Integrated Resource Plan 2026

VOLUME 1 / INTEGRATED RESOURCE PLAN

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TVA TENNESSEE VALLEY AUTHORITY

Executive Summary

Unleashing American Energy

For over 90 years, the Tennessee Valley Authority (TVA) has executed its mission to serve the Tennessee Valley region – to provide affordable and reliable power, be a responsible steward of the environment, and support economic development. That mission continues as TVA plans the energy system of the future, working to unleash American energy in the region for the coming decades.

TVA's 2026 Integrated Resource Plan (IRP) and associated programmatic Environmental Impact Statement (EIS) evaluate the long-term demand for power in the TVA region, the resource options available for meeting that demand, and the potential economic, operating, and environmental impacts of these options. Consideration of stakeholder input is integral to TVA's IRP process. The IRP will provide strategic direction for meeting the region's energy needs between now and 2050, establishing a strong planning foundation and informing TVA's next long-range financial plan.

Why is the IRP Important?

Having the right resources at the right time to power the homes, businesses, and industries in the region requires continual and proactive planning. Developing and building new power plants to serve the region's energy needs often takes several years or more. Periodically, TVA develops an IRP that goes beyond standard annual asset planning to take a broader view of potential electricity demand, evolving regulations, and technology advancements, all while incorporating stakeholder input into the planning process.

The Tennessee Valley is one of the fastest growing regions in the nation, and strides are being made in emerging energy technologies, making the work of this IRP especially important. The IRP recommendations, which are based on statutory least-cost planning principles, will shape the future power system, ensuring that the region has affordable, reliable, and resilient energy for years to come.

TVA Overview

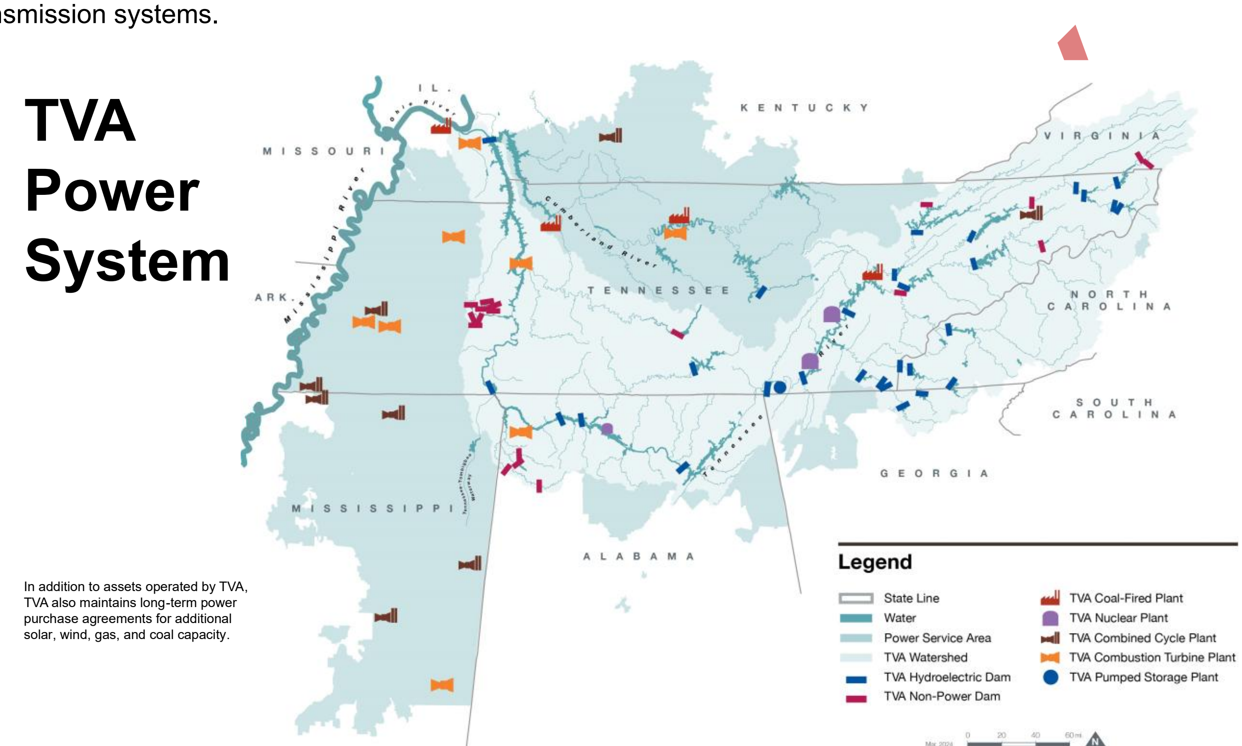
TVA's Mission

TVA was created by Congress in 1933 and charged with a unique mission – to improve the quality of life in the Valley through the integrated management of the region's resources. For more than 90 years, TVA has carried out this mission to serve the region, providing affordable and reliable energy, being a responsible steward of the environment, and supporting economic development. TVA funds virtually all operations through electricity sales and power system bond financing. TVA sets rates as low as feasible and reinvests net income into power system improvements and economic development initiatives. Additionally, TVA provides flood control, navigation, land management, and natural resource stewardship for the Tennessee River watershed. Today and in the future, TVA will drive growth and prosperity across the seven-state region through excellence in operations, financial discipline and a commitment to the fundamentals of TVA's mission.

TVA Power System

As the nation's largest public power supplier, TVA delivers affordable, reliable, and resilient electricity to 153 local power companies and 62 directly served customers. The TVA power system serves approximately 10 million people in a seven-state, 80,000 square-mile region. TVA's portfolio has evolved over the years to meet growing demand for electricity, diversify the generation mix, and ensure reliable service at low rates. In Fiscal Year (FY) 2025, TVA delivered nearly 168 billion kilowatt-hours of electricity to customers from a power supply that was 33% nuclear, 35% natural gas, 18% coal-fired, 10% hydro, and 4% wind and solar. Additionally, TVA programmatic energy efficiency efforts reduced power demand by approximately 257 gigawatt-hours of net incremental savings.

To meet the region's energy needs in all types of weather, TVA maintains 42,140 megawatts (MW) of generating capability (FY 2025). TVA operates a generating asset portfolio of 32,268 MW, maintains long-term agreements with third-party power producers totaling 8,482 MW, and offers demand response programs that provide 1,390 MW of capacity. To reliably deliver this energy, TVA operates one of the nation's largest transmission systems.



Objectives of Resource Planning

Integrated resource planning at TVA is grounded in least-cost principles. TVA applies the following least-cost principles, aligned with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, and resilient energy over the long term:

Low Cost	Risk Informed	Environmentally Responsible
Reliable and Resilient	Diverse	Flexible

Least-cost planning evaluates cost, operational, environmental, and other risk factors in order to provide reliable service at the lowest system cost. A system that is flexible, resilient, and diverse is more reliable, year in and year out, so these aspects are key considerations. Planning must also ensure compliance with all applicable environmental regulations, while considering opportunities to cost-effectively reduce environmental impacts. Finally, TVA evaluates variations in electricity demand, commodity prices, resource costs, and United States (U.S.) energy policy to ensure plans are risk informed and flexible to adapt as the future evolves. Metrics used in the IRP reflect least-cost planning principles, providing insights into tradeoffs across alternative business strategies. When making specific asset decisions, TVA stays within the planning direction and resource ranges that were studied and approved in the most recent IRP.

Integrated resource planning at TVA is not used to set or establish wholesale or retail electricity rates. Additionally, the IRP does not identify specific sites for new resources or act as an approval mechanism for specific generation projects. Finally, TVA's IRP is not designed to be a distribution integrated resource plan.

Delivering on Prior IRP Recommendations

Before embarking on the 2026 IRP, it was important to evaluate the progress made on recommendations from the last IRP. The 2019 IRP provided strategic direction for the existing fleet, system flexibility, renewable and distributed resources, energy usage, and distribution planning. Meaningful progress has been made, as shown below:

- Maintained the existing, low-cost nuclear and hydro fleets and pursued nuclear license extensions
- Invested in the gas fleet to maintain reliability and enhance system flexibility
- Added more solar and battery storage to the resource mix
- Evaluated energy efficiency potential to inform future efforts
- Increased investment in low-income energy efficiency programs

TVA is also investing in the future bulk transmission grid. This includes a new, state-of-the-art System Operations Center which is nearing completion. The center will employ smart technologies to improve reliability, have improved physical security from the previous center, and be flexible to help accommodate operational needs of the future. The new system is expected to be complete and fully operational in 2026.

Key Signposts Informing this IRP

The 2019 IRP identified key signposts – or market signals – to monitor. These signposts included changing market conditions, evolving policy and regulations, and technology advancements. Movements in these signposts influenced refinements to annual plans and helped determine the timing for initiating the next IRP.

Changing Market Conditions

After a decade of flat electricity demand, the TVA region is now experiencing increasing demand for electricity driven by population, employment, and industrial growth, weather trends, and increasing electrification. Industrial forecasts are being driven in part by growth in high-energy users like data centers and electrification of processes. TVA's planning efforts must also account for volatility in both winter temperatures and natural gas prices. Finally, TVA is experiencing rising consumer demand for specific characteristics in generation resources, and in some cases, customers are willing to pay more to utilize those options.

Evolving U.S. Energy Policy

U.S. energy policy and regulations have evolved since the last IRP. Throughout 2025 and continuing in 2026, the utility industry experienced significant policy and regulatory shifts. Executive Order 14156, issued January 20, 2025, formally declared a national energy emergency. In parallel, the U.S. Environmental Protection Agency (USEPA) announced intentions to provide regulatory relief affecting existing coal and future natural-gas generation. The USEPA proposed a rule to repeal all greenhouse gas emissions standards for the power sector under Section 111 of the Clean Air Act (the "2024 GHG Rule"), as well as a final rule authorizing state permit writers to extend compliance deadlines under the Effluent Limitation Guidelines (ELG) for steam electric generating units.

In addition to these policy and regulatory changes, the One, Big, Beautiful Bill Act (OBBB) was signed into law on July 4, 2025. OBBB included updates to investment tax credit (ITC) opportunities available for renewable, storage, and nuclear resources. All IRP scenarios reflect the impacts of OBBB on resource costs and national and regional energy prices.

Technology Advancements

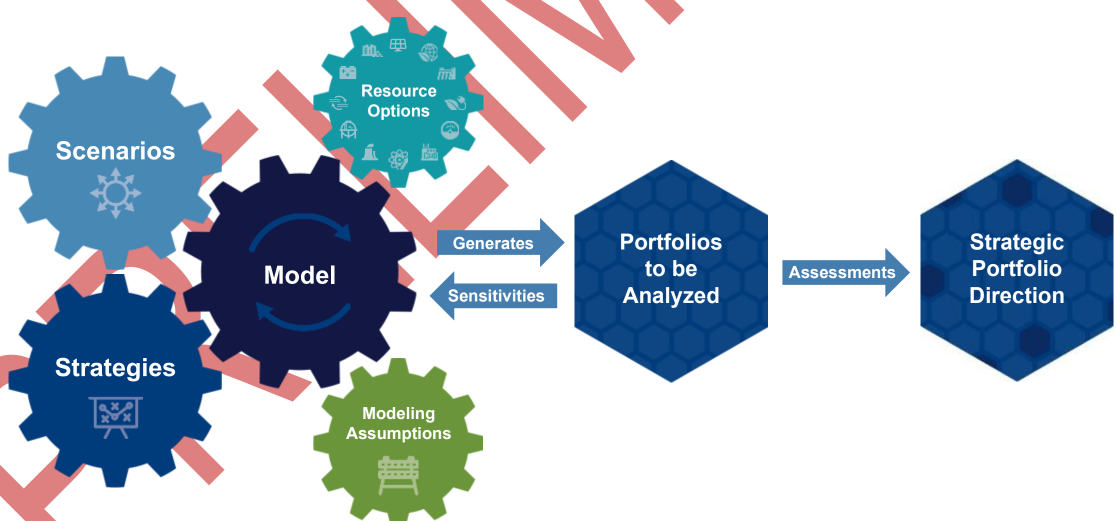
Progress is accelerating on emerging technologies such as advanced nuclear and advanced storage. TVA is collaborating with the Department of Energy, Oak Ridge National Laboratory, Electric Power Research Institute, universities, startup accelerators, and other industry partners to advance the viability and cost-effectiveness of these emerging technologies. Additionally, TVA has gained experience with increasing amounts of new solar generation and battery storage on the system.

Ensuring that resources will be online to replace expiring purchased power contracts and resources reaching their end of life, meet expected load growth, and comply with evolving U.S. energy policy, as well as having confidence in new technology performance, will be essential to meeting the electricity needs of the region between now and 2050.

Planning Approach

Key Planning Elements

TVA used a rigorous and comprehensive scenario and strategy approach to evaluate potential paths for providing affordable, reliable, and resilient energy into the future. This framework is summarized in the graphic below, with each component explained further in the following sections.



Informed by stakeholder input and public feedback, scenarios and strategies were designed to be evaluated in the IRP. Scenarios explored possible futures that TVA may find itself operating in that have varying levels of macro-economic conditions, electricity demand, and environmental policy and regulations. Strategies modeled alternative approaches TVA could employ to meet electricity demand by emphasizing certain resource options.

For each unique scenario and strategy combination, the planning model solved for the lowest-cost generating resource portfolio. Each of these portfolios was then analyzed using metrics that reflect TVA's mission and least-cost planning principles. Sensitivity analysis was performed to answer key "what if?" questions, with consideration of IRP Working Group and Regional Energy Resource Council (RERC) input and public comments on the draft IRP and EIS. The EIS evaluated the environmental impacts of potential changes in the portfolio. Collectively, these evaluations informed the IRP recommendations for strategic portfolio direction included in this final IRP report.

Scenarios and Strategies

The three external scenarios and three business strategies evaluated in the IRP are summarized below. The scenarios explore potential futures, including varying electricity demand growth and potential for future environmental regulations. The strategies depict business approaches TVA could employ to meet energy demand in these future worlds.

SCENARIOS	STRATEGIES
1 Reference Represents TVA's current forecast that reflects moderate population, employment, and industrial (primarily data center) growth, weather-normal trends, growing electrification, and increasing efficiencies	**A Baseline Utility Planning** Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies
2 High Growth Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity	**B Innovation** Emphasizes emerging, firm and dispatchable technologies such as advanced nuclear and long-duration storage through innovation, continued R&D, and partnerships.
3 Carbon Legislation Reflects the impact of potential future carbon legislation designed to reduce power sector emissions.	**C Distributed** Emphasizes distributed technologies such as batteries, renewables, and demand-side programs to reduce reliance on central station generation and utilize virtual power plants

Resource Options

Maintaining resource mix diversity is fundamental to TVA's ability to provide affordable, reliable, and resilient energy to the residents, businesses, and industries in the region. The IRP considered a wide range of supply-side, distributed, and demand-side resources. Shown below are the resource options included, categorized by the following fuel types: nuclear, hydro, coal, natural gas, renewables, storage, and energy efficiency and demand response (EE and DR).

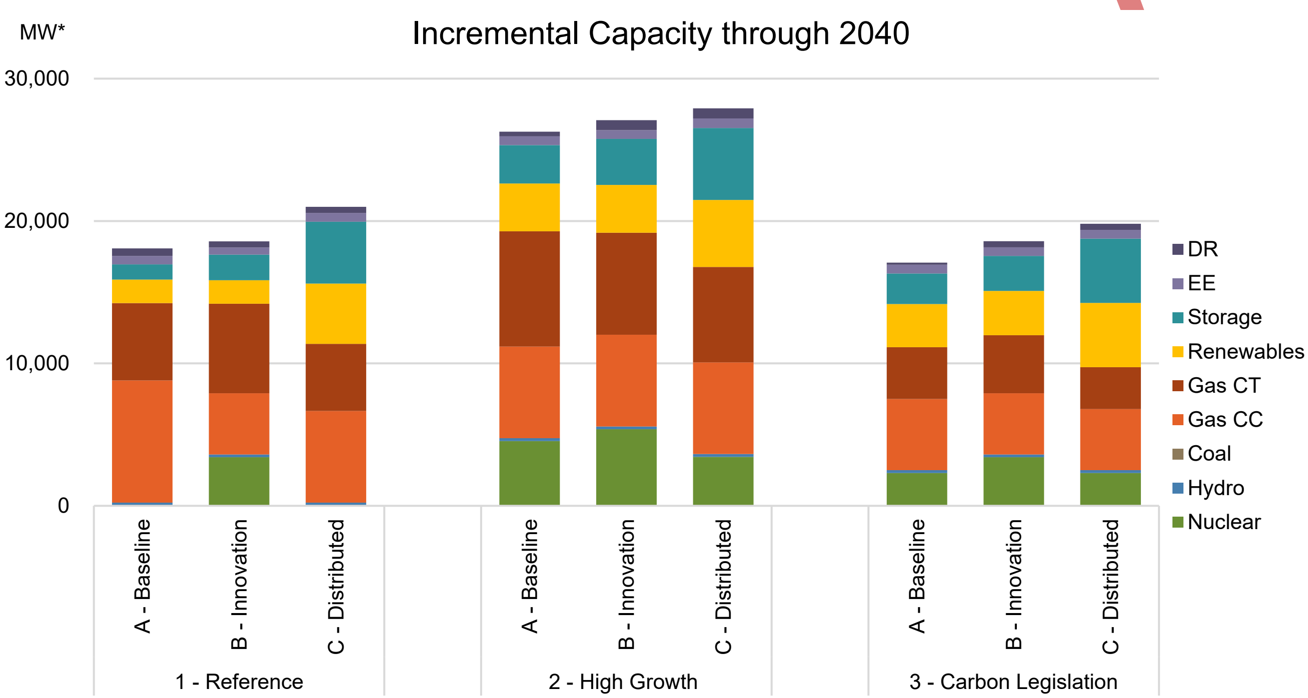
Nuclear	Hydro	Coal	Gas	Renewables	Storage	EE and DR
Advanced pressurized water reactor (APWR) Light water small modular reactor (LW SMR) Generation IV small modular reactor (Gen IV SMR)	Hydro uprates	Supercritical pulverized coal Supercritical pulverized coal with carbon capture	Combined cycle (CC) CC with carbon capture Combustion turbine (CT) Aeroderivative Reciprocating engine (RICE)	Utility-scale solar Distributed solar Midwest wind Southeast high-hub wind	Pumped storage Lithium-ion battery (4-hour) Advanced chemistry battery (8-hour) Distributed storage	Energy efficiency (EE) Demand response (DR)

Portfolio Results

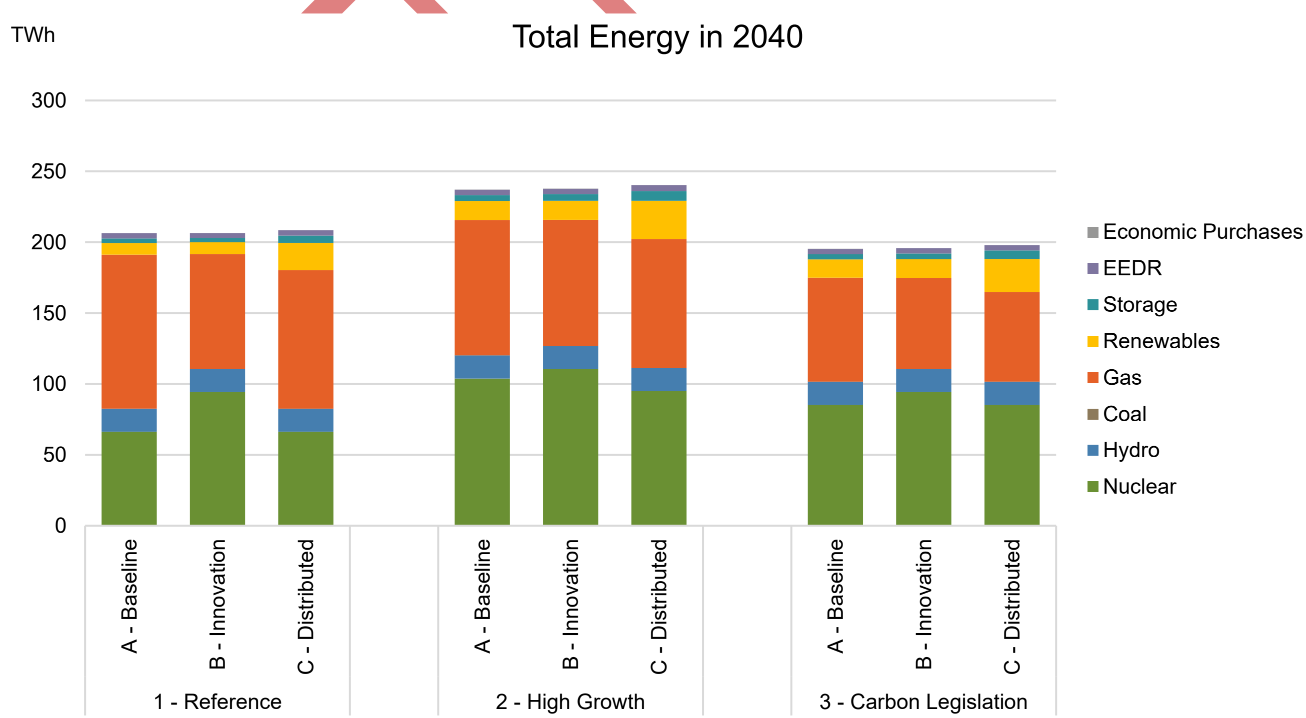
During the IRP process, TVA – with input from stakeholders and the public – considered a range of future scenarios, various business strategies, and a wide range of resource options. Applying the three strategies in the three scenarios generated nine potential resource portfolios to analyze.

2040 Portfolios

The charts below show the portfolio results through 2040. Results are presented in two ways – incremental capacity additions from now through 2040 and total energy in 2040. Incremental capacity represents the new resources selected to fill capacity needs. Capacity needs are driven by forecasted growth in energy demand and the expiration or expected end of life of approximately 11,000 MW of existing capacity. Total energy represents the economic dispatch of resources in the capacity plans for each portfolio. The results for each scenario are grouped together. Within a scenario, strategy results are grouped by resource type, which varies based on strategic focus and the impact on portfolio optimization.

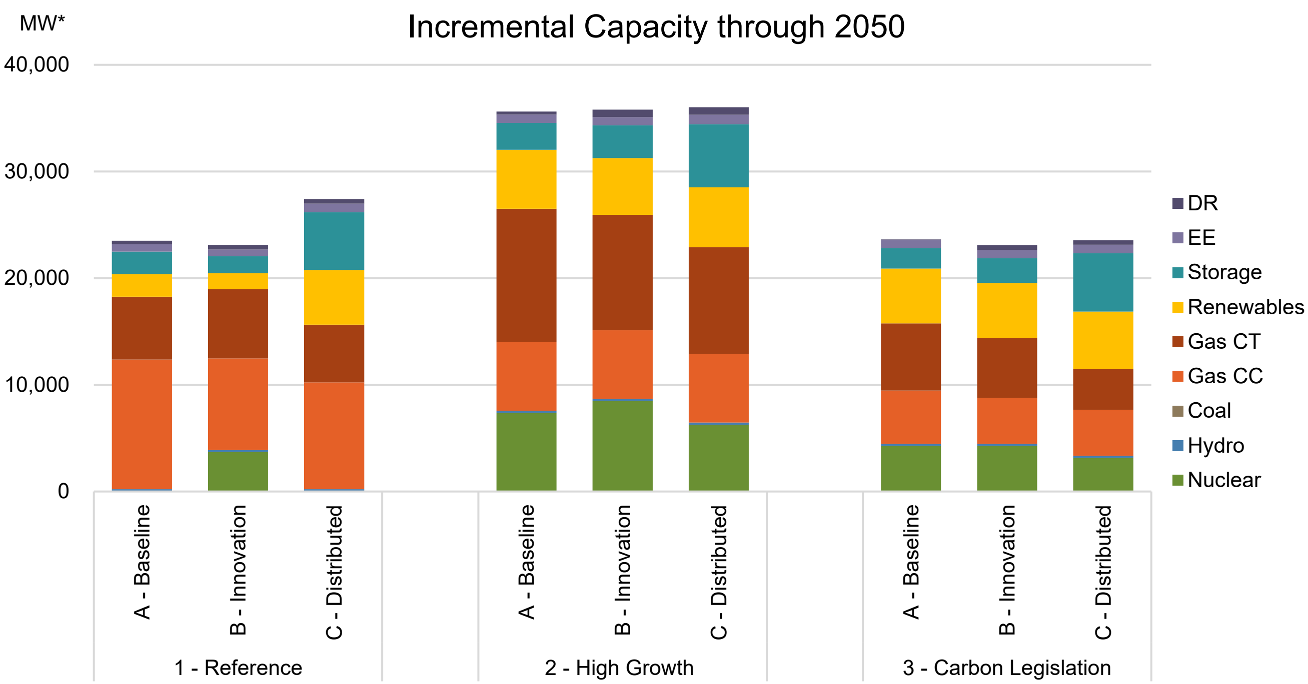


* MW summer net dependable capacity.

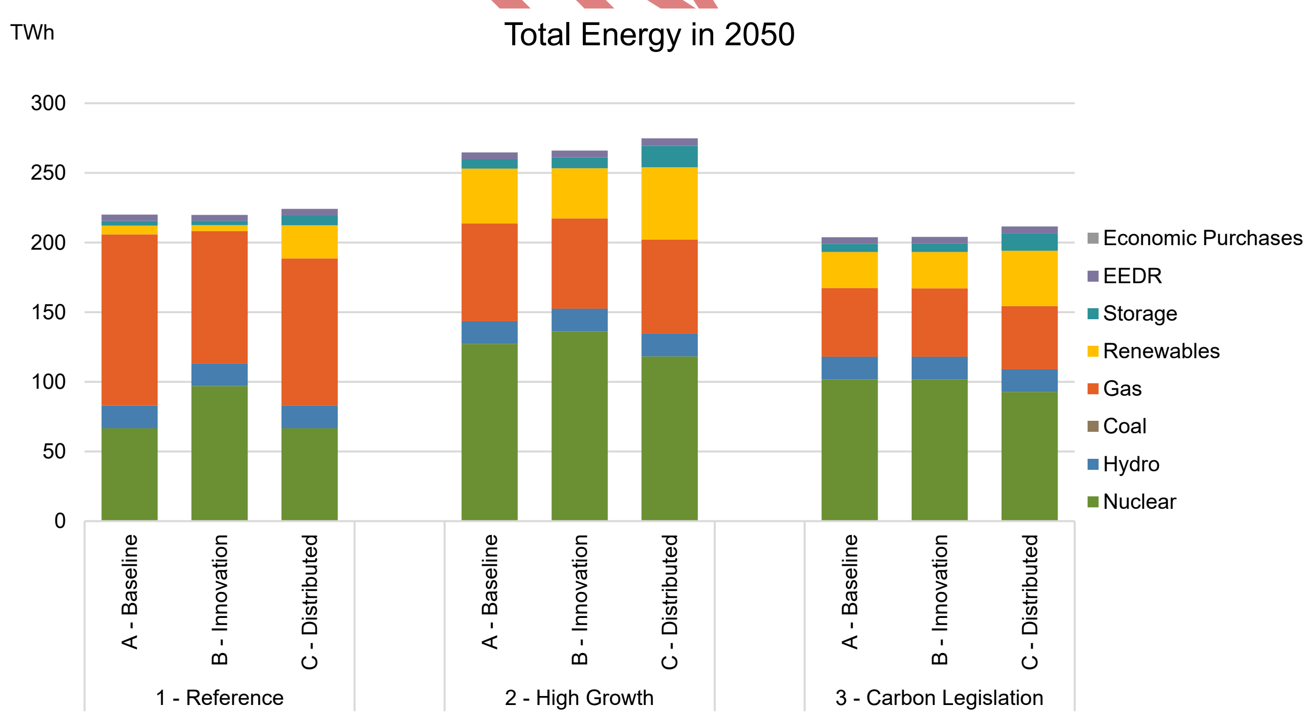


2050 Portfolios

The charts below show the portfolio results for 2050, including incremental capacity changes from now through 2050 and total energy in 2050. Capacity needs are driven by forecasted growth in energy demand and the expiration or expected end of life of approximately 14,000 MW of coal, gas, and renewable capacity. Total energy represents the economic dispatch of resources in the capacity plans for each portfolio.



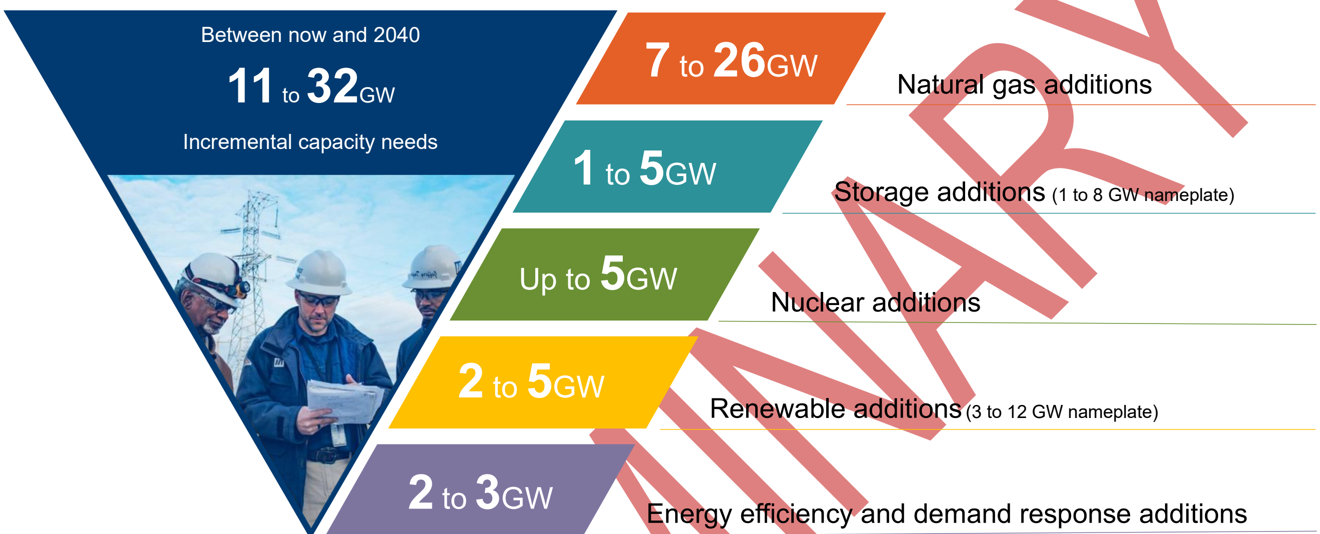
* MW summer net dependable capacity.



Key Themes

Uncertainty in electricity demand, legislative or regulatory actions, resource costs, and available technologies increases as the forecast horizon extends further into the future. The IRP analyzed potential ways the resource portfolio might evolve between now and 2050 to respond to changes in these key drivers, and insights gained from evaluating the entire planning horizon were used to inform strategic portfolio direction, with a focus on results through 2040. Key themes are expressed in gigawatts (GW), with one GW providing enough energy to power about 585,000 average homes.

Looking across all portfolios, including sensitivity analysis, through 2040, IRP results suggest:



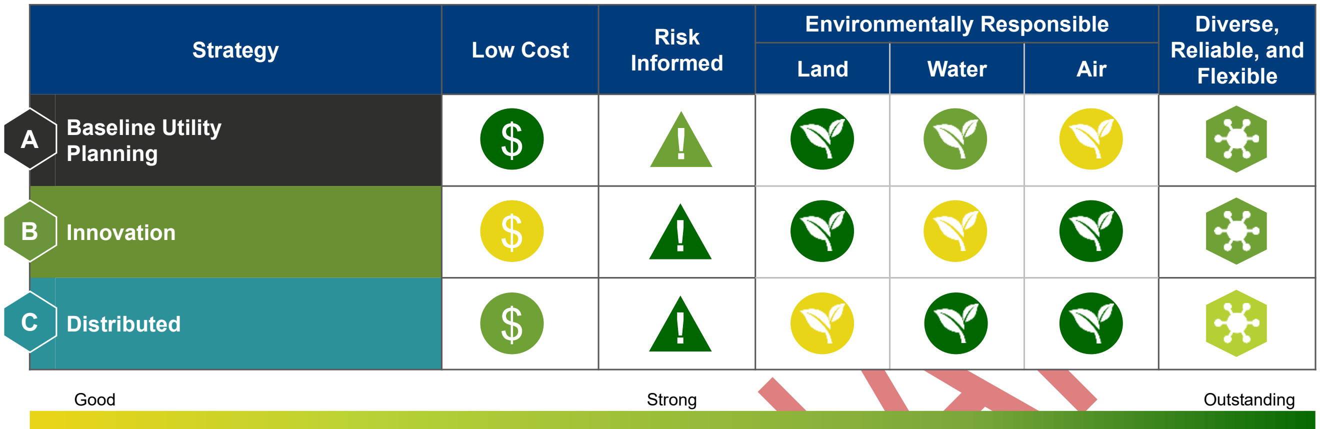
Power supply mix ranges, summarized in summer net dependable gigawatts (GW) above, vary based on energy demand, market conditions, policy and regulations, and technology advancements.

