Argentina	0.51
China	0.59
Chile	0.51
Egypt, Arab Rep.	0.28
Indonesia	0.33
Thailand	0.33
United Arab Emirates	0.61
Ukraine	0.36
United States	1.00

The price-level ratio of PPP conversion factors to market exchange rates indicates the difference in price levels compared to the United States. A value below 1 suggests that a certain number of USD can buy more goods and services than it would in the United States.

PPP-adjusted international dollars are often more useful than market exchange rates for cross-country comparisons. Market exchange rates reflect how much one currency can be exchanged for another, but it fails to account for differences in price levels. PPP conversion rates, on the other hand, consider the relative prices of goods and services, making them more reliable for comparing economic well-being across countries [18]. For instance, prices tend to be higher in wealthier countries due to differences in productivity, higher productivity in tradable goods, leading to higher wages and, consequently, higher prices for non-tradable goods like services [19].

It is important to note that despite its advantages, PPP has limitations. The data used to calculate PPP conversion rates, especially in low-income countries, can be incomplete or imprecise. Additionally, differences in consumption patterns across countries make it difficult to identify a standard “basket of goods” for comparison. These challenges can affect the accuracy of PPP-adjusted figures and the policies based on them [20].

2.2.8. Impacts Of Import Tariffs On Equipment Costs

For the imported portion of equipment costs, it is expected that countries with tariffs will maintain them, and the costs of imported nuclear equipment will need to be adjusted by said amounts. The applied tariff corresponds to the custom duty that must be paid by purchasers when importing goods from the United States.

The tariff levels were sourced from the United Nations Trade and Development (UNCTAD) and the World Trade Organization. They specifically measure tariff levels on “nuclear reactors; non-irradiated fuel elements (cartridges) for nuclear reactors; machines and apparatus for isotopic separation: Parts of nuclear reactors" with the assumption that equipment is imported from the United States (WTO) [21]. Table 7 highlights the values on a per-country basis.

Table 7. Import tariff rates from countries importing pieces from the United States.

Country	Import Tariff Rate
United States	Country of origin of imports
Chile	6%
Indonesia	5%
Egypt	2%
Nigeria	5%
Argentina	14%
Thailand	0%
India	7.50%
Ukraine	0%
South Africa	0%

2.3. O&M Cost Adjustment

Similar to what was done with OCC, high-level O&M had to be broken up into categories and levels of localization needed to be determined. O&M was categorized, following what was done in Reference [1], into three major categories. This included fuel, fixed, and variable non-fuel categories. Table 8 shows the reported cost ranges broken out into categories and reported for both large reactors and SMRs.

Table 8. GAIN report large LWR U.S. fixed (operations and non-fuel), variable (non-fuel), and nuclear fuel cost breakout.

Large Reactors	Optimistic	Base	Conservative
Fuel ($/MWh)	$9.1	$10.3	$11.3
Fixed O&M ($/MWh) @ 93% capacity factor[a]	$15.5	$21.5	$25.1
Variable non-fuel O&M ($/MWh)	$1.9	$2.8	$3.4
Total O&M ($/MWh)	**$26**	**$35**	**$40**
Small Modular Reactors	**Optimistic**	**Base**	**Conservative**
Nuclear fuel costs ($/MWh)	$10.0	$11.0	$12.1
Fixed O&M ($/MWh) @ 93% capacity factor[b]	$14.5	$16.6	$26.5
Variable non-fuel O&M ($/MWh)	$2.2	$2.6	$2.8
Total O&M ($/MWh)	**$27**	**$30**	**$41**

It was assumed that fuel and variable non-fuel costs would be sourced entirely outside of the country and, in this case, would match U.S. costs for these categories. Fixed costs, which are primarily labor driven, were assumed to be fully localized and sourced domestically. Subsequently, the driving factor for O&M cost differences from country to country stems from differences in labor costs.

Table 9 shows the specific adjustment factors used for each country when adjusting O&M costs. Recall that costs sourced from the United States are not adjusted and therefore take on an adjustment factor of 1 in this case. Note that the lowest labor costs correspond to Nigeria, Indonesia, and India, while the highest costs (excluding the United States) are in Chile, Argentina, and South Africa.

Table 9. O&M cost adjustment factors by category, normalized to United States costs.

Country	Fixed	Fuel	Variable Non-fuel
United States	1.00	1.00	1.00
Chile	0.19	1.00	1.00
Indonesia	0.03	1.00	1.00
Egypt	0.04	1.00	1.00

[a] Fixed O&M for large reactors was converted to a $/MWh value using a 93% capacity factor in this instance to allow it to be summed up with variable and fuel O&M. Prior to this adjustment, the fixed O&M values were $126/kWe-yr (optimistic), $175/kWe-yr (base), and $203/kWe-yr (conservative), respectively.

[b] Fixed O&M for SMRs was converted to a $/MWh value using a 93% capacity factor in this instance to allow it to be summed up with variable and fuel O&M. Prior to this adjustment, the fixed O&M values were $118/kWe-yr (optimistic), $136/kWe-yr (base), and $216/kWe-yr (conservative), respectively.

Country	Fixed	Fuel	Variable Non-fuel
Nigeria	0.03	1.00	1.00
Argentina	0.11	1.00	1.00
Thailand	0.10	1.00	1.00
India	0.04	1.00	1.00
Ukraine	0.10	1.00	1.00
South Africa	0.16	1.00	1.00

2.4. Cost Escalation Methodology

To compare projected costs against realized costs in other countries from previous years, an escalation method was developed to bring all costs in 2022 USD terms. The method adjusted costs by a country-specific GDP implicit price deflator (IPD) plus an additional amount. The additional amount, which varied by case, was defined by measuring the gap between the U.S. GDP-IPD and the weighted nuclear construction cost index from Reference [1] in the year the foreign build took place.

This gap represents the relative difference between nuclear cost levels to general cost levels (represented using GDP) across the United States. Assuming this gap is constant over time means that one expects nuclear costs to increase at the same rate as general costs, but the associated premium between the two will remain constant. Additionally, it assumes that a similar gap size between U.S. nuclear cost levels and general cost levels would be present for other countries. In practice, this is expected to vary with differences in regulation and the evolution of specific industries with a country, among other factors. However, a lack of data on nuclear costs in foreign countries warrants making such a simplification. Equation 6 below shows how this is applied.

$$Escalation_x^t = GDP\_IPD_x^{2022} + (NCI^t - GDP\_IPD_{us}^t)$$

Equation 6. Escalation equation for cost adjustment to 2022 USD values.

Where,

- Escalation represents the escalation factor used to adjust prices from a given year to 2022 USD values
- X represents a given country
- t represents the base year from which the costs need to be adjusted to 2022 values
- GDP_IPD represents the GDP implicit price deflator
- NCI represents the nuclear construction cost index developed in Reference [1] (note this is an index exclusive to the United States and leverages a weighted average approach to combining multiple nuclear-related indexes).

2.5. Non-Cost Parameterization Methodology

Beyond costs, this report also provides guidance on other expected operational parameters. These additional parameters include construction time, reactor lifetime, capacity factor, load-following capability, and retirement costs. For each of the construction and operational parameter recommendations, a combination of U.S.-centric data and global data was leveraged. Where enough data was available, it was evaluated to show trends in distribution. First, second, and third quartiles were highlighted as the basis for the expected range of values for a given parameter. It should be noted that while this method is an effective means of producing statistically sound ranges, in some instances, observed commercial values may be more tightly grouped than is reported by the proposed quartile method. For select categories, expected performance ranges are discussed, and recommendations are made based on existing research and operational experience.

Given the NZW focuses on leveraging nuclear energy for more than just electricity production, two non-electrical applications are outlined in this research. Recommendations for modeling values were provided. The two applications discussed are nuclear-powered hydrogen production and district heating. In both instances, performance of said systems is discussed including input requirements. In the case of nuclear-powered hydrogen production, a range of costs is presented from existing research.

3. NUCLEAR COSTS ESTIMATED COSTS BY COUNTRY

3.1.1. Country-Specific Nuclear Overnight Capital Costs

The results of the overnight cost adjustments are shown in

Figure 3. It shows that generally all NZW countries will likely incur similar nuclear costs with some variation. Countries such as Indonesia, Thailand and Ukraine which have the lowest relative equipment, material and labor costs show the lowest relative costs. The conservative costs for most countries appear to be close to or below the optimistic level for the United States. This highlights the impact of localization and lower rates of labor on nuclear construction costs.

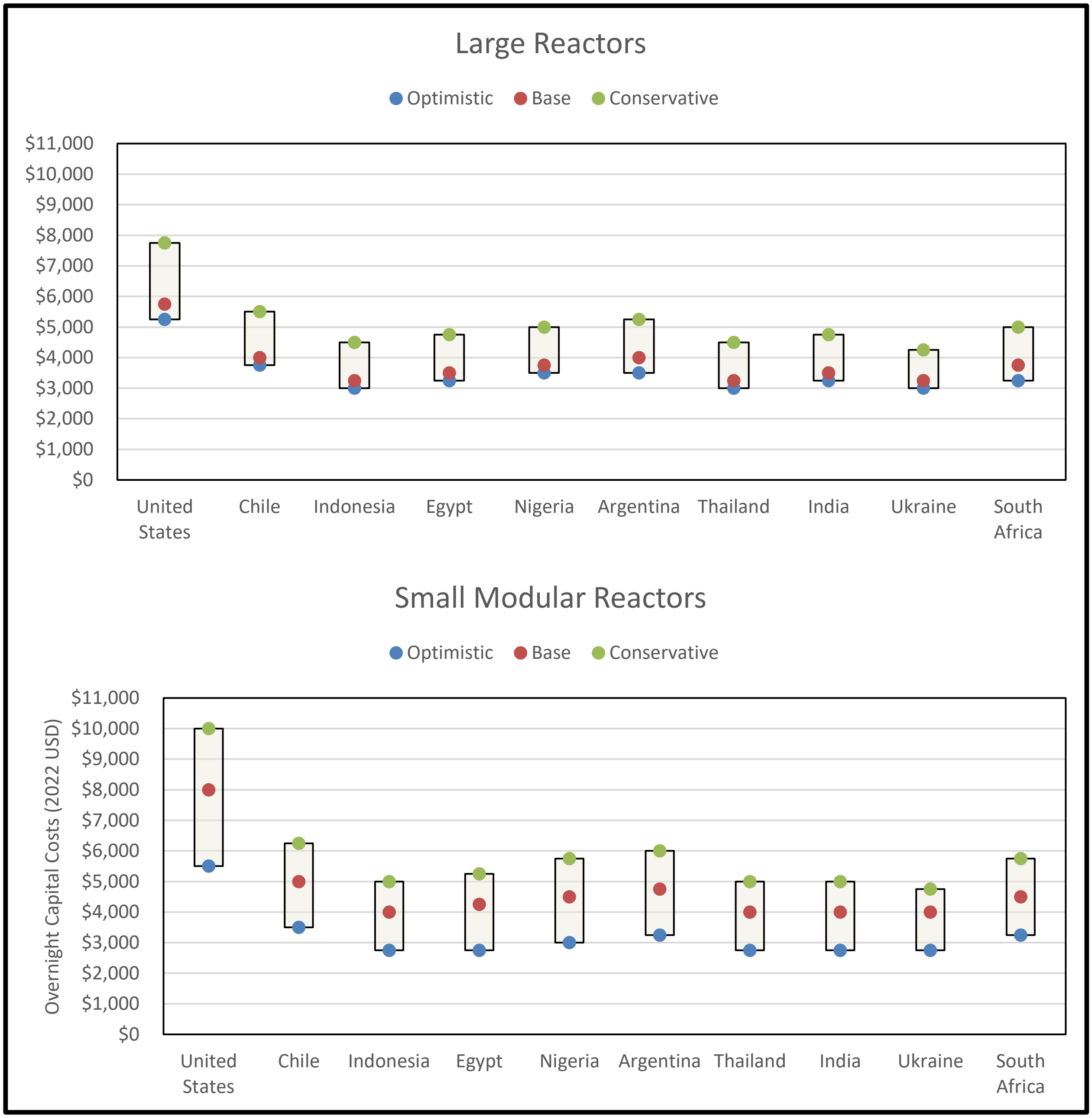


Figure 3. Country-specific nuclear overnight capital cost ranges for large reactors (top) and small modular reactors (bottom), shown as 2022 USD values.

Figure 3 values are shown in Table 10. In both, all-nuclear OCC outputs from the model were rounded to the nearest multiple of 250. These estimates are recommended to be used in the modeling activities for NZW.

Table 10. Country-specific nuclear overnight cost ranges for large reactors, shown as 2022 USD values.

	Large Reactors			SMR		
Country	Optimistic	Base	Conservative	Optimistic	Base	Conservative
United States	$5,250	$5,750	$7,750	$5,500	$8,000	$10,000
Chile	$3,750	$4,000	$5,500	$3,500	$5,000	$6,250
Indonesia	$3,000	$3,250	$4,500	$2,750	$4,000	$5,000
Egypt	$3,250	$3,500	$4,750	$2,750	$4,250	$5,250
Nigeria	$3,500	$3,750	$5,000	$3,000	$4,500	$5,750
Argentina	$3,500	$4,000	$5,250	$3,250	$4,750	$6,000
Thailand	$3,000	$3,250	$4,500	$2,750	$4,000	$5,000
India	$3,250	$3,500	$4,750	$2,750	$4,000	$5,000
Ukraine	$3,000	$3,250	$4,250	$2,750	$4,000	$4,750
South Africa	$3,250	$3,750	$5,000	$3,250	$4,500	$5,750

3.1.2. Comparison Against Observed Costs

The methodology was followed and applied to the case of China and the UAE, where observed costs from imported NPPs exist. In China, these two builds were the Sanmen and Taishan reactors. The Sanmen 1 and 2 builds were AP1000 pressurized-water reactors (PWRs) developed by Westinghouse Electric Company that came online one after the other during 2018. Combined, the two Sanmen reactors have a nameplate capacity of 2,314 MWe. The Taishan 1 and 2 builds were European pressurized reactors developed by Areva, now Framatome, (France) that came online in 2018 and 2019. Combined, the two Taishan reactors have a nameplate capacity of 3,320 MWe. In the UAE, the build used for comparison was the Barakah reactor. The plant consists of four units with a nameplate capacity of 5,380 MWe. The Barakah builds are APR-1400 PWR reactors developed by the Korea Electric Power Corporation, and units 1, 2, 3, and 4 entered commercial operation in the years 2020, 2021, 2022, and 2024, respectively.