- New capacity is needed in all scenarios to support load growth or replace expiring and end of life capacity.
- Firm, dispatchable technologies are needed to ensure system reliability throughout the year.
- Gas expansion serves broad system needs, with the ability to provide firm, dispatchable capacity, economic energy, and system flexibility.
- Storage expansion continues, driven by both battery storage and the potential for additional pumped storage.
- New nuclear technologies, with continued advancements, can support load growth and reduce fuel volatility and regulatory risks.
- Solar expansion plays a complementary role, meeting customer needs and providing economic energy.
- Energy efficiency deployment reduces energy needs, particularly between now and 2040, and demand response programs grow with the system and the use of smart technologies.

A mix of resource types – both supply and demand-side – will be required to meet system needs. In all scenarios, TVA will continue to provide affordable, reliable, and resilient energy for years to come.

Strategy Performance

Reflecting least-cost planning principles and feedback from the IRP Working Group, TVA developed a set of metrics to assess the performance of the portfolios. Metrics were grouped into four categories – low cost, risk informed, environmentally responsible, and diverse, reliable, and flexible system operations. Metrics were calculated for the nine portfolios and were used to evaluate tradeoffs between each strategy.



Looking across the metric categories, there were key tradeoffs to consider. Key takeaways include:

- Strategy A that applies baseline utility planning is the lowest cost strategy overall, though its reliance on natural gas generation results in higher financial risk exposure than alternative strategies.
- Strategy B is the most expensive overall, as it would require significant investments in nuclear expansion, but performs well in risk informed and operational metrics with low variation in operating cost due to lower fuel price volatility.
- Strategy C is generally the median in cost and performs well in risk informed metrics due to low variation in operating cost due lower fuel price volatility; Strategy C is most challenged in operational metrics as higher reliance on intermittent renewable generation increases the risk of unserved energy and energy curtailment.
- All strategies include timeline, technological, transmission, and/or market depth uncertainty and execution risks, which are amplified by load growth and regulatory impacts.
- Strategies feature environmental tradeoffs, such as Strategy C having the highest land use, Strategy B having the highest water consumption, and Strategy A having the highest carbon dioxide (CO_2) intensity.
- All strategies perform well in operational metrics on an absolute basis and would continue to result in a reliable and resilient system.

Sensitivity Analysis

When analyzing draft results and considering IRP Working Group, RERC, and public input, TVA identified questions related to key assumptions that warranted further evaluation. TVA used sensitivity analysis to vary a key assumption and isolate the impact of that change on portfolio results. TVA performed sensitivity analysis focused on electricity demand changes, resource costs and availability, and natural gas commodity prices to gain additional insights and inform IRP recommendations. In general, sensitivity results fell within the capacity expansion bounds for resource selection of the nine core portfolios with the exception of Higher EE Availability and Deployment and Supercharged Growth.

Environmental Impacts

As a federal agency, TVA is required to comply with the National Environmental Policy Act (NEPA), which includes evaluating the impact of proposed plans or actions on the environment before final decisions are made. In accordance with NEPA, the EIS (2026 IRP, Volume 2) is a programmatic review that broadly assesses the natural, cultural, and socioeconomic impacts associated with the 2026 IRP portfolios and Preferred Alternative. The primary study area is the TVA service area, but for resources such as air quality and greenhouse gas emissions, the assessment area extends beyond the TVA region. Baseline Utility Planning (Strategy A) is the No Action Alternative, and the other two strategies and the IRP recommendations are the Action Alternatives. The analysis considers the power supply mix ranges and strategic portfolio direction from the IRP recommendations as the Preferred Alternative. The EIS analyzes and identifies the relative impacts of strategies and sensitivity analysis on the natural and human environment.

Highlights of EIS observations include:

Environmental Resources	Summary of Impacts
Air Quality	Long-term reductions in all air emissions based on expected end of life for existing coal units*
Climate and Greenhouse Gases	Long-term reductions in CO_2 emissions and intensity, lowest in Strategies B and C
Water Resources	Long-term reductions in water use for all cases; water consumption rises in cases with nuclear expansion, highest in Strategy B
Land Resources	Long-term increases in land use requirements, particularly to support renewable expansion, highest in Strategy C
Solid and Hazardous Waste	Long-term production of coal combustion residuals drops to zero based on expected end of life for existing coal units*

*Subject to further site-specific evaluation, TVA Board approval, and environmental review

Environmental impacts differ less between strategies than between scenarios, as the scenario that materializes for load and U.S. energy policy is the primary driver of environmental profiles. For most environmental resources, impacts would be greatest in Scenario 2 (High Growth) and lowest in Scenario 3 (Carbon Legislation). IRP strategies feature environmental tradeoffs, such as Distributed (C) having the highest land use, Innovation (B) having the highest water consumption, and Baseline (A) having the highest air quality and climate impacts.

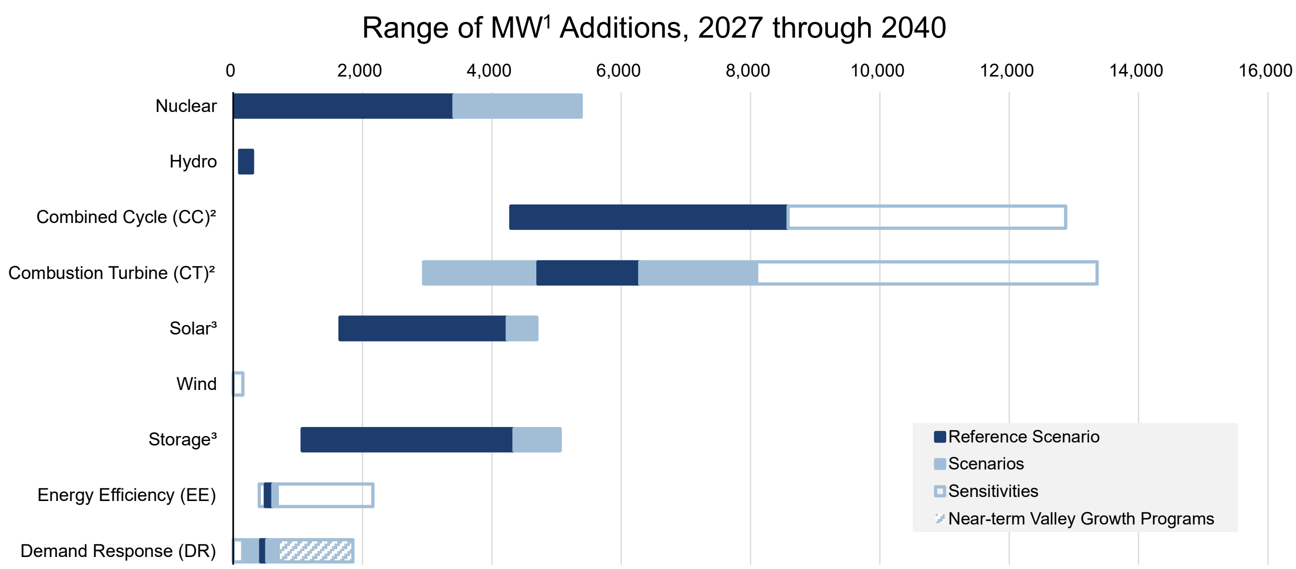
While the IRP is not site-specific, the IRP and EIS provide insights into potential impacts to communities across the region. For example, the average system cost metric is directionally indicative of overall trends in customer bills (Strategy A is the lowest cost strategy overall), and metrics related to emissions are directionally indicative of air quality trends in the region (Strategies B and C have the lowest air emissions). Site-specific aspects of actions that are later proposed to implement the IRP strategic direction will be addressed and considered in tiered environmental reviews. Public comments on the draft IRP and EIS are addressed in the final EIS.

IRP Recommendations

The IRP results – including the nine core portfolios, metrics, sensitivities, and EIS – provide robust analysis that offers insights into the potential power supply mix and impacts to the customer priorities of power cost, reliability, resiliency, and environmental responsibility. The IRP recommendations include power supply mix ranges through 2040 and 2050, strategic portfolio direction, and key signposts to monitor to understand potential implications to recommended actions and evolution of the power system over the long term.

Power Supply Mix Ranges through 2040

Exploring potential scenarios and strategies in the IRP is fundamental to ensuring TVA is well prepared to meet the region's energy needs however the future unfolds. The chart below shows the power supply mix ranges – or incremental additions – from now through 2040. The ranges encompass the full set of results, with reference scenario results shown in the dark blue bars, and alternative scenario and sensitivity results outside of the reference ranges shown in the light blue bars and outline-only bars, respectively. In general, the upper end of most ranges are set by the High Growth scenario or the Supercharged Growth sensitivity.



[1] MW capacity expressed in summer net dependable capacity.
[2] CC and CT additions could include control technologies, such as carbon capture and sequestration, alternative fuel co-firing (e.g., hydrogen), or gas re-firing of existing coal burners.
[3] Solar and storage include utility-scale and distributed resource additions.

Strategic Portfolio Direction

TVA's IRP analysis reaffirms the importance of adhering to least-cost planning principles to ensure the continued delivery of affordable, reliable, and resilient power to the Tennessee Valley. The results underscore that no single resource will fully meet future system needs; rather, maintaining a diverse portfolio remains essential. In the near-term, TVA should prioritize the addition of firm, dispatchable resources, particularly natural gas and storage, to address capacity requirements. TVA should also continue collaborating with industry and federal partners to prepare for the potential deployment of firm, dispatchable advanced nuclear technologies, which could support long-term load growth while mitigating fuel volatility and regulatory risks. Finally, complementary deployment of solar, demand-side, and distributed generation resources should be used to satisfy capacity requirements, provide economic energy, and/or meet customer needs.

The 2026 IRP's strategic portfolio direction includes the following recommended actions:

Existing Resources

- Invest in the hydro and nuclear fleets and pursue nuclear license extensions to maintain low-cost generation
- Invest in the gas and storage fleets to maintain reliability
- Continue operation of the coal fleet, subject to regulatory requirements, to reduce total system cost and reliability risk

Supply-side Resource Additions

- Add firm, dispatchable gas to maintain system reliability and enhance flexibility
- Add firm, dispatchable storage to maintain system reliability and improve system efficiency
- Pursue solar to reduce total system costs or meet customer needs
- Suspend wind additions given cost and portfolio fit challenges

Demand-side Resource Additions

- Utilize demand response and behind-the-meter resources to enable near-term interconnection of new industrial loads
- Partner with customers to leverage cost-effective energy efficiency and demand response
- Collaborate with local power companies on the evolution of distributed generation programs

Grid and Innovation Enablement

- Prepare for Gen III+ and Gen IV nuclear to support load growth and reduce fuel volatility and regulatory risks while pursuing external funding opportunities
- Pursue transmission system enhancements to deliver low-cost generation resources
- Collaborate with industry partners to evaluate emerging technologies, such as fusion and long-duration storage

The table below outlines the IRP ranges, current actions in progress, and planned actions through 2040 for existing resources and mature resource additions including supply-side and demand-side resources. A combination of resource additions is needed to ensure the region continues to have affordable, reliable, and resilient power. Additions will vary within the ranges based on movements in key signposts.

Resource Type	GW through 2040	Actions in Progress	Planned Actions through 2040
Nuclear	Up to 5 GW	Pursuing license extensions for and investing in the existing nuclear fleet; evaluating advanced nuclear options	Continue investing in the existing nuclear fleet and cost-effective opportunities to increase output; potential for advanced nuclear deployment
Hydro	Up to 1 GW	Ongoing investments in the Hydro Life Extension (HLE) program, leveraging cost-effective ways to increase output	Continue investing in the existing hydro fleet, maximize cost-effective uprate potential, and evaluate market opportunities
Coal	Expected to reach end of life by 2040	Continuing operation of coal fleet, subject to regulatory requirements, as an immediate, cost-effective option to reduce total system cost and system reliability risk	Evaluate existing fleet, as needed, considering material condition, system reliability, system cost, regulatory requirements, and replacement generation
Gas Combined Cycle (CC)	4 to 13 GW	2 GW of CC capacity being added by 2028 to address capacity requirements and provide grid support	Continue investing in the existing fleet and evaluate future CC additions and market opportunities for system reliability needs
Gas Combustion Turbine (CT)	3 to 13 GW	2 GW of Frame and Aero capacity being added by 2028 to address capacity requirements, provide grid support, and enhance system flexibility	Continue investing in the existing fleet and evaluate future CT additions and market opportunities for system reliability, flexibility, and resiliency needs
Solar	2 to 5 GW (3 to 12 GW nameplate)	3 GW (nameplate) of Green Invest, self-directed, and Generation Flexibility solar projects contracted to come online by 2030	Evaluate solar additions to either lower system costs or meet customer needs utilizing regular procurement cycles

Resource Type	GW through 2040	Actions in Progress	Planned Actions through 2040
Wind	<1 GW (Up to 1 GW nameplate)	Screening wind offers through request for proposal processes for cost-effectiveness and system fit	Monitor wind proposals to determine if cost and system fit challenges are improving
Storage	1 to 5 GW (1 to 8 GW nameplate)	0.7 GW of Green Invest, self-directed, and Generation Flexibility battery projects contracted to come online by 2030; evaluating pumped storage option	Continue investing in the existing pumped storage fleet and evaluate storage options to support reliability, resiliency, and system flexibility; potential for additional pumped storage deployment
Energy Efficiency (EE)	1 to 2 GW	Investing in residential, commercial, and industrial EE programs using insights from the potential study	Partner with customers to realize cost-effective EE program potential, reducing power generation resource needs
Demand Response (DR)	Up to 2 GW	Investing in residential, commercial, and industrial DR programs to enable interconnection of new industrial loads and to serve system needs	Collaborate with customers to realize cost-effective DR program potential, reducing power generation resource needs

A portion of resource additions will be driven by local power companies through flexible generation options or the evolution of contractual arrangements. Also, TVA will continue to evaluate future market offers received on a one-off basis in the context of least-cost planning and the IRP's strategic direction.

Additions of new energy resources of all types typically require additional investments in the transmission system. Generally, these investments include optimizing existing infrastructure through projects such as reconductoring transmission lines and upgrading substations, along with building new transmission infrastructure such as transmission lines, substations, and other devices that support system reliability and stability. Where possible, TVA prefers to utilize brownfield sites with existing infrastructure and easements. TVA is also expanding its use of grid-enhancing and grid-supporting technologies, such as advanced conductors and STATCOMS, as well as exploring dynamic line ratings, to greater leverage the existing transmission system when adding new generation and storage to the system.

Additions of new gas-fired resources typically require new or expanded gas pipeline infrastructure. The TVA region has a robust gas pipeline network, and future siting efforts will seek to leverage existing pipelines and minimize the need for infrastructure expansion to the extent possible. To support reliability of gas-fired plants, TVA typically contracts for a high level of fuel delivery priority and/or invests in a backup fuel source on site, depending on the expected operations profile of a particular plant.

The strategic portfolio direction also includes recommended actions to advance emerging technologies, such as advanced nuclear. Actions for emerging resources focus on enabling and demonstrating emerging energy technologies, leveraging partnerships that reduce cost and risk.

Key Signposts and Implications

TVA identified key signposts to monitor that will provide insights into potential impacts to recommended actions between now and 2040 and will ultimately guide future portfolio decisions. The key signpost themes relate to changing market conditions, evolving policy and regulations, and emerging technologies. Movement in key signposts can signal potential shifts in the portfolio mix and indicate the appropriate timing for the next IRP.

Theme	Signpost
Changing Market Conditions	Electricity demand
	Natural gas prices
	Customer needs
	Resource costs
Evolving Policy and Regulations	Shifts in U.S. energy policy
	Tax credits and incentives
	Regulatory requirements
	Permitting and siting challenges
Emerging Technologies	Advanced nuclear technologies
	Advanced storage technologies

Implementation

In finalizing the IRP and EIS and developing the IRP recommendations, TVA considered the input received throughout the process, including from the IRP Working Group, RERC, and during the public comment period. Any actions taken by the Board and TVA with respect to the IRP will comply with requirements of the Administrative Procedure Act and NEPA.

A key next step in implementing the IRP recommendations is translating the IRP's strategic direction into an executable asset strategy from an operational, commercial, and financial perspective. A successful asset strategy also relies on partnering with TVA customers, especially on the distributed and demand-side aspects of the plan, and with other key stakeholders. Site-specific aspects of actions that are later proposed to implement the IRP strategic direction will be addressed and considered in tiered environmental reviews and subject to any required TVA Board approvals.

Conclusion

The IRP provides strategic guidance for the region's future energy system. The full IRP and EIS provide additional information on planning the future system, stakeholder engagement, process and methodology, portfolio results and assessments, and recommendations and implementation, along with an environmental impacts analysis. TVA greatly appreciates the input, review, and insights provided by the IRP Working Group and the RERC, along with the comments received from other stakeholders and the public that have strengthened the analysis and recommendations. TVA looks forward to continued stakeholder and public involvement as the IRP recommendations are implemented, paving the way for affordable, reliable, and resilient energy in the region through 2040 and beyond.

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List of Acronyms

Acronym	**Description**
Aero	aeroderivative combustion turbine
APWR	advanced pressurized water reactor
ARL	adoption readiness level
ATB	Annual Technology Baseline
Btu	British Thermal Units
CAGR	compound annual growth rate
CARAT	Commercial Adoption Readiness Assessment Tool
CBO	Congressional Budget Office
CC	combined cycle
CCS	carbon capture and sequestration
CDD	cooling degree days
CO_2	carbon dioxide
CT	combustion turbine
DG	distributed generation
DPP	Dispersed Power Program
DOE	Department of Energy
DR	demand response
DSM	demand-side management
EE	energy efficiency
EEDR	energy efficiency and demand response
EIS	Environmental Impact Statement
ELCC	effective load carrying capability
FOM	fixed operating and maintenance
FY	fiscal year
GADS	Generating Availability Data System
GDP	Gross Domestic Product
GHG	greenhouse gases
GW	gigawatt
GWh	gigawatt-hour
HDD	heating degree days
Hg	mercury
HLE	hydro life extension
HVAC	heating, ventilation, and air conditioning
ILB	Illinois basin
IP	interruptible power
IRP	Integrated Resource Plan
ITC	investment tax credit
kW	kilowatt
lbs	pounds
LCOE	levelized cost of energy
LOLE	loss of load expectation
LPC	local power company
MMBtu	Metric Million British Thermal Units
MW	megawatt
MWh	megawatt-hour

NDC	net dependable capacity
NEPA	National Environmental Policy Act
NERC	North American Electric Reliability Corporation
NLR	National Laboratory of the Rockies (formerly NREL)
NOx	nitrogen oxides
NRC	Nuclear Regulatory Commission
OBBB	One, Big, Beautiful Bill Act
ORNL	Oak Ridge National Laboratory
PPA	power purchase agreement
PRB	Powder River Basin
PV	photovoltaic
PVRR	present value of revenue requirements
PWR	pressurized water reactor
RERC	Regional Energy Resource Council
RICE	reciprocating internal combustion engines
SEM	Strategic Energy Management
SERVM	Strategic Energy and Risk Valuation Model
SMR	small modular reactor
SND	summer net dependable
SO_2	sulfur dioxide
TN WAP	Tennessee Weatherization Assistance Program
TRL	technology readiness level
TVA	Tennessee Valley Authority
TWh	terawatt hour
U.S.	United States
USEPA	U.S. Environmental Protection Agency
VOM	variable operating and maintenance

1 Unleashing American Energy

For over 90 years, the Tennessee Valley Authority (TVA) has executed its mission to serve the Valley region – to provide affordable and reliable power, be a responsible steward of the environment, and support economic development. That mission continues as TVA is planning the energy system of the future, working to unleash American energy in the region for the coming decades.

TVA's 2026 Integrated Resource Plan (IRP) and associated programmatic Environmental Impact Statement (EIS) evaluate the long-term demand for power in the TVA region, the resource options available for meeting that demand, and the potential economic, operating, and environmental impacts of these options. Stakeholder input and feedback is integral to TVA's IRP process. The IRP will provide strategic direction for meeting the energy needs of TVA's customers and residents of the Valley region from now through 2050, establishing a strong planning foundation and informing TVA's next long-range financial plan.

The 2026 IRP analyzed how TVA can provide affordable, reliable, and resilient energy over the next 25 years. In addition to considering mature resources such as gas, renewables, and storage, the IRP included assumptions for emerging technologies like advanced nuclear, advanced storage, and carbon capture and sequestration that may play a role in America's energy future.

In planning the future energy system, it is important to first understand the environment TVA is operating in. For example:

- What actions has TVA recently taken based on prior IRPs which support affordable, reliable, and resilient energy?
- What insights can be gleaned from key planning signposts, or market signals?
- What foundational enablers will likely be part of any successful strategy to unleash American energy?

Discussions on these questions follow, providing useful insights into the planning environment for the 2026 IRP.

1.1 Delivering on Prior IRP Recommendations

Before embarking on the 2026 IRP, it was important to evaluate the progress made on recommendations from the last IRP. TVA's last three IRPs from 2011 to 2019 evaluated the benefits of a diversified portfolio, modeling energy efficiency and renewables as selectable resources, and system flexibility. Specifically, the 2019 IRP provided strategic direction for the existing fleet, system flexibility, renewable and distributed resources, energy usage, and distribution planning to help pave the way for further evolution of the power system. The sections below summarize the progress made on prior IRP recommendations.

Continued Emphasis on a Diversified Portfolio

TVA's recent IRPs have all underscored the importance of a diversified portfolio. TVA's portfolio has continued to evolve to a more diverse mix of generation resources, which has supported delivery of affordable and reliable power. Diverse portfolios are more resilient to factors such as weather impacts, fuel supply constraints, and unit performance and can more readily adapt to changing conditions impacting forecasts and plans. Keeping an eye on portfolio diversity is an integral part of ongoing planning efforts.

Maintained the Existing, Low-Cost Nuclear and Hydro Fleets

Hydropower has been a vital part of TVA since the beginning, and TVA operates one of the largest nuclear fleets in the nation. In total, the hydro and nuclear fleets provide roughly half of TVA's annual energy generation. Recent IRPs have stressed the importance of the hydro and nuclear fleets, which provide low-cost energy across all hours of the day and seasons of the year. TVA invests in its nuclear and hydro fleets so they can continue to contribute substantial amounts of low-cost and clean energy, which is critical to the future resource mix. Through these investments and leveraging best practices, TVA's goal is to operate the nation's top nuclear fleet.

Pursued Steps for Nuclear Fleet License Renewal

The second or subsequent license renewal application for all three Browns Ferry units was submitted in January 2024. The Nuclear Regulatory Commission (NRC) approved the renewals on December 11, 2025, which extended the licenses for an additional 20 years on all three Browns Ferry units – to 2053, 2054, and 2056, respectively. Now, work on the first license renewal application for Watts Bar Unit 1 is underway, targeting submission in late 2026 and approval in 2028, which will be followed by work on the second license renewal for Sequoyah Units 1 and 2. Inherent in license renewals is continued investment in plants and related infrastructure to ensure safe operation based on the latest guidance from the NRC and global nuclear organizations.

Invested in the Gas Fleet to Maintain Reliability and Enhance System Flexibility

TVA has invested in the existing natural gas fleet and in additional gas capacity. Maintaining and modernizing the existing gas fleet ensures TVA has sufficient capacity and enhances system flexibility, in alignment with 2019 IRP key findings. Since 2019, TVA has approved plans to build about 5,500 megawatts (MW) of new gas capacity, with about 1,850 MW currently operating and 3,650 MW expected to come online over the next several years. Currently, TVA is conducting environmental reviews for additional gas capacity to meet anticipated load growth, maintain system reliability, and enhance system flexibility.

Added More Solar and Battery Storage to the Resource Mix

The 2019 IRP included near-term actions to add solar based on economics and to meet customer demand, along with gaining battery storage experience. As of FY 2018, TVA had contracted for about 140 MW of utility-scale solar nameplate capacity through power purchase agreements. By the end of FY 2019, that amount grew to about 800 MW, and TVA has contracted for additional solar capacity each year. As of FY 2025, the total solar amount contracted through these agreements has increased more than four-fold to approximately 4,000 MW nameplate, with about 1,650 MW of these installations currently operating and the balance forecasted to come online over the next several years. To help integrate solar expansion, approximately 800 MW of contracted battery storage has been added to the resource mix, with 150 MW currently operating and the balance coming online over the next several years. Many of these solar and battery storage additions have been made possible through partnerships with customers, primarily via TVA's Green Invest program, which matches customer demand with renewable supply and is designed to meet the needs of customers while not raising costs for the remainder of TVA customers.

Additionally, TVA is pursuing an approximately 100 MW solar facility at the Shawnee Fossil Plant site using a solar cap system on the closed coal combustion residuals facility.

Evaluated Energy Efficiency Potential to Inform Future Efforts

In 2022, DNV (a global leader in energy program consulting) conducted a study for the TVA region to evaluate the achievable potential for energy efficiency programs that incentivize investment in making homes and businesses more energy efficient. The study indicated a 10-year potential for regional energy efficiency gains ranging from 2-7% of sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications. In 2023, TVA announced a major expansion of energy efficiency and demand management efforts, supported by over $1.5 billion in dedicated funding through FY 2028. This investment strengthens TVA's ability to manage long-term system needs, reduce peak demand, and provide cost-effective alternatives to new generation. Due to inflationary pressures and the unique partnership arrangement between

TVA and the local power companies (LPCs), customer uptake of EE programs has been slower and more costly than anticipated in the 2022 Energy Programs Potential Study though momentum began to increase in 2025 and the portfolio remains cost-effective. Learnings from the potential study and subsequent market experience have informed the inputs in the 2026 IRP.

Increased Investment in Low-Income Energy Efficiency Programs

TVA introduced its Home Uplift program in 2018, in partnership with local power companies and communities. By FY 2019, about 1,300 Valley residences were retrofitted with more energy efficient technology for heating and cooling, water heating, and insulation. This number grew to about 7,900 retrofitted residences by the end of FY 2025, reducing system energy needs by more than 28,000 megawatt hours, benefitting low-income households. TVA provides matching funds for local power companies and local communities to support this program. Additionally, the School Uplift program provides education and efficiency improvements to schools within TVA's service territory, which has especially benefited low-income communities.

TVA is also investing in the future bulk transmission grid. This includes a new, state-of-the-art System Operations Center which is nearing completion. The center will employ smart technologies to improve reliability, have improved physical security from the previous center, and be flexible to help accommodate operational needs of the future. The new system is expected to be complete and fully operational in 2026.

1.2 Implications of Planning Signposts

Since completion of the last IRP in 2019, TVA has monitored key planning signposts – or market signals – related to changing market conditions, evolving regulations, and technological advancements. In the 2019 IRP, the forecast for electricity demand was essentially flat; however, since that time the TVA region has experienced rapidly increasing demand for electricity and forecasts indicate continued load growth into the future. The following table summarizes recent developments in key signposts and the resulting implications for resource planning.

Table 1-1: Key Signposts and Implications to Planning

Signpost	Developments	Planning Implications
Increasing Demand for Electricity	• Population, employment, and industrial growth, particularly from data centers • Energy demand increasing 16% by 2040 in Reference scenario (~60% in highest case)	More resources currently needed to reliably meet load growth and maintain reserve requirements
Fuel Prices and Risk	• Growing connection to global markets • Higher electric demand increasing natural gas use • More variable generation resources increasing market power and natural gas price volatility	Analyze wide range of gas prices in IRP cases and test impact of movement in natural gas prices
Evolving Customer Expectations	• Sustainability goals established by large customers and some local governments • Consumer interest in specific types of generation	Ensure plans are flexible to allow higher volumes of programmatic or customer-driven resource additions

Signpost	Developments	Planning Implications
Policy and Regulatory Requirements	• Tax credit implications of One, Big, Beautiful Bill Act (OBBB) • Changes to Effluent Limitations Guidelines (ELG) Rule • Proposed rule to repeal all greenhouse gas (GHG) emission guidelines • Infrastructure siting and permitting timelines	Reflect evolving U.S. energy policy and updated incentives
Operating Costs for Existing Fleet	• Investing in winterization to address extreme cold risks • Gas unit cycling impacts as renewables increase	Use latest assumptions for unit operating costs
Solar and Wind Costs	• Cost pressure from solar supply chain challenges • Long interconnection timelines for multiple solar sites • Improvements in high-hub wind technologies	Use latest assumptions for solar and wind costs and interconnection timelines
Progress on Emerging Technologies	• Clinch River environmental assessment completed, and small modular reactor detailed design underway • Industry partnerships focused on advancing emerging technologies such as advanced nuclear, carbon capture, advanced battery chemistries, and alternative fuels	Use latest cost and timing estimates for emerging technologies from Clinch River and other research and development and partnership efforts

Collectively, movement in signposts and input from the IRP Working Group and public comments informed the scenarios, strategies, modeling assumptions, and resource options evaluated in the 2026 IRP. Scenarios were heavily influenced by increasing electricity demand and shifts in United States (U.S.) energy policy, while strategies reflected opportunities to explore advanced technologies or shift to a more distributed energy generation model. Assumptions for resource options incorporated the latest information based on TVA's recent experience, industry estimates, and strategic partnership efforts to advance emerging energy technologies.

1.3 Key Enablers to Unleash American Energy

The following key enablers are foundational elements to providing affordable, reliable, and resilient energy and will support the strategic recommendations from this IRP.

Nuclear License Renewals

Low-cost generation from TVA's three nuclear plants contributes nearly 40% of the total power supply today. Nuclear generation provides substantial, long-term system benefits and will play a significant role in America's energy future. The first step to ensuring this is continuing to invest in and extend the licenses of TVA's existing nuclear plants for another 20 years of safe, reliable operations. Pursuing nuclear license renewals was a recommended action from the 2019 IRP, and it will continue to be foundational in future plans. TVA has recently received approval to extend the operating license of all three units at Browns Ferry nuclear plant, with Watts Bar Unit 1 and Sequoyah nuclear plant extension requests to be submitted in the near future.

Firm, Dispatchable Resources to Maintain Reliability and Integrate Renewables

Recent IRPs have noted that adding renewable generation – especially solar – can be both cost-effective and further diversify the power supply mix. Successfully integrating increasing amounts of renewables requires firm, dispatchable resources to maintain reliability and provide the operational flexibility needed to manage changes in net load across all hours of the day and year. Natural gas units provide energy when renewable sources are not generating, and they can ramp up and down as intermittent renewable generation varies. TVA's Raccoon

Mountain Pumped Storage plant provides significant longer-duration system benefits in this regard, and battery storage additions will contribute shorter-duration system benefits, providing further diversity and a fuel hedge that complements the dispatchability of gas generation. Emerging long-duration storage technologies, such as advanced chemistry batteries and other nascent technologies, have the potential to provide benefits similar to or perhaps even longer duration than Raccoon Mountain. Collectively, gas, storage, and renewable resources can work together to maintain reliability and provide diversity benefits as the system evolves and emerging energy technologies develop.

Collaboration with Customers on Innovative Programs and Tools

Collaboration with customers is an integral part of TVA's public power model, and it will be increasingly important to navigate changes in the resource mix and leverage the advantages of evolving distributed generation and demand-side resources in the resource mix. TVA has provided local power company partners the flexibility to generate up to 5% of their own energy to meet consumer demand for new renewables and address other local needs. TVA and local power companies in the region can work together to design new, innovative programs to influence load and distributed generation for overall benefit, as well as develop the tools needed to better forecast local electricity demand and distributed resources that can be factored into planning. Also, TVA and industrial customers can collaborate to design new programs and tools tailored to the industrial sector that help meet future energy needs and align with other customer goals.

Strategic Partnerships

To support the pace of change in the utility industry and spread the cost and risk of developing emerging energy technologies, strategic partnerships are essential. TVA's partnerships to advance the future of new nuclear is a recent example of this. TVA is working with the University of Tennessee – Knoxville to engage with students and prepare the nuclear workforce of the future. TVA is collaborating with Oak Ridge National Laboratory (ORNL) to combine ORNL's world-leading research capabilities and TVA's operating expertise to accelerate the next generation of cost-effective nuclear power.

Also, TVA sponsors promising startup companies in ORNL's Innovation Crossroads program and Electric Power Research Institute's Incubatenergy Labs to take world-changing ideas from research and development to the marketplace. These new technologies range from advanced battery chemistries and spent nuclear fuel reprocessing to the use of submersible robotics for safety inspections.

Preparing for Emerging Technology Opportunities

As TVA executes near to mid-term plans, ways to prepare for emerging technology opportunities are being considered and incorporated wherever possible. This includes collaborating on innovative pilot projects, seeking third-party funding support to reduce first-of-a-kind financial risks, and considering site requirements for emerging technologies.

TVA in partnership with Kairos Power and Google, was the first U.S. utility to sign a PPA to buy electricity from an advanced, generation IV nuclear reactor via the Hermes 2 plant in Oak Ridge, Tennessee, which is scheduled to begin operations in the 2030s. Additionally, TVA is collaborating with Type One Energy on Project Infinity to potentially deploy a pilot stellarator fusion power plant, named Infinity Two, at TVA's former Bull Run Fossil site.

In December 2025 the U.S. Department of Energy announced that TVA was selected to receive up to $400 million to accelerate the deployment of the first U.S. small modular reactor (SMR) at the Clinch River nuclear site in Oak Ridge. Also, partnerships such as the recently announced Japan-U.S. strategic investment in SMRs in Tennessee and Alabama could present opportunities to advance emerging nuclear technologies.

TVA is also studying the potential for the current natural gas fleet to accommodate alternative fuels, such as hydrogen, and/or be retrofitted with carbon capture and sequestration equipment, if needed to meet current or future regulatory requirements. New gas units can be “hydrogen capable” to facilitate future hydrogen blending or ultimately run on hydrogen. The potential use of these technologies, along with the associated logistics, will factor into site decisions using the best information available at the time.

Streamlined Interconnection Process

In order to meet growing demand and facilitate economic development, TVA is actively working to streamline the process for interconnecting new generating resources and reduce associated timelines. Reducing interconnection timelines will help support and accelerate the deployment of all power resources, including firm, dispatchable resources such as gas and storage as well as other mature technologies such as solar.

1.4 Conclusion

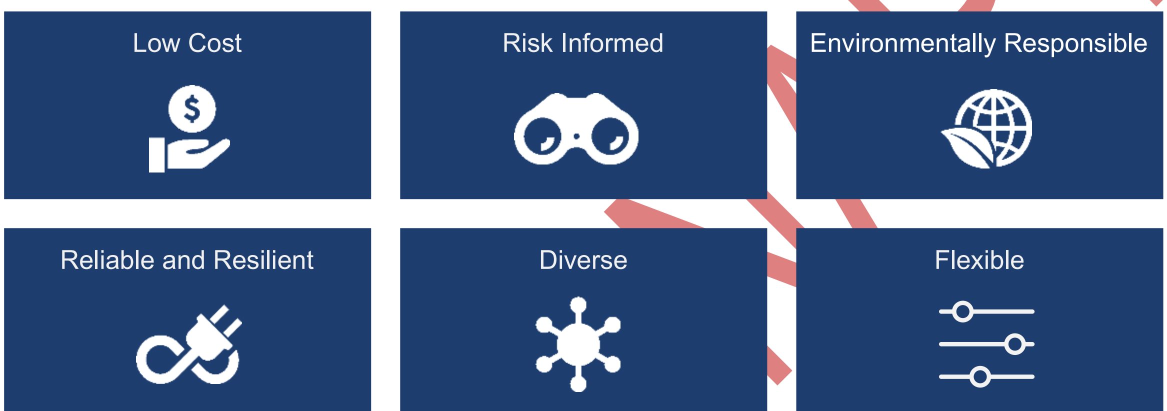
The 2026 IRP builds on the work of previous IRPs as TVA works to continue meeting its mission to serve the Valley region and unleash American energy. Based on movement in key signposts, TVA initiated the 2026 IRP to evaluate a broad set of potential futures for electricity demand, technology advancements, and environmental regulations and to inform a strategic path forward for the power system.

2 Process and Methodology

Having the right resources at the right times to power the homes and businesses in the region requires continual planning. Periodically, TVA develops an IRP that goes beyond annual updates to take a broader view of potential electricity demand, evolving policy and regulations, and technology advancements, and it incorporates stakeholder input into the planning process. This chapter explains planning objectives, how the IRP process works, and the methodology used in the 2026 IRP for the key steps in the process.

2.1 Objectives of Resource Planning

Integrated resource planning at TVA is grounded in least-cost principles. TVA applies the following least-cost principles, in alignment with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, and resilient energy over the long term:



Least-cost planning evaluates cost, operational, environmental, and other risk factors in order to provide reliable service at the lowest system cost. A system that is diverse, resilient, and flexible is more reliable, year in and year out, so these aspects are key considerations. Planning must also ensure compliance with all applicable environmental regulations, while considering opportunities to cost-effectively reduce environmental impacts. Finally, TVA evaluates variations in electricity demand, commodity prices, resource costs, and U.S. energy policy to ensure plans are risk informed and flexible to adapt as the future evolves. Metrics used in the IRP reflect least-cost planning principles, providing insights into tradeoffs across alternative business strategies.

Resource planning must consider that electric load varies across all hours of the day and seasons of the year, with weather being a large driver of this variation. Peak electric loads are typically of short duration, often occurring during the period of highest heating or cooling demand in the Tennessee Valley. Resources have various operational, economic, and environmental characteristics and constraints that must be considered in order to achieve the best overall portfolio.

In conducting least-cost planning, TVA must comply with the following requirements in Section 113 of the Energy Policy Act of 1992:

- The least-cost planning program "evaluates the full range of existing and incremental resources (including new power supplies, energy conservation and efficiency, and renewable energy resources) in order to provide adequate and reliable service…at the lowest system cost";
- System cost encompasses only those costs that are "direct and quantifiable net costs for an energy resource over its available life, including production, transportation, utilization, waste management, and environmental compliance"; and

- In addition to cost, the planning process will also consider “necessary features for system operation,” including diversity of resources, reliability, dispatchability, and other factors of risk.

When making specific asset decisions, TVA stays within the planning direction, including the resource ranges, that were studied and approved in the most recent IRP.

Integrated resource planning at TVA is not used to set or establish wholesale or retail electricity rates. Additionally, the IRP does not identify specific sites for new resources or act as an approval mechanism for specific generation projects. Finally, TVA’s IRP is not designed to be a distribution integrated resource plan.

Environmental Review

As a federal agency, TVA is required to comply with the National Environmental Policy Act (NEPA), which includes evaluating the impact of proposed plans or actions on the environment before final decisions are made. In accordance with NEPA, the EIS (2026 IRP, Volume 2) is a programmatic review that broadly assesses the natural, cultural, and socioeconomic impacts associated with the 2026 IRP portfolios and Preferred Alternative. As a part of this environmental review, opportunities for public and stakeholder engagement are provided. Comments received from the public and stakeholders during public scoping helped define the analysis presented in the IRP and EIS, which describes potential resource portfolios and associated environmental impacts. Public and stakeholder input received during the draft IRP and EIS comment period was considered in completing the analysis.

2.2 IRP Timeline and Incorporating Stakeholder Input

Consideration of stakeholder feedback is an important component of TVA’s IRP process. Throughout the development of the IRP and EIS multiple avenues and opportunities to provide input were provided. Examples of key stakeholders include local power company customers, directly served customers, federal advisory councils, governmental representatives, and members of the public.

2.2.1 IRP Timeline

The process for the development of the IRP consisted of seven distinct steps, complemented by public outreach efforts and the incorporation of stakeholder input along the way.

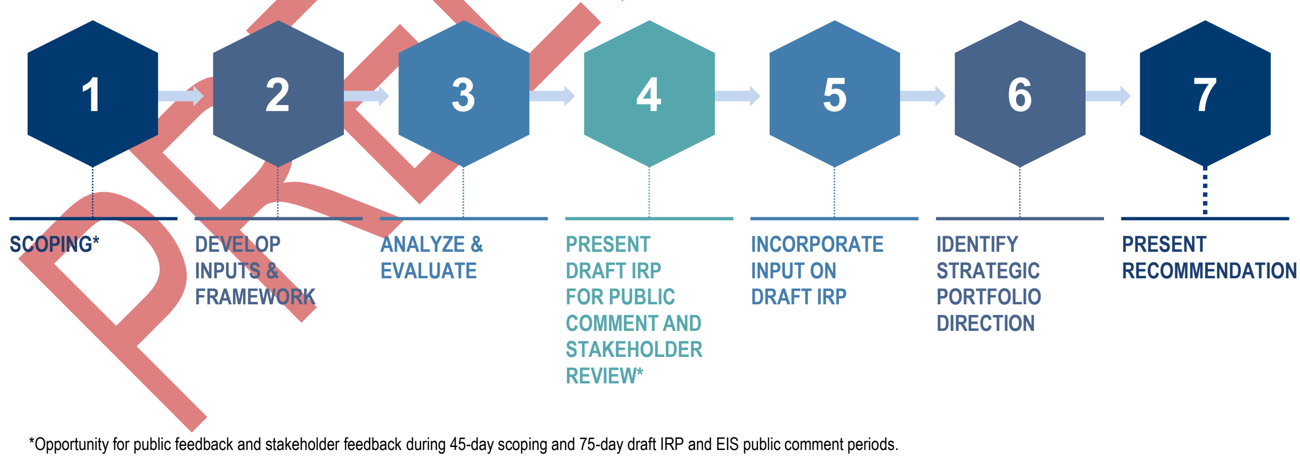


Figure 2-1: IRP Timeline

The process began with the publication of a Notice of Intent filed under NEPA in the Federal Register in May 2023 that initiated a 45-day public scoping comment period. TVA published a Public Scoping Report in October 2023 that summarized public input received and considered in framing the scope of the IRP effort.

Over the ensuing months, TVA worked closely with the IRP Working Group, a group of stakeholders with broad-ranging perspectives, to establish the inputs for the analysis, evaluate case results, and summarize findings of the IRP. In September 2024, TVA provided the draft IRP and EIS for public review during a 75-day comment period. TVA originally anticipated publication of the final IRP and EIS in the Spring of 2025, however due to a loss of quorum on the TVA Board of Directors, this publication was delayed.

Stakeholder engagements throughout 2023 to 2025 included:

- Public scoping (May - July 2023) with 2 public webinars including 115 participants.
- Public outreach and briefings with 4 public webinars including 386 participants.
- Board public listening sessions across 6 sessions including 47 IRP related comments.
- The Regional Energy Resource Council's (RERC) 20 stakeholder representatives held 6 IRP discussions.
- The IRP Working Group's 23 stakeholder representatives participated in 24 working meetings.
- Regional engagements achieved 840 touchpoints across 5 regions.
- Public review of the Draft IRP and EIS (September - December 2024) with 12 open houses and 2,500 comments.

Throughout the Spring and Summer of 2025 a number of key changes in electric utility landscape occurred, which have been summarized in Table 2-1, below.

Table 2-1: Key Changes in Electric Utility Landscape, Spring and Summer 2025

Key Change	Description	Implication to IRP Analysis
Tax Credit Phase-outs	Updated tax credit phase-outs under the One, Big, Beautiful Bill Act require construction commencement by 2027 for renewables and by 2033 for nuclear and storage resources[1].	The majority of draft IRP cases assumed investment tax credits (ITC) would not be subject to phase-outs prior to 2050, therefore new requirements will increase effective resource costs, particularly for renewables.
Executive Orders and Regulatory Relief	The Administration issued Executive Orders encouraging investment in existing coal and new nuclear technologies. Additionally, the EPA announced intentions to provide regulatory relief across several rules, including the GHG Rule and ELG[2].	Previously announced coal retirements and planning assumptions have been re-evaluated, including taking steps to continue operations at Cumberland and Kingston fossil plants to reduce total system cost and reliability risks, subject to permitting and regulatory requirements; resource costs and end-of-life dates have been updated and refined, as applicable.
Strong Demand Growth	The Tennessee Valley region continues to see rising electricity demand driven by population, employment, and industrial growth (primarily data center load)	TVA's actual and forecasted electricity demand has increased relative to the draft IRP's Reference scenario and is approaching the Higher Growth Economy scenario primarily due to data center growth (e.g., artificial intelligence, hyperscaler, etc.).

[1]Solar/wind ITC drops to 0% following 2027 construction commencement; nuclear/storage ITC includes a 3-year phase out of 75%, 50%, 0% of full value following 2033 construction commencement.
[2]Greenhouse Gas (GHG) Rule of 2024 and Effluent Limitations Guidelines and Standards for the Steam Electric Power Generating Point Source Category (ELG)

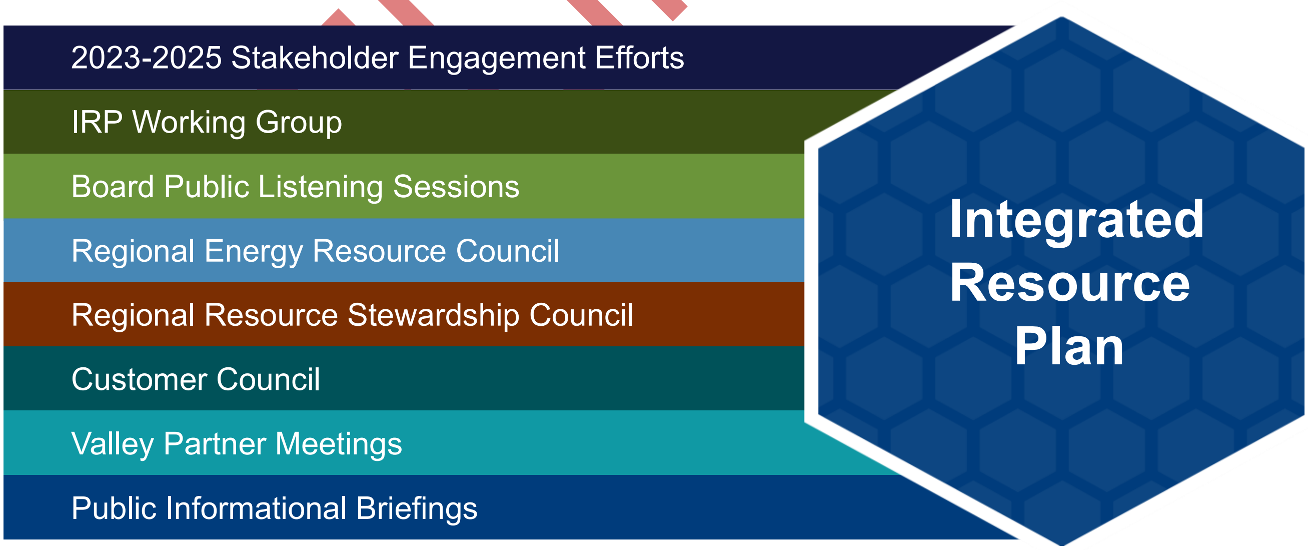
The key changes in the electric utility landscape described above resulted in changes to several baseline assumptions inherent in the draft 2025 IRP. As such, throughout the winter of 2025/2026 TVA staff worked to update baseline IRP scenario, strategy, and resource cost assumptions to more accurately reflect the updated planning environment. As a part of this effort, TVA considered input received throughout the entire IRP process from the IRP Working Group, the RERC, and public comments received on the draft reports. Based on previous analysis, staff identified ways to streamline modeling efforts, such as through the use of simplified scenarios and strategies which decreased the total number of core portfolios from 30 down to nine, all while maintaining a robust analytical framework strengthened through the use of targeted sensitivity analysis. All IRP findings, including insights from additional analysis performed based on input received during the public comment period, were considered in developing the strategic portfolio direction.

The final IRP and EIS will be made available to the TVA Board for its consideration. The Board may make a decision that will conclude the NEPA process for the IRP.

2.2.2 Engaging Stakeholders and Incorporating Feedback

In developing the IRP analysis and recommendations for the region's future energy system, TVA considered and balanced the varying needs and priorities of TVA's approximately 10 million stakeholders. Throughout the development of the IRP, TVA engaged external stakeholders to gather their views on the future power system, challenge assumptions, and help shape the analysis and outcomes. TVA looked for ways to expand and enhance public participation opportunities to gain additional insights from all the communities it serves so their opinions on the future power system can be considered.

In addition to IRP specific events, TVA has leveraged other existing forums to reach more stakeholders and facilitate participation in the IRP process. The primary avenues for stakeholder engagement in the IRP process included:



IRP Working Group

To ensure stakeholder views and needs were considered throughout the process, TVA established the IRP Working Group, a group of stakeholders with broad-ranging viewpoints that reviews and challenges IRP inputs and assumptions, analyzes outputs, helps design evaluation criteria, and reviews results and recommendations. The 23 members represent local power companies, customer associations, academia and research, state governments, environmental non-government organizations, community stakeholders, and other special interest groups. In addition to representing their individual views to TVA, they also represented and kept their constituencies informed during the IRP process. 2026 IRP Working Group members were:

Dr. Kendra Abkowitz (TN) City of Nashville	Wes Kelley (AL) Huntsville Utilities	Cortney Piper (TN) Tennessee Advanced Energy Business Council
Mike Butler (TN) Tennessee Wildlife Federation	Mike Knotts (TN) Tennessee Electric Cooperative Association	David Rogers (NC) Sierra Club
Dr. Don Colliver (KY) University of Kentucky	Dr. Teja Kuruganti (TN) Oak Ridge National Laboratory	Tim Smith (MS) Tippah Electric Power Association
Odell Frye (Valley) Associated Valley Industries	Melissa Lapsa (TN) Department of Energy – Energy Efficiency	Brian Solsbee (TN) Tennessee Municipal Electric Power Association
Lindsay Hanna (TN) Nature Conservancy	Kim Lewis (AL) PROJECTXYZ, Inc.	Landon Stevens (National) Clear Path
Shane Homan (MS) Community Development Foundation	Pete Mattheis (Valley) Tennessee Valley Industrial Committee	Kenya Stump (KY) State of Kentucky
Gil Hough (TN) Tennessee Solar Energy Industries Association	Susan Hadley Maynor (TN) Greater Memphis Chamber	Michelle Owenby (TN) Tennessee Dept. of Environment and Conservation
Mark Iverson (KY) Bowling Green Municipal Utilities	Doug Peters (Valley) Tennessee Valley Public Power Association	

Figure 2-2: IRP Working Group

Board Public Listening Sessions

Another opportunity for public participation in the IRP was through TVA Board public listening sessions. These quarterly sessions provided an open forum for stakeholders and the public to convey their perspectives directly to the Board on any topic related to TVA that is important to them. A number of stakeholders took advantage of the opportunity to share their thoughts with the Board on the IRP process and what they would like to see considered in the analysis and recommendations. The Board reflects on what they hear in public listening sessions as they deliberate and make decisions on all topics, including the IRP.

Regional Energy Resource Council

The RERC, established under the guidelines of the Federal Advisory Committee Act, is comprised of a group of external stakeholders representing regional government, customers, academia, and advocacy groups. The RERC provided guidance on how TVA plans and manages its energy resources against competing objectives and values. During the IRP process, the RERC received progress updates on the project and provided advice to TVA to be considered in the IRP. The meetings of the RERC are open to the public, meeting agendas are posted to the Federal Register, and the minutes from the meetings are published on the TVA website. The public is invited to provide comments on related topics, including the IRP, at listening sessions at RERC meetings.

Regional Engagements

New to this IRP, TVA leveraged ongoing regional engagements to heighten awareness of the IRP and solicit public input on considerations for how to best meet future electricity demand. These regional engagements provided the opportunity to personalize interactions and utilize local forums to convey information about the IRP to the public. TVA also kept important stakeholder bodies such as Regional Resource Stewardship Council as well as customer and local power company councils engaged and updated with opportunities for feedback. With the support of its regional representatives, TVA carried the IRP message to a broader audience, answering questions of local interest and receiving additional feedback.

Draft IRP and EIS Publication and Public Comments

The draft IRP and EIS, which incorporated stakeholder input received through that time, were posted on TVA's website on September 23, 2024, with a Notice of Availability published in the Federal Register on September 27, 2024. The draft IRP included an executive summary and discussions of the planning environment, stakeholder engagement, process and methodology, and portfolio results and assessments, followed by supporting appendices. The associated draft EIS provided information on the environmental impacts of potential future resource portfolios evaluated in the IRP.

To provide information on the IRP analysis and answer questions, TVA held two public webinars and 10 in-person open houses across the region and participated in smaller community events to address the interests of local audiences. Two of the open houses were rescheduled due to the impacts of Hurricane Helene in the surrounding communities. TVA encouraged stakeholders and the public to review the materials and provide their comments on the draft IRP and EIS during the 75-day comment period (extended from 60 days to accommodate rescheduled open houses) that concluded on December 11, 2024. About 600 members of the public attended the public webinars and in-person open houses, representing a 32% increase in open house public participation from the last IRP. TVA also engaged on the IRP in district meetings, federal advisory committee meetings, local power company board meetings, customer association meetings, community and civic meetings, utility conferences, and meetings with local elected and federal officials. In total, TVA received more than 2,500 official public comments on the draft IRP and EIS. Comments could be submitted through the online portal, via email or U.S. mail, or submitted at an in-person open house meeting during the public comment period. About 900 comments were submitted through the online portal, and the balance were largely submitted via email. In total, about 1,900 of the online and email submittals contained form letters that were pro-renewables and urged TVA toward decarbonization. About 70 discrete emails and letters were also submitted, including letters from agencies, a government representative, about 20 non-governmental organizations, and other organizations and individuals. Comments were received from individuals and entities in Tennessee, other Southeast states, California, New York, and other states across the nation.

Key themes from public comments include:

- Power infrastructure considerations, such as reliability, decentralization, using existing infrastructure, benefits of storage, and concerns about high demand data centers
- Economic considerations, such as benefits or costs of programs, maintaining a ratepayer focus, and rebates or incentives
- Environmental considerations, such as concerns about climate change, extreme weather, the environment, wildlife, and pollution
- Support for more clean energy generation and calls for decarbonization
- For/against certain resource technologies (e.g., nuclear, gas, coal, renewables)

Additional information about public comments and responses can be found in Appendix H of the EIS (Volume 2).

Public Informational Briefings

TVA hosted a total of five public webinars throughout the process, in addition to the two scoping and two draft IRP virtual open houses, to keep the public informed on the latest IRP updates. Initial webinars provided an overview of the process and analytical framework. Later webinars provided the public with a preview of IRP modeling results, strategic performance, and preliminary recommendations. Public webinars also offered the opportunity for participants to submit questions for IRP staff to answer at the end of the presentation. Following each webinar, recordings of the presentation and Q&A session were posted to the TVA website for playback on-demand.

In addition to the attendees at the four webinars mentioned above in Section 2.2.1, the IRP Public Informational Briefing webinar held in March 2026 included over 250 participants.

Incorporating Stakeholder Feedback

Outreach efforts prompted significant stakeholder and public engagement. Comments received during scoping helped frame the IRP effort. In addition, the IRP Working Group provided input that influenced the scenarios and strategies, challenged assumptions, refined the resource options, and strengthened the analysis and recommendations. Comments received on the draft IRP and EIS prompted additional analysis that was considered in developing the recommendations included in the final IRP, such as the inclusion of the Higher EE Availability and Deployment sensitivity. TVA has also incorporated additional information in the final IRP document based on public comments.

2.3 How Integrated Resource Planning Works

TVA used a rigorous and comprehensive scenario and strategy approach to evaluate potential paths for providing affordable, reliable, and resilient energy into the future. Stakeholder feedback was a key component in the development of all model inputs during the process.

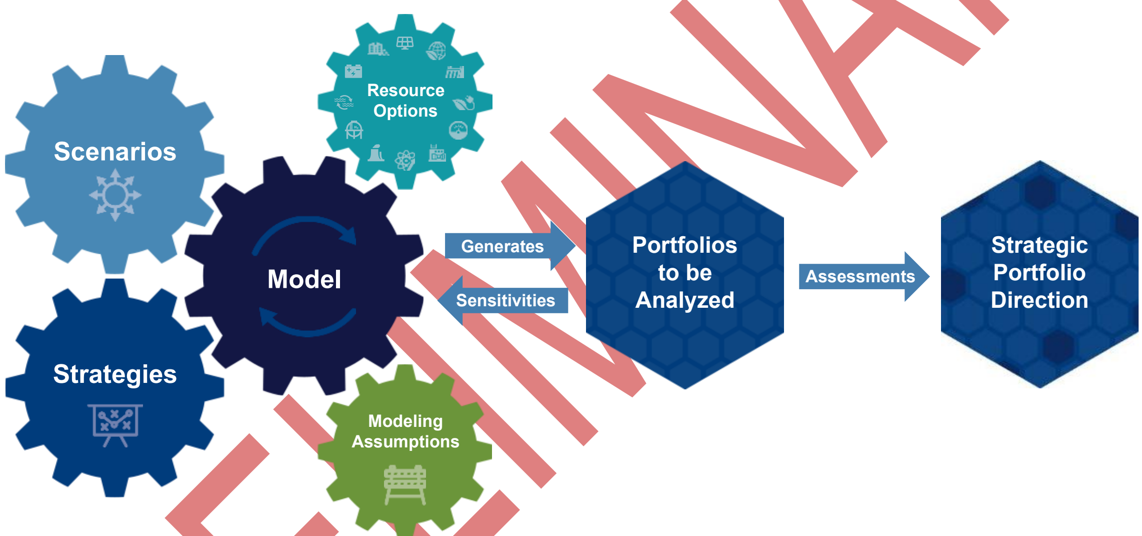


Figure 2-3: TVA's Integrated Resource Planning Process

TVA considered feedback from the IRP Working Group and public comments to design scenarios and strategies to be evaluated in the IRP. Scenarios explored possible futures that TVA may find itself operating in that have varying levels of macro-economic conditions, electricity demand, and environmental policy and regulations. Strategies modeled alternative approaches TVA could employ to meet electricity demand by emphasizing certain resource options. A robust set of mature and emerging resource options was prepared for consideration in the IRP analysis.

For each unique scenario and strategy combination, the planning model solved for the lowest-cost generating resource portfolio. Each of these portfolios was then analyzed using metrics that reflect TVA's mission and least-cost planning principles. Further analysis was performed to answer key "what if?" questions, with consideration of IRP Working Group and RERC input and public comments on the draft IRP and EIS. The EIS evaluated the environmental impacts of potential changes in the portfolio. Collectively, these evaluations informed the IRP recommendations for strategic portfolio direction included in the final IRP report.

Benchmarking Peer IRPs

Early in the IRP process, TVA engaged Deloitte to review TVA's 2019 IRP and benchmark utility peer IRPs. In their review, Deloitte found that TVA's 2019 IRP had an organized structure, strong stakeholder participation, thorough scenario and strategy analysis, and a variety of data sources and third-party involvement. Also, Deloitte reviewed the IRPs of 10 peer utilities primarily located in adjoining regions. Benchmarking analyzed load and other trends, scenarios and methodologies, and resource options with a focus on emerging technologies. Deloitte reviewed a summary of its findings with the IRP Working Group for consideration in providing input on TVA's IRP.

2.4 Creating Possible Scenarios

Often forecasts rely primarily on continuations of historical trends to suggest the possible future. In its IRP, TVA used scenarios as the mechanism to explore a more robust range of ways the future could unfold. Generally defined, scenarios are the future worlds which TVA may find itself operating in. They are driven by factors outside of TVA's control but to which TVA must be prepared to respond. The IRP scenarios were designed assuming that key uncertainties would deviate from historical trends in the future. Key uncertainties identified relate to electricity demand, environmental policy and regulations, macro-economic trends, and other factors. As possible scenarios were considered and developed, TVA strove for a set of possible futures that was relevant, informative, and diverse. Scenarios were supplemented with additional sensitivity analysis, such as alternative trajectories for electricity demand and natural gas prices, which are described further in Section 2.9.

2.4.1 Scenario Development

Scenario development begins with initial brainstorming before being further refined. As scenario narratives are crafted, consideration must be given to how the future might be shaped by changes in key uncertainties such as economic trends, electricity demand, consumer preferences, regulations, and technology advancements. Themes emerged, leading to potential scenarios that combined key uncertainties and correlated impacts. The scenarios and associated narratives were refined to ensure that each one:

- Reflected a possible future in which TVA might be operating between now and 2050
- Was unique from the other scenarios being studied
- Provided a robust foundation for analyzing a range of resource selections
- Encompassed the relevant interests of key stakeholders

Below are the three unique scenarios selected for study in the IRP analysis, with results and metrics from all scenarios reflected in a balanced manner.

SCENARIOS

1	**Reference** Represents TVA's current forecast that reflects moderate population, employment, and industrial (primarily data center) growth, weather-normal trends, growing electrification, and increasing efficiencies
2	**High Growth** Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity
3	**Carbon Legislation** Reflects the impact of potential future carbon legislation designed to reduce power sector emissions.

Figure 2-4: IRP Scenarios

The High Growth and Carbon Legislation scenarios represent different futures TVA could find itself facing based on key assumption changes from the Reference scenario. Taken together, along with sensitivities to be discussed later, the analysis reflects a range of futures TVA could operate in.

The following subsections provide highlights on the key elements underpinning the scenarios. Additional details can be found in Appendix B – Scenario Design and Forecasts.

2.4.2 Electric Load Forecast

Based on the scenario narratives, forecasts were then developed for key uncertainties, beginning with drivers of the load forecast. The load forecast represents the future energy needs for the region under normal weather conditions for each of the modeled scenarios. Variations from normal weather conditions are addressed in the Need for Power Analysis section that follows. In addition to native demand, the load forecast considers factors such as household growth, industrial growth, and electrification across all sectors that increase demand as well as growth in behind-the-meter generation and evolving codes and standards that reduce demand. All scenarios reflect the near-term impacts of rapidly increasing demand for electricity in the TVA region following a decade of roughly flat electricity demand. The figure below shows energy and peak demand forecasts for each scenario and the associated compound annual growth rates (CAGR) over the study window.