Figure 4 shows the projected nuclear overnight cost ranges in China and the UAE. Each uses local labor and material multipliers as highlighted in Section 2.2. The realized costs are then compared against these ranges. The solid black and dashed blue lines show the actual costs incurred for reactors and escalated to 2022 USD. U.S. cost ranges were included for reference as well.

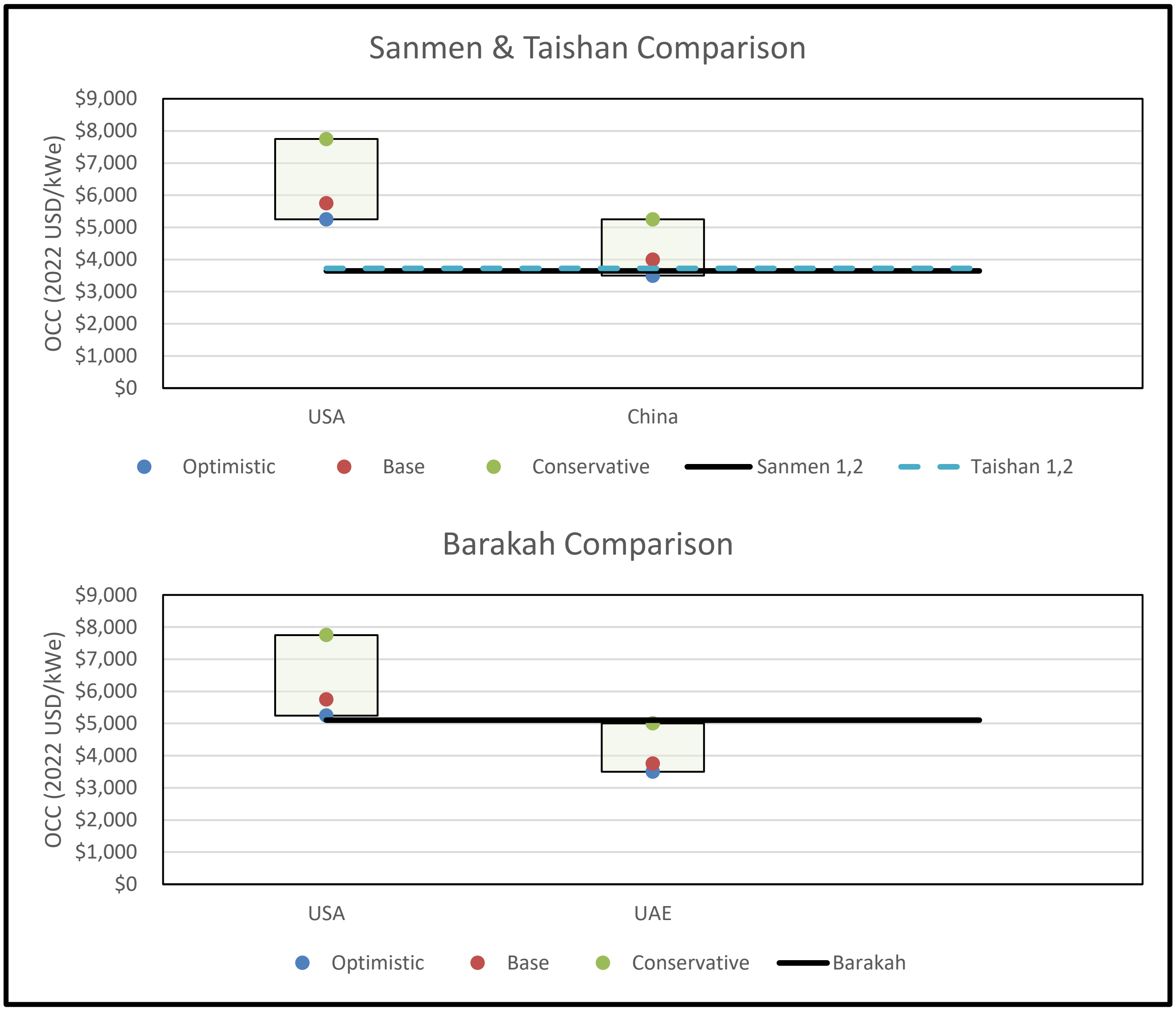


Figure 4. Estimated nuclear overnight cost comparisons for China (top) and the UAE (bottom).

Care must be taken when comparing the results from the methodology used here against observed costs. The methodology makes no assumption regarding the domestic capabilities within a country, which in the case of China are relatively mature. The methodology also assumes the BOAK costs are a good basis for projection in other countries compared to the original FOAK costs. Third, the costs incurred in China and UAE were escalated to 2022 USD assuming similar trends to U.S. indexes. This is an approximation that may not be entirely accurate. Last, no detailed breakdown of the costs for these projects has been made public. It remains uncertain how comprehensive these cost estimates are and if they include additional costs not considered in the analysis (e.g., design certification) or if they exclude items (e.g., indirect cost overruns).

Nevertheless, the figures do show that the methodology would result in costs that are roughly in line with observations in those two examples. In the case of China, the projection is higher than the experience at the two plants. This is even though both countries experienced cost overruns and delays [20] [22]. This is likely because the rate of localization in this country with an established nuclear industry is higher than the assumption in Table 2. This would result in lower overall costs than the methodology currently assumes. In the case of the build in the UAE, the observed data falls in the more conservative bound of the model. The realized costs for Barakah (~$4,000 in 2017 USD, when not adjusted for inflation) fall closer to the base estimate. Overall, the fact that new build constructions fall within the bounds of the methodology does provide some level of confidence in the ranges provided.

3.2. Operating and Maintenance Costs

3.2.1. Country-Specific Nuclear O&M Costs

The results of the O&M cost modeling are shown in Figure 5. The plot aggregates all the various O&M costs into one total for each country represented in USD/MWh. Note that values are rounded to the nearest multiple of 0.25. These results also show that NZW countries tend to cluster around a similar range with some skewing further up (Chile). For O&M costs, even optimistic U.S. costs are above the highest projected estimate of all NZW countries. Again, this showcases the significant impact of the cost of labor (the only cost factor that is country-specific here) on overall operating costs.

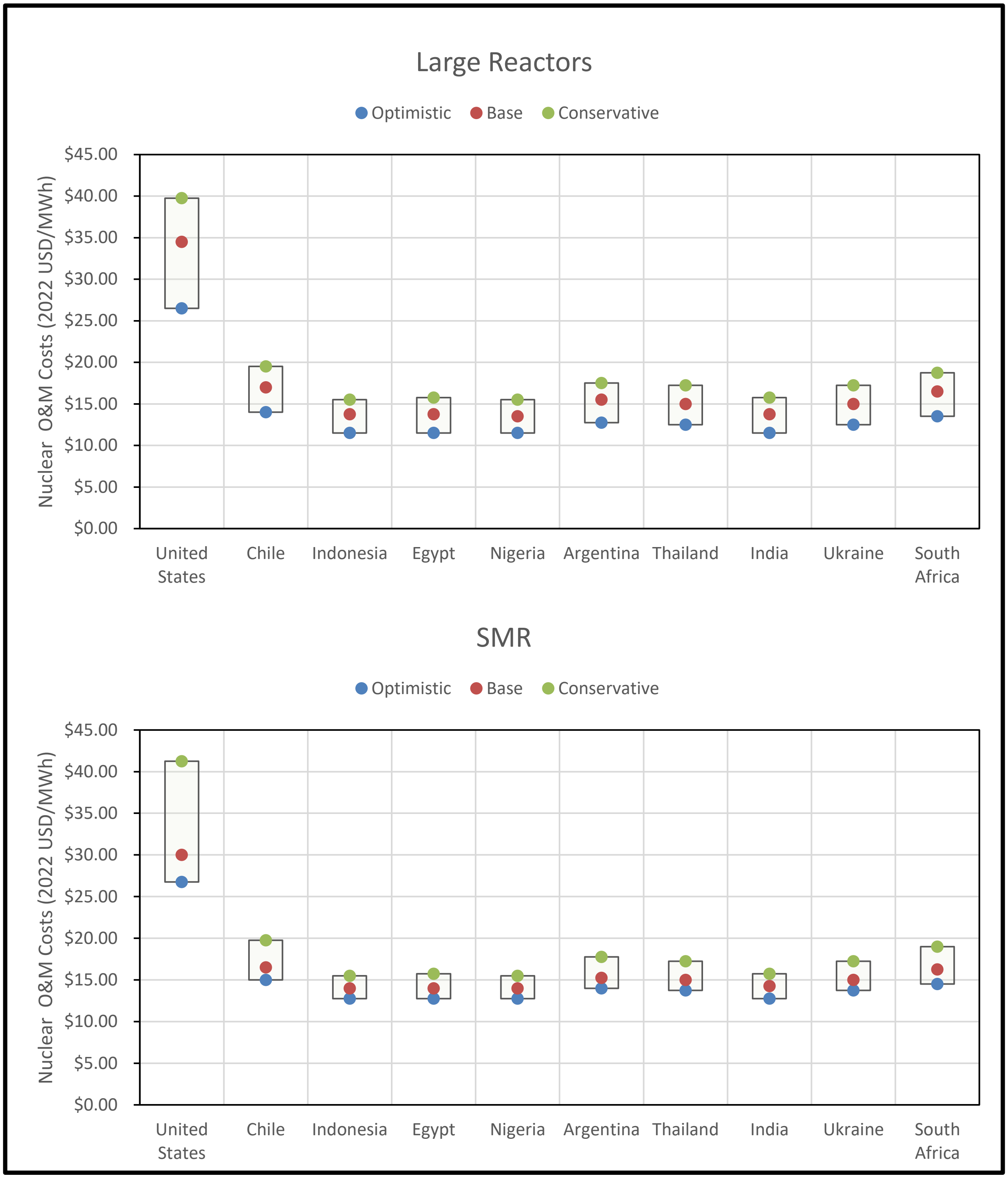


Figure 5. Country-specific nuclear O&M cost (including fixed, variable, and fuel costs) ranges for SMRs and large reactors. Shown as 2022 USD values.

Values from Figure 5 are also divided into fixed (show on a USD/kWe-yr basis) and variable (shown on a USD/MWh basis) portions in Table 11 and Table 12. Recall from Section 2.2 that fixed O&M consisted of labor-driven operation costs and subsequently vary from country to country, but variable O&M consisted of fuel and non-fuel variable costs, which were considered to be constant irrespective of location, and therefore are shown as identical across all countries.

Table 11. Country-specific nuclear O&M cost ranges for large reactors with optimistic/base/conservative estimates.

Country	Fixed O&M (USD/kWe-yr)	Variable O&M (USD/MWh)
United States	$136 / $188 / $219	$11.00 / $13.00 / $14.75
Chile	$26 / $35 / $42	$11.00 / $13.00 / $14.75
Indonesia	$4 / $7 / $7	$11.00 / $13.00 / $14.75
Egypt	$4 / $7 / $9	$11.00 / $13.00 / $14.75
Nigeria	$4 / $4 / $7	$11.00 / $13.00 / $14.75
Argentina	$15 / $22 / $24	$11.00 / $13.00 / $14.75
Thailand	$13 / $18 / $22	$11.00 / $13.00 / $14.75
India	$4 / $7 / $9	$11.00 / $13.00 / $14.75
Ukraine	$13 / $18 / $22	$11.00 / $13.00 / $14.75
South Africa	$22 / $31 / $35	$11.00 / $13.00 / $14.75

Table 12. Country-specific nuclear O&M cost ranges for small modular reactors with optimistic/base/conservative estimates.

Country	Fixed O&M (USD/kWe-yr)	Variable O&M (USD/MWh)
United States	$127 / $145 / $232	$12.25 / $13.50 / $14.75
Chile	$24 / $26 / $44	$12.25 / $13.50 / $14.75
Indonesia	$4 / $4 / $7	$12.25 / $13.50 / $14.75
Egypt	$4 / $4 / $9	$12.25 / $13.50 / $14.75
Nigeria	$4 / $4 / $7	$12.25 / $13.50 / $14.75
Argentina	$15 / $15 / $26	$12.25 / $13.50 / $14.75
Thailand	$13 / $13 / $22	$12.25 / $13.50 / $14.75
India	$4 / $7 / $9	$12.25 / $13.50 / $14.75
Ukraine	$13 / $13 / $22	$12.25 / $13.50 / $14.75
South Africa	$20 / $24 / $37	$12.25 / $13.50 / $14.75

An additional factor to consider outside of standard operational costs is the potential for a spent fuel tax. In 1982, the United States enacted a spent fuel tax on nuclear utilities of 1.0 mil per kilowatt-hour, which translates into $0.001/kWh or $1.00/MWh as shown in Table ES-1 [23]. Given the low relative size of this value, a flat amount of $1.00/MWh is assumed across the scenarios and the value is included in the O&M numbers provided within this report.

3.2.2. Comparison Against Observed Operating Costs

To verify the cost adjustment approach for O&M, the methodology was compared against the case of reported O&M costs in China. Local country-specific labor adjustments were applied as in Table 2, and Figure 6 shows the projected total nuclear O&M ranges in China. The solid black line shows the values for China O&M costs, taken from the MIT 2018 report [7].