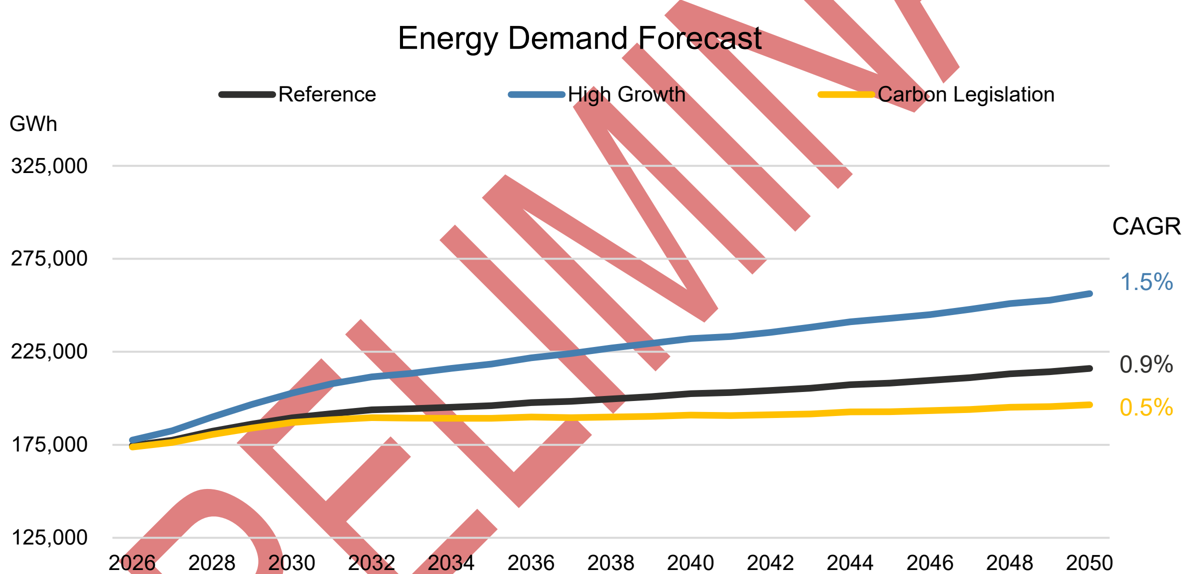


Figure 2-5: Energy Demand Forecast

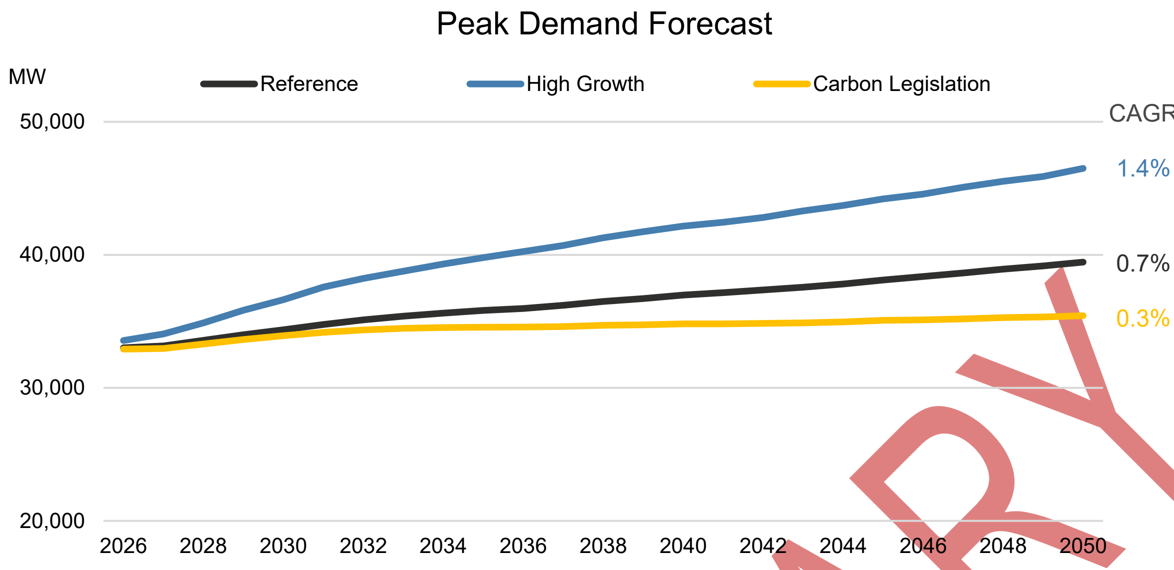


Figure 2-6: Peak Demand Forecast

- **Reference**: Reflects TVA's current forecast, including moderate economic growth including population, employment, and industrial (primarily data center) growth as well as continued growth in electrification across all sectors and increasing efficiencies that combine to drive steady load growth.
- **High Growth**: Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity across all customer segments.
- **Carbon Legislation**: Reflects the impact of potential future carbon legislation designed to reduce power sector emissions, resulting in higher national electricity prices, increased natural adoption of energy efficiency, and potential for fuel-switching all of which dampens demand growth.

Market-driven Energy Efficiency (EE)

An important aspect to note about the load forecast is that it incorporates anticipated impacts of evolving codes and standards, such as those set by the Department of Energy (DOE), that drive more efficient energy use and reduce net energy demand. TVA refers to this impact as market-driven, or naturally occurring, EE. By 2040 through 2050, the cumulative impacts of market-driven EE are forecasted to reduce net energy demand by an average of about 4% in the Reference scenario.

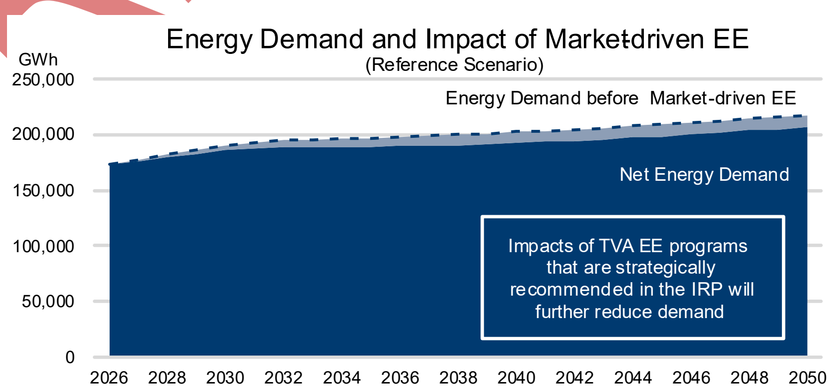


Figure 2-7: Impact of Market-driven Energy Efficiency on Net Energy Demand

TVA EE programs incentivize residents, businesses, and industries to accelerate the adoption of more energy efficient technologies above and beyond the impacts of codes and standards, or market-driven EE. Reporting of utility programmatic EE impacts is not fully consistent across the industry, as some utilities appear to report a portion of market-driven impacts in their numbers. TVA EE numbers reflect only the estimated impacts of programs that are in addition to market-driven EE.

2.4.3 Need for Power Analysis

The next step in creating scenarios was to develop capacity requirements for winter and summer for each scenario. Capacity requirements represent the megawatts (MW) needed to serve projected demand plus required planning reserves in each season. Electric utilities utilize planning reserves to provide sufficient resources above forecasted load to respond to risks and variations from normal weather, consumer behavior, and generating unit availability (see Appendix D, Section D.1 for further information on TVA's Planning Reserve Margin Study). Calculating capacity needs requires understanding the forecast for baseline firm supply from existing resources, which declines over time due to contract expirations and end of life assumptions for existing units. Then, firm capacity requirements are compared to projected baseline firm supply from existing resources and power purchases to identify the capacity gap – or the need for incremental power resources. The capacity gap reflects the minimum amount of new capacity that would be required to meet energy demand in each scenario.

To illustrate this concept, the figure below shows winter firm capacity requirements for each scenario compared to baseline firm supply. The difference between a scenario's firm requirements and the forecast for baseline firm supply over time represents the capacity gap.

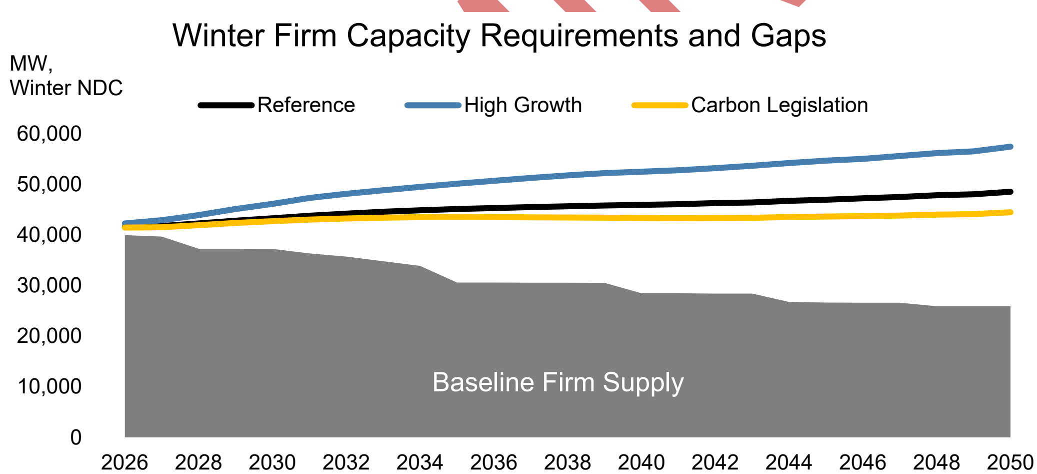


Figure 2-8: Winter Firm Capacity Requirements and Capacity Gaps

2.4.4 Current and Potential Future U.S. Energy Policy

The changing U.S. energy policy landscape represented another key uncertainty in scenario design. Two of the most recent key elements in policy and regulatory space were the One, Big, Beautiful Bill Act (OBBB) and regulatory relief actions undertaken in 2025 and early 2026. Additionally, Scenario 3 (Carbon Legislation) includes a forecasted carbon tax to serve as a proxy for current and potential future legislation and/or regulatory actions seeking to reduce greenhouse gas emissions.

One, Big, Beautiful Bill Act (OBBB)

The OBBB was signed into law on July 4, 2025. OBBB included updates to investment tax credit (ITC) opportunities available for renewable, storage, and nuclear resources. All IRP scenarios reflect the impacts of the OBBB on resource costs and national and regional energy prices. The figure below shows the level of ITC assumed in the IRP modeling of scenarios and resource cost assumptions. TVA generally assumed a 30% ITC for nuclear, renewable, and storage resources with phaseouts based on commercial operations date, or in-service date, as illustrated in the chart below. The OBBB allows up to a 50% ITC if wage and apprenticeship standards, domestic content guidelines, and siting criteria (in an energy or low-income community) are met. To account for potential cost increases to meet requirements, siting challenges, and other risk factors, the IRP analysis applies a 30% ITC. TVA will seek to maximize ITC value on a project-specific basis during the implementation of future applicable projects.

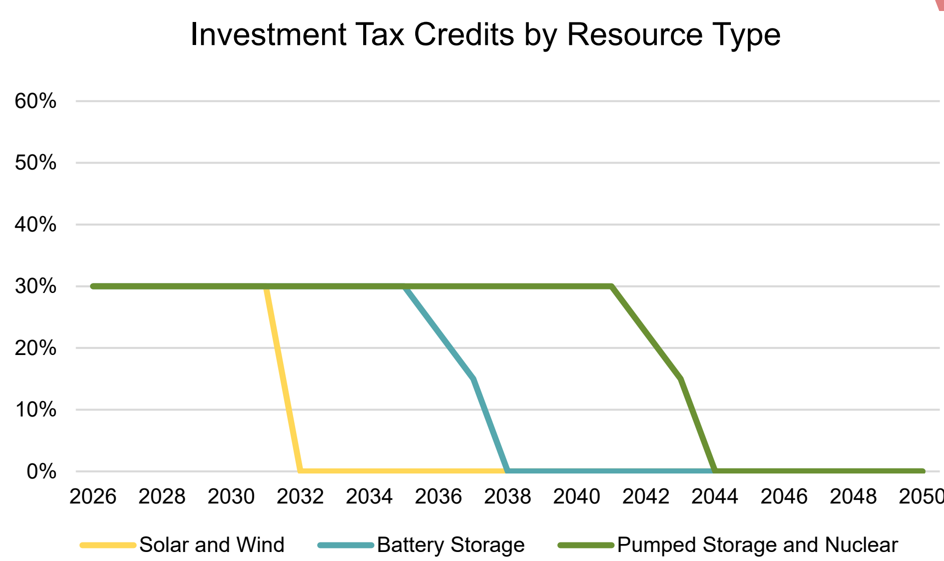


Figure 2-9: Investment Tax Credits by Resource Type and Commercial Operations Date

Also, the IRP analysis reflects the impact of the Section 45Q tax credit for carbon capture projects under construction before 2033. Credits are available for the first 12 years of commercial operation.

Executive Orders and Regulatory Relief

Throughout 2025 and continuing in 2026, the U.S. utility industry experienced significant policy and regulatory shifts as the Trump Administration sought to bolster domestic energy security and promote continued investment in both existing dispatchable resources, such as coal-fired power plants, and emerging technologies, including advanced nuclear. Executive Order 14156, issued January 20, 2025, formally declared a national energy emergency.

In parallel, the U.S. Environmental Protection Agency (EPA) announced intentions to provide regulatory relief across multiple rules affecting existing coal and future natural-gas generation. This included a proposed rule to repeal all greenhouse gas emissions standards for the power sector under Section 111 of the Clean Air Act (the "2024 GHG Rule"), as well as a final rule authorizing state permit writers to extend compliance deadlines under the Effluent Limitation Guidelines (ELG) for steam electric generating units. EPA has indicated intentions to finalize the proposed repeal of the 2024 GHG Rule in the Spring of 2026.

Against this backdrop, in February 2026 the TVA Board authorized TVA to take steps to allow for the continued operation of the Cumberland and Kingston fossil plants, subject to compliance with applicable permitting and regulatory requirements, to meet rapidly increasing demand for electricity and address associated reliability concerns in the TVA region. TVA also re-evaluated and updated planning assumptions related to end-of-life expectations for all coal units, alongside updates to resource cost assumptions across all technologies, as applicable.

Carbon Tax

Over the past several decades, a number of legislative proposals have been made and regulatory actions undertaken in an effort to reduce greenhouse gas emissions from the electric power sector, such as the Clean Power Plan and Greenhouse Gas Rule. While recent actions have been undertaken to repeal or revise these rules and provide regulatory relief, utilities must still account for the possibility that current regulatory efforts are stalled or new legislation or regulatory actions will be taken in the future. To account for this, Scenario 3 - Carbon Legislation includes a forecasted carbon tax to serve as a proxy for current and potential future legislation and/or regulatory actions seeking to reduce greenhouse gas emissions. The carbon tax assumptions used in the Carbon Legislation scenario are not based on any specific forecasts, regulations, or legislative proposals. Rather, the carbon tax forecast uses the same trajectory studied in TVA's 2019 IRP (from the Double Decarbonization sensitivity), with adjustments to start in 2032 and ramp-up five years later.

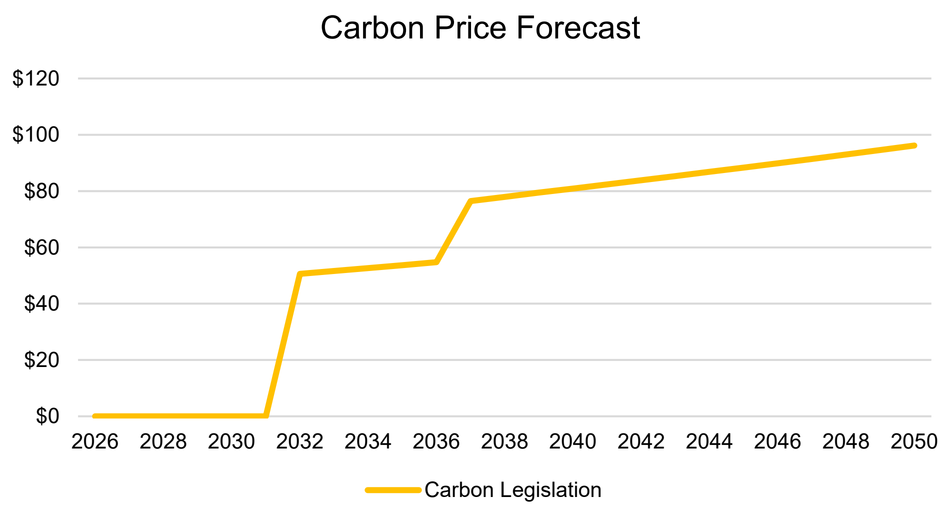


Figure 2-10: Carbon Tax Price Forecast - Carbon Legislation Scenario

2.4.5 Commodity Prices

The price of commodities over the study period are an uncertainty that varied across the scenarios, and they also plays a role in resource selection. Informed by their narratives, each of the three scenarios utilized unique forecasts for key commodities, including natural gas, coal, uranium, and market electricity. Natural gas prices are a key uncertainty with high potential to impact new resource selections. Natural gas price forecasts for each scenario are shown in the chart below. Additional information regarding commodity price forecasts by scenario, including coal basin prices, uranium, and electricity market price forecasts, are found in Appendix B.5.

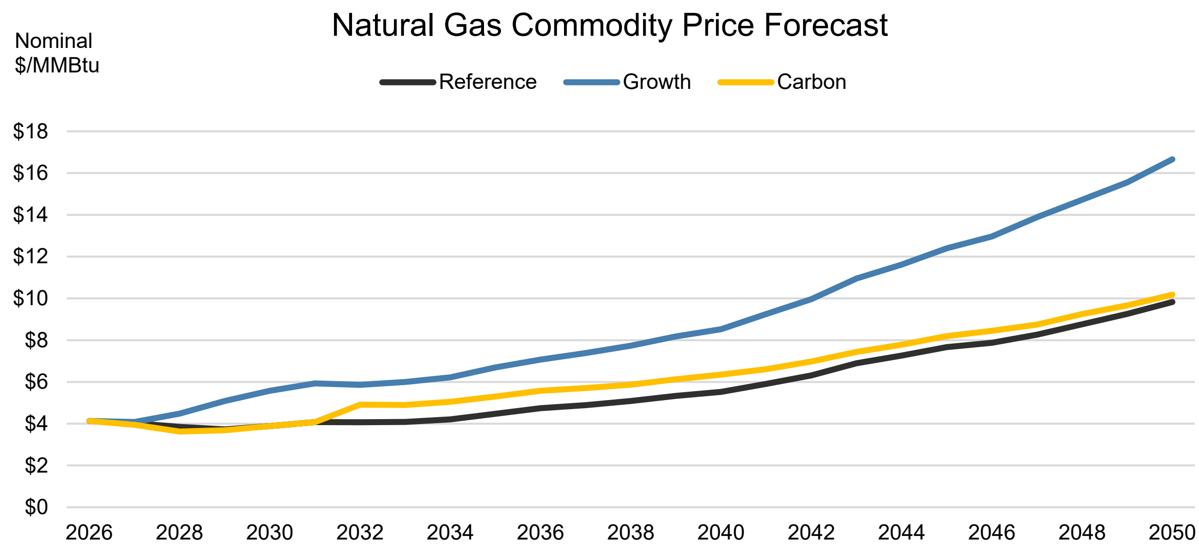


Figure 2-11: Natural Gas Price Forecast

- **Reference**: Industrial demand and growing export volumes are the primary drivers of nominal natural gas price increases in this scenario, while prices adjusted for inflation remain relatively stable.
- **High Growth**: High growth in electricity demand in this scenario is assumed to be high nationally as well as regionally. This increasing demand for electricity, along with the ITC phase-out for renewable resources, has a corresponding increase in natural gas demand pushing prices higher throughout the study period.
- **Carbon Legislation**: Carbon tax legislation drives electric utilities away from coal into lower carbon fuel alternatives including natural gas, resulting in increased demand for natural gas and higher prices relative to the reference scenario.

2.4.6 Resource Technology Assumptions

Scenario development generally assumes the same resource technology cost baseline for all scenarios, adjusted for differences in scenario inflation forecasts.

2.5 Identifying Potential Strategies

After scenario forecasts were developed, the next task was to identify planning strategies. Where scenarios describe the potential futures TVA may find itself operating in, strategies depict business approaches TVA could employ to meet energy demand in these future worlds. The IRP analysis compares baseline utility planning with alternative strategies that promote certain resource types to evaluate tradeoffs.

2.5.1 Strategy Development

TVA brainstormed ideas and considered feedback from the IRP Working Group to identify and develop a set of strategies to analyze. Narratives for alternative strategies were developed to explain the goal of each strategy and then resource types to be emphasized were identified to achieve each strategy's goal. Baseline Utility Planning represents fundamental least-cost planning, and all strategies apply a planning reserve margin to provide sufficient resources to account for variations in load and generating unit availability. The alternative strategies emphasize specific themes – from promotion of emerging, firm, dispatchable resources through innovation, research and developmentR&D and partnerships to promotion of distributed and demand-side resources or smaller, more dispersed resources that enhance local resiliency.

TVA decided on three distinct strategies to explore in the IRP analysis, supported by the following narratives:

STRATEGIES

A **Baseline Utility Planning**
Represents TVA's current outlook based on least -cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies

B **Innovation**
Emphasizes emerging, firm and dispatchable technologies such as advanced nuclear and long-duration storage through innovation, continued R&D, and partnerships.

C **Distributed**
Emphasizes distributed technologies such as batteries, renewables, and demand-side programs to reduce reliance on central station generation and utilize virtual power plants

Figure 2-12: IRP Strategies

Resource promotion was accomplished by defining minimum amounts of emphasized resources to be selected, either annually or by a given year. All resource options are available to be selected in each strategy, including those with no promotion, allowing the model to select and optimize the resource portfolio from the full suite of available resources.

2.5.2 Strategy Design and Evaluation

The IRP analysis compared Baseline Utility Planning with the alternative strategies to evaluate tradeoffs based on least-cost planning principles. At a high level, the steps in the strategy design and evaluation process were:

- Develop Baseline Utility Planning cases for all scenarios (no resources promoted)
- Identify emphasis of resource types to achieve objectives in each strategy
- Run cases with resource emphases for alternative strategies in all scenarios
- Evaluate tradeoffs across all portfolios using metrics based on least-cost planning principles

The details of strategy design involved identifying the level and mechanism for emphasizing resources. TVA opted for either base (no promotion) or emphasize (promotion) to drive differentiation across the strategies. Each strategy required minimum additions of certain resources in order to drive diverse portfolio outcomes. The potential impact of higher or lower than forecasted resource cost trajectories for select resources were analyzed as sensitivity cases, further described in Section 2.9.

The Strategy Design Matrix below provided the roadmap for how resource emphasis was applied in the strategies. All resource types were available for selection in all strategies.

STRATEGY	UTILITY-SCALE RESOURCES							DISTRIBUTED AND DEMAND-SIDE RESOURCES			
	Nuclear	Coal	Gas CC and Frame CT	Aero CTs and RICE	Renewables	Battery Storage	Long-duration Storage	Distributed Solar	Distributed Storage	Energy Efficiency	Demand Response
A Baseline	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
B Innovation	Emphasize	Base	Base	Base	Base	Base	Emphasize	Base	Base	Base	Emphasize

STRATEGY	UTILITY-SCALE RESOURCES							DISTRIBUTED AND DEMAND-SIDE RESOURCES			
	Nuclear	Coal	Gas CC and Frame CT	Aero CTs and RICE	Renewables	Battery Storage	Long-duration Storage	Distributed Solar	Distributed Storage	Energy Efficiency	Demand Response
C Distributed	Base	Base	Base	Emphasize	Emphasize	Emphasize	Base	Emphasize	Emphasize	Emphasize	Emphasize

Figure 2-13: Strategy Design Matrix and Resource Promotion

Each of the three strategies was modeled in each of the three scenarios, resulting in nine core portfolios. Additional details, including required minimum addition amounts, can be found in Appendix C – Strategy Design and Application.

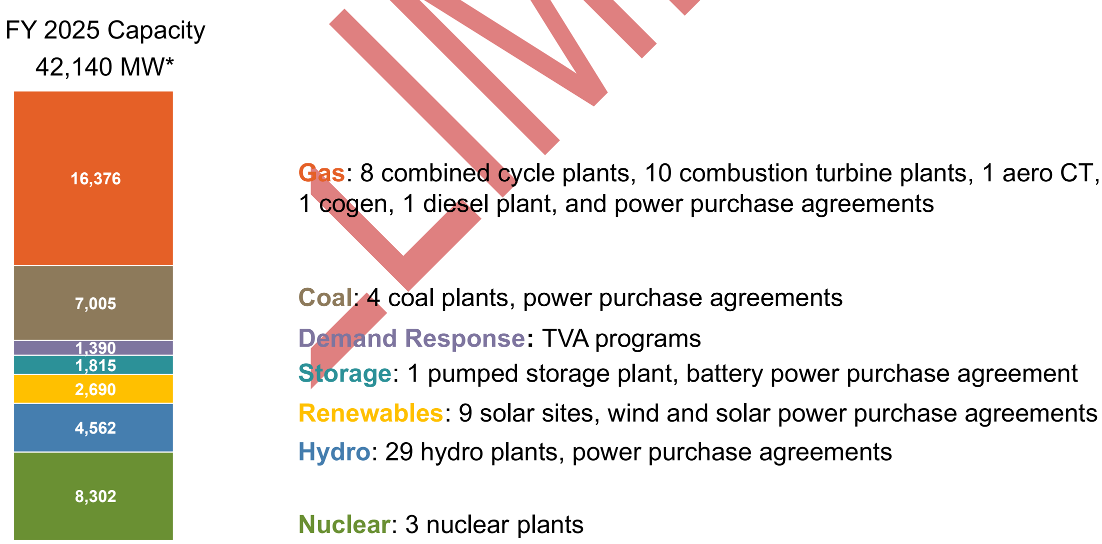
2.6 Defining Resource Options

The next step in the IRP process was to define resource options. This entailed understanding the current set of existing resources, identifying new resource options, and defining the key assumptions for each resource option to accurately model operational characteristics and costs.

2.6.1 Existing Resources

TVA employs a diverse resource mix to meet the region's energy demand. Power generation resources serve different needs – from those that run continually to meet constant energy needs, to those that help meet fluctuating needs, to those that are used for a few hours when energy demand is at its highest.

Today, the TVA power system is comprised of generating resources and power purchase agreements that provided 42,140 MW of summer net capability in FY 2025.



* Capacity aligns to FY 2025 10-K summer net capability and power purchase agreement tables, adjusted to include demand response programs. Planning capacity is lower, as it accounts for hydro, renewable, and storage expected generation at peak, fuel blend deratesand other factors.

Figure 2-14: TVA's Existing Resource Portfolio

The resource planning model uses net dependable capacity (NDC), or the expected output of a given resource at the forecasted time of peak demand. Net dependable capacity is lower than summer net capability published in TVA's annual 10-K report, as it accounts for hydro and renewable expected generation at peak, fuel blend derates, and other factors. Renewable resources may be referred to in NDC or nameplate capacity (maximum hourly generating capability), depending on the need and context.

The forecasted capacity available from existing resources changes over the study window as purchased power contracts expire and some generating units are projected to reach the end of their useful life, as shown below.

Table 2-2: Significant Baseline Firm Supply Reductions (MW Summer NDC)

Year	Coal	Gas CC	Gas CT	Diesel	Hydro	Solar	Wind	Other Renewable	Battery	Total MW SNDC
Baseline Firm Supply 2026										38,228
2027		220	75							295
2028	1,114	200	979	62				22		2,377
2029										
2030				23						23
2031		735					55	1		791
2032	434			20		3	103			560
2033		833					37	6		876
2034		749								749
2035	2,663			10	356					3,029
2036								12		12
2037						51				51
2038						116				116
2039						60				60
2040	2,041									2,041
2027-40	6,252	2,737	1,054	115	356	230	195	41		10,980
Baseline Firm Supply 2040										27,248
2041										
2042						256				256
2043										
2044		1,646				113			50	1,809
2045						374			50	424
2046						172			65	237
2047										
2048		652								652
2049										
2050										
2027-50	6,252	5,035	1,054	115	356	1,142	195	41	165	14,358
Baseline Firm Supply 2050										23,870

An updated baseline for the IRP analysis was established in fall of 2025; however, TVA may have entered into short-term purchased power contracts since that time. Dates for TVA-owned coal and combined cycle (CC) plants reflect end of life planning assumptions based on anticipated regulatory requirements, age, and/or material condition that are subject to further evaluation, environmental review, and TVA Board approval.

2.6.2 Resource Options

Maintaining resource mix diversity is fundamental to TVA's ability to provide affordable, reliable, and resilient energy to the residents, businesses, and industries in the region. A diverse portfolio reduces fuel price risk and reliability risks associated with single modes of failure. To promote a robust resource mix, the IRP analysis considered a wide range of supply-side, distributed, and demand-side management resources. Distributed resources would be installed behind the meter by end-use customers.

The IRP analysis includes incremental capacity additions from several projects that are anticipated to come online over the next few years. TVA explicitly includes TVA Board-approved projects and signed contracts with third-party developers for solar, gas, and storage additions, along with the first few years of demand-side program volumes.

To be considered in the IRP, a given resource option must utilize a proven technology, or one that has reasonable prospects of becoming commercially available in the planning horizon. It must also be available to TVA within the region or be able to be imported through a power purchase agreement. As the 2026 IRP looks out to 2050, several emerging technologies, such as generation III+ and generation IV nuclear and advanced chemistry batteries, were included as options using best available industry data. Other emerging technologies, such as nuclear fusion, are considered promising but technology readiness remains too low to be included in the IRP study. TVA will continue to monitor all viable and promising emerging technologies for inclusion in future planning studies.

The major resource types evaluated in the IRP include nuclear, hydro, coal, natural gas, renewables, storage, and energy efficiency and demand response (EE and DR), and they were available for selection in all cases. The figure below shows the major resource types, technologies, and relative advantages and considerations.

Major Resource Types	Nuclear	Hydro	Coal	Gas	Renewables	Storage	EE and DR
Resource Technologies	• Advanced pressurized water reactor (Gen III+) • Light water small modular reactor (Gen III+) • Gen IV small modular reactor	• Hydro uprates	• Supercritical pulverized coal • Supercritical pulverized coal w/ carbon capture	• Combined cycle (CC) • CC w/ carbon capture • Combustion turbine • Aeroderivative • Reciprocating engine	• Utility-scale solar • Distributed solar • Midwest wind • Southeast high-hub wind	• Pumped storage • Lithium-ion battery • Advanced chemistry battery • Distributed storage	• Energy efficiency • Demand response
Advantages	• Dispatchable • Large energy output • Low operating cost • Carbon-free	• Dispatchable • No fuel cost • Low variable cost • Carbon-free	• Dispatchable • Large energy potential	• Dispatchable • Large energy potential • Operational flexibility	• No fuel cost • Low variable cost • Carbon-free	• System efficiency benefits • Operational flexibility	• Reduced need to construct new resources • Carbon-free
Considerations	• High build and fixed cost • Cost and timeline risk for new builds • Spent fuel disposal	• Energy limited based on water availability and other missions	• Waste disposal • Environmental risk • CO2 storage and transportation • Carbon-emitting	• Fuel price volatility • Pipeline challenges • CO2 storage and transportation • Carbon-emitting	• Weather and time dependent • Solar land use • Local wind speeds • Wind importation cost and risk	• Energy limited based on hours of duration • Round trip efficiency losses	• Program protocols and limitations • Free ridership • Evolving codes and standards

Figure 2-15: Summary of Resource Options

2.6.3 Technology and Adoption Readiness

The ability to successfully deploy a technology is dependent upon the maturity of the technology itself, as well as the readiness to adopt that technology throughout its entire value chain. To better assess adoption readiness, the DOE has developed a Commercial Adoption Readiness Assessment Tool (CARAT) that establishes an Adoption Readiness Level (ARL) framework to complement the existing Technology Readiness Level (TRL) framework. Taken together, they provide a more complete view of the readiness to deploy various resource technologies in the energy sector.

Technological readiness is assessed with a 1 to 9 TRL score that ranges from research to development and demonstration to commissioning and operations. The ARL framework establishes a rubric for evaluating the commercial factors related to a technology's value proposition, market acceptance, resource maturity, and license to operate, resulting in an overall 1 to 9 ARL score that reflects level of readiness across the adoption value chain. A high-level summary of TRL and ARL scoring levels is shown below.

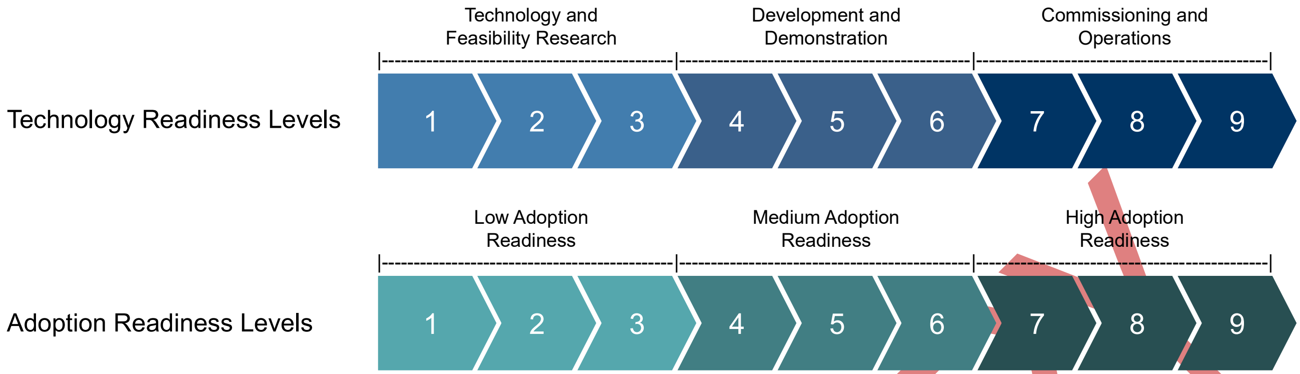


Figure 2-16: DOE's TRL and ARL Frameworks

Using DOE rubrics, TVA scored the technology and adoption readiness levels for the various resource options included in the IRP analysis. TVA referenced industry-led risk registers to help identify technology-specific risk types and levels. For the ARL assessment, TVA considered production, transportation, and distribution infrastructure in a 3-to-5-year commercialization window. The figure below summarizes the scoring results.