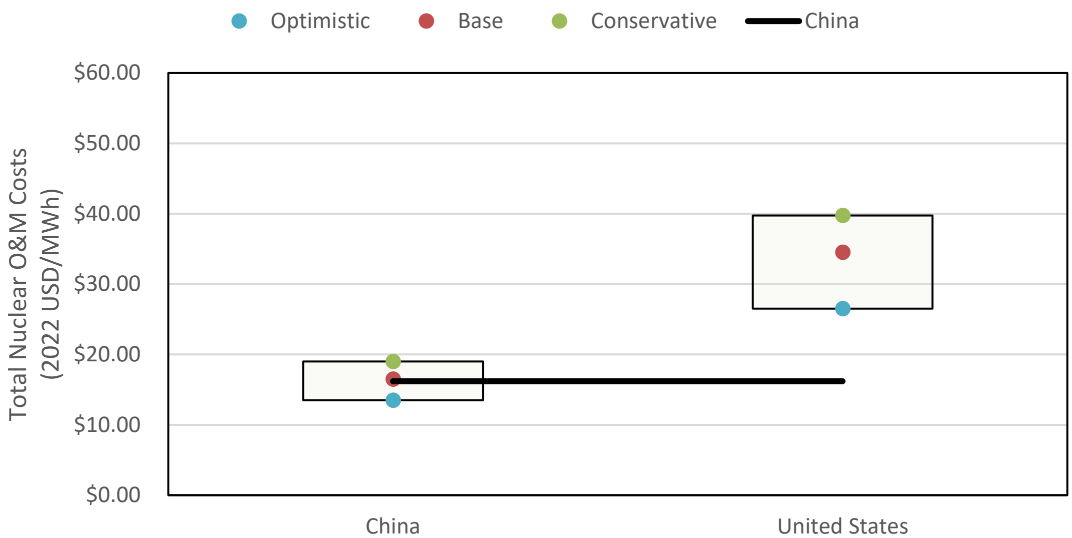


Figure 6. Estimated China nuclear O&M costs compared to MIT 2018 reported.

The figure above shows that the cost adjustment method produces a range that captures reported actual nuclear O&M costs. In this instance, the projected range for O&M in China indicates that observed costs are close to the base costs from the methodology. This helps to validate this approach produces accurate estimates that can be used in modeling efforts.

However, it should be noted that only when the total O&M costs are aggregated to a single USD per MWh are they consistent with those found in the MIT report. When the data is disaggregated between fixed O&M and variable O&M, the breakout values deviate from those in the MIT report. This may be due to differences in operational costs between 2018 (when the MIT study was conducted) and 2022. Additionally, the categorization of what is considered fixed versus variable between the O&M data used and the MIT data could be different. This could produce values that aggregated to similar totals but differ when broken out. It is also possible that the methodology used in this report is overestimating the cost reductions in labor rates (producing a fixed cost value that is lower than MIT reports) but underestimating the change in variable costs, fuel and non-fuel, (producing a variable cost value that is higher than observed by MIT). This combination of overestimations and underestimation may have resulted in an error cancellation when aggregated to a single USD per MWh value. Further work is needed to identify the exact cause of the discrepancies in the disaggregated costs [24].

3.3. Resulting Breakdown of Foreign Versus Domestic Investment

Imported products are assumed to have a similar overall cost as the original U.S.-based estimates used in this study (neglecting shipping costs). However, some items (such as labor, commodities, and a few equipment) can be expected to be sourced locally. Based on the methodology outlined in previous sections, it is possible to untangle total expenses between "foreign" (assumed to be predominantly U.S.-based) and "domestic." While the aggregated total values are shown in Table 19, the values are broken down between subcomponents in Figure 7. The plot distinguishes between expense type (labor, material, equipment, or other) and if they are foreign-born (dashed boxes) or domestic. Only the base costs are plotted here. Large reactors are not shown but exhibit a similar pattern to SMRs when shown graphically. For every kWe of U.S.-reactor deployment, the figure allows stakeholders to visualize an approximate breakdown of expenditures that are local versus U.S.-based. The figure showcases how higher domestic labor and material adjustment factors result in larger domestic costs relative to other countries.

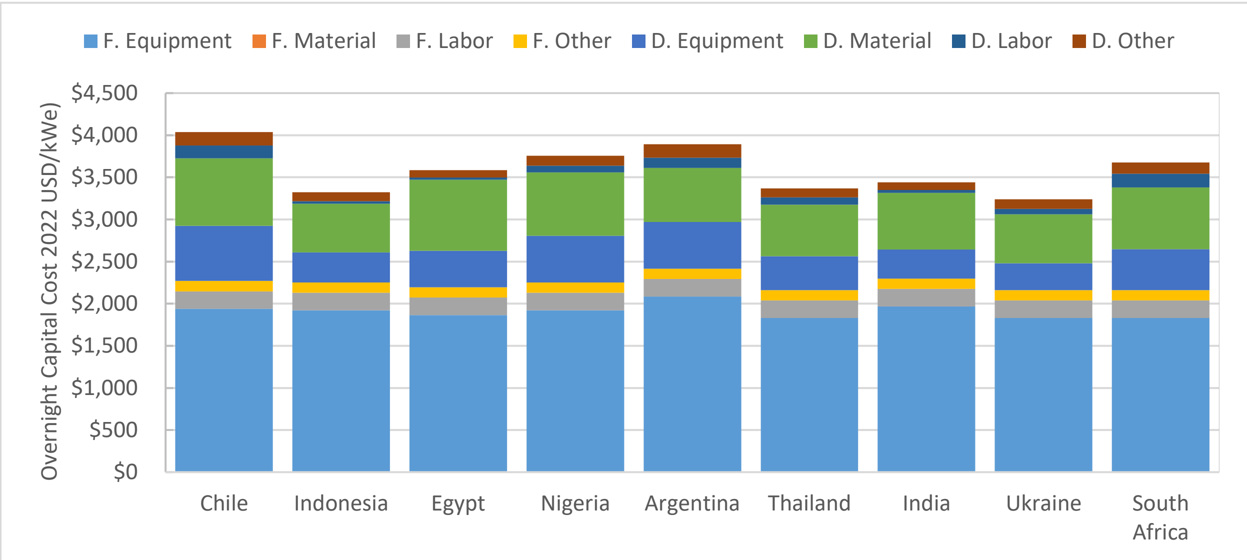


Figure 7. SMR base overnight capital cost breakout by category for NZW countries. In the key above the graph, "F" denotes foreign sourcing while "D" denotes domestic.

Table 13 shows the estimated percent of total costs for large and small reactors between foreign and domestic sources. This highlights how the split between domestic versus local expenses is country specific. This is primarily due to the differences in local market conditions (again, no assumption is made at this stage about local heavy industry capacity or skilled labor force). In general, for large reactors, it appears that around 30–45% of costs are expected to be born locally. A similar trend is seen for both large reactors and SMRs. The results should not be taken to be definitive quantifications—to do so would require detailed case-by-case cost projections. They do, however, provide a useful high-level estimation of the likely split between foreign and domestic investment for every U.S.-based reactor deployed in other countries.

Table 13. Percent of total costs from foreign verses domestic investment.

	Large Reactors		SMR	
Country	**Foreign Sourcing**	**Domestic Sourcing**	**Foreign Sourcing**	**Domestic Sourcing**
Chile	56%	44%	56%	44%
Indonesia	68%	32%	70%	30%
Egypt	61%	39%	65%	35%
Nigeria	60%	40%	61%	39%
Argentina	62%	38%	62%	38%
Thailand	64%	36%	65%	35%
India	67%	33%	70%	30%

	Large Reactors		SMR	
Country	Foreign Sourcing	Domestic Sourcing	Foreign Sourcing	Domestic Sourcing
Ukraine	67%	33%	68%	32%
South Africa	59%	41%	58%	42%

3.4. Retirement (Decommissioning Costs)

Retirement costs, also referred to as decommissioning costs, are incurred throughout the reactor's lifetime. In the United States, these costs are placed into a trust that is formed during the construction of the plant and collected over the lifetime of the plant [25]. At the end of the reactor lifetime when decommissioning is carried out, the funds are used. Alternatively, the trust can be sold to a third party that performs the decommissioning using the accrued funds. To better understand the range of required final costs that could be incurred, projected final retirement costs of U.S. reactors were collected from the Nuclear Regulatory Commission and a U.S. utility [26]. Costs were escalated to 2022 USD values using the overnight cost escalation methodology discussed in the previous sections and converted to a dollar per kWe basis to normalize them across reactor sizes.

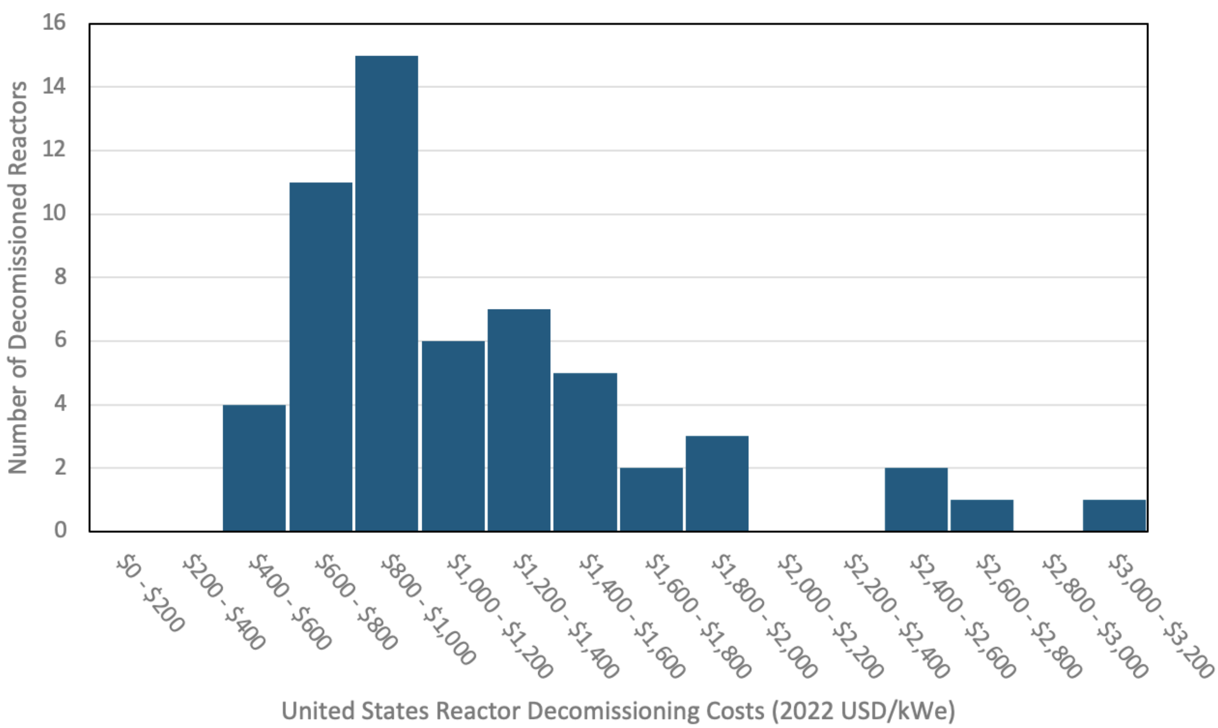


Figure 8. U.S. Decommissioning cost ranges.

Figure 8 shows the distribution of the projected reactor decommissioning costs normalized on a $/kWe basis [27]. The distribution is right tailed with a small number of reactors showing substantial projected decommissioning costs. Again, it is important to note that these costs should not be conflated with OCC and are typically incurred as an annual fee accumulated throughout operations. These ranges as also leveraged in Reference [1] and annualized therein. The recommended value in that report of $10/kWe-year is adopted and subsequently included in the O&M costs provided. Note that this value accounts for the impacts of compounded expecting returns from contributions made to the trust earlier on in the reactor's lifetime.

3.5. Additional Adjustment Factors

3.5.1. Multi-Unit Adjustment

Building multiple reactor plants at the same site can help reduce the costs associated with nuclear projects. Co-locating several plants allows for capital and operational efficiencies, such as shared warehousing facilities and rotating maintenance crews between units as needed. Based on a review of existing data from Reference [1], the cost adjustments factors from Table 14 are recommended for multi-unit sites, in addition to the expected cost reductions from learning.

Table 14. Multi-unit cost reduction factors for OCC and O&M.

Number of Units	OCC Cost Reduction	O&M Cost Reduction
1	1	1
2	0.9	0.67
4	0.8	0.67
8	0.7	0.67
>8	0.7	0.67

It is also important to consider that the definition of a "unit" may vary across different designs. Some vendors, for example, offer reactors in four- or six-pack configurations. In these cases, cost reductions might differ between a single pack and the first and subsequent packs. For simplicity in analysis, it is recommended to apply the cost reductions by treating each multi-unit pack as a single unit. Similar factors are recommended for both large reactors and SMRs.

3.5.2. FOAK Multipliers

Adjustment factors for FOAK builds were also based on recommendations from Reference [6], and the learning rate recommendations were based on Reference [1]. Recall that estimates for OCC numbers are not considered to be FOAK demonstrations nor NOAK. To adjust numbers downward for NOAK builds or upward for FOAK builds, the adjustment factors shown in Table 15 should be used. For countries without existing nuclear programs, the FOAK adjustment factors would not include the cost for starting a nuclear program in that country. In these instances, models would only represent FOAK OCCs, and additional costs would need to be accounted for to represent the formation of a national nuclear program to accompany the adoption of the technology. Only a single value is recommended from FOAK premium. This is because typically conservative FOAK adjustment factors are likely correlated with optimistic

BOAK costs and vice versa. For simplicity, and to provide a more consistent analysis, a single reference premium multiplier is recommended for any of the three scenarios.

Table 15. FOAK capitals cost adjustment factor ranges and learn rate capital cost reduction ranges.

Category	Small Modular Reactors	Large Reactors
FOAK premium	1.5	1.5
Learning rate [%]	9.5%	8.0%

For additional context, the recommended learning rates in Table 15 were obtained from Reference [1], which surveyed a variety of bottom-up estimates. The learning rate in this instance is defined as a percentage reduction in cost when a doubling in number of deployments is achieved. For example, a learning rate of 5% implies that the cost of the second plant will be 95% that of the FOAK, and the fourth plant will be 90.25% (95% of 95%) and so on. The method can be employed to calculate the learning rate associated with any number of reactors as it smooths values between doublings. Mathematically, this can be expressed as shown in Equation 7.

$$Cost_n = FOAK(1 - LR)^{log_2 n}$$

Equation 7. Learning rate adjustment equation.

Where,

- Cost represents the learning rate adjusted cost of the nth reactor
- n represents the number of reactor deployments
- FOAK represents the OCC costs of the FOAK deployment
- LR represents the desired learning rate from Table 15.