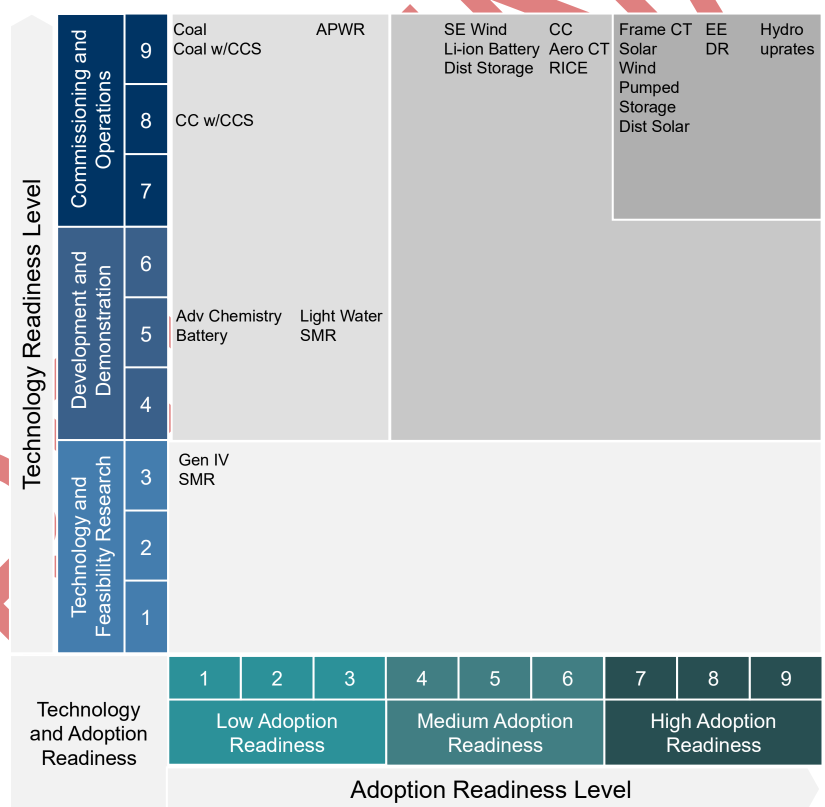


Figure 2-17: TRL and ARL Assessment Summary

The IRP analysis considered relative technology maturity in strategy design and in determining earliest deployment, as well as in risk assessments. Also, the strategic portfolio direction from the IRP will help shape TVA's future innovation and research efforts. More information on DOE's TRL and ARL assessment tools and details of the scoring results for the resource options included in the IRP analysis can be found in Appendix E – Utility-Scale Resource Methodology.

2.6.4 Key Assumptions by Resource Type

After determining the resource types to include in the IRP, TVA then developed detailed assumptions for each resource option and reviewed a summary with the IRP Working Group. To effectively model a resource option, certain questions need to be answered, including:

- How soon can a specific resource option be designed, reviewed, constructed, and brought online?
- How many units of each resource type can be added annually and over the planning horizon?
- What are the operational characteristics and constraints for each resource option?
- What contribution to peak load will renewable and storage resources have as installation increases?
- How much does each resource cost, and how do costs change over time?

The following table highlights the key modeling assumptions by resource type for the Reference scenario.

Table 2-3: Key Assumptions by Resource Type (Reference Scenario)

Resource Type	Key Assumptions
Nuclear	• First-of-a-kind light water small modular reactor available beginning 2033 with costs for subsequent units declining to nth-of-a-kind over first eight units; annual limit of one build • Advanced pressurized water reactor available beginning 2039; annual limit of one build • Gen IV small modular reactor available beginning 2041; annual limit of one build
Hydro	• Hydro uprates available beginning 2031 as part of established Hydro Life Extension program • Assumptions are specific to potential opportunities across the TVA power system which total 200 MW
Coal	• Supercritical pulverized coal available beginning 2032; annual limit of two builds • Supercritical pulverized coal with carbon capture and sequestration available beginning 2033; annual limit of one build, total limit of 11 builds
Gas	• Conventional natural gas available beginning 2032; annual limit of two builds of each type • Combined cycle with carbon capture and sequestration available beginning 2033; annual limit of one build, total limit of 11 builds • RICE units available beginning 2032; representative of small-scale gas generators installed at either utility- or distribution-scale.
Solar	• Solar available beginning 2031; annual limit of 1,000 MW nameplate • Single-axis tracking (storage modeled separately) • Incremental solar contribution to peak of 68% in summer and 15% in winter, declining as installation amounts increase • Average capacity factor of 25%
Wind	• Midwest and Southeast high-hub wind available beginning 2031; annual limit of 1,000 MW nameplate • Incremental wind contribution to peak of 19% in summer and 33% in winter, declining as installation amounts increase • Average capacity factor of 40% (Midwest) and 30% (Southeast high-hub)

Resource Type	Key Assumptions
Storage	• Pumped storage available beginning 2035; cumulative limit of 1 build • Lithium-ion battery (4-hour) available beginning 2031; annual limit of 500 MW nameplate • Advanced chemistry battery (8-hour) available beginning 2031; annual limit of 500 MW nameplate
EE and DR	• Current program cycle extends through 2029 • Expansion EE and DR programs available beginning 2030 • Program tier design informed by recent Energy Programs Potential Study and subsequent TVA market experience • Demand response capability is assumed to grow with the size of the system
Distributed Generation	• Baseline forecast for distributed generation adoption modeled based on consumer payback • For strategy where distributed generation was promoted, accelerated adoption was modeled based on level of promotion and impact on consumer payback

Best practice in utility planning is to use annual limits as the modeling vehicle for simulating the practical ability to construct or procure new resources, so the analysis will generate executable portfolios. The IRP analysis includes annual limits for all resource types based on recent experience designing, permitting, and constructing new generating assets and procuring new resources through Request for Proposal processes. For example, the market capability for solar has increased, and this is reflected with solar limits that are more than double the limits used in the 2019 IRP. These limits should be viewed as long-term, average annual limitations as unique circumstances or future project timing may allow TVA to exceed these limits in some years during implementation of TVA's Asset Strategy. Cumulative limits for the entire study period also apply to simulate physical limitations for certain resources, such as uprate potential at existing hydro plants.

Scenario 2, High Growth, and the Supercharged Growth sensitivity feature annual limits that are approximately 50% higher than the Reference and Carbon Legislation scenarios, to account for assumptions around increased economic productivity. For example, annual gas limits for each technology type increase from two to three builds, annual solar limits increase from 1,000 MW to 1,500 MW nameplate, annual battery storage limits increase from 500 MW to 750 MW nameplate, and annual nuclear light water SMR limits increase from one unit to two units following the completion of the first four units.

2.6.5 Resource Technology Costs

Developing the costs for the various resource options considered in the IRP was the next step in the process. The sub-sections below summarize the general methodology used to develop resource costs, how recent policy changes were incorporated, and the overnight capital cost for each resource technology.

General Methodology

For utility-scale options, TVA used a combination of direct experience with recent projects, market-based request for proposal responses, industry expertise working with equipment manufacturers, and industry forecasts to inform resource costs. For example, informed by direct experience exploring designs for potential SMRs at the Clinch River Nuclear Site, TVA used refined forecasts for new nuclear resources that reflect all-in costs plus risk contingencies and may be higher than some industry estimates. The refined nuclear forecasts utilize information from structured estimate determination efforts. Hydro expansion costs were based on internal estimates specific to opportunities across the TVA power system. Gas and hydro pumped storage expansion estimates were based on recent project experience and discussions with equipment manufacturers. Solar and battery storage costs in the near-term are based on market offers submitted through recent, competitive requests for proposal, with long-term forecasts including adjustments for continued technological advancements. Finally, wind expansion costs were sourced from the 2024 National Laboratory of the Rockies' (NLR) (formerly the National Renewable Energy Laboratory, or NREL) Annual Technology Baseline and incorporate transmission wheeling estimates to deliver this energy. For more details on utility-scale resource assumptions, see Appendix E – Utility-scale Resource Methodology.

Adoption of distributed generation resources (distribution-scale solar and storage) was modeled based on consumer payback, with accelerated adoption in the Distribution strategy. The modeling of demand-side resource options, including EE and DR program tiers, was designed based on TVA program experience and information included in the Energy Programs Potential Study. Further information on the methodology and costs for distributed generation and demand-side resource options is included in Appendix F – Distributed Generation Resource Methodology and Appendix G – Demand-side Resource Methodology, respectively.

One, Big, Beautiful Bill Act (OBBB)

As mentioned previously, estimated impacts from the OBBB were applied in all IRP scenarios for applicable resources. The primary impact to resource costs was in the form of ITCs that incentivize investment in specific energy sources. In IRP modeling, TVA generally assumed a 30% ITC for nuclear, renewable, and storage resources with phaseouts as noted above in Section 2.4.4. This assumption is reflective of an ITC which could be as high as 50%, but has been adjusted for risk factors related to meeting all requirements to achieve the maximum ITC (see section 2.4.4 for additional explanation).

Overnight Costs by Technology

A key assumption contributing to resource selection is the cost to construct a particular resource. Overnight capital costs represent the total estimated cost to build a given resource in the first year available, restated in 2026 dollars and divided by its capacity in kilowatts ($/kW). Cost assumptions were derived from the sources explained in the general methodology section, incorporating the impacts of recent policy changes. The table below summarizes overnight capital costs for the utility-scale resource options considered in the IRP, prior to the impacts of any applicable tax credits. Capacity is expressed as Summer NDC for thermal resources and as nameplate for renewable and storage resources. Further information on utility-scale resource characteristics and costs can be found in Appendix E – Utility-scale Resource Methodology.

Table 2-4: Overnight Capital Costs (Prior to any applicable ITC)

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2026 $/kW)
Nuclear	Advanced Pressurized Water Reactor (APWR)	1,100	14,235
	Small Modular Reactor – Light Water (first-of-a-kind)	285	17,263
	Small Modular Reactor – Light Water (nth-of-a-kind)	285	8,743
	Small Modular Reactor – Gen IV with Integrated Storage	345 / 500[1]	9,751
Hydro	Hydro Uprates	200	1,818
Coal	Coal Supercritical Pulverized	650	3,482
	Coal Supercritical Pulverized with Carbon Capture and Sequestration	650	4,905
Natural Gas	Combined Cycle – 3x1x1[2]	2,145	2,148
	Combined Cycle with Carbon Capture and Sequestration – 2x1x1	1,430	3,635
	Frame Combustion Turbine – 4x[2]	884	1,161
	Aeroderivative Combustion Turbine – 20x[2]	1,060	2,513

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2026 $/kW)
	Reciprocating Internal Combustion Engine – 12x[2]	432	2,305
Solar (nameplate)	Solar Single-Axis Tracking	50	1,698
Wind (nameplate)	Wind – Midwest	200	1,574
	Wind – Southeast High-Hub	200	2,205
Storage (nameplate)	Pumped Storage	1,212	3,191
	Battery – Lithium-ion (4-Hour)	50	2,158
	Battery – Advanced Chemistry (8-Hour)	50	3,886
EE and DR	Energy Efficiency and Demand Response Programs	Varies by program – refer to Appendix G for modeling details	
Distributed Generation	Distributed Solar, Storage, and Combined Heat and Power	Varies by resource – refer to Appendix F for modeling details	

[1]Base reactor capacity of 345 MWe with 155 MW of integrated storage (~5.5 hours) for combined output of 500 MW
[2]Smaller configurations of these resources were also offered as available options.

Depending on how an asset's dispatch costs compare to others in the fleet, the amount of energy generated from a specific asset may vary significantly over time. For example, when gas prices are low, assets powered by natural gas serve customers with more energy than when gas prices are high. A concept that is sometimes utilized to compare asset costs is Levelized Cost of Energy (LCOE). LCOE divides the total cost of an asset (i.e., construction and capital, ongoing operating and maintenance, and dispatch costs which are primarily fuel) by expected output or generation. Because dispatch costs and expected output vary widely across the IRP scenarios, LCOE is not a useful metric to benchmark resource costs.

Transmission Costs

In addition to the costs to build or procure resources, costs are incurred to connect each resource to the transmission system. Transmission costs are based on a review of recent projects constructing new generating assets of various types across the TVA system, incorporating adjustments based on expected future changes to project complexity, material costs, and labor requirements as the system continues to evolve.

Large resource additions like natural gas and nuclear plants typically require more robust transmission buildouts, including items like new substations and longer transmission lines for interconnection, along with significant upgrades to existing transmission assets in the local area. Inverter-based resources such as solar and battery storage often require relatively fewer traditional transmission upgrades. However, the size and dispersed nature of these resources makes the scale of new and upgraded transmission projects more complex on a per MW basis compared to larger generating plants. Also, inverter-based resources typically require supplemental reactive resource transmission projects to ensure system stability and reliability that are not as likely to be required for spinning generation. As the deployment of inverter-based solar and battery storage increases on the TVA system, the likelihood of more extensive network upgrades increases, given the growing interdependence of each system modification.

2.7 Incorporating Modeling Assumptions

For the IRP, TVA used an industry-standard model for resource planning that applies a planning reserve margin and other key assumptions, forming the modeling framework for the analysis.

2.7.1 Modeling Software

TVA utilized the EnCompass capacity expansion and production cost simulation package, licensed through Yes Energy, as the primary modeling tool for the IRP analysis. In 2022, TVA upgraded to the EnCompass model to leverage its multi-user functionality and enhanced ability to consider the chronology of energy needs in resource selection. EnCompass is also used as the primary resource planning tool by a number of other utilities in the Southeast and across the nation.

Based on the set of assumptions and constraints applicable in a given analysis, the EnCompass model seeks to determine the lowest cost resource portfolio and the expected energy output for each resource in the portfolio. The model can also be used to calculate portfolio metrics to inform business decisions. Additional information on how the model works is included in the discussion on developing and evaluating portfolios in section 2.8.

2.7.2 Planning Reserve Margin

Planning reserve margin is the excess capacity that TVA maintains above forecasted peak load, as required of all electric utilities, to provide reliable service to customers while keeping rates low. Maintaining additional capacity accounts for uncertainty in the amount of load and available generation on a future peak day. For example, future loads are uncertain due to variations in weather conditions, and electric generators can experience unplanned outages due to equipment failure. TVA has a dual-peaking power system, as peak demand for summer and winter is roughly the same. While forecasted peaks are similar, uncertainty and risks vary with the seasons, so TVA uses seasonal reserve margin targets to account for this. Periodically, TVA conducts a study reflecting the latest data on changes in electricity demand and the power system to establish updated planning reserve margin targets.

In the IRP analysis, TVA used the following assumptions:

- 18% planning reserve margin target in the summer
- 26% planning reserve margin target in the winter

These values were based on the 2024 Reserve Margin Study, a probabilistic study that estimates the amount of reserve capacity required to meet an industry best practice of a 1-in-10-year loss-of-load expectation for reliability. Weather is a key driver of load. The variability of weather during winter in the TVA region is much greater than in summer, and the region has a relatively high share of electric heat. Also, power generation performance varies by season. Overall, weather-related uncertainty is the primary contributor to the relatively higher winter reserve margin.

The region has recently experienced extreme winter temperatures in each of the last few years, some of which have set new winter peak records, such as the current all-time record peak of 35,319 MW set in January 2025. Extreme winter events drive increased peak demand, and cold temperatures can also cause additional generator outages and impact market import capability. Other Southeast peer utilities are seeing similar trends. While weather factors are out of TVA’s control, TVA made significant investments during 2023 to further harden its generating resources, which improved cold weather performance during winter storms in 2024 and 2025 that set new peak records. Additional information on planning reserve margin and related studies can be found in Appendix D – Key Modeling Assumptions.

2.7.3 Discount Rate

The objective function of the EnCompass capacity expansion model is to minimize the present value of revenue requirements (PVRR) while meeting the reliability and operational needs of the power system. To calculate the PVRR of a given expansion path, the model applies a discount rate to the forecasted total system costs by year over the study window to reflect those costs in today's dollars. The current discount rate of 7% is based on TVA's weighted average cost of capital, and it reflects the time value of money and other factors such as investment risk. The model calculates and compares the PVRR of numerous expansion paths that meet power system needs and determines the least-cost option.

2.7.4 Other Supporting Studies

Net Dependable Capacity Study

TVA performed a study to evaluate the NDC of solar, wind, and storage resources. NDC is a measurement of a resource's ability to produce energy at times of peak demand, expressed as a percentage of nameplate capacity. The seasonal NDC of intermittent and storage resources can be determined by evaluating historical generation patterns and/or an Effective Load Carrying Capability study. NDC decreases over time with increasing installation of solar, wind, and battery storage resources on the system. Solar output is relatively high at the typical summer peak late in the afternoon but is substantially less at the typical winter peak early in the morning. Wind generation is more variable overall and is generally higher in winter than in summer. Battery storage NDC is generally higher with more hours of storage duration. Results of the study indicated:

- NDC for incremental solar resources at the beginning of the study period was 68% in summer and 15% in winter, and NDC declines as installation of solar resources on the system increases.
- NDC for incremental wind resources at the beginning of the study period was 19% in summer and 33% in winter, and NDC declines as the installation of wind resources on the system increases.
- NDC for incremental 4-hour battery storage begins at 100% for up to 500 MW, falls to about 80% by 1,500 MW, and decreases further as installation increases.
- NDC for incremental 8-to-10-hour storage assumes significant installation of 4-hour battery storage, begins at 67% by 6,000 MW of total storage installation, and decreases as installation increases.

TVA applied NDC study results in the IRP to reflect the contribution of solar, wind, and storage resources to meeting peak demand over the planning horizon. More information on the NDC study can be found in Appendix D – Key Modeling Assumptions.

Energy Program Potential Study

In 2022, DNV (a global leader in energy program consulting) conducted a study for the TVA region to evaluate the achievable potential for energy efficiency programs that incentivize investment in making homes and businesses more energy efficient. The study indicated a 10-year potential for energy efficiency gains in the region ranging from 2-7% of energy sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric space heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications. Due to inflationary pressures and the unique partnership arrangement between TVA and the LPCs, customer uptake of EE programs has been slower and more costly than anticipated in the 2022 Energy Programs Potential Study though momentum began to increase in 2025 and the portfolio remains cost-effective. Learnings from the potential study and subsequent market experience have informed the inputs in the 2026 IRP.

Additional details on the Energy Program Potential Study can be found in Appendix D – Key Modeling Assumptions and the study's use in developing IRP program inputs in Appendix G - Demand-side Resource Methodology.

2.8 Developing and Evaluating Portfolios

TVA utilized the EnCompass model to take the inputs related to the scenarios, strategies, resources options, and key modeling assumptions and develop portfolios for evaluation in the IRP. Combining the three business strategies in the three planning scenarios resulted in nine core portfolios, as shown in the matrix below.

STRATEGIES	SCENARIOS		
	1 Reference	2 High Growth	3 Carbon Legislation
A Baseline Utility Planning	1A	2A	3A
B Innovation	1B	2B	3B
C Distributed	1C	2C	3C

Figure 2-18: Portfolio Matrix

The process for developing the portfolios included capacity expansion and production cost modeling, stochastic modeling, and metrics development. Together, these elements provided the information necessary to evaluate and compare key tradeoffs in portfolio performance.

2.8.1 Capacity Expansion Modeling

Capacity expansion models are effective tools to assess a broad range of resource options and determine a resource mix that minimizes system costs under planning parameters that simulate real-world operations and availability of resources. The model:

- Considers assumptions for energy demand, fuel prices, and potential regulations in a scenario
- Applies a planning reserve margin to determine firm capacity requirements
- Considers resource options, along with promotion parameters applicable in a strategy
- Applies other key modeling assumptions, such as NDC
- Applies operational and other practical constraints
- Ensures compliance with existing state and federal laws and regulations
- Derives a lowest-cost resource portfolio for a unique scenario and strategy combination

The model seeks to identify a portfolio of resources that minimizes total system costs, including capital costs for new resources as well as ongoing operations, maintenance, and fuel costs. Given the complexity of all the possible resource combinations, the capacity planning model uses a simplified representation of hourly demand to develop the lowest-cost resource portfolio for further evaluation. Total system cost is expressed as the PVRR. PVRR represents the present-day value of all future costs over the planning horizon, discounted at 7% to reflect the time value of money and other factors such as investment risk.

2.8.2 Production Cost Modeling

Next, each capacity plan was evaluated using an hourly production cost model, also using the EnCompass model. The production cost model uses detailed chronological, hourly granularity to simulate the commitment and dispatch of the system to meet hourly weather-normal loads on a least-cost operations basis. At this lower level of granularity, resource operating characteristics and constraints that apply can now be modeled. For each unique scenario and strategy combination, the production cost model provides the forecasted energy contribution for each resource in the portfolio. Also, the model calculates detailed production costs, including fuel and other variable operating costs, which are then combined with the construction and capital costs from the capacity model to derive total costs for a portfolio.

2.8.3 Stochastic Modeling and Risk Assessment

While scenarios explore step changes in possible futures, stochastic analysis evaluates the risk of uncertainty around multiple key assumptions. Fundamental forecasts for key variables, while useful in planning, will inevitably change over time. Variability is due to many factors such as temperature, extreme weather, economic cycles, market conditions, supply/demand disruptions, and technology improvements. Stochastic analysis bounds the uncertainty in key assumptions and identifies the risk exposure that is inherent in long-term power supply planning.

Two primary uses of stochastic analysis in the IRP are to quantify financial risk and operational performance. The first step is to identify the key drivers of portfolio costs and performance associated with electricity demand, fuel prices, generating unit availability, unit operating and capital costs, and interest rates. Then, a distribution around the fundamental forecasts for each of the drivers is developed using scalars based on historical variability.

The stochastic model uses a Monte Carlo simulation (a form of repeated random sampling) to test the variability of key assumptions and understand the likely range of results, allowing for a comparison of financial risk and operational performance across portfolios. Stochastic modeling was used to calculate the risk-informed metrics and some of the operational metrics, which are described further in the following section. Additional information on stochastic analysis can be found in Appendix A – Integrated Resource Planning Fundamentals.

2.8.4 Metrics Development

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles, and with input from the IRP Working Group, TVA developed a set of metrics to assess the performance of the different strategies across the scenarios. Metrics cover the 2026-2050 study period, except for one metric that focuses on 2050, as noted.

Table 2-5: Metrics and Definitions

Metric Category	Metric	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Total plan cost (capital and operating) expressed as expected present value of revenue requirements
	System Average Cost ($/MWh)	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	PVRR above expected value based on stochastic analysis

Metric Category	Metric	Definition
Environmental Responsibility	Land Use Intensity (Acres/GWh)	Acreage needed for expansion units divided by energy generated and purchased in 2050
	Water Consumption Intensity (Million Gallons/MWh)	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Million Tons/GWh)	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	Carbon Dioxide (CO_2) Direct Emissions (Million Tons)	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Average annual CO_2 emitted divided by average annual energy generated and purchased
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
	P95 Average Unserved Energy Ratio	Stochastic 95th percentile average annual amount of energy shortfall (MWh) over study period divided by average annual sales (MWh)
	Expected Average Energy Curtailment Ratio	Stochastic expected average annual curtailed energy (MWh) over study period divided by average annual sales (MWh)

After capacity and energy plans were developed for the nine portfolios, TVA leveraged the EnCompass model results to produce metrics for each portfolio.

2.8.5 Portfolio Evaluation

Each IRP case represents a combination of expectations about the future environment and potential strategies TVA could employ that result in unique resource portfolios. Evaluating the portfolios starts with understanding the relative differences in incremental resources added to the system and how that impacts total capacity and energy plans. Then, metrics can be utilized to assess least-cost planning tradeoffs across the portfolios and strategies. For example, a particular portfolio may be lower in cost and fare better in operational metrics than another portfolio but have higher environmental impacts. Looking at results for a particular strategy across all scenarios can indicate relative performance for that strategy with respect to a particular metric. Collectively, portfolio evaluations provide insights to overall strategy performance.

2.9 Performing Sensitivity Analysis

A sensitivity analysis varies a key assumption to isolate the impact of a change in that assumption. When analyzing results from the core cases and considering IRP Working Group, RERC, and public comments, TVA identified questions that warranted further evaluation before finalizing the study. Questions typically related to key assumptions that have the potential to influence results. To explore impacts of changes in key assumptions and provide additional information for consideration in developing IRP recommendations, the IRP analysis includes a list of sensitivity assessments to perform. Results from sensitivities are summarized in Chapter 3, section 3.10.

2.10 Developing Recommendations

All IRP findings, including evaluations of the nine core portfolios and insights gained from sensitivity analysis, were considered in developing the IRP recommendations. Recommendations include power supply mix ranges by resource type, recommended strategic portfolio direction, and how key signposts will influence future portfolio direction through 2040 and beyond. The more site-specific effects of actions that are later proposed to implement the IRP will be addressed and considered in tiered environmental reviews.

2.11 Conclusion

The 2026 IRP analysis tests a broad range of external scenarios and business strategies, along with a robust set of resource options, to generate potential resource portfolios to be analyzed. Stakeholder engagement and feedback is an important factor throughout the process. The following chapter presents the portfolio results, assessments, and sensitivity analysis that were considered in developing the IRP recommendations.

3 Portfolio Results and Assessments

This chapter describes the findings of the 2026 IRP. Applying three business strategies in three external scenarios generated nine distinct resource portfolios. The results for the nine core resource portfolios are presented, along with associated scorecard measures that evaluate relative portfolio performance and tradeoffs. These nine core portfolios were supplemented with additional sensitivity analysis which explored the impacts of changing a single key assumption to isolate its impact on portfolio results. The three external scenarios and three business strategies evaluated in the IRP were:

SCENARIOS		STRATEGIES	
1	**Reference** Represents TVA's current forecast that reflects moderate population, employment, and industrial (primarily data center) growth, weather-normal trends, growing electric vehicle use, and increasing efficiencies	A	**Baseline Utility Planning** Represents TVA's current outlook based on least -cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies
2	**High Growth** Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity	B	**Innovation** Emphasizes emerging, firm and dispatchable technologies such as advanced nuclear and long-duration storage through innovation, continued R&D, and partnerships.
3	**Carbon Legislation** Reflects the impact of potential future carbon legislation designed to reduce power sector emissions.	C	**Distributed** Emphasizes distributed technologies such as batteries, renewables, and demand-side programs to reduce reliance on central station generation and utilize virtual power plants

Figure 3-1: IRP Scenarios and Strategies

Throughout the discussion of results, scenarios are referred to by number and strategies by letter. Portfolios represent the combination of a scenario and a strategy, referred to by the relevant number and letter reference, as summarized in the table below. For example, the Reference scenario and the Baseline Utility Planning strategy combination is referred to as 1A.

STRATEGIES		SCENARIOS		
		1 Reference	2 High Growth	3 Carbon Legislation
A	Baseline Utility Planning	1A	2A	3A
B	Innovation	1B	2B	3B
C	Distributed	1C	2C	3C

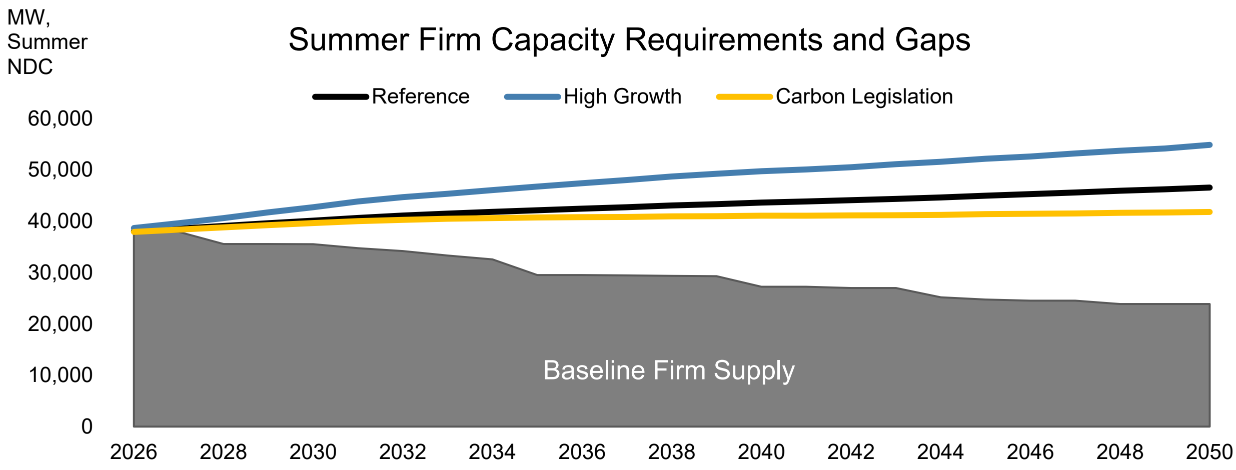
Figure 3-2: Portfolio Matrix

3.1 Capacity Needs

The three scenarios forecasted varying levels of electricity demand, which drove varying levels of capacity requirements and need for incremental resources in each scenario. The planning model also considers the ability of different resource types to contribute to meeting demand at peak times.

3.1.1 Firm Capacity Requirements and Capacity Gaps

As described in Chapter 2, TVA identified the firm capacity requirements for each scenario for both summer and winter, based on projected electricity demand and required reserves in each season. Firm requirements were highest in Scenario 2 (High Growth) and lowest in Scenario 3 (Carbon Legislation).



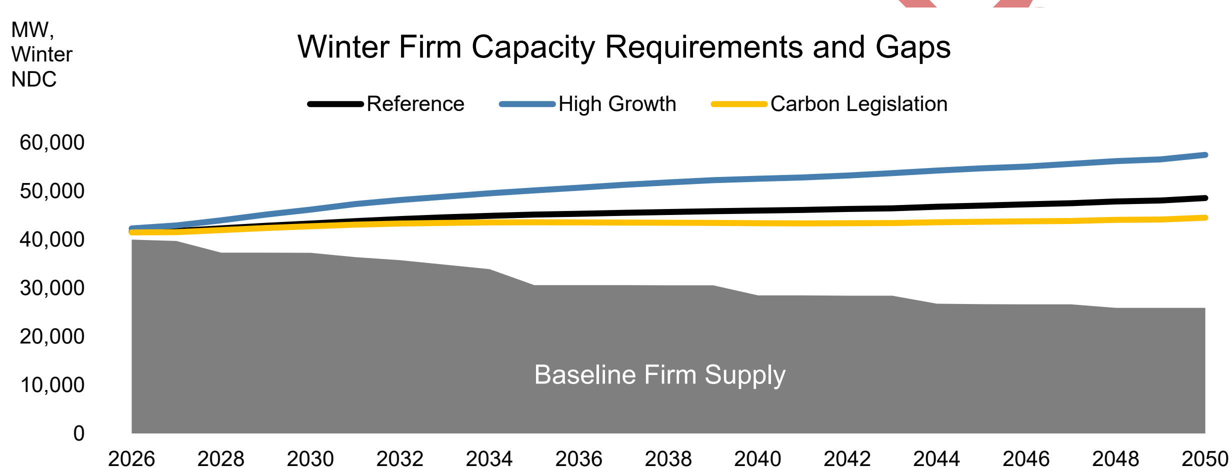


Figure 3-3: Summer and Winter Firm Capacity Requirements

Baseline firm supply – or the forecasted capacity available from existing resources – changes over time as generating units reach the end of their useful life and purchased power contracts expire. The figure below shows forecasted reductions in firm supply of coal, gas, and renewable resources by 2050. Dates for TVA-owned coal and CC plants reflect end of life planning assumptions based on anticipated regulatory requirements, age, and/or material condition that are subject to further evaluation, environmental review, and TVA Board approval. Approximately 11,000 MW and 14,000 MW of existing capacity is expected to expire or reach end of life by 2040 and 2050, respectively.

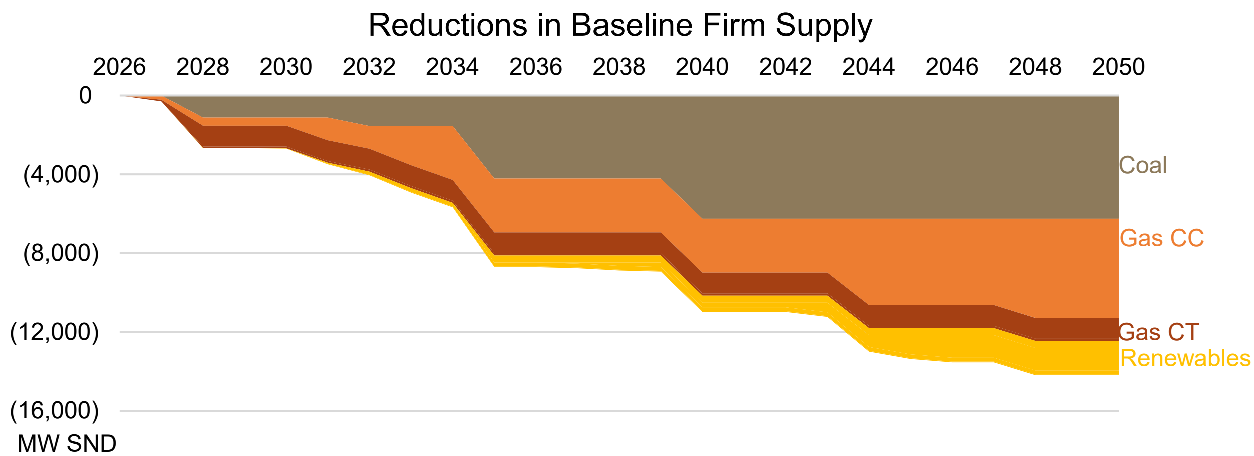


Figure 3-4: Significant Baseline Firm Supply Reductions by Resource Type

The difference between firm capacity requirements and baseline firm supply from existing resources represents the capacity gap, or the need for incremental resources, in each scenario. The capacity gap was highest in Scenario 2 and lowest in Scenario 3. The capacity gap impacts the magnitude and timing of incremental resource additions.

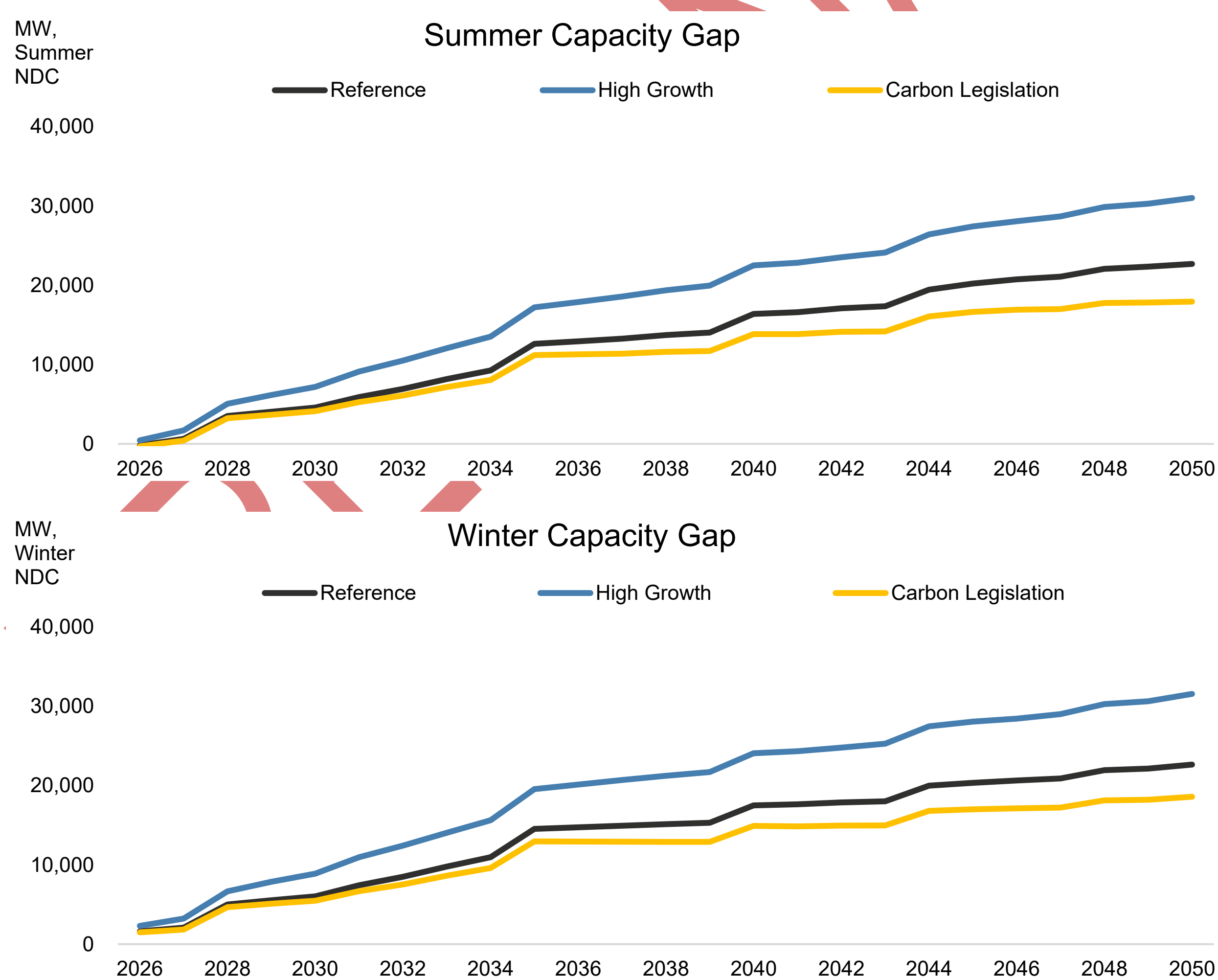


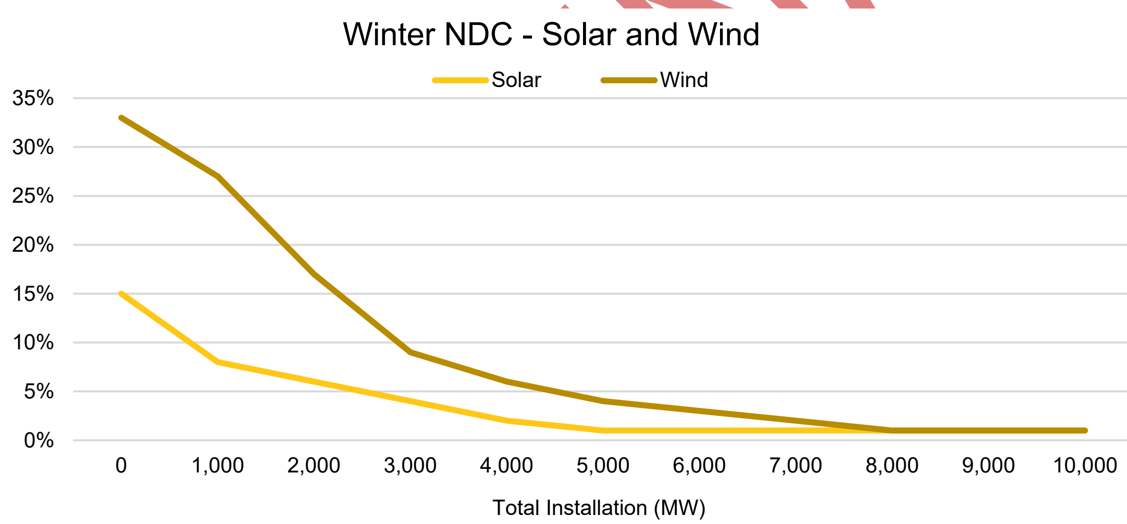
Figure 3-5: Summer and Winter Capacity Gaps

In addition to peak demand needs, the planning model also considers the pattern of energy required across the day, year, and planning horizon to determine the optimal mix of resources that meets system requirements at the lowest cost for each scenario and strategy combination.

3.1.2 Net Dependable Capacity of Renewables and Storage

When optimizing each portfolio, the planning model considers the cost and operating characteristics of all resource options and how each resource can help meet peak and energy demand. The figures and graphics included in the IRP show renewables and storage in nameplate capacity, which is typical for these resources. However, the model understands the ability of these resources to contribute to meeting summer and winter peak demand, expressed as a percentage of nameplate capacity. This percentage is determined by a study that evaluates the amount of solar, wind, and storage generation likely to be available at seasonal peak demand times compared to a fully dispatchable gas resource. This percentage is called net dependable capacity (NDC), and it differs by season and decreases as installation amounts of solar, wind, and storage resources increase. With higher capacity needs in winter, contribution to meeting winter peak demand is most relevant in the planning model.

The figures below show NDC for incremental solar, wind, and storage resources in winter that are applied in IRP modeling. Given the negligible contribution to meeting winter peak demand at high levels of installation, solar is being selected primarily to meet energy needs (see Appendix D.2 for summer and winter values). More information on the NDC study and resource characteristics can be found in Appendices D and E.



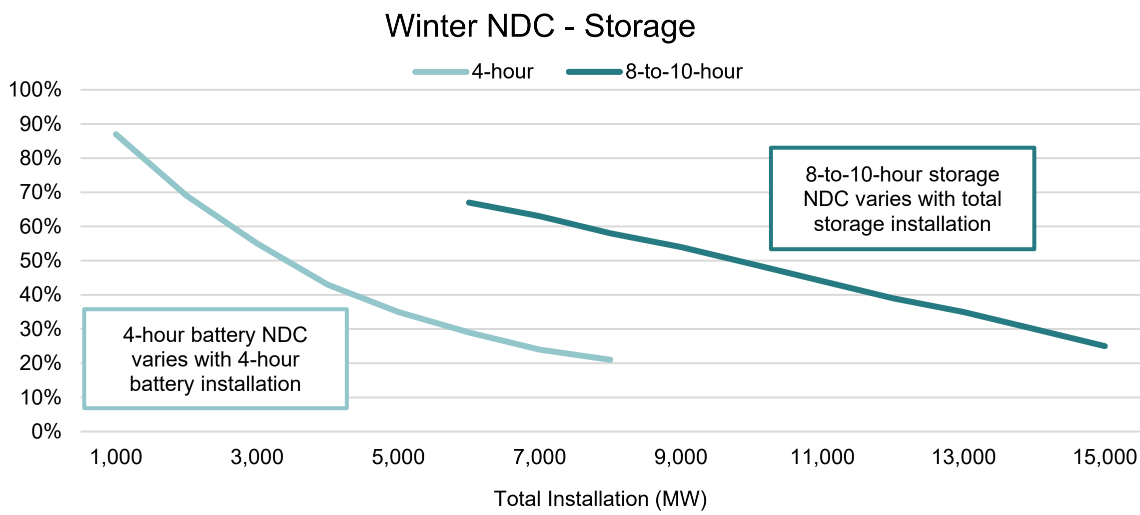


Figure 3-6: Winter NDC for Solar, Wind, and Storage

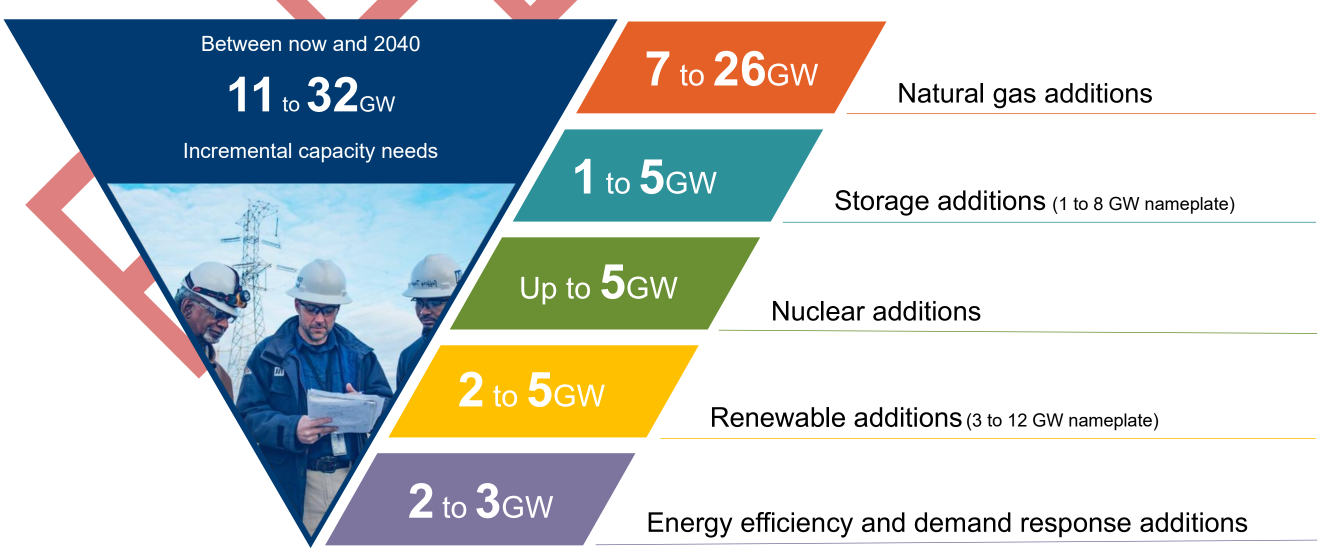
3.2 Expansion Plans

Considering the capacity needs and other parameters in each scenario, along with applying the resource promotions identified for each strategy, the planning model solved for the lowest cost portfolio for each unique scenario and strategy combination. This section summarizes key themes from the expansion plans and provides results for all nine core portfolios.

3.2.1 Key Themes

Uncertainty in electricity demand, legislative or regulatory actions, resource costs, and available technologies increases as the forecast horizon extends further into the future. The IRP analyzes potential ways the resource portfolio might change between now and 2050 to respond to changes in these key drivers, and insights gained from evaluating the entire planning horizon were used to inform strategic portfolio direction. Key themes are expressed in gigawatts (GW), with one GW providing enough energy to power about 585,000 average homes.

Looking across all portfolios, including sensitivity analysis, through 2040, IRP results suggest:



Power supply mix ranges, summarized in summer net dependable gigawatts (GW) above, vary based on energy demand, market conditions, policy and regulations, and technology advancements.

- New capacity is needed in all scenarios to support load growth or replace expiring and end of life capacity.
- Firm, dispatchable technologies are needed to ensure system reliability throughout the year.
- Gas expansion serves broad system needs, with the ability to provide firm, dispatchable capacity, economic energy, and system flexibility.
- Storage expansion continues, driven by both battery storage and the potential for additional pumped storage.
- New nuclear technologies, with continued advancements, can support load growth and reduce fuel volatility and regulatory risks.
- Solar expansion plays a complementary role, meeting customer needs and providing economic energy.
- Energy efficiency deployment reduces energy needs, particularly between now and 2040, and demand response programs grow with the system and the use of smart technologies.

A mix of resource types – both supply and demand-side – will be required to meet system needs. In all scenarios, TVA will continue to provide affordable, reliable, and resilient energy for years to come.

3.2.2 Incremental Capacity Changes

Incremental capacity changes – or the resources selected to fill the capacity gap – are presented below. The first chart shows incremental changes by 2040, and the second chart shows changes by 2050. These include all new resource additions, but do not reflect planned end-of-life expectations and contract expirations already included in the forecast for baseline firm supply. While both summer and winter capacity needs and capabilities factored into portfolio optimization, summer net dependable capacity values are being shown throughout the document when presenting incremental capacity results.

The results for each scenario are grouped together, and incremental capacity additions are grouped by resource type. Scenario 3 has the lowest demand forecast, driving the lowest amount of incremental capacity. Conversely, Scenario 2 has the highest demand forecast and the highest amount of incremental capacity need. Within each scenario, strategy results vary due to the impact of resource promotions on portfolio optimization.

The figure below compares the incremental capacity for all portfolios by 2040.

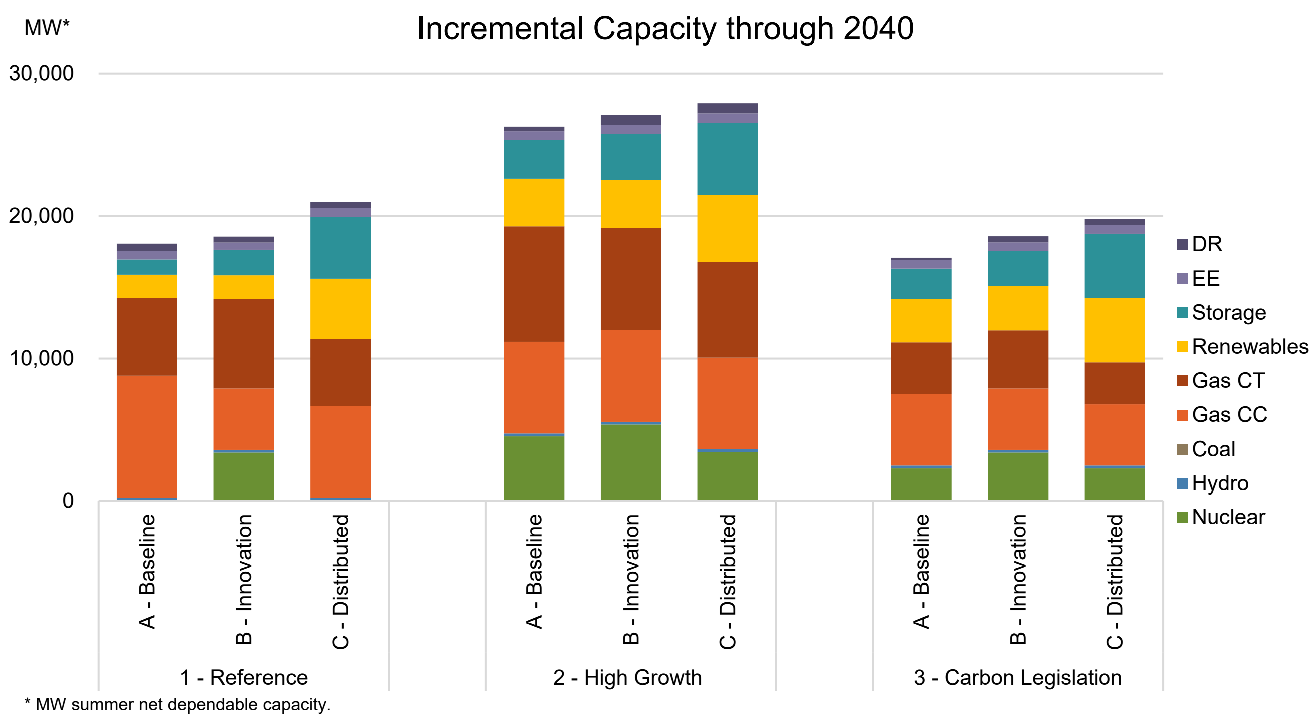


Figure 3-7: Incremental Capacity through 2040 (Summer NDC)

Highlights of the incremental capacity changes by 2040 by resource type include:

Nuclear: The Innovation strategy includes a minimum of 3,400 MWs of new nuclear by 2040. Economic nuclear capacity, up to 5,400 MW in case 2B, is selected after the BWRX achieves Nth of a kind cost; the High Growth and Carbon Legislation scenarios also include economic nuclear selection based on a combination of higher electricity demand, higher natural gas prices, and/or regulatory requirements.

Hydro: 200 MW of hydro expansion was selected by 2040 in all cases as part of an optimal portfolio mix.

Coal: Though available in all scenarios, new coal was not selected in any scenario.

Gas CC: 4,300 MW to 8,600 MW of Gas CCs were added to the resource mix driven by forecasted load and strategic emphasis.

CC with Carbon Capture and Sequestration (CCS): Though available in all scenarios, CC with CCS was not selected in any scenario, including Scenario 3 - Carbon Legislation.

Gas Combustion Turbine (CT): 3,000 MW to 8,100 MW of Gas CTs were added to the resource mix driven by forecasted load.

Renewables: Renewable nameplate additions were all solar, which includes utility- and distribution-scale, and they varied with forecasted load and strategic focus. Additions ranged from about 1,700 MW (2,500 MW nameplate) in 1A and 1B to 4,700 MW (12,000 MW nameplate) in 2C, were highest overall in the Distributed strategy, and averaged about 3,300 MW (6,100 MW nameplate) across all nine portfolios.

Storage: Storage additions ranged from 1,100 MW to 5,100 MW (1,100 MW to 7,600 MW nameplate), averaged 3,000 MW (3,600 MW nameplate) across all cases, and were a mix of short and long duration, including hydro pumped storage.

EE: Energy efficiency additions ranged from 500 MW to 700 MW (700 MW to 900 MW maximum hourly summer reduction) and averaged 600 MW (800 MW maximum hourly summer reduction) across all cases. Incremental EE was highest in the Distributed strategy.

DR: Demand response additions ranged from <200 MW to 700 MW and averaged 500 MW across all cases; in the near-term, Valley Growth programs push incremental additions as high as 1,900 MW to enable near-term interconnection of new industrial loads.

The figure below compares incremental capacity for all portfolios by 2050 (note difference in scale from 2040).

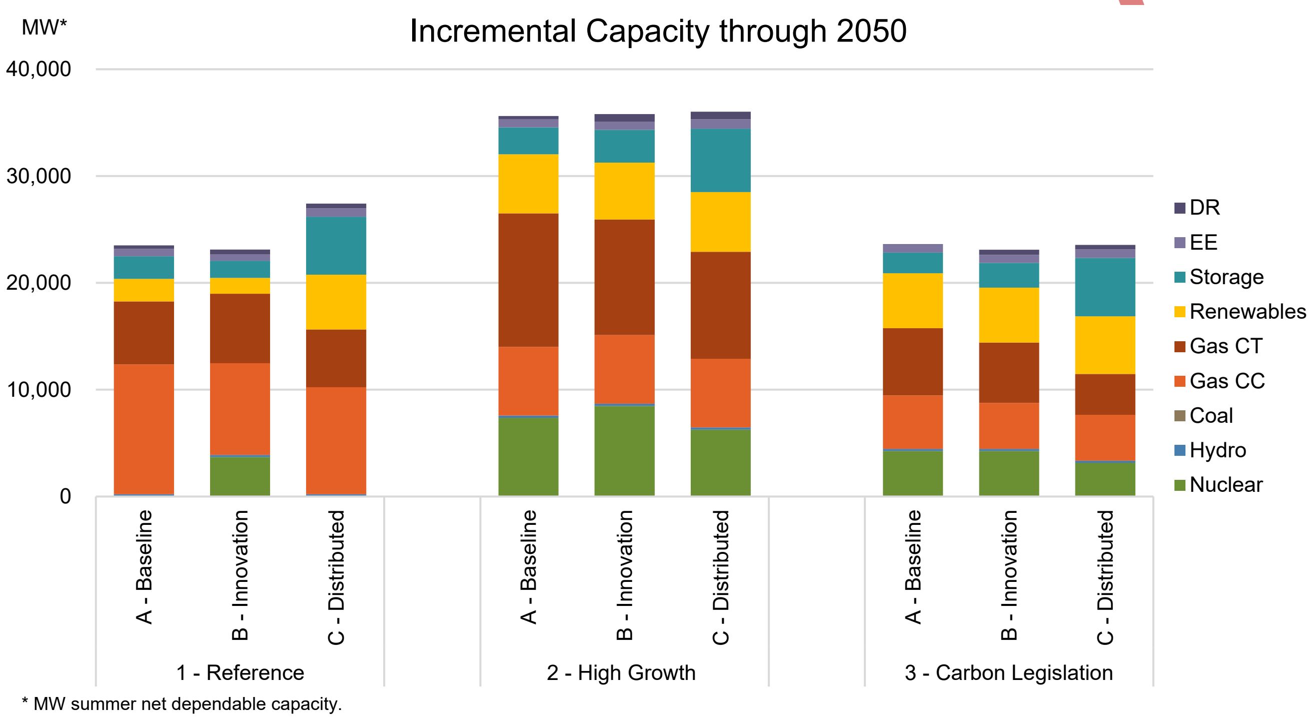


Figure 3-8: Incremental Capacity through 2050 (Summer NDC)

Highlights of the incremental capacity changes by 2050 by resource type include:

Nuclear: The Innovation strategy includes a minimum of 3,400 MWs of new nuclear. Economic nuclear capacity, up to 8,500MW in case 2B, is selected after the BWRX achieves Nth of a kind cost; the High Growth and Carbon Legislation scenarios also include economic nuclear selection based on a combination of higher electricity demand, higher natural gas prices, and/or regulatory requirements.

Hydro: 200 MW of hydro expansion was selected in all cases as part of an optimal portfolio mix.

Coal: Though available in all scenarios, new coal was not selected in any scenario.

Gas CC: About 4,300 MW to 12,200 MW of Gas CCs were added to the resource mix depending on forecasted load and strategic emphasis.

CC with CCS: Though available in all scenarios, CC with CCS was not selected in any scenario, including Scenario 3 - Carbon Legislation.

Gas CT: CT additions varied significantly, ranging from about 3,800 MW to 12,500 MW, driven primarily by forecasted load in each scenario and strategic emphasis.

Renewables: Renewable nameplate additions were primarily solar, which includes utility- and distribution-scale, with a small amount of wind in the High Growth scenario in the late 2040s, and they varied with load growth and strategic emphasis. Additions ranged from about 1,500 MW (2,200 MW nameplate) in 1B to 5,600 MW (25,000 MW nameplate) in 2C, were highest in the Distributed strategy, and averaged 4,500 MW (14,000 MW nameplate) across all nine portfolios.

Storage: Storage additions varied significantly with strategic emphasis, ranging from 1,600 MW to 5,900 MW (1,600 MW to 11,600 MW nameplate) and averaging 3,400 MW (4,900 MW nameplate) across all cases. Additions were a mix of short and long duration, including hydro pumped storage, with the Distributed strategy having the highest level of additions.

EE: Energy efficiency additions ranged from 600 MW to 900 MW (900 MW to 1,200 MW maximum hourly summer reduction) and averaged 800 MW (1,000 MW maximum hourly summer reduction) across all cases. Incremental EE was highest in the Distributed strategy cases.

DR: By 2050 incremental demand response additions ranged from <100 MW to 700 MW and averaged 400 MW across all cases, as DR additions earlier in the plan phase-out at the end of their program life.

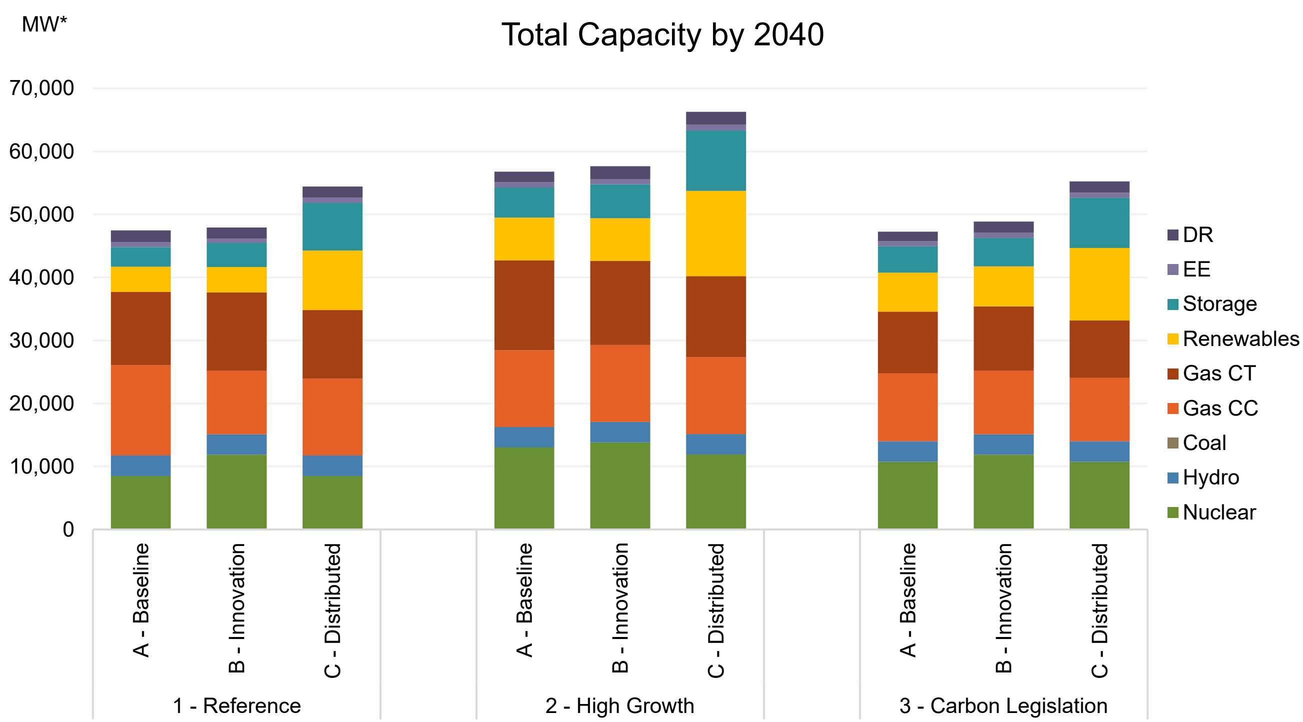
Further information on incremental capacity changes can be found in Appendix H – Capacity and Energy Plan Summaries.

3.3 Capacity Plans

Capacity plans and highlights are discussed in this section. Capacity plans are comprised of baseline firm supply plus incremental capacity changes, or the total megawatts (MW) available to meet demand. Results are shown in summer net dependable capacity, except for renewables and storage, which are shown in nameplate, and energy efficiency, which is shown as maximum hourly summer energy reduction. Capacity plan details can be found in Appendix H – Capacity and Energy Plan Summaries.

Total capacity plans for 2040 and 2050 are presented below, grouped by scenario and segmented by resource type. Driven by varying levels of forecasted demand, Scenario 2 (High Growth) portfolios have the highest total capacity and Scenario 1 and 3 (Reference and Carbon Legislation) portfolios have similar total capacity need. The strategy results within each scenario differ based on emphasis of alternative resource types.

This figure compares the total capacity plans for all portfolios in 2040 (FY 2025 capacity was approximately 42,000 MW).



* MW summer net dependable capacity, except for renewables and storage shown in nameplate and energy efficiency shown as maximum summer reduction.

Figure 3-9: Total Capacity Plans in 2040

Highlights of the total capacity plans in 2040 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios.

Nuclear capacity is higher with the addition of Gen III+ SMRs and/or AP1000 in the Innovation strategy as well as in all High Growth and Carbon Legislation scenario cases.

Hydro capacity is slightly higher in all portfolios with the addition of hydro uprates.

Coal capacity is projected to be zero in all cases, with no new coal selected and existing coal plants expected to reach end of life by 2039, subject to further evaluation, environmental review and TVA Board approval.

Gas CC capacity is lowest in the Carbon Legislation scenario cases; CC capacity averages the same in the Reference and High Growth scenarios with lesser variations by strategy in the Reference scenario cases.

CC with CCS was not selected in any portfolio, including the Carbon Legislation scenario cases, but was available in all cases.

Gas CT capacity is highest in the High Growth scenario due to higher load growth and lowest in the Carbon Legislation scenario with carbon legislation and lower load growth.