In the case of calculating FOAK build costs, the value shown in Table 15 is used as a direct multiplier, meaning the OCC cost should just be multiplied by the FOAK premium to get an expected FOAK cost. Again, a mathematical representation is shown in Equation 8.

$$FOAK = BOAK \times FP$$

Equation 8. FOAK cost adjustment equation.

Where,

- FOAK represents FOAK OCC
- BOAK represents a given OCC value from Table 10
- FP represents FOAK premiums Table 15.

4. REFERENCE DATA ON NUCLEAR CONSTUCTION AND OPERATION

While considering construction and operational parameters within this section, recall that construction time and capacity factor methodologies leverage the use of quartiles from observed data to produce a suggested range of values for modeling. This approach was also leveraged for estimating decommissioning cost ranges This method is an effective means of producing statistically sound ranges, but in some instances, observed commercial values may be more tightly grouped. This differentiation likely stems from the use of globally data overtime where differences in parameters may produce minor skewing.

4.1. Construction Time

Time to complete a nuclear reactor can vary based on several factors. This includes regulatory approval timelines, issues with material sourcing, project management issues, etc. It is also expected that SMRs and large reactors have distinctly different construction times due to size and construction methods. For this reason, recommendations are separated again into large reactor and SMR categories. Values for both categories also come from Reference [1]. It is also possible for expected times to change depending on technology selection, workforce availability, regulatory stringency, and political support. Note that this time excludes the time needed to obtain regulatory approval for siting the reactor at a given location. Table 16 summarizes the recommended ranges.

Table 16: Construction time large and small modular reactors.

Construction Timeline (Months)	Large Reactors	Small Modular Reactors
Optimistic	60	43
Base	82	55
Conservative	125	71

4.2. Capacity Factor

A capacity factor is an important aspect of nuclear modeling that can have a substantial impact on total energy production. Because NPPs can operate for a larger percent of the year, more value can be drawn from the asset. Capacity factors vary around the globe with the highest coming from U.S. reactors. Because SMRs are not currently deployed, a single capacity factor based off large reactor data is recommended for both. Power Reactor Information System (PRIS) data was leveraged again to understand the distribution of capacity factors across the globe [28].

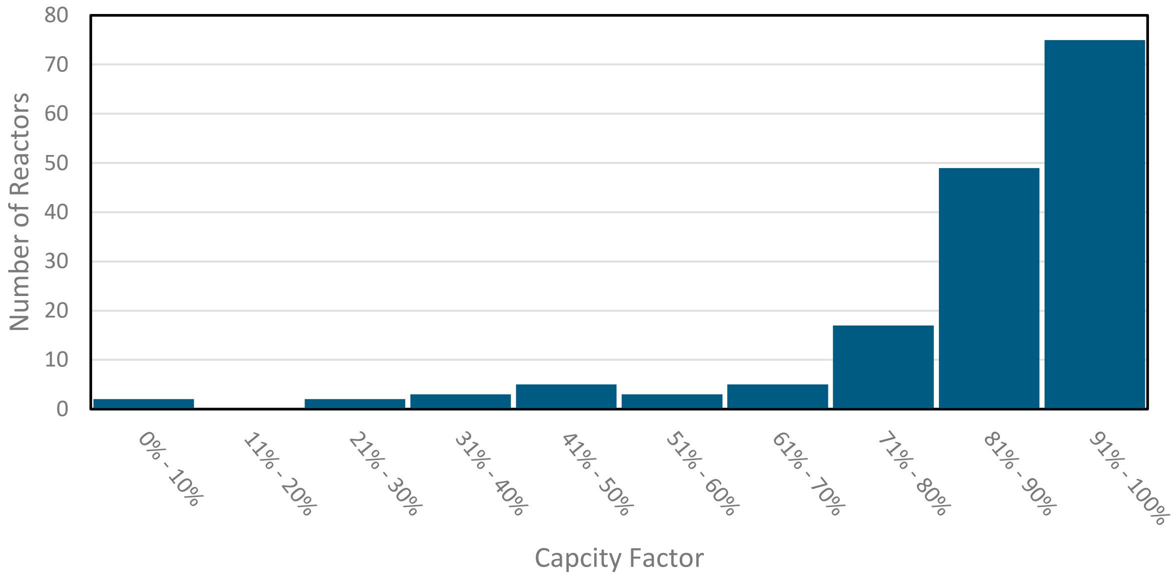


Figure 9. Global nuclear capacity factor distribution, site-specific reporting.

Figure 9 shows that nuclear capacity factors are grouped around 80–100% with a long left tail. Reactors with a 0% capacity factor were removed from the dataset (as they were assumed to be non-operational), but some reactors in the dataset still showed extremely low-capacity factors. It is likely that some of the low-capacity data points are from test reactors or reactors with low utilization due to abnormal operational circumstances. In commercial applications, operators are incentivized to keep capacity as high as possible to maximize profitability. Despite the presence of outliers in the dataset, Table 17 indicates that the first and third quartiles are 80% and 95% with a global median capacity factor of 90%. A lower end capacity factor of 80% is considered very unlikely for normal commercial operation (the data may be skewed by noncommercial or nontraditional operations). On the other hand, the upper bound of 95% may be considered overoptimistic, but the range obtained is essentially a function of the methodology. In the United States, the average capacity factor for commercial reactors is 93% and could be used for modeling purposes if the hope is to replicate the U.S. experience with maximizing capacity factors. Note that PRIS data reports site-specific data and not reactor-specific data (i.e., reactor site with four reactors counts as a single data point instead of four).

Table 17. Global nuclear capacity factor statistics, site-specific reporting.

Global Nuclear Capacity Factors		
Low – 1st Quartile	**Medium – 2nd Quartile**	**High – 3rd Quartile**
80%	90%	95%

4.3. Reactor Lifetime

The average age of U.S. reactors is approaching 40 years, and there are no technical limits to these units operating beyond that point. To date, 20 reactors in the United States are planning or intending to operate up to 80 years [29]. Though nuclear plants are originally intended to operate safely for 40 years, experts agree that older reactors could last another 50 years [21]. The lifetime of a reactor is assumed to be at least 60 years according to Dominion Energy research [27]. This is taken to correspond to the "conservative" case. The base case recommendation is 80 years, and the optimistic is taken to be 100 years [27].

4.4. Nuclear Plant Load-Following Capability

NPPs were designed for load-following operation, and the nuclear industry in various countries accrued decades of experience successfully ramping up/down operations of their nuclear fleet. Below is a summary of European utilities' requirements for NPP maneuvering capabilities, where "conservative" refers to minimum requirements and "optimistic" refers to capability currently achieved by some NPP concepts [30].

Table 18. Maneuverability and other performance metrics for nuclear.

	Min	Max
Load-following operation available during cycle length	90%	100%
Ramp rate of load-following operation	3%Pr/min	5%Pr/min
Daily maneuverability	2 daily cycles/day 5 cycles per week 200 cycles per year	No limit
Lower range of power operation	50%Pr	20%Pr
Primary frequency control (available at all times)	+/- 2%Pr	+/- 5%Pr
Secondary frequency control	(optional)	+/- 10%Pr with ramps of 5%Pr/min

Additional features include the possibility of NPPs participating in emergency load variation with ramp rate of 20%Pr/min down to minimum load of the unit and grid restoration with a ramp-up of 10%Pr/min.[c]

It should be noted that many recent designs (including the AP1000) are certified to comply with these requirements. Similar utility requirements were defined in the United States [31].

Added costs to load-following operation are not included here since those are expected to be mostly accounted for by the reduced reactor utilization while still incurring fixed operating costs. Reduced fuel utilization and maintenance costs due to load-following operations can be estimated via variable O&M costs [32].

These maneuvering capabilities are based on large, advanced light-water reactors technologies while some advanced SMRs may provide improved maneuvering performance. For instance, the TerraPower Natrium, Westinghouse LFR, and Moltex concepts are designed to couple with

[c] %Pr/Min is defined as the measure of change per minute in percent of power rated.

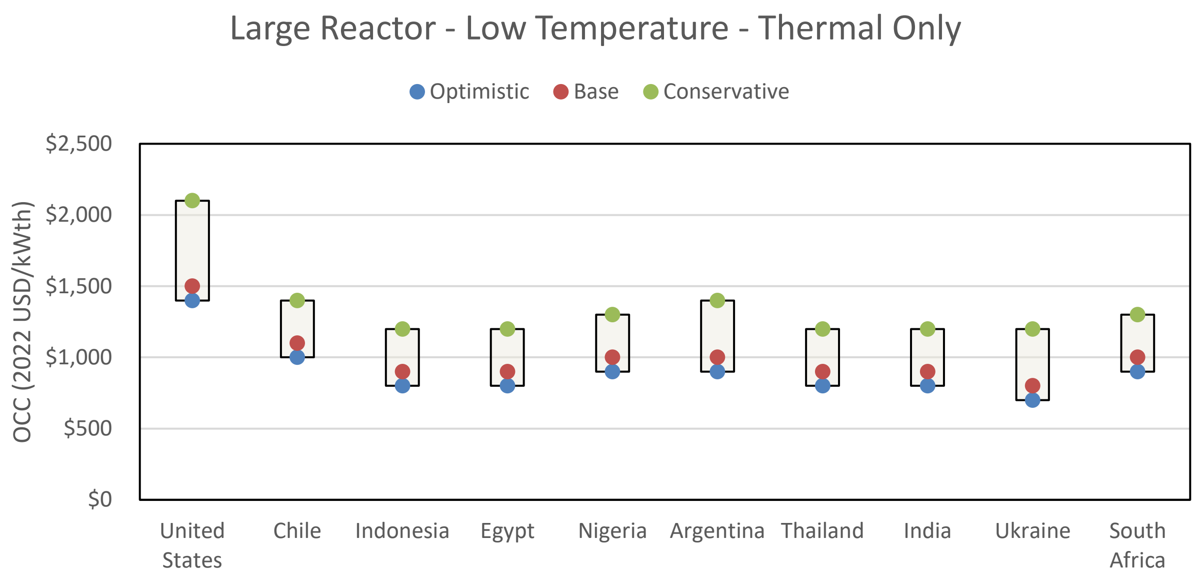
thermal energy storage (several hours of storage are being considered), which enables ramping up/down the plant electrical output without varying nuclear plant output.

5. NON-GRID NUCLEAR ENERGY APPLICATIONS

The previous sections of this report have mainly focused on the costs associated with the production of electricity for the grid. However, when electricity and/or heat produced by an NPP is utilized by a non-grid application, there are additional factors that should be considered. First, non-grid applications may require modifications to the typical NPP design, particularly applications that utilize heat. This section provides a set of recommendations for modeling these nuclear applications.

5.1. Cost Assumptions for Heat-only Applications

In cases where only heat is utilized and no electricity is generated, there will be significant changes to the plant design, which impact both the direct and indirect costs. Adjustments to capital costs must be made to account for the removal of equipment such as turbomachinery. To make these adjustments, heat-only multipliers from Reference [1] were used to alter OCC costs down for thermal-only applications. Additionally, to convert the costs to USD/kWth, the cost in USD/kWe should be multiplied by the reactor thermal efficiency. Here, two possibilities are shown: low-temperature reactors with a thermal efficiency of 33% and high-temperature reactors with a thermal efficiency of 40%. The impacts of these adjustments are highlighted in



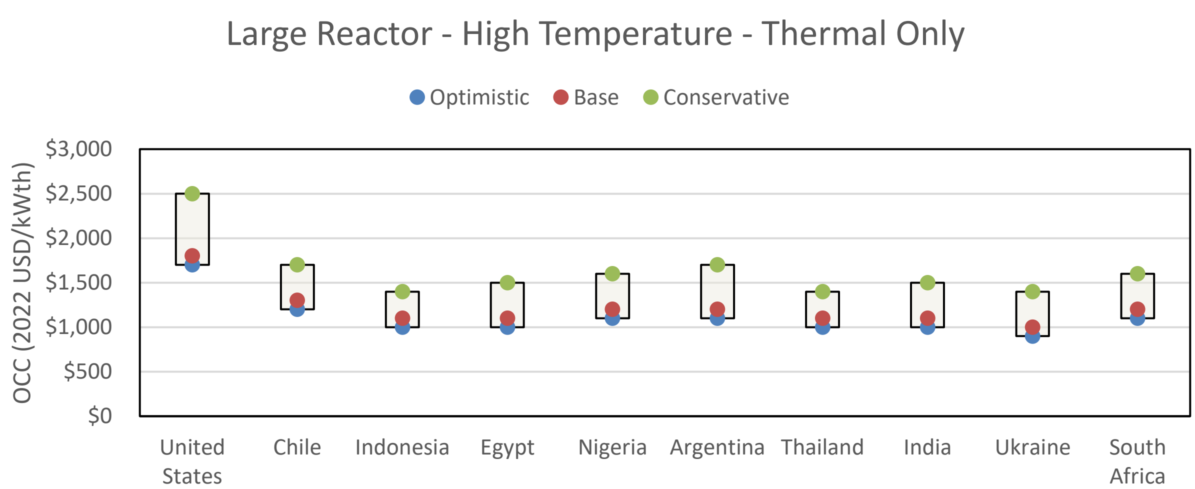


Figure 10 and Table 19. In both, values were rounded to the nearest multiple of 100.