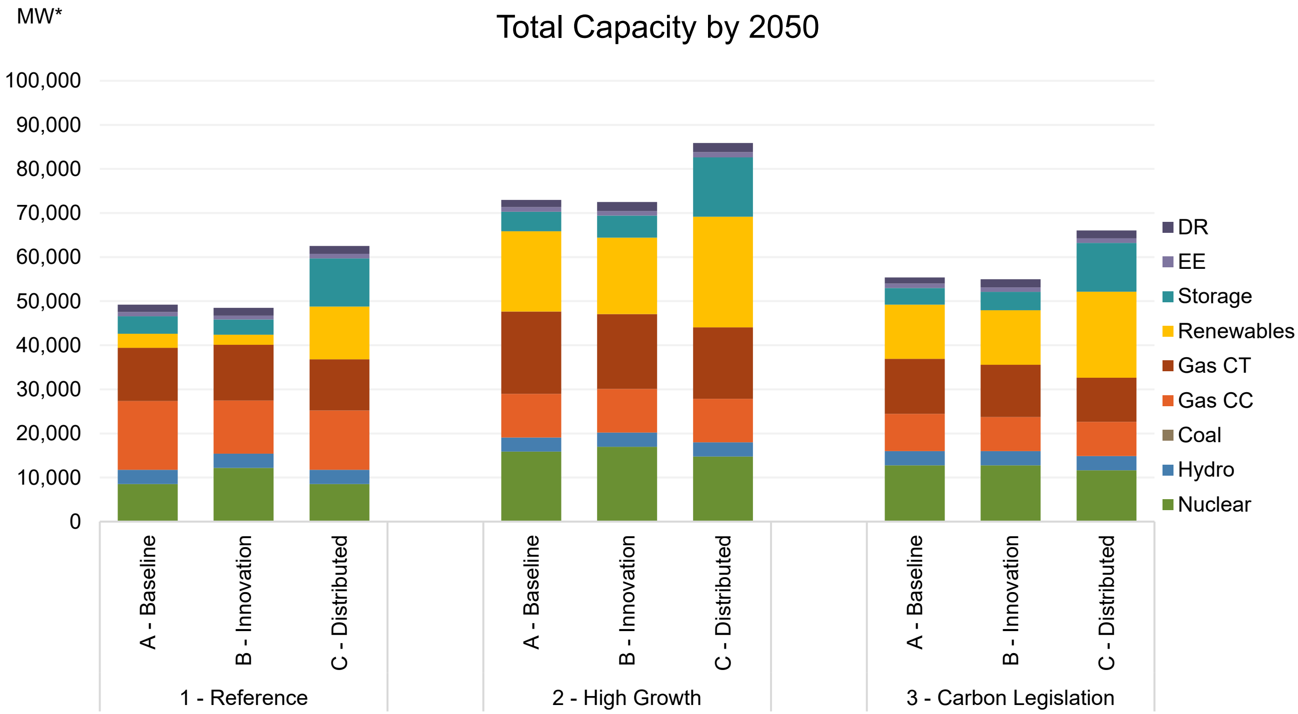
Renewable nameplate capacity, primarily solar, is highest in the High Growth and Carbon Legislation scenarios and in the Distributed strategy portfolios.

Storage capacity, which is a mix of short and long duration, including hydro pumped storage, is generally increasing in the portfolios and is highest in the High Growth scenario and in the Distributed strategy portfolios.

EE increases in all portfolios and is highest in the Distributed strategy cases.

DR increases in all portfolios.

The figure below compares total capacity plans for all portfolios in 2050 (note difference in scale from 2040).



* MW summer net dependable capacity, except for renewables and storage shown in nameplate and energy efficiency shown as maximum summer reduction.

Figure 3-10: Total Capacity Plans in 2050

Highlights of the total capacity plans in 2050 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios. Trends are similar to the 2040 highlights but are generally higher in magnitude driven by the forecasted load growth in the scenarios.

Nuclear capacity is highest in the High Growth scenario cases driven by increases in the electric load forecast and natural gas price forecast. The Carbon Legislation scenario cases also have higher nuclear capacity than the Reference scenario cases driven by carbon legislation and higher natural gas prices.

Hydro capacity is slightly higher in all portfolios with the addition of hydro uprates.

Coal capacity is projected to be zero in all cases, with no new coal selected and existing coal plants expected to reach end of life by 2039, subject to further evaluation, environmental review and TVA Board approval.

Gas CC capacity is highest in the Reference scenario cases as the other cases tend to have higher amounts of nuclear and/or storage resources.

CCs with CCS was not selected in any portfolio, including the Carbon Legislation scenario cases, but was available in all scenarios.

Gas CT capacity is highest in the High Growth scenario cases due to higher levels of load growth.

Renewable nameplate capacity, primarily solar, is highest in the High Growth scenario and Distributed strategy portfolios.

Storage capacity, which is a mix of short and long duration options, including hydro pumped storage, is increasing in all portfolios and is highest in the High Growth scenario and in the Distributed strategy portfolios.

EE increases in all portfolios and is generally highest in the Distributed strategy cases.

DR increases in all portfolios, though by 2050 incremental demand response additions included earlier in the plan may have phased-out at the end of their program life.

3.4 Energy Plans

Total energy plans are presented below, grouped by scenario and segmented by resource type. These plans represent the energy expected from the economic dispatch of the resources available in each capacity plan and from economic purchases of market power, shown in terawatt-hours (TWh). Further information on energy plans can be found in Appendix H – Capacity and Energy Plan Summaries.

This figure compares the total energy plans for all portfolios in 2040 (FY 2025 total energy was nearly 168 TWh).

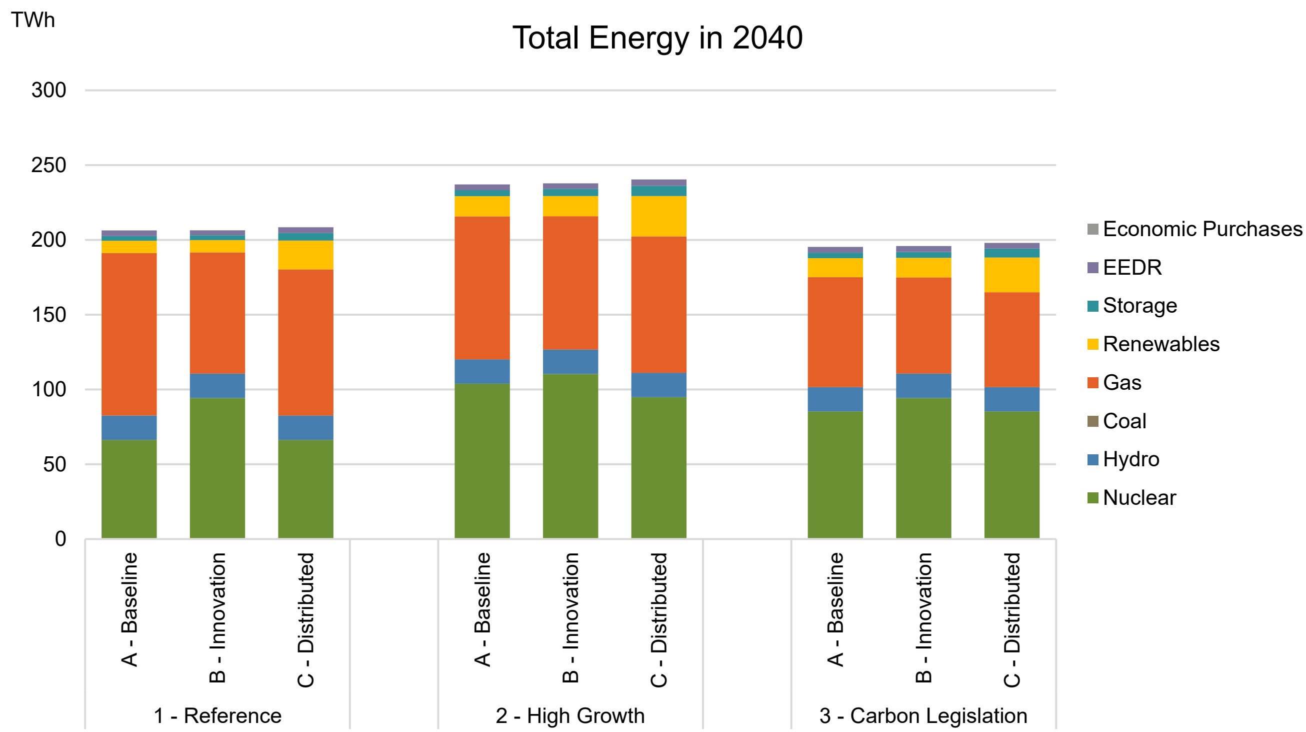


Figure 3-11: Total Energy Plans in 2040

Highlights of the total energy plans in 2040 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios.

Nuclear generation is highest in the Innovation strategy cases and is also higher in all High Growth and Carbon Legislation scenario cases.

Hydro generation is slightly higher in all portfolios with the addition of hydro uprates.

Gas generation is highest in the Reference scenario cases, lowest in the Carbon Legislation scenario cases, and is typically lowest in the Innovation strategy which has the highest nuclear generation.

Renewable generation is primarily solar and is highest in the High Growth scenario and Distributed strategy cases.

Storage generation is highest in the High Growth scenario and Distributed strategy portfolios.

EE and DR energy impact is highest in the Distributed strategy cases and lowest in the Innovation strategy cases.

The figure below compares the total energy plans for all portfolios in 2050.

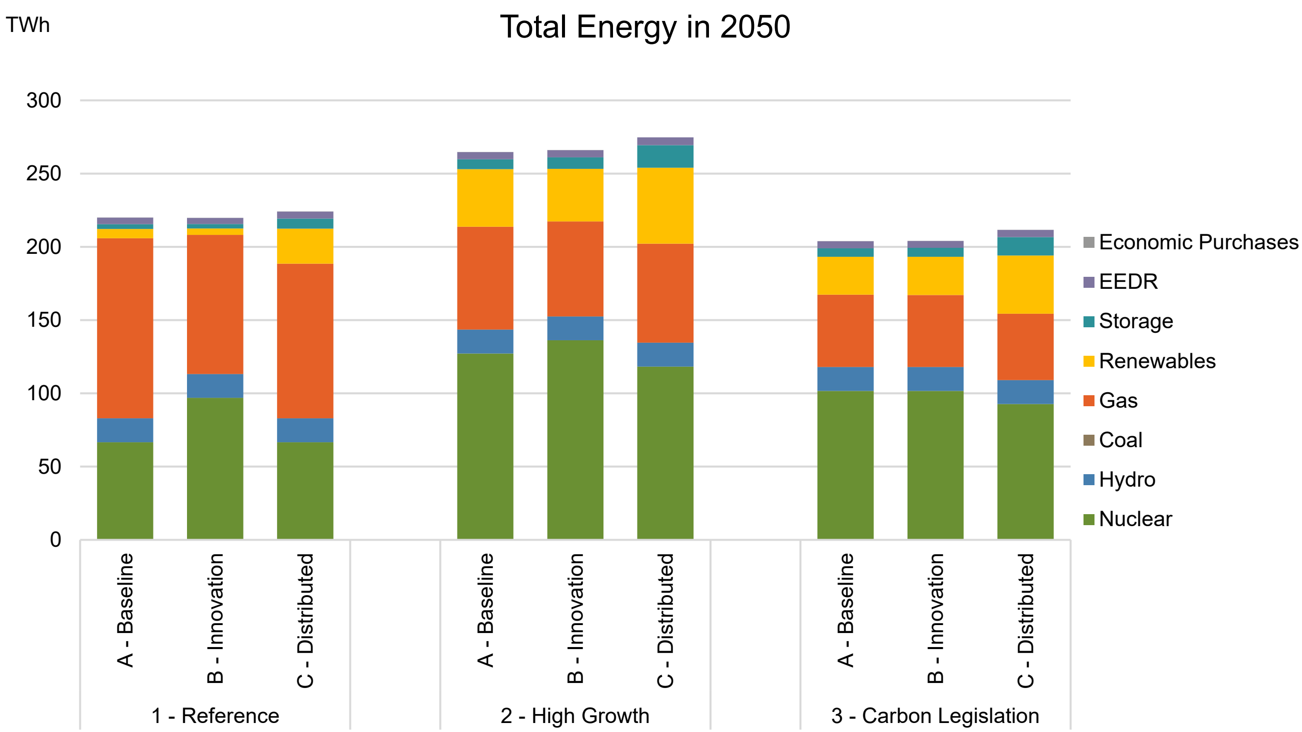


Figure 3-12: Total Energy Plans in 2050

Highlights of the total energy plans in 2050 are summarized below, driven by the impact of incremental capacity changes on total capacity across the portfolios. Trends are similar to the 2040 highlights but are generally higher in magnitude driven by the forecasted load growth in most of the scenarios.

Nuclear generation is highest in the Innovation strategy cases and is also higher in all High Growth and Carbon Legislation scenario cases.

Hydro generation is slightly higher in all portfolios with the addition of hydro uprates.

Gas generation is highest in the Reference scenario cases, lowest in the Carbon Legislation scenario cases, and is typically lowest in the Innovation strategy which has the highest nuclear generation.

Renewable generation is primarily solar and is highest in the High Growth scenario and Distributed strategy cases.

Storage generation is highest in the High Growth scenario and Distributed strategy portfolios.

EE and DR energy impact is highest in the Distributed strategy cases and lowest in the Innovation strategy cases.

Further information on energy plans can be found in Appendix H – Capacity and Energy Plan Summaries.

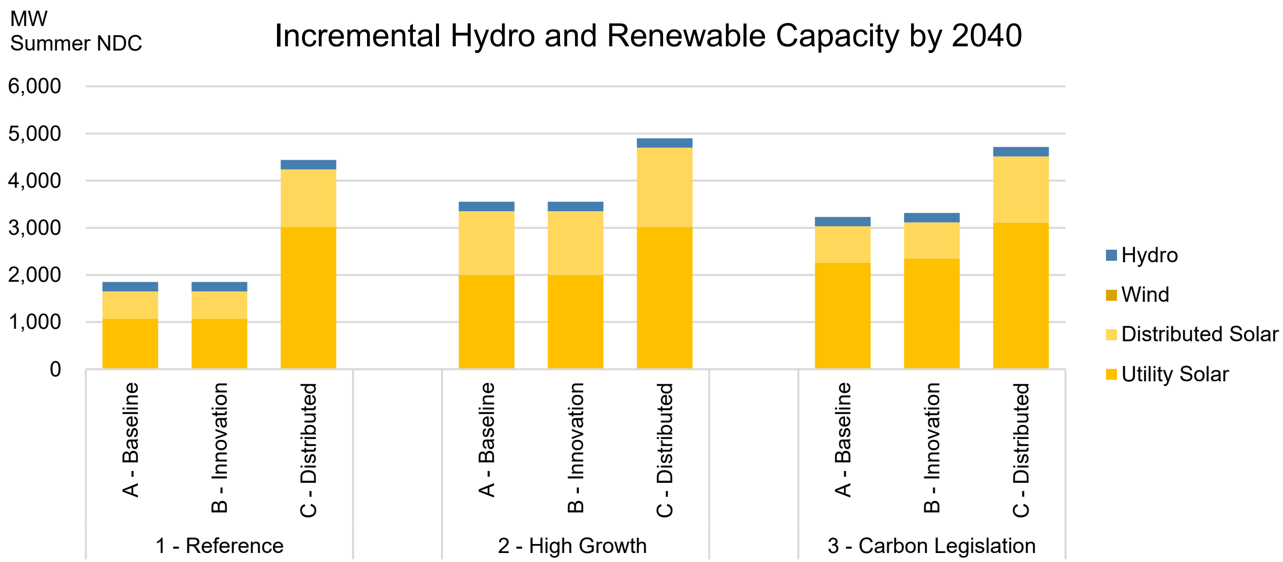
3.5 Incremental Capacity by Resource Type

The following sections describe incremental capacity by resource type in more detail, providing additional insights into the specific technologies included in each optimized portfolio.

Incremental Hydro and Renewable Capacity

As described in Chapter 2, hydro uprates are offered as an expansion option in the IRP. Additional renewable resource options include utility-scale solar, distributed solar, and two wind options – Midwest and Southeast high-hub. The approach used to model distributed solar adoption and the impact of promotion in the Distributed strategy is discussed in Appendix F – Distributed Generation Resource Methodology.

The charts below show incremental renewable additions by 2040 and 2050 in Summer net dependable capacity (note differences in scale), grouped by scenario and segmented by renewable technology type.



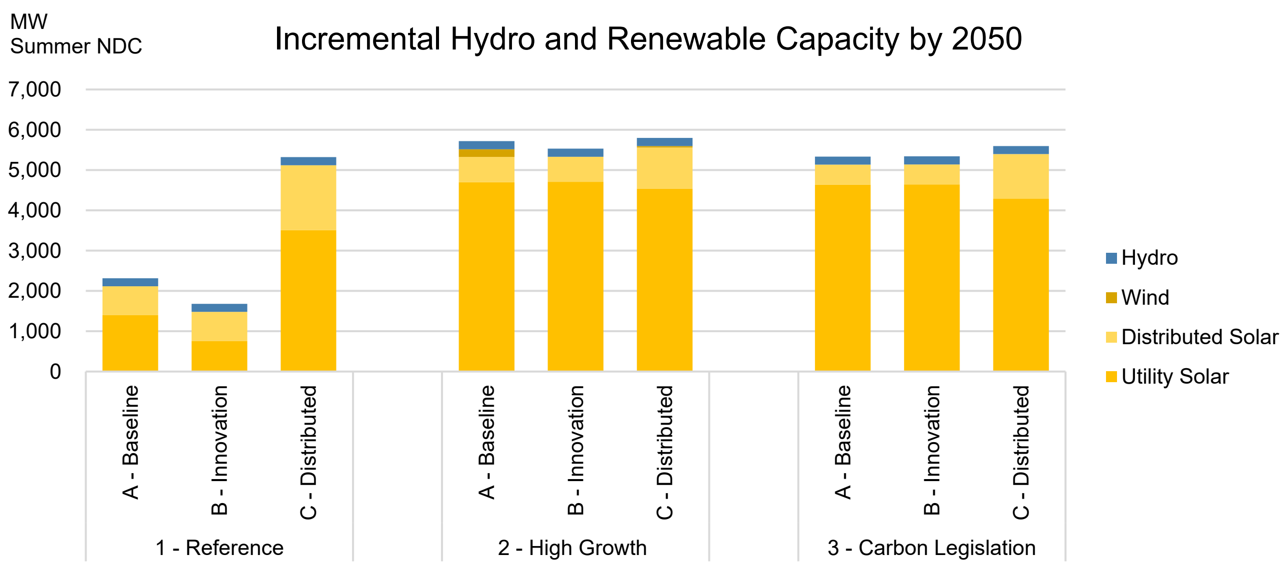


Figure 3-13: Incremental Hydro and Renewable Capacity by 2040 and 2050 (Summer Net Dependable Capacity)

The chart below shows incremental renewable additions by 2040 (left) and 2050 (right) in nameplate capacity, grouped by scenario and segmented by renewable technology type.

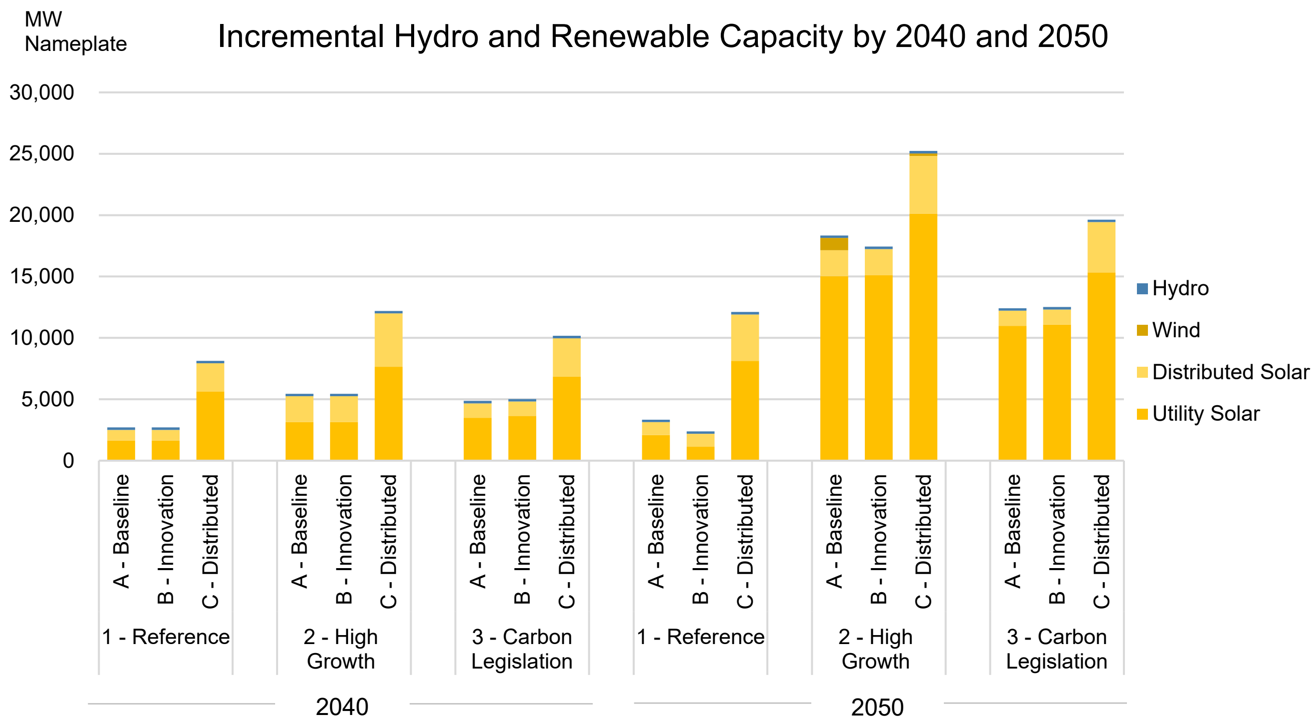


Figure 3-14: Incremental Hydro and Renewable Capacity by 2040 and 2050 (Nameplate MW)

Solar expansion is greatest in the High Growth and Carbon Legislation scenario cases and is highest in the Distributed strategy. Distributed strategy portfolios have the highest total levels of renewables. Hydro expansion options on the system are limited but are selected in all portfolios by 2040. Due to cost and portfolio fit challenges, a limited amount of wind is selected in only two cases within the High Growth scenario, and only in the late 2040s.

Incremental Storage Capacity

Storage resource options in the IRP include pumped storage, lithium-ion battery, advanced chemistry battery, and distributed battery storage. The approach used to model distributed battery adoption and the impact of promotion in the Distributed strategy is discussed in Appendix F – Distributed Generation Resource Methodology.

The charts below show incremental storage additions by 2040 and 2050 in Summer net dependable capacity (note differences in scale), grouped by scenario and segmented by storage technology type.

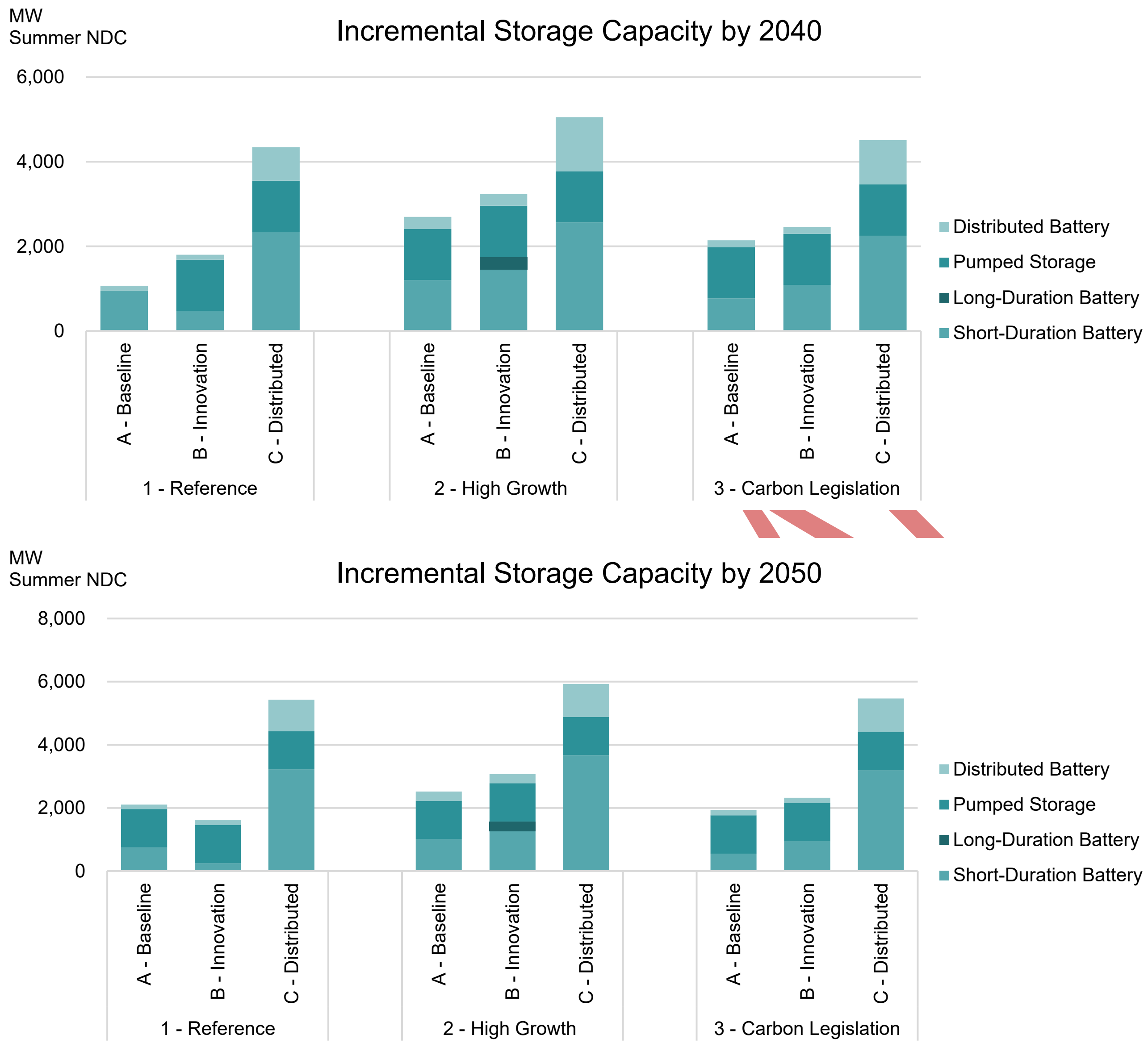


Figure 3-15: Incremental Storage Capacity by 2040 and 2050 (Summer Net Dependable Capacity)

The chart below shows incremental storage additions by 2040 (left) and 2050 (right) in nameplate capacity, grouped by scenario and segmented by storage technology type.

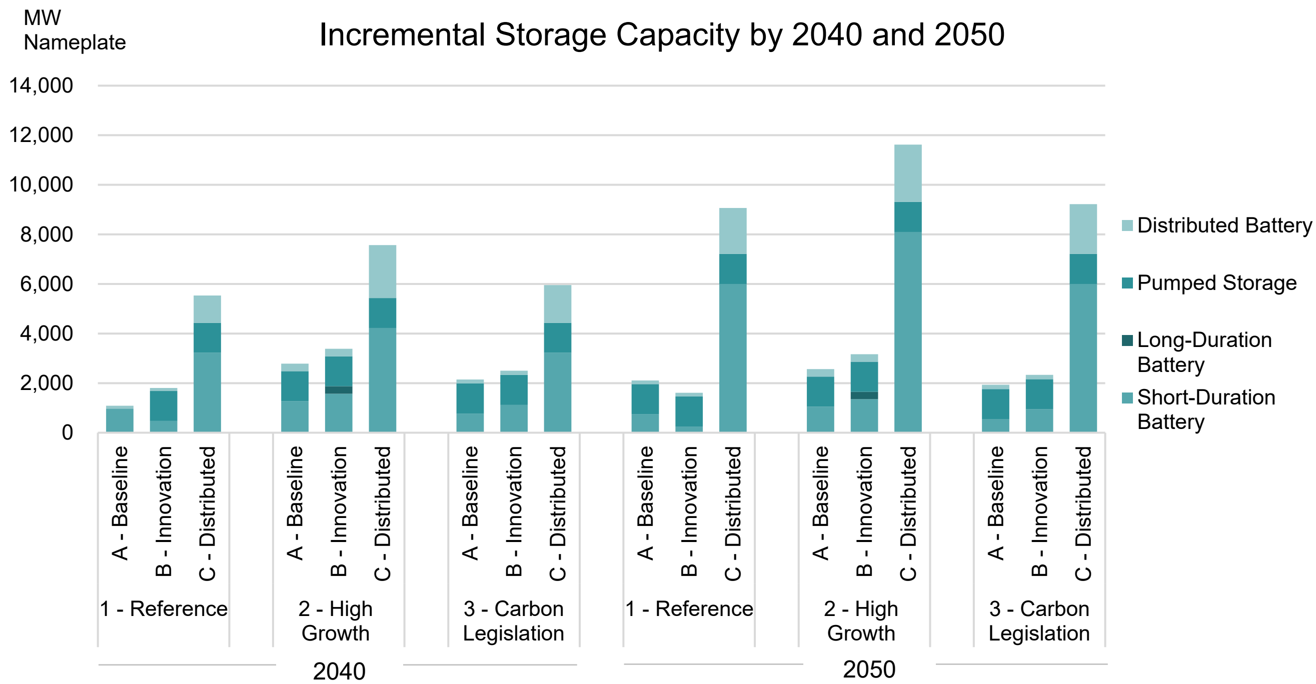


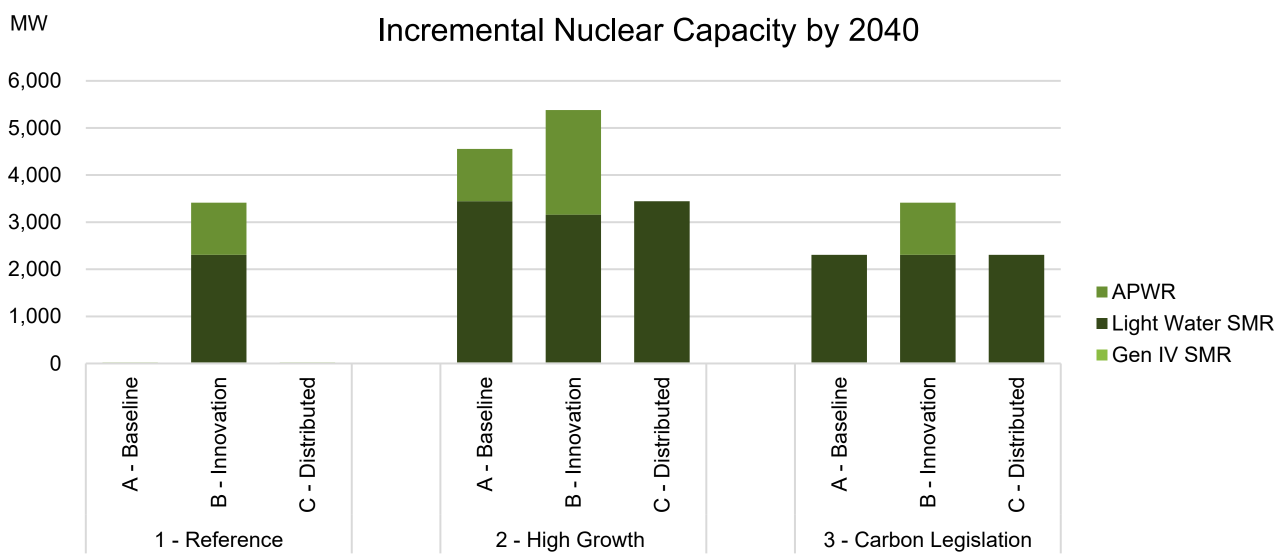
Figure 3-16: Incremental Storage Capacity by 2040 and 2050 (Nameplate MW)

Storage plays an increasing role in the resource mix, with continued advancements in battery technologies and the potential for additional pumped storage. Long-duration storage technologies, which include pumped storage and emerging advanced chemistry batteries, provide firm dispatchable capacity supporting system reliability and complement intermittent renewable resources. Storage expansion is promoted in the Distributed strategy, which emphasizes distributed resources, and has the highest amount of distributed storage additions.

Incremental Nuclear Capacity

Nuclear resource options include advanced pressurized water reactors (APWR) and light water and next generation SMRs. APWRs are assumed to be available in 2039 due to expected build time for large reactors. SMR technology for electric utility use is still developing. Leveraging work TVA has done to advance the potential to deploy SMRs at the Clinch River site, light water SMRs are assumed to be available in 2033, and Gen IV SMRs are assumed to be available in 2041. Both APWR and Light Water SMR options are considered to be Gen III+ nuclear reactors. These assumptions impact the incremental additions by 2040 and 2050.

The charts below show incremental nuclear additions by 2040 and 2050 (note differences in scale), grouped by scenario and segmented by nuclear technology type.



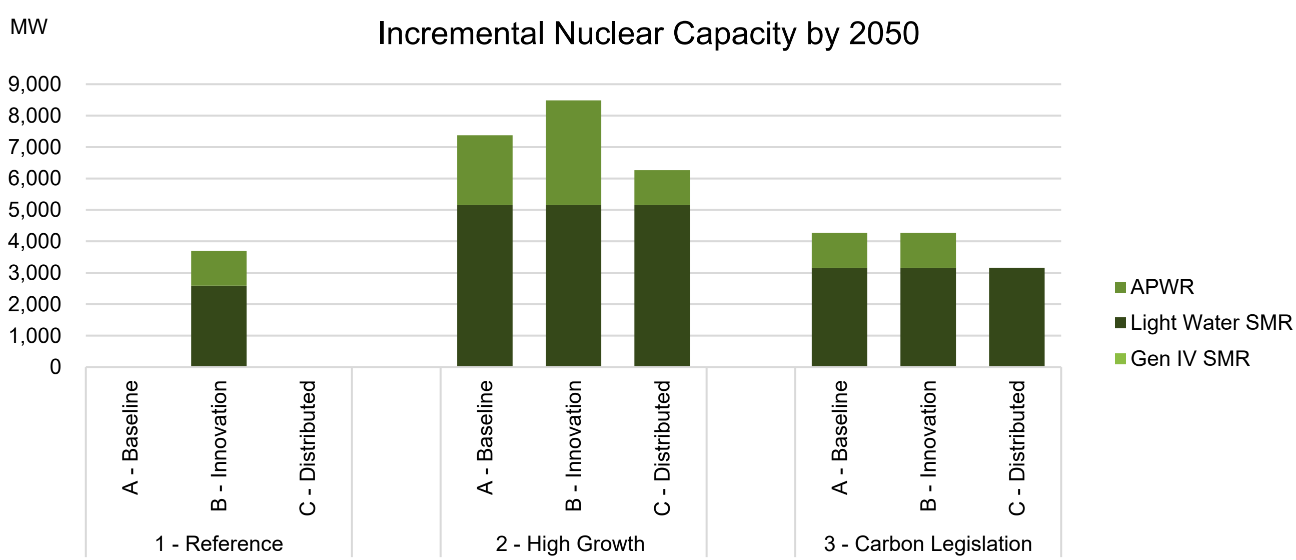


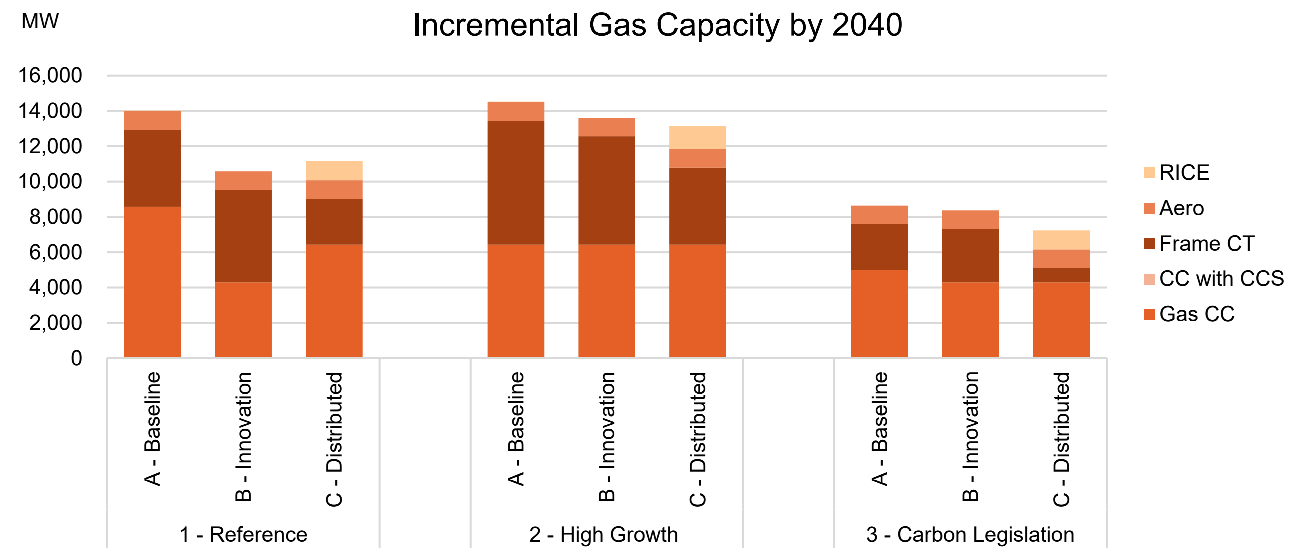
Figure 3-17: Incremental Nuclear Capacity by 2040 and 2050

The Innovation strategy, which emphasizes new, innovative technologies, has the highest level of nuclear expansion overall. In the High Growth scenario, which assumed the highest loads and natural gas prices, large APWR units were selected in all portfolios by 2050, along with light water SMRs. All Carbon Legislation scenario cases, which assume a carbon tax and higher natural gas prices, also included expansion nuclear.

Incremental Gas Capacity

Natural gas resource options in the IRP include CC, CC with CCS, frame CT, aeroderivative CT (Aero), and reciprocating internal combustion engine (RICE).

Incremental gas additions by 2040 and 2050 (note differences in scale), grouped by scenario and segmented by gas technology type, are shown below.



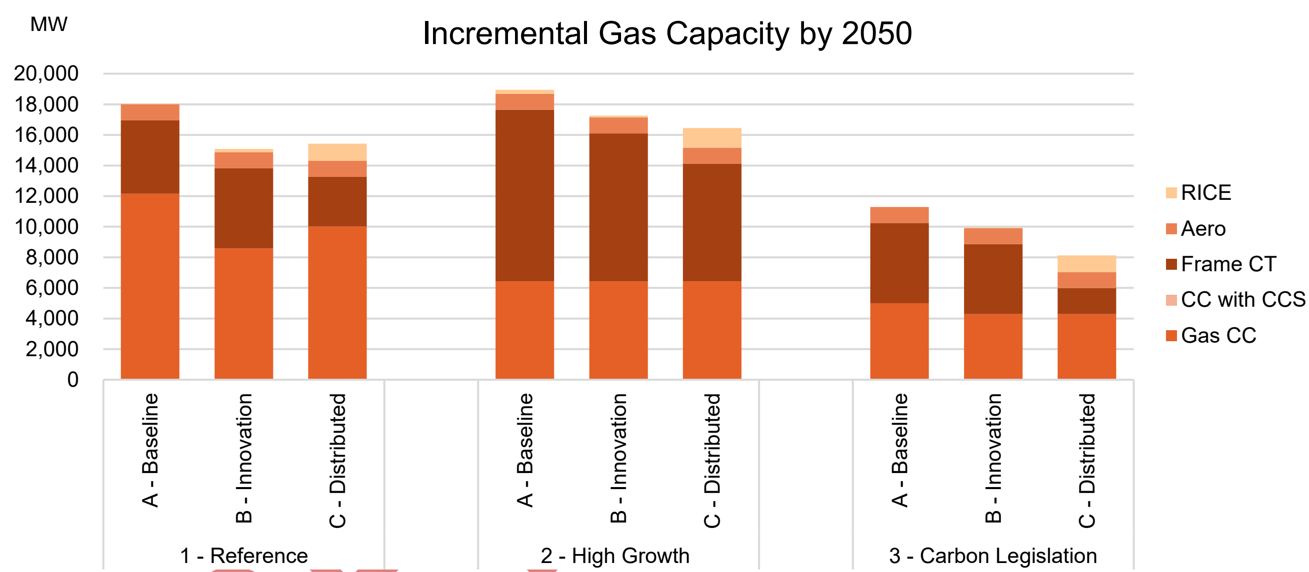


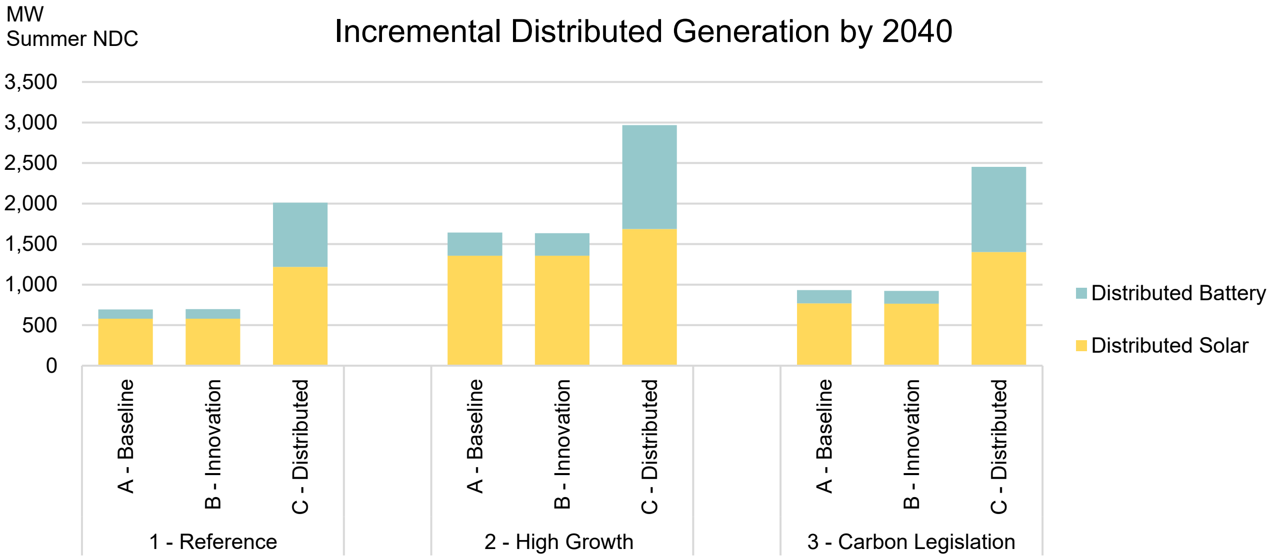
Figure 3-18: Incremental Gas Capacity by 2040 and 2050

Firm, dispatchable gas resources are selected in all cases to support system reliability and provide economic energy, with relative magnitudes driven by forecasted load in the scenarios, potential carbon legislation, and strategic emphasis.

Incremental Distributed Generation Capacity

Distributed resource options, which would be installed behind TVA's wholesale meter, include distributed solar and battery storage. These resources are included in their respective resource types in the above sections and are collectively shown here. Distributed resources were available in all cases with growth forecasted by the distributed generation adoption model and were emphasized in the Distributed strategy. The approach used to model the adoption of distributed resources is discussed further in Appendix F – Distributed Generation Resource Methodology.

The charts below show incremental distributed resources by 2040 and 2050 in Summer net dependable capacity (note differences in scale), grouped by scenario and segmented by distributed generation type. For portfolios with larger installation levels of solar and storage (utility-scale and distributed), the relative net dependable capacity of these resources may fall even as total nameplate installation increases through time.



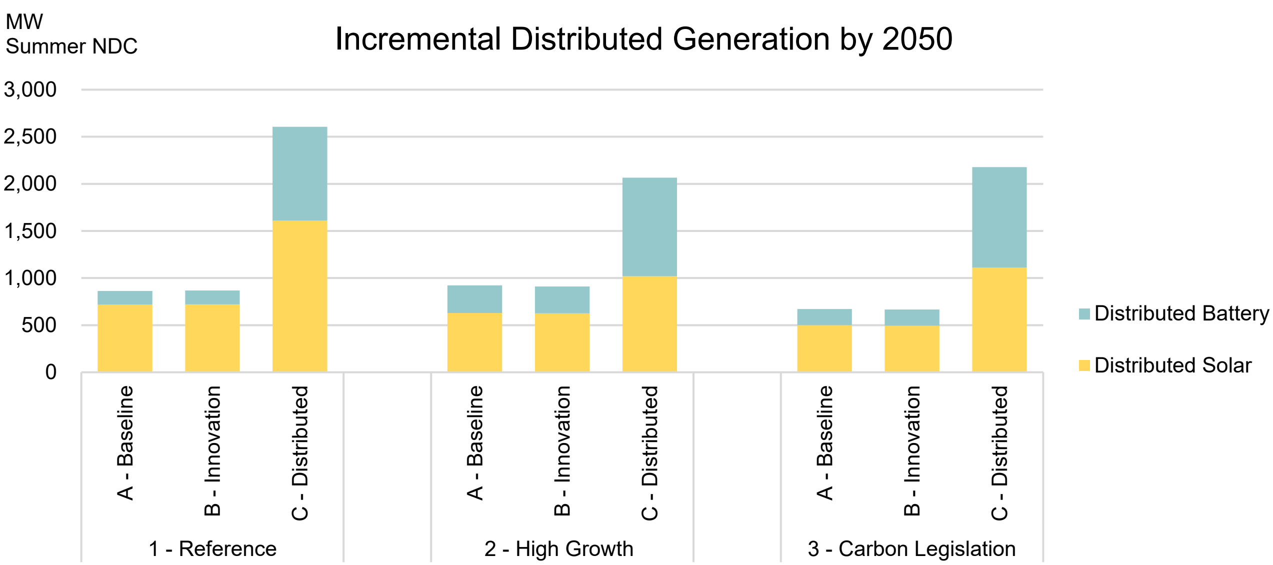


Figure 3-19: Incremental Distributed Generation Capacity by 2040 and 2050 (Summer Net Dependable Capacity)

The chart below shows incremental distributed resource additions by 2040 (left) and 2050 (right) in nameplate capacity, grouped by scenario and segmented by storage technology type.

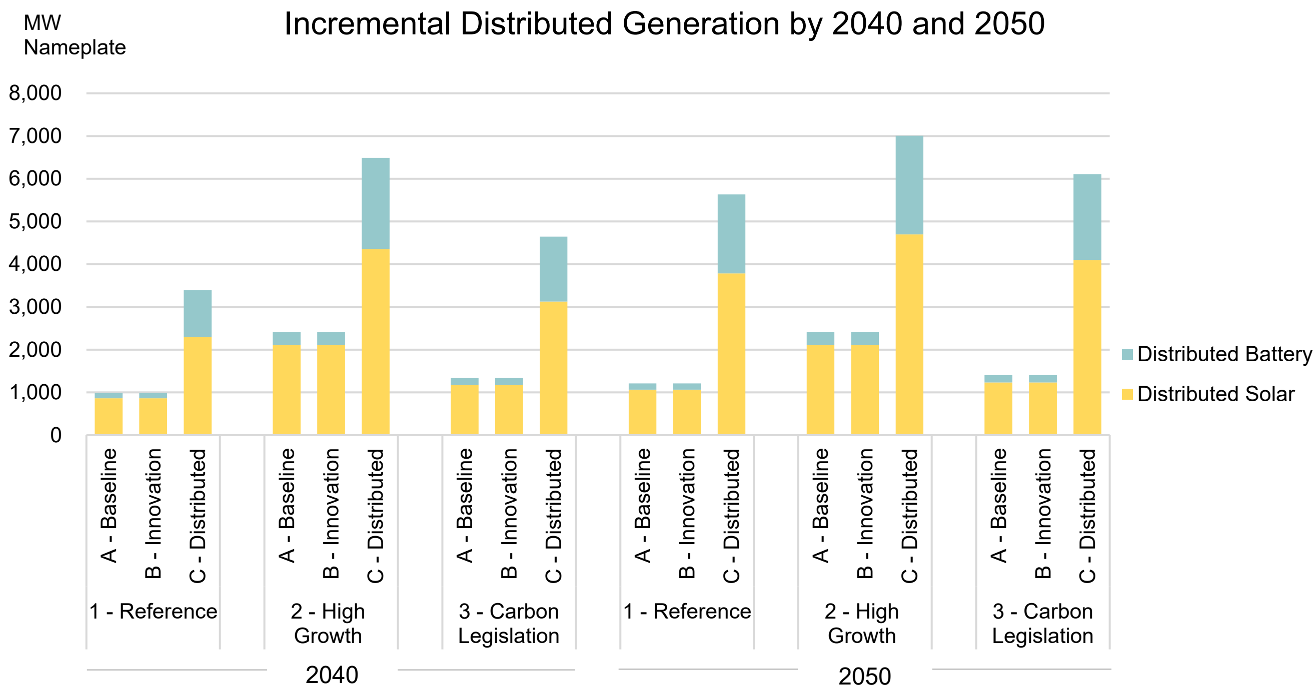


Figure 3-20: Incremental Distributed Generation Capacity by 2040 and 2050 (Nameplate MW)

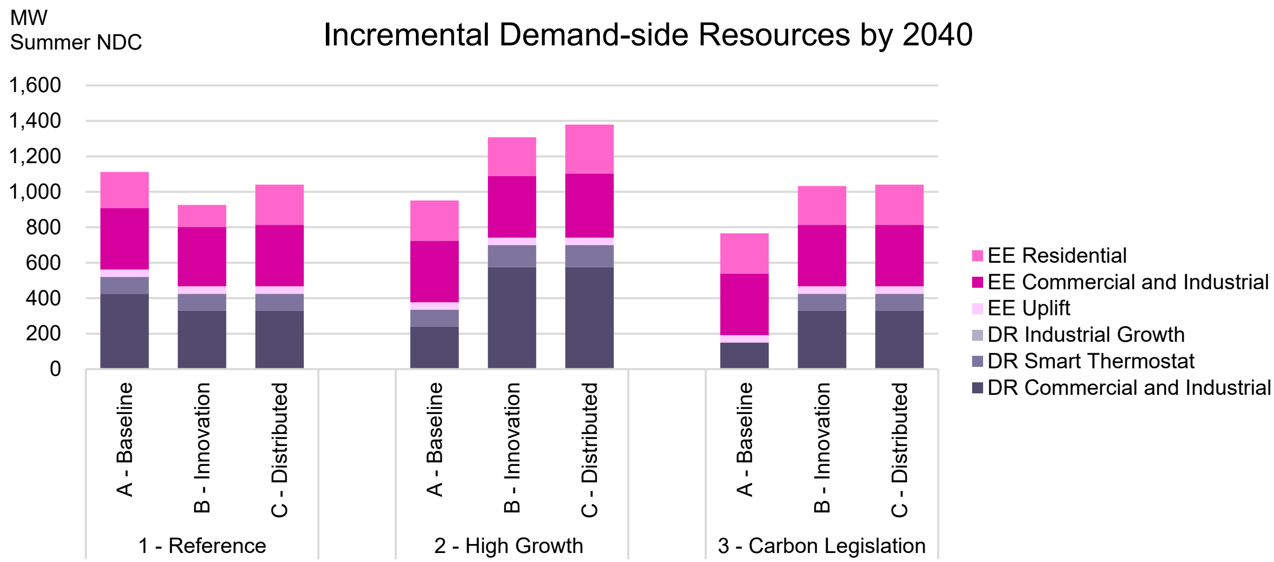
Distributed generation additions are highest overall in the High Growth scenario that has the highest load growth. Within each scenario, the Distributed strategy portfolios have the most distributed generation due to the emphasis within the strategy.

Incremental Demand-side Resources

Demand-side resource options in the IRP include EE and DR. Based on the Energy Program Potential Study and subsequent market experience, TVA developed tiers of EE and DR program offerings that were available to be selected in all portfolios. Certain strategies promoted demand-side resources, and in those cases, minimum tiers were included in portfolio results. The approach used to promote EE and DR is discussed further in Appendix G – Demand-side Resource Methodology.

Through its DR programs, TVA partners with businesses and residents to reduce usage at peak times. TVA EE programs incentivize residents, businesses, and industries to accelerate the adoption of more energy efficient technologies above and beyond the impacts of codes and standards, or market-driven EE (see section 2.4.2 for discussion of market-driven EE impact on the electric load forecast). EE programs drive accelerated adoption of more efficient appliances and equipment that reduces energy use across many hours, and estimates capture program impacts relative to the expected adoption of these technologies without the influence of EE programs.

The charts below show incremental demand-side resource impacts forecasted for 2040 and 2050 in Summer net dependable capacity (note differences in scale), grouped by scenario and segmented by DR and EE program type.



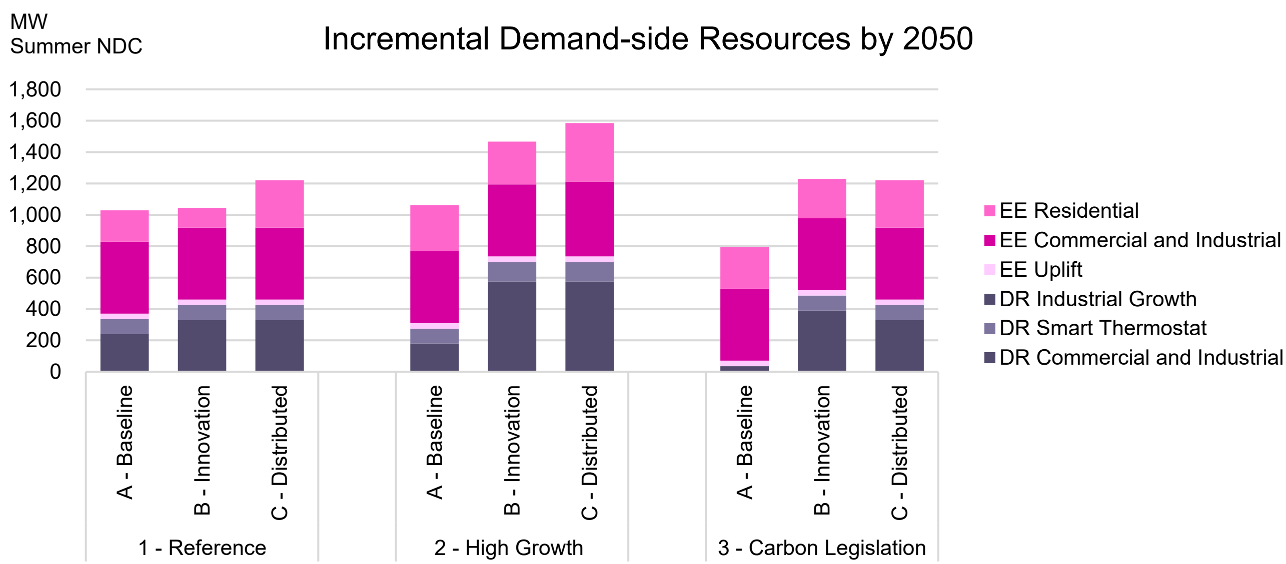


Figure 3-21: Incremental Demand-side Resource Capacity by 2040 and 2050 (Summer Net Dependable Capacity)

The resource planning model utilizes net dependable capacity, or firm capacity, to estimate dependable EE program reduction at the time of the expected summer and winter peak. Each EE program also utilizes a load shape, or expected energy generation pattern, to simulate hourly energy reduction. For each EE program tier the maximum Summer hourly energy reduction was also calculated, which can be thought of as similar in concept to nameplate capacity for a renewable resource. The chart below shows incremental demand-side resource impacts for the Summer hour with the maximum forecasted reduction for 2040 (left) and 2050 (right), grouped by scenario and segmented by DR and EE program type.

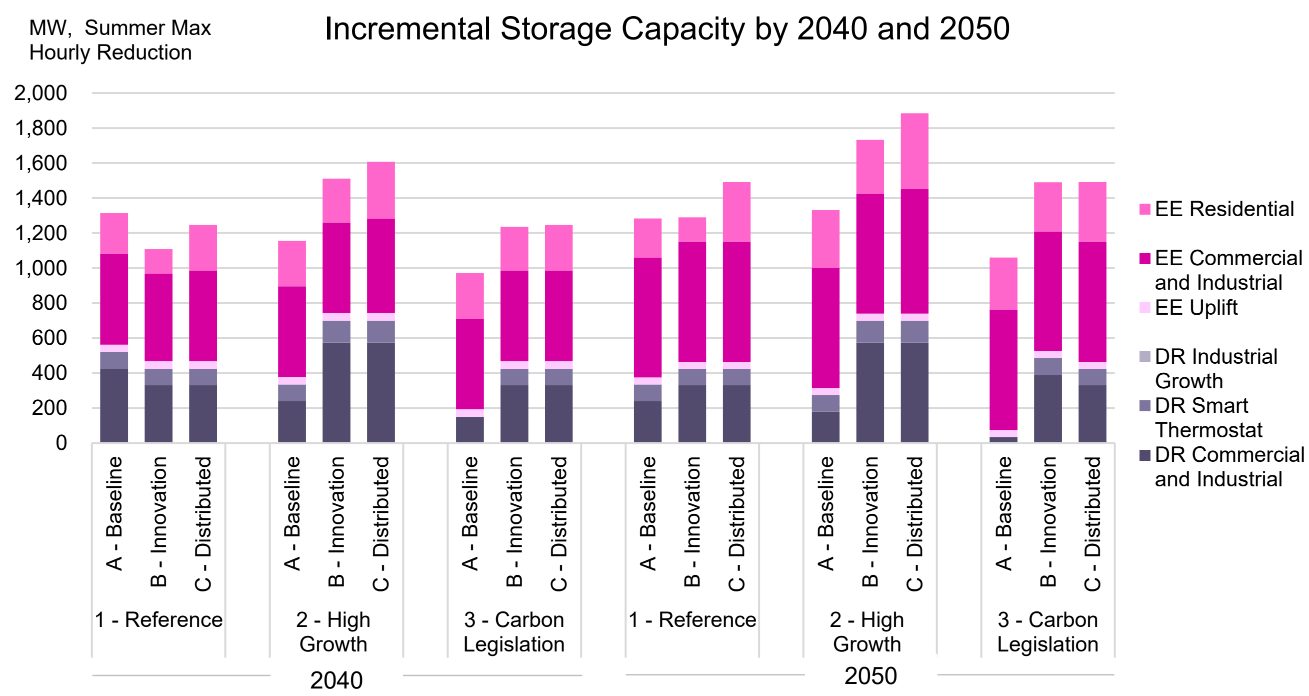


Figure 3-22: Incremental Demand-side Resource Capacity by 2040 and 2050 (Summer Maximum Hourly Reduction)

Average EE and DR additions were relatively similar in magnitude across the scenarios, with the Distributed strategy including promotion of all demand-side programs. All strategies saw value in EE and DR additions, particularly between now and 2040. The Distributed strategy, which focused on distributed and demand-side resources, generally has the highest amount of EE and DR across the strategies.

3.6 Scorecard Metric Definitions

Definitions of the scorecard metrics are provided below. Metrics cover the 2026-2050 study period, except for one metric that focuses on 2050, as noted. Metrics are calculated based on the optimization results for the nine core portfolios. See Chapter 2 for a discussion on metrics development and Appendices I-K for further details on cost, risk, environmental, and operational metrics.

Table 3-1: Metrics and Definitions

Metric Category	Metric	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Total plan cost (capital and operating) expressed as expected present value of revenue requirements
	System Average Cost ($/MWh)	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	PVRR above expected value based on stochastic analysis

Metric Category	Metric	Definition
Environmentally Responsible	Land Use Intensity (Acres/GWh)	Acreage needed for expansion units divided by energy generated and purchased in 2050
	Water Consumption Intensity (Gallons/MWh)	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Tons/GWh)	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	Carbon Dioxide (CO_2) Direct Emissions (Million Tons)	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Average annual CO_2 emitted divided by average annual energy generated and purchased
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
	P95 Average Unserved Energy Ratio	Stochastic 95th percentile average annual amount of energy shortfall (MWh) over study period divided by average annual sales (MWh)
	Expected Average Energy Curtailment Ratio	Stochastic expected average annual curtailed energy (MWh) over study period divided by average annual sales (MWh)

3.7 Strategy Assessments

Assessing strategy performance across all scenarios by metric yields some key findings. A discussion of these assessments is grouped into four major categories – low cost, risk informed, environmental responsibility, and diverse, reliable, and flexible system operations. Additionally, comparing performance across categories provides insights into key tradeoffs across the strategies and least-cost planning principles.

3.7.1 Low Cost

Cost metrics include PVRR, system average cost, and total resource cost. PVRR reflects costs incurred by TVA, while total resource cost also includes costs incurred by consumers for incremental distributed generation and energy efficiency investments. System average cost relates PVRR to average total energy for each portfolio and is directionally indicative of customer bill impacts.

The charts below compare PVRR, total resource cost and system average cost results for each strategy within the three scenarios (lower is good). Additional information on cost metrics can be found in Appendix I.

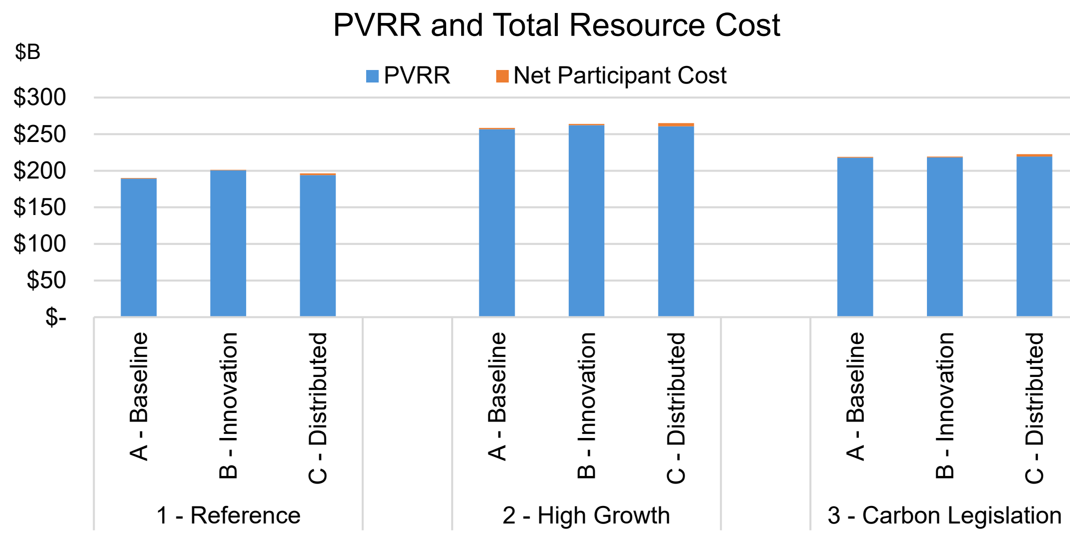


Figure 3-23: PVRR and Total Resource Cost

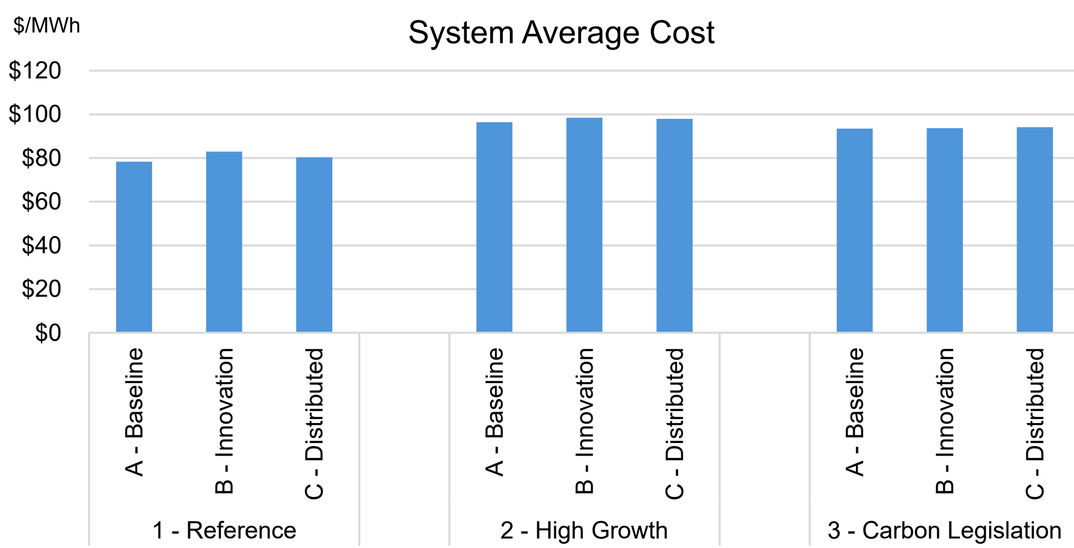


Figure 3-24: System Average Cost

Key takeaways from evaluating cost performance across the portfolios include:

- Financial metrics (PVRR, total resource costs, and system average cost) are highest in the High Growth scenario that has the highest load growth and lowest in the Reference scenario where no specific technologies are emphasized.
- As Strategy A employs baseline utility planning and does not emphasize any specific technology