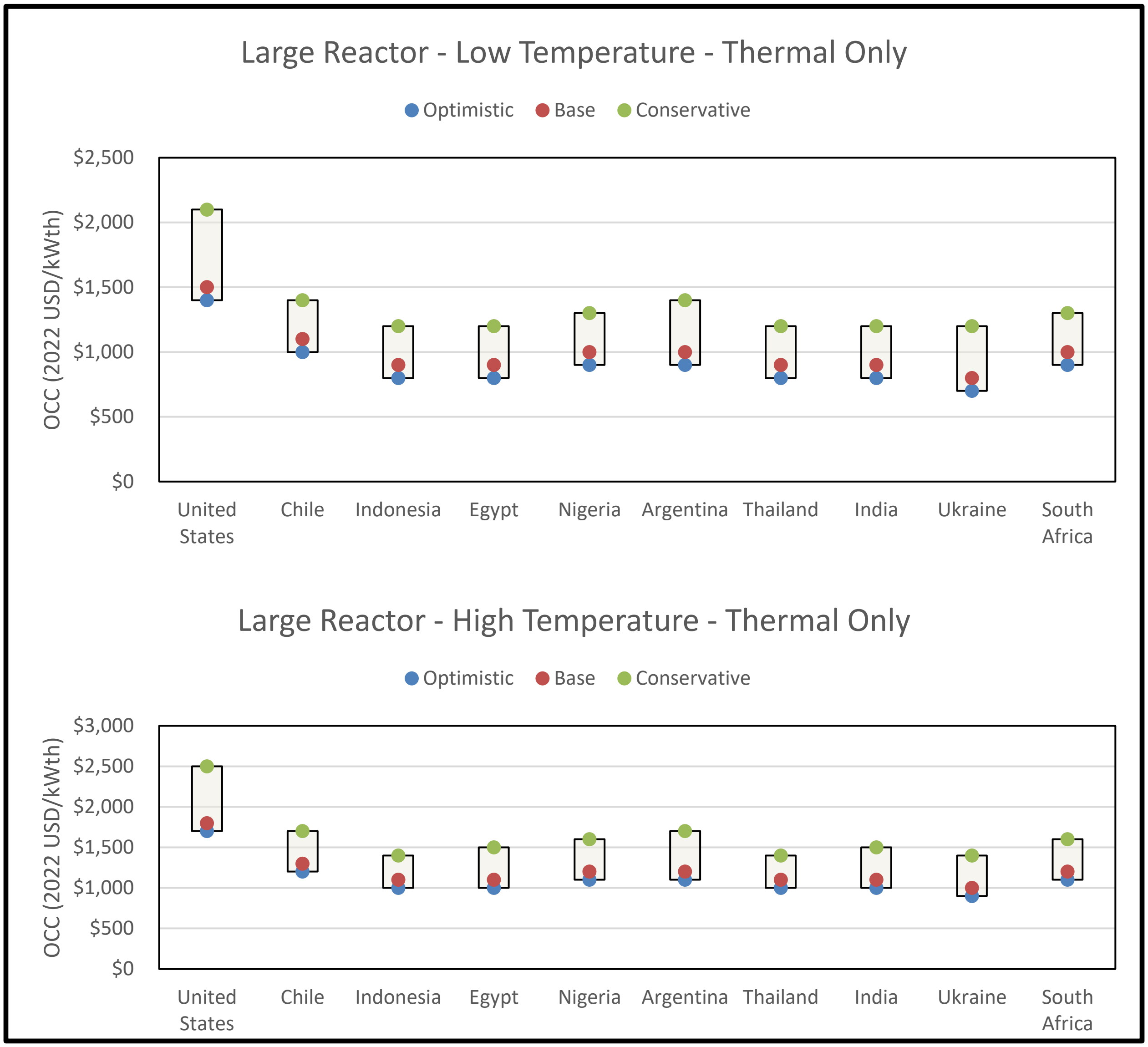


Figure 10 Country-specific thermal-only nuclear overnight cost ranges ($/kWth) for low-temperature and high-temperature large reactors, shown as 2022 USD values.

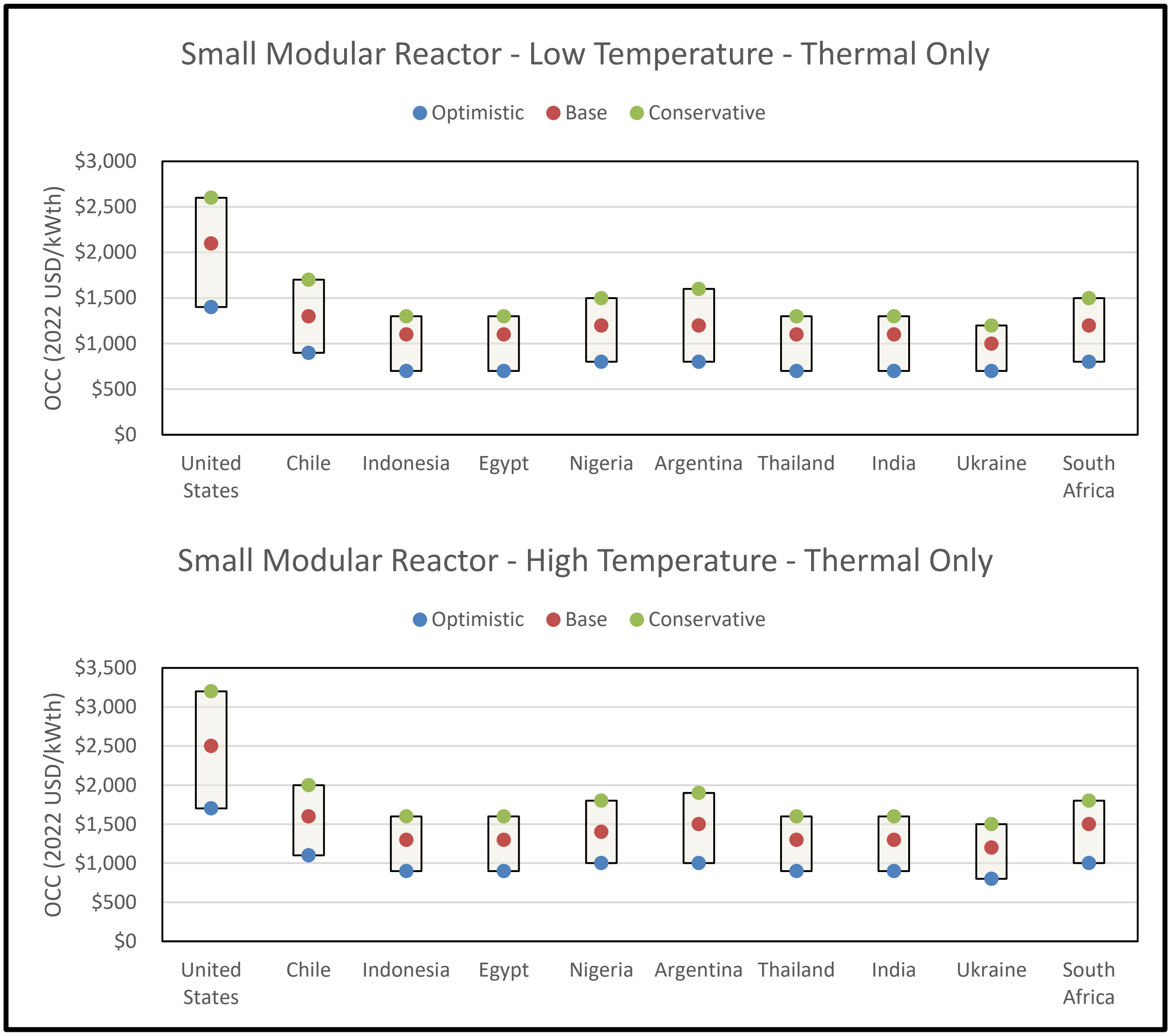


Figure 11 Country-specific thermal-only nuclear overnight cost ranges ($/kWth) for low-temperature (top) and high-temperature small modular reactors (bottom), shown as 2022 USD values.

Table 19. Country-specific thermal-only nuclear overnight cost ranges, shown as 2022 USD values. The upper values correspond with a low-temperature reactor (thermal efficiency = 33%) and the lower values correspond with a high-temperature reactor (thermal efficiency = 40%)

	Large Reactors			Small Modular Reactors		
Country	**Optimistic**	**Base**	**Conservative**	**Optimistic**	**Base**	**Conservative**
United States	$1,400 $1,700	$1,500 $1,800	$2,100 $2,500	$1,400 $1,700	$2,100 $2,500	$2,600 $3,200
Chile	$1,000 $1,200	$1,100 $1,300	$1,400 $1,700	$900 $1,100	$1,300 $1,600	$1,700 $2,000

	Large Reactors			Small Modular Reactors		
Country	**Optimistic**	**Base**	**Conservative**	**Optimistic**	**Base**	**Conservative**
Indonesia	$800 $1,000	$900 $1,100	$1,200 $1,400	$700 $900	$1,100 $1,300	$1,300 $1,600
Egypt	$800 $1,000	$900 $1,100	$1,200 $1,500	$700 $900	$1,100 $1,300	$1,300 $1,600
Nigeria	$900 $1,100	$1,000 $1,200	$1,300 $1,600	$800 $1,000	$1,200 $1,400	$1,500 $1,800
Argentina	$900 $1,100	$1,000 $1,200	$1,400 $1,700	$800 $1,000	$1,200 $1,500	$1,600 $1,900
Thailand	$800 $1,000	$900 $1,100	$1,200 $1,400	$700 $900	$1,100 $1,300	$1,300 $1,600
India	$800 $1,000	$900 $1,100	$1,200 $1,500	$700 $900	$1,100 $1,300	$1,300 $1,600
Ukraine	$700 $900	$800 $1,000	$1,200 $1,400	$700 $800	$1,000 $1,200	$1,200 $1,500
South Africa	$900 $1,100	$1,000 $1,200	$1,300 $1,600	$800 $1,000	$1,200 $1,500	$1,500 $1,800

In the case of heat-only applications, it is expected O&M costs will decrease to some extent. Following the recommendation of Reference [1], the projected O&M costs from Section 3.2.1 were adjusted to represent thermal-only applications. Figure 12 represents the values graphically while Table 20 and Table 21 provide country-specific values separated into fixed and variable O&M groupings. Note that in the case of O&M, the expected decrease in costs for thermal-only applications is less than the drop observed for thermal-only OCC. This is unsurprising as it is expected that much of the plant will operate similarly from a staffing and maintenance standpoint. Subsequently, the reductions are lesser in this case.

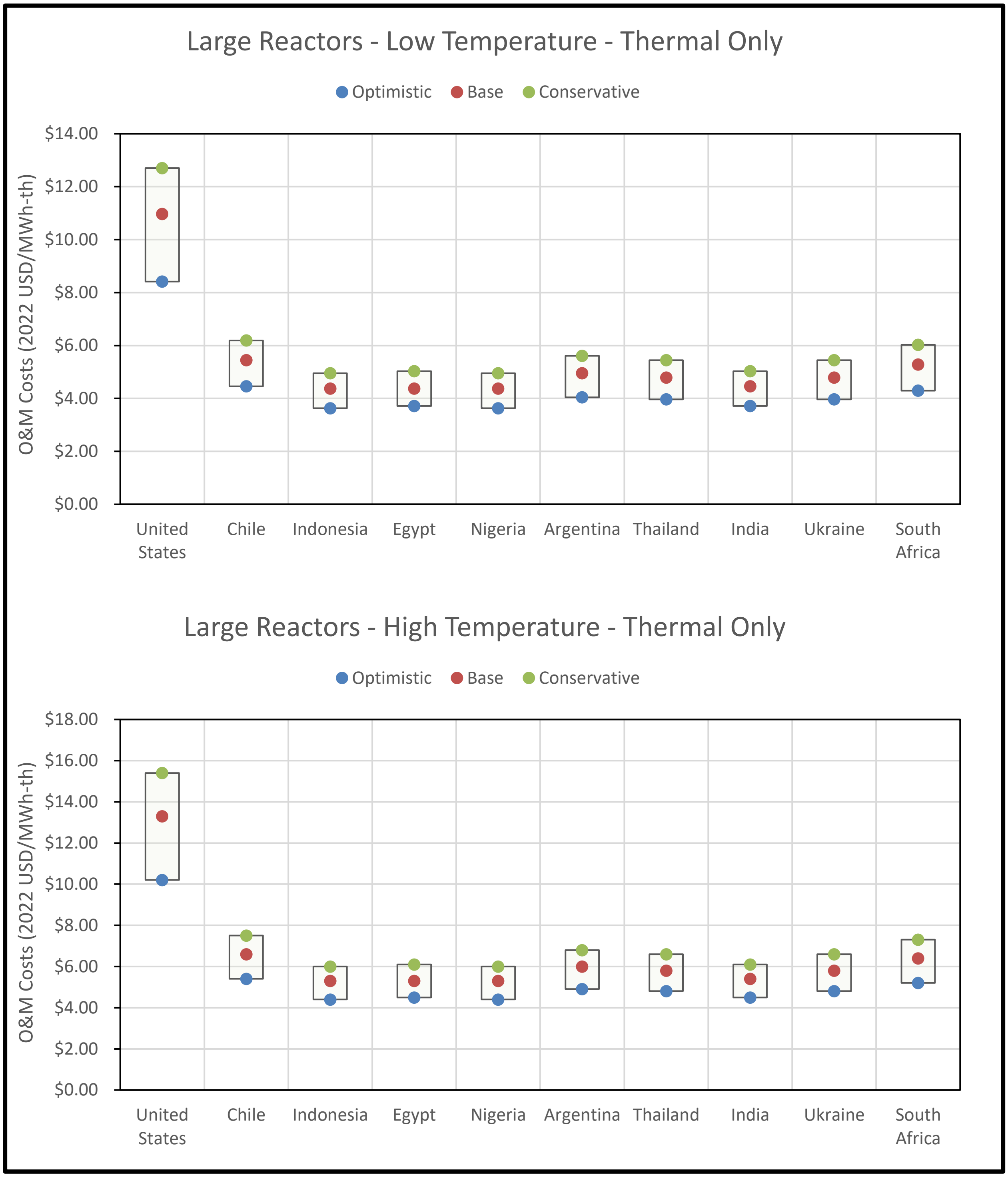


Figure 12. Country-specific thermal-only nuclear operating cost ranges for low-temperature large reactors (top) and high-temperature large reactors (bottom), shown as 2022 USD values.

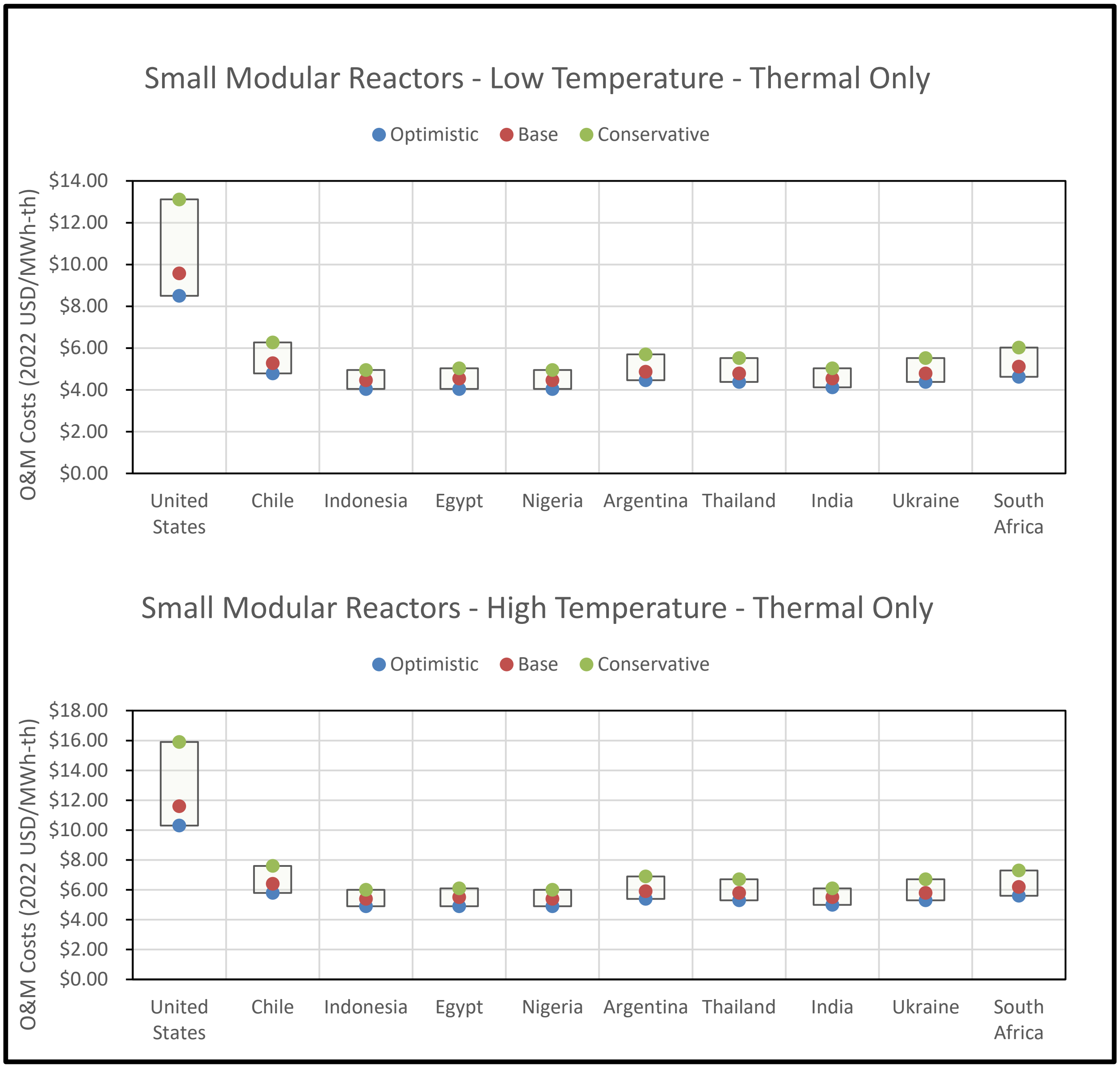


Figure 13. Country-specific thermal-only nuclear operating cost ranges for low-temperature SMRs (top) and high-temperature SMRs (bottom), shown as 2022 USD values.

Table 20. Country-specific thermal-only nuclear O&M cost ranges for low- and high-temperature large reactors with optimistic/base/conservative estimates. The upper values correspond with a low-temperature reactor and the lower values correspond with a high-temperature reactor

Country	Fixed O&M (USD/kWth-yr) Low-Temperature	Fixed O&M (USD/kWth-yr) High-Temperature	Variable O&M (USD/MWh) Low-Temperature	Variable O&M (USD/MWh) High-Temperature
United States	$43 / $60 / $70	$52 / $73 / $85	$4 / $4 / $5	$4 / $5 / $6
Chile	$8 / $11 / $13	$10 / $14 / $16	$4 / $4 / $5	$4 / $5 / $6
Indonesia	$1 / $2 / $2	$2 / $3 / $3	$4 / $4 / $5	$4 / $5 / $6

Country	Fixed O&M (USD/kWth-yr) Low-Temperature	Fixed O&M (USD/kWth-yr) High-Temperature	Variable O&M (USD/MWh) Low-Temperature	Variable O&M (USD/MWh) High-Temperature
Egypt	$1 / $2 / $3	$2 / $3 / $3	$4 / $4 / $5	$4 / $5 / $6
Nigeria	$1 / $1 / $2	$2 / $2 / $3	$4 / $4 / $5	$4 / $5 / $6
Argentina	$5 / $7 / $8	$6 / $8 / $9	$4 / $4 / $5	$4 / $5 / $6
Thailand	$4 / $6 / $7	$5 / $7 / $8	$4 / $4 / $5	$4 / $5 / $6
India	$1 / $2 / $3	$2 / $3 / $3	$4 / $4 / $5	$4 / $5 / $6
Ukraine	$4 / $6 / $7	$5 / $7 / $8	$4 / $4 / $5	$4 / $5 / $6
South Africa	$7 / $10 / $11	$8 / $12 / $14	$4 / $4 / $5	$4 / $5 / $6

Table 21. Country-specific thermal-only nuclear O&M cost ranges for low- and high-temperature small modular reactors with optimistic/base/conservative estimates. The upper values correspond with a low-temperature reactor (thermal efficiency = 33%) and the lower values correspond with a high-temperature reactor (thermal efficiency = 40%)

Country	Fixed O&M (USD/kWth-yr) Low-Temperature	Fixed O&M (USD/kWth-yr) High-Temperature	Variable O&M (USD/MWh) Low-Temperature	Variable O&M (USD/MWh) High-Temperature
United States	$40 / $46 / $74	$49 / $56 / $90	$4 / $4 / $5	$5 / $5 / $6
Chile	$8 / $8 / $14	$9 / $10 / $17	$4 / $4 / $5	$5 / $5 / $6
Indonesia	$1 / $1 / $2	$2 / $2 / $3	$4 / $4 / $5	$5 / $5 / $6
Egypt	$1 / $1 / $3	$2 / $2 / $3	$4 / $4 / $5	$5 / $5 / $6
Nigeria	$1 / $1 / $2	$2 / $2 / $3	$4 / $4 / $5	$5 / $5 / $6
Argentina	$5 / $5 / $8	$6 / $6 / $10	$4 / $4 / $5	$5 / $5 / $6
Thailand	$4 / $4 / $7	$5 / $5 / $8	$4 / $4 / $5	$5 / $5 / $6
India	$1 / $2 / $3	$2 / $3 / $3	$4 / $4 / $5	$5 / $5 / $6
Ukraine	$4 / $4 / $7	$5 / $5 / $8	$4 / $4 / $5	$5 / $5 / $6
South Africa	$6 / $8 / $12	$8 / $9 / $14	$4 / $4 / $5	$5 / $5 / $6

5.2. Recommendations for Cogeneration

Other non-grid applications require the cogeneration of heat and electricity, which may require modifications to the plant design, thus impacting cost. At a minimum, additional components, such as piping and heat exchangers, will likely be required for cogeneration. It is also likely that these modifications introduce other non-equipment costs, such as engineering costs and permitting costs. The modifications required for non-electric applications and the costs associated with these modifications will be site-specific and depend on the specific requirements of the non-grid application. When units are used for cogeneration, the cost estimates provided in Section 3 should be used.

Another factor that must be considered for cogeneration scenarios is the impact that heat removal has on electricity generation. To supply heat to some non-grid processes, steam can be extracted from the reactor BOP (also referred to as the power conversion system). There are many different locations where steam can be extracted, such as before the high- or low-pressure turbines as well as from within the turbines, similar to steam extraction for feedwater heating. The location of steam extraction will dictate the temperature and pressure of the steam as well as the impact that extraction has on electricity generation. When steam is removed from the BOP, it is no longer available for electricity generation, which results in a decrease in electricity generation. Furthermore, if the steam flowrate through a turbine is significantly altered, the turbine will be operating at off-design conditions, which can further reduce electricity generation due to a reduction in isentropic efficiency. The reduction in electricity generation caused by heat removal can have a significant impact on the economics of the system and is further explored in this section.

Previous research investigated the feasibility of coupling nuclear power with negative emissions technologies and included an in-depth investigation of the relationship between steam extraction and electricity production [33]. To do so, steam cycle models were used to simulate extraction from the BOP. This work included the analysis of three Rankine-cycle-based reactor types: PWR, sodium-cooled fast reactor (SFR), and high-temperature gas-cooled reactor (HTGR). Nominal conditions for each reactor type are provided in Table 22. For each reactor type, several extraction locations were selected and analyzed. For each extraction location, the extraction flow rate was increased from zero up until the simulation could no longer converge. In all cases, the extracted flow was routed to the condenser to stabilize operation. It should be noted that this modeling approach did not account for the impact of operating the turbines at off-design conditions and therefore may underestimate the reduction of electricity generation, particularly at higher extraction flow rates. Results from this analysis are provided in Figure 14 and Table 23. For each reactor type, results for the two extraction locations, main steam extraction and a lower temperature/pressure steam extraction—each chosen to be around 150°C, are provided. The extraction mass flow rate is normalized to the nominal main steam mass flow rate, and the electricity generation is normalized to the nominal (no extraction) value. A linear line was fit to each curve shown in Figure 14 and is provided in Table 23. In these equations, E_{gen} represents the amount of electricity generated (MW_e), $\dot{m}_{ext}$ represents the extraction mass flow rate (kg/s), and $\dot{m}_{MS}$ represents the nominal main steam mass flow rate (kg/s) as provided in Table 22.

Table 22. Reactor nominal parameters.

	PWR	SFR	HTGR
Reference Design	AP-1000 [34]	AFR-100 [35, 36]	Xe-100 [37, 38]
Reactor Thermal Power	3,415 MW_{th}	250 MW_{th}	203 MW_{th}
Nominal Net Electricity Generation	1,100 MW_e	100 MW_e	81 MW_e
Nominal Net Thermal Efficiency	32%	41%	40%
Nominal Main Steam Mass Flow Rate	1,880 kg/s	111 kg/s	78 kg/s

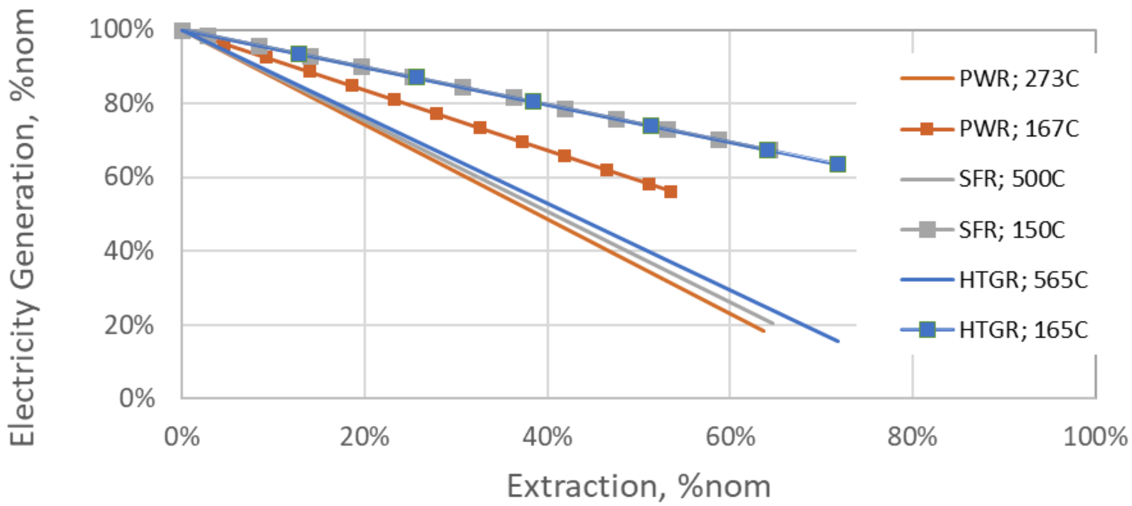


Figure 14. Relationship between steam extraction for non-grid applications and the resulting decrease in electricity generation [33].

Table 23. Extraction conditions and curve fits for the results in Figure 14.

Reactor Type	Temperature [°C]	Pressure [bar]	Enthalpy [kJ/kg]	Extraction Curve Fit
PWR	273	56.7	2,792	$E_{gen} = 1 - 1.2796\ (\dot{m}_{ext}/\dot{m}_{MS})$
PWR	167	4.4	2,788	$E_{gen} = 1 - 0.8188\ (\dot{m}_{ext}/\dot{m}_{MS})$
SFR	500	160	3,297	$E_{gen} = 1 - 1.2328\ (\dot{m}_{ext}/\dot{m}_{MS})$
SFR	150	4.7	2,596	$E_{gen} = 1 - 0.5054\ (\dot{m}_{ext}/\dot{m}_{MS})$
HTGR	565	164	3,478	$E_{gen} = 1 - 1.1745\ (\dot{m}_{ext}/\dot{m}_{MS})$
HTGR	165	7.0	2,754	$E_{gen} = 1 - 0.5074\ (\dot{m}_{ext}/\dot{m}_{MS})$

As expected, results of this analysis showed that increasing the extraction mass flow rate causes a larger reduction in electricity generation. Additionally, the extraction of higher temperature/pressure steam will result in a larger reduction in electricity generation than extraction from lower pressure streams. While high levels of extraction are shown here, it should be noted that for existing cogeneration nuclear reactors, the amount of heat removal is minor (~5%) [39].

The relationships provided in Figure 14 and Table 23 can be applied to many cogeneration scenarios. To do so, one must relate the amount of steam extracted to the amount of heat provided to the heat application, which is likely not the same as the amount of heat removed from the NPP. For a given rate of extraction, the amount of heat removed from the NPP is known; however, the amount of heat that is provided to the heat application is dependent on the temperature requirements of the given application and the integration design. Here, it is assumed that the heat from the extracted steam is transferred to the heat application working fluid via a process heat exchanger, and only one extraction stream supplies this heat. In this case, the amount of heat supplied to the heat application can be calculated as the extraction mass flow rate multiplied by the change in enthalpy on the NPP side of the heat exchanger or as the mass flow rate on the heat application side of the heat exchanger multiplied by the change in enthalpy on the heat application side of the heat exchanger, as shown in Equation 9.

$$Q = \dot{m}_{ext}\Delta h_{ext} = \dot{m}_{app}\Delta h_{app}$$

Equation 9. Conservation of energy equation for the process heat exchanger.

Where,

- Q [kW] is the amount of heat supplied to the heat application
- $\dot{m}_{ext}$ and $\dot{m}_{app}$ [kg/s] are the mass flow rates on the NPP side and heat application side of the heat exchanger, respectively
- Δh_{ext} and Δh_{app} [kJ/kg] are the changes in enthalpy across the NPP side and heat application side of the heat exchanger, respectively.

The conditions of the inlet and outlet streams on the heat application side of the heat exchanger are dependent on the system design and energy requirements and will therefore be specific to each heat application. On the NPP side of the heat exchanger, the conditions of the inlet stream are determined by the extraction location, while the conditions of the outlet stream can vary based on the heat exchanger design. Commonly, some pressure drop is assumed across the heat exchanger, and the temperature of the outlet stream on the NPP side is assumed to be some amount higher than the temperature of the outlet stream on the heat application side, commonly 10°C. This approach for quantifying the relationship between steam extraction, electricity generation, and heat provided to the heat application is demonstrated in Section 5.4 for district heating.

5.3. Clean Hydrogen Production

One non-grid application for nuclear power that has gained global interest is clean hydrogen production. High-temperature steam electrolysis (HTSE) is one method of hydrogen production that can be coupled with nuclear power to produce emissions-free hydrogen. HTSE systems operate around 700–800°C, which is a higher temperature than most NPP designs can supply [40]. However, this high-temperature heat can be effectively supplied by recouperation and electric topping heaters. Rather, low-temperature heat from an NPP can be used for feedwater vaporization, which only requires temperatures around 100–200°C [40]. In addition to heat, the HTSE systems require electricity (both ac and dc), which can also be supplied by the NPP along with an ac-dc rectifier.

Previous analysis developed a plant design and cost estimation for an HTSE system integrated with an NPP [40], the results of which will be presented here. Some updates and adjustments have been made to the original cost estimates including:

- Adjusted plant capacity to 10 MW_{dc}, 20 MW_{dc}, 100 MW-dc, and 500 MW_{dc} sizes
- Changed HTSE plant type to FOAK (does not include cost reductions from learning effects)

- Adjusted the 10 and 20 MW_{dc} case stack costs to the value computed for 100 MW/yr manufacturing capacity [41]: $145/kW plus 10% contingency and 30% markup ($207/kW-dc total)
- Adjusted the 100 and 500 MW_{dc} case stack costs to the value computed for 1,000 MW/yr manufacturing capacity [41]: $78/kW plus 10% contingency and 30% markup ($112/kW-dc total)
- Updated rectifier cost to $220/kW [42]
- Adjusted "engineering and design" and "process contingency" indirect cost multipliers to represent the FOAK plant type rather than NOAK plant type.

The resulting hydrogen production rate and cost estimates are presented in Table 24 for four different HTSE system sizes (presented in terms of the amount of dc electricity the stack consumes). The cost estimates for varying system sizes show that while the energy requirements for each system are the same, the systems benefit from economies of scale in both OCC and O&M categories (most notable in OCC where a reduction in USD/kW_{DC} of more than 50% is observed).

Table 24. Hydrogen production capacity and cost estimates from [40].

HTSE Plant Size [MWe]	10 MW_{dc}	20 MW_{dc}	100 MW_{dc}	500 MW_{dc}
Plant Design Capacity [tonnes H_2/day]	7.0	14.0	70.2	351
Cell Degradation Factor	96.7%	96.7%	96.7%	96.7%
OCC [USD/kW_{dc}]	$2,119	$1,783	$1,230	$1,030
Fixed O&M [USD/kW_{dc}/yr]	$160	$117	$64	$46
Variable O&M [USD/MW_{dc}-h]	$9.0	$8.7	$5.0	$4.8

The plant design capacity is the theoretical production rate if the plant were to operate at a 100% capacity factor, not accounting for stack degradation; however, the actual plant output will be lower. Over time, the stack will degrade, resulting in a decrease in hydrogen production. Here, it is assumed that stack degradation causes the actual plant output to decrease to 96.7% of the design capacity when averaged over the course of the year. Therefore, to calculate the actual plant output, the plant design capacity should be multiplied by the cell degradation factor and the operational capacity factor. For example, to calculate the actual plant output for the 10 MW_{dc} system assuming a 90% capacity factor, the plant design capacity (7.0 tonnes/day) should be multiplied by the cell degradation factor (96.7%) and the capacity factor (90%), resulting in an actual average plant output of 6.1 tonnes/day.

The OCC includes the stack cost, BOP costs equipment costs, installation costs, and indirect costs, including site preparation, engineering and design, contingency, and land. The fixed O&M costs include labor, general and administrative costs, property tax and insurance, as well as maintenance and repair costs. The variable O&M costs include the cost of process and cooling water, annual stack replacement, and unplanned equipment replacement costs. It should be noted that the variable O&M does not include the cost of heat or electricity. Instead, these costs can be determined based on the energy requirements for the HTSE system. The thermal and electric energy requirements (corresponding to the plant design capacity) are provided in Table 25, as well as the total reactor thermal power needed to provide this energy. This value is calculated by dividing the electrical consumption requirement by the NPP thermal efficiency and adding this to the thermal consumption requirement. This approximation assumes that main steam is used to supply heat to the HTSE system, which is provided at 155°C.

Table 25. Energy requirements for HTSE system coupled with NPPs of varying thermal efficiencies.

	PWR (33% efficiency)	HTGR (40% efficiency)
Electrical Energy Consumption [kW_{ac}-h/kg_{H2}]	36.8	36.8
Thermal Energy Consumption [kW_{th}-h/kg_{H2}]	6.4	6.4
Total Reactor Thermal Power Required [kW_{th}-h/kg_{H2}]	118	98

The amount of electricity that is no longer available to sell to the grid due to the operation of the HTSE system can be determined by multiplying the total reactor thermal power required for operating the system by the NPP thermal efficiency. Thus, for every kilogram of hydrogen produced, the amount of electricity available to sell to the grid decreases by 38.9 kW_e-h for the PWR and 39.4 kW_e-h for the HTGR. This includes both the electricity that is consumed by the HTSE system and the electricity that is no longer generated due to the heat removal from the BOP.

Here it was assumed that main steam is used to provide heat to the HTSE system although the steam provided to the HTSE system is at 155°C, which could be provided by a lower temperature extraction stream. However, since the energy requirements for the HTSE system are dominated by electricity consumption rather than thermal consumption, the impact that the extraction location will have on electricity generation is minimal. Thus, no alternative extraction locations are considered here.

5.4. Nuclear Power Plant Performance for District Heating

Another way in which nuclear power can support net-zero goals is through district heating, which provides decarbonized heat to nearby users. The overall cost of a district heating system includes the cost of heat production, transport, and distribution [39]. The overall system cost is dominated by the capital cost, which is largely dependent on the cost of the distribution pipeline, which can be as high as 10 million Euros per kilometer [39]. Therefore, the separation distance between the NPP and end user has a large influence on the overall system. A recent study that reviewed and characterized past and current nuclear district heating systems reported separation distances as low as 2 km and as high as 64 km [43]. Due to the site-specific nature of the distribution pipeline cost, the capital costs of a district heating project should be evaluated on a case-by-case basis.

In addition to the capital costs of a nuclear district heating system, it is also important to consider the impact that supplying heat to the district heating system will have on electricity generation. Heat removed from the BOP for district heating is no longer available for electricity generation, thus reducing the amount of electricity that can be produced. The relationship between steam extraction and electricity generation, provided in Table 23, can be used to approximate the relationship between the amount of heat supplied to a district heating system and the resulting decrease in electricity generation.

Typically, a heat exchanger is used to transfer heat from the extracted steam to the district heating working fluid [43]. By assuming the thermodynamic conditions of the heat exchanger inlet and outlet streams, the amount of heat provided to the district heating system can be related to the steam extraction mass flow rate as well as electricity production rate. To do so, conditions for the district heating supply and return streams must be selected. Most existing nuclear district heating systems utilize hot water (rather than steam) as the working fluid [44]. The temperature of the hot water supplied to the district heating system is typically 80–130°C, while the return temperature is typically 45–70°C [44]. Here, the hot water supply and return temperatures are assumed to be 130°C and 70°C, respectively. The lower temperature extraction options provided in Figure 14 are a sufficiently high temperature to provide heat at the desired temperature of 130°C; the thermodynamic conditions of these streams are provided in Table 23. To determine the enthalpy of the outlet stream on the NPP side of the condenser, it is assumed that there is no pressure drop, and the temperature (80°C) is 10°C higher than the district heating hot water return temperature (70°C). With these assumptions, the curve fits the data provided in Table 23 and the relationship shown in Equation 9; the amount of heat supplied to the district heating system can be related to the amount of electricity generated by the NPP, as shown in Figure 15. The amount of heat supplied to the district heating system is expressed as the percentage of total reactor thermal power, and the amount of electricity generated is normalized to the nominal (no extraction) value. Additionally, curve fits are provided in Table 26; Q_{DH} represents the amount of heat provided to the district heating system (MW]), while Q_{RX} represents the total reactor thermal power (MW), as provided in Table 22.

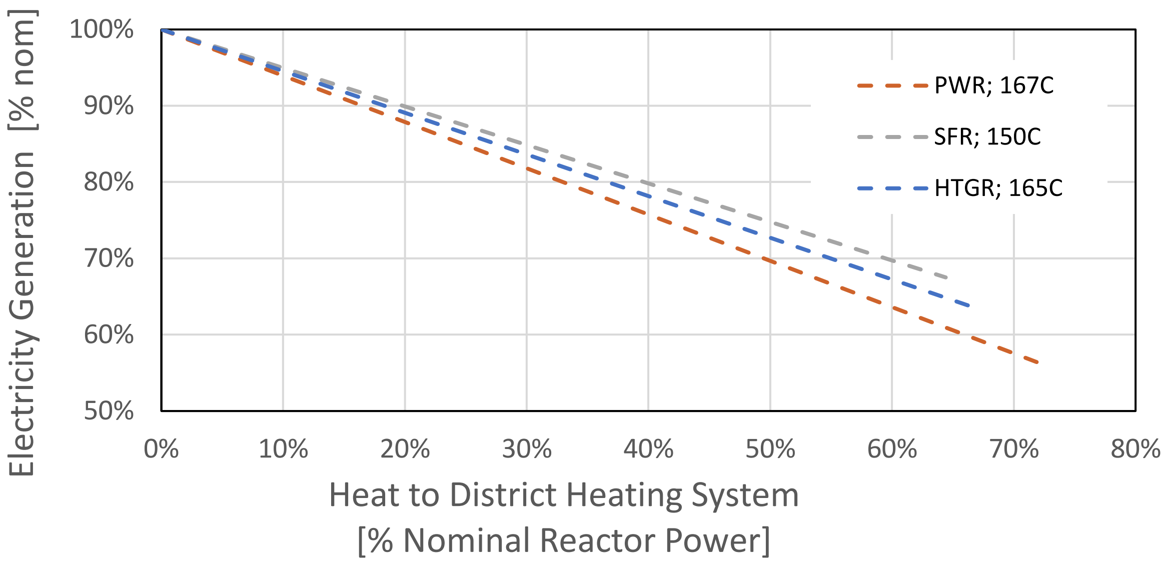


Figure 15. Heat extraction for district heating.

Table 26. Curve fits relating heat supply to a district heating system to NPP electricity generation.

Reactor Type	Extraction Steam Temperature	Extracted Steam Enthalpy	Extraction Curve Fit
PWR	167°C	2788 kJ/kg	$E_{gen} = 1 – 0.6064\ (Q_{DH}/Q_{RX})$
SFR	150°C	2596 kJ/kg	$E_{gen} = 1 – 0.5044\ (Q_{DH}/Q_{RX})$
HTGR	165°C	2754 kJ/kg	$E_{gen} = 1 – 0.5459\ (Q_{DH}/Q_{RX})$

Note that this calculation quantifies the amount of heat provided to the district heating system at the location of the nuclear plant, not the amount of heat that is available at the end user's location. There is no attempt to quantify thermal losses along the transmission line since this will be affected by many site-specific factors. Additionally, it should be noted that although these results are provided for a large range of values, it is common for the amount of heat removal during a cogeneration application to be minor (~5%) [39].

6. LIMITATIONS AND FUTURE WORK

The modeling recommendations provided in this report are not without weaknesses and can be improved as part of future work. Several key aspects to consider further are highlighted below:

1. More representative costs for nuclear overnight costs are needed. An alternative approach could be to focus on observed costs throughout the world and provide a baseline for the NZW participating countries.
2. Additional work is needed to make the breakdown more consistent with each country's industrial base by analyzing the potential of each country to develop suppliers in the nuclear industry value chain and how that would affect the costs of the local components

3. A more granular and robust methodology is needed to account for local cost multipliers. In an ideal case, all labor-based expenses would be broken into hours spent, type of laborer, and rates. These would then be adjusted on a country-by-country basis, accounting for changes in rates and productivity. Furthermore, a more detailed methodology may be able to account for non-local labor factions that should be held constant across all nations.
4. Additional work is also needed to improve the methodology for O&M cost estimation across countries. Notably, the discrepancy between variable and fixed costs should be investigated further to improve accuracy when costs are disaggregated from a total O&M cost number to fixed and variable costs.
5. The impact of cost reductions at multi-unit sites (both on OCC and O&M) could be investigated in further details if models can capture these nuances.
6. The costs associated with non-grid applications could be further investigated—in particular, the costs associated with plant modification for cogeneration scenarios. Additionally, the HTSE system costs provided assume construction in the United States and should be adjusted for construction in other NZW participating countries.

In addition to improvements of the methodology highlighted above, the study could be expanded to account for additional considerations. For instance, microreactors are expected to be of interest to remote communities. Microreactor costs are expected to vary substantially from those observed for the larger reactors emphasized in this study. In addition to hydrogen, synthetic fuels (ammonia- or carbon-based) could be considered as part of the model. Similarly, thermal energy storage (and other forms of storage) could be considered when accounting for maneuverability of reactors and load-following. Coupling a nuclear reactor to a direct air capture system results in net-negative emissions and therefore could be of particular interest when exploring aggressive net-zero targets. Last, siting constraints are also important considerations for the large scale deployment of nuclear technology.

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7. APPENDIX

7.1. Appendix A – Cost of Capital

While not a primary focus of this report, some research was done into the expected cost of capital for nuclear projects and how this may vary between NZW countries. The cost of capital was taken considering the ownership class (public or private) of the energy companies/utilities in each country. When the ownership is public, data from the short-term interest rate from each central bank was taken from Reference [45]. For those countries with private utilities, the data was taken from Reference [46].

Between countries, it is necessary to take into account inflation and exchange rate variations to explain the different rates. They are not independent from the weighted average cost of capital (WACC). Also, it is vital to note that the WACC is expressed in the currency of each country. So, a higher WACC does not mean a higher internal rate of return in dollars. When the WACC is transformed from the country currency to dollars using the exchange rate, it will result in a lower WACC in dollars closer to the United States, and the difference will be the risk premium.

The interest rate from the central bank (in this case for Ukraine) is the nominal short-term interest rate not adjusted by inflation and controlled by the central bank authority representing the opportunity cost of the economy (i.e., it is the minimum rate that another investment should pay if they want to be competitive against the central bank by putting money in the bank instead of in any investment). The short-term rate is the only variable the central bank controls (as is the case in most countries in the world). Furthermore, the concatenation of the short-term interest rate will be the long-term rate. In summary, the short-term rate can be used for long-term modeling and recovery and post-recovery investments. In the long run, it is assumed that the variables tend to return to their steady state (long-term equilibrium) position, and furthermore, there should not be a difference between the interest rate of the central bank and any other interest rate of the economy.

Table A-1. Country-specific weighted average cost of capital by ownership type.

Country	Owner	WACC
United States	Public/Private	[5%;10.8%]
Chile	Private	11.30%
Indonesia	Public	5.75%
Egypt	Public	18.25%
Nigeria	Private	8.88%
Argentina	Public	91%
Thailand	Public	2%
India	Public/Private	[4.54%;6.5%]
Ukraine	Public	25%
South Africa	Public	8.25%

7.2. Appendix B – Labor Productivity Differences

As discussed in the main body, one limitation of the high-level translation of costs from the United States to NZW participants was that this did not account for granularity in the wages and hour spent in construction. While changes in productivity will also have an impact on labor costs (countries with less productive construction labor will require more hours incurring more cost to complete the project), this is not entirely captured by the high-level cost estimation used here. However, productivity changes are partly captured in the index selected to normalize energy-specific construction between countries. Starting from the assumption that the price of a given good is the sum of the inputs used directly and indirectly in its production. The cost of commodities in each country (steel, cement, etc.) results from the capital productivity level in each industry, the cost of inputs for production, plus the cost of workers' hours (wages). If cement is cheaper in country A, this would also indicate that the capital could be more productive, but it could also be because the wage paid there is lower, or the minimum wage is lower, or some other production input is cheaper, etc. In this sense, it becomes relevant to understand what could happen to the workers' wages.

It is possible to write the wage in one country as a function of four variables as follows:

$$Wage = f(labor\ skill, min\ wage\ policy, labor\ bargaining\ power, labor\ productivity)$$

Furthermore, it is not easy to differentiate and measure the effect of each variable on the final cost of a commodity. Based on the minimum wage, bargaining power and worker skills are relatively fixed in the short and medium run. For instance, governments are not changing minimum wage from year-to-year, they are not enacting laws giving more bargaining power to workers, and workers are not obtaining new qualification each year. It can be assumed that the change in cost year-to-year is due to productivity changes or because costs of a critical input used in the production process went down (e.g., because of subsidized electricity or the use of strategic oil reserves that decrease oil prices).

Differentiating the effects of variables on cost levels is only important when working with time series rather than a specific point in time. Higher productivity should be reflected in the lower production costs and lower market prices of the corresponding prices of inputs or final goods even when the hours worked are not considered, as this study is using monetary values (physical quantity times a price) and not only physical quantities, but the effect of productivity is also implicitly included. For instance, higher productivity (from labor and capital) relates to lower production costs of the commodities used directly and indirectly in the reactor's construction project. Furthermore, higher productivity could be reflected in lower monetary values. If a productivity effect is added, it will essentially be counted twice because the prices already reflect the productivity effect.

7.3. Appendix C – Gross Fixed Capital Formation Components Description

The index included in the GFCF by country is presented below. Note the costs are significatively different for each country relative to the United States.

Machinery and Equipment: This ICP classification heading covers expenditures for fabricated metal products, except machinery and equipment; electrical and optical equipment; general purpose machinery; special purpose machinery; road transport equipment; and other transport equipment.

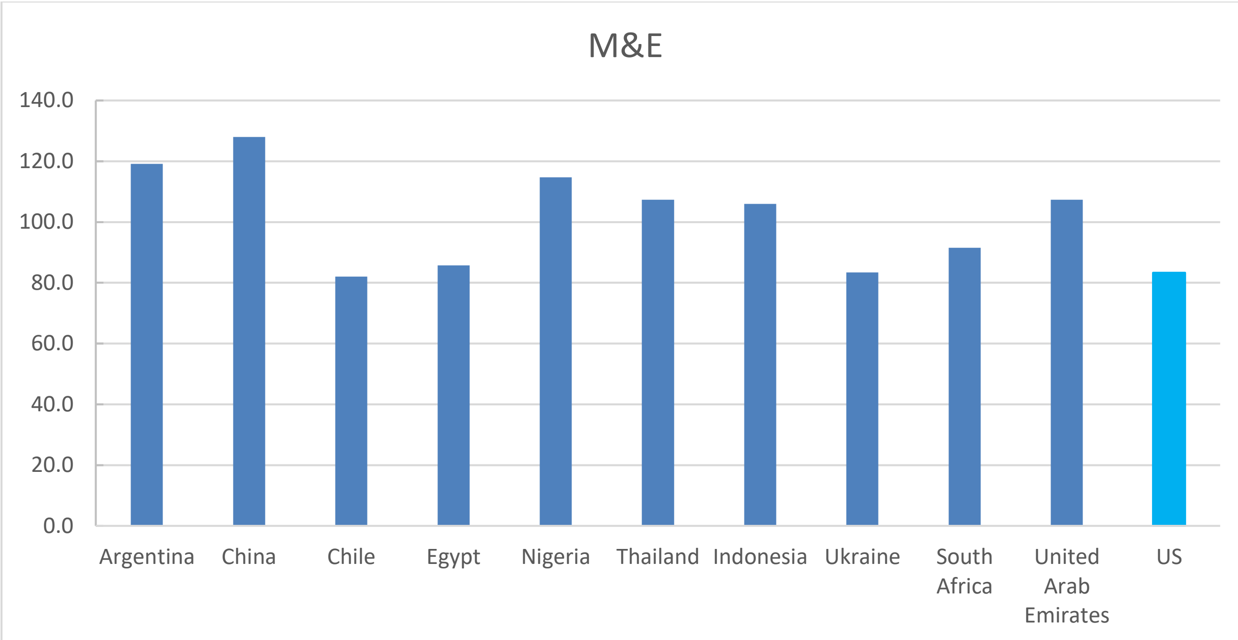

Figure 16. Price-level machinery and equipment by country.

Construction: This ICP classification heading covers expenditures for residential buildings; non-residential buildings; and civil engineering works.

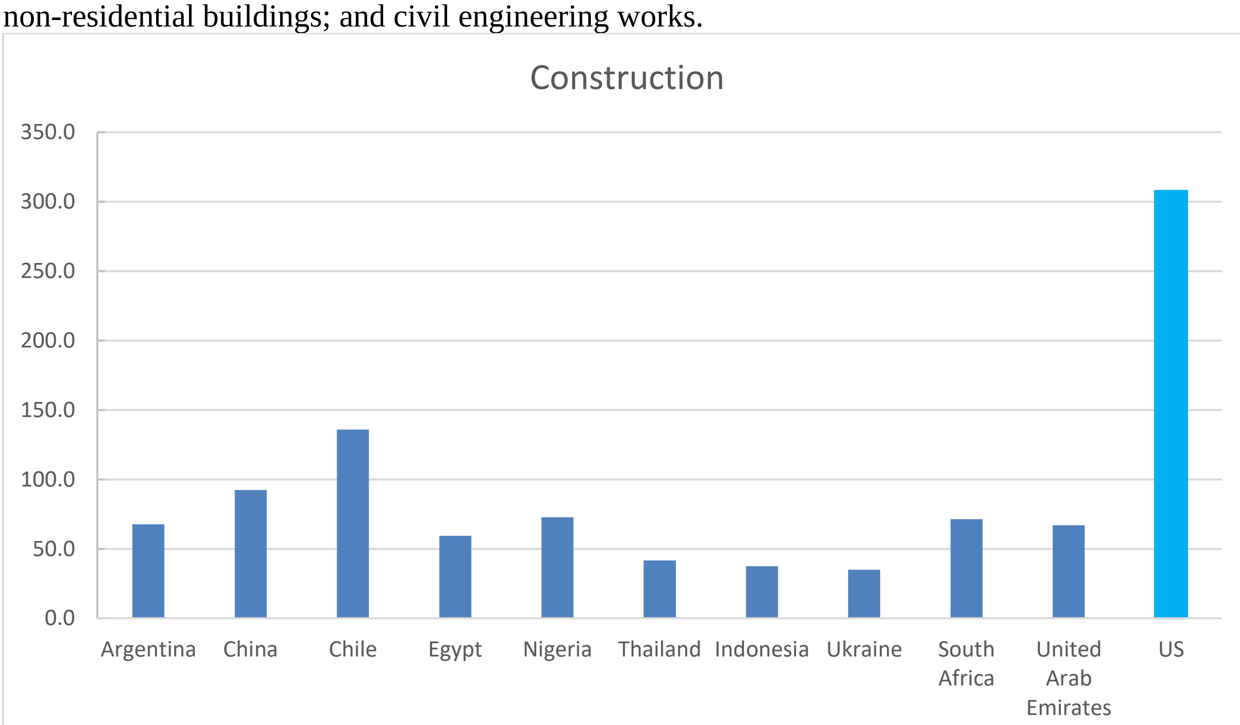

Figure 17. Price-level construction by country.

Other Products: This ICP classification heading covers expenditures for other products related with the gross fixed capital formation.

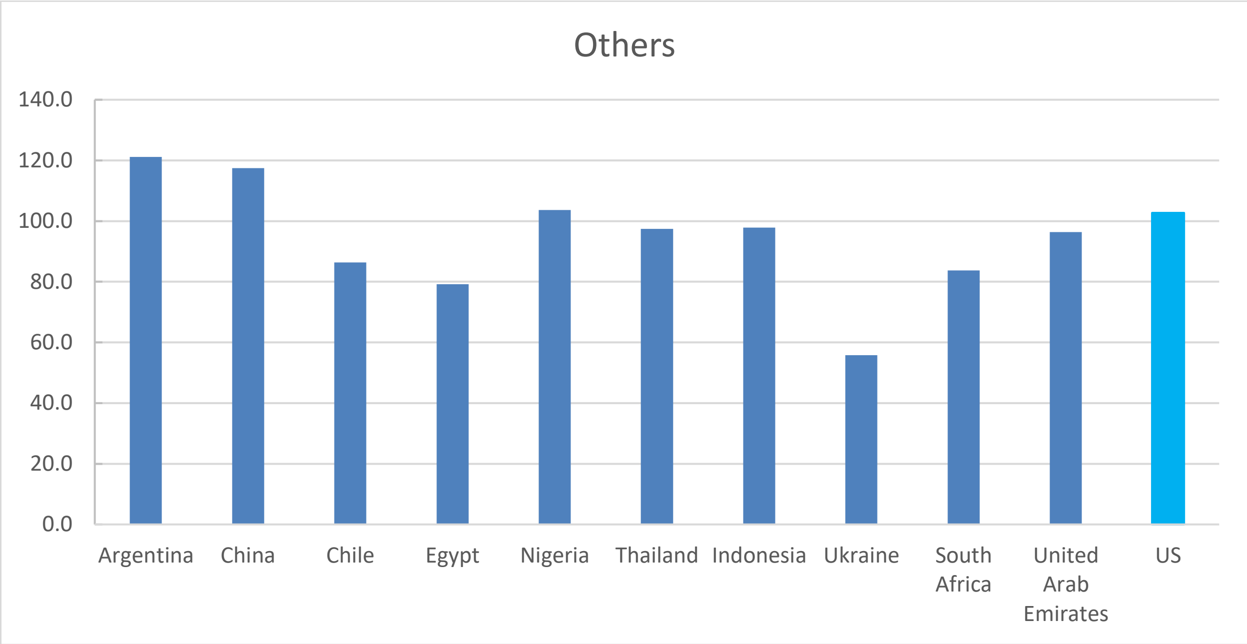

Figure 18. Price-level other products by country.

7.4. Appendix D – Preconstruction and Supplementary Cost Categorization

Note that for preconstruction and supplementary costs, it was assumed that large reactors and SMRs have identical breakouts.

Table 27. Preconstruction cost breakout.

Account Number	Account Description	Labor	Other
11	Land and Land Rights	0%	100%
12	Site Permits	0%	100%
13	Plant Licensing	100%	0%
14	Plant Permits	0%	100%
15	Plant Studies	100%	0%
16	Plant Reports	100%	0%
17	Community Outreach and Education	NA	NA

Account Number	Account Description	Labor	Other
18	Other Pre-Construction Costs	100%	0%
19	Contingency on Preconstruction Costs	0%	100%

Table 28. Supplementary cost breakout.

Account Number	Account Description	Labor	Other
51	Taxes	0%	100%
52	Insurance	0%	100%
53	Spent Fuel Storage	NA	NA
54	Decommissioning	0%	100%
55	Other Owners' Costs	NA	NA
56	Fees	NA	NA
57	Management Reserve	NA	NA
59	Supplementary Contingencies	0%	100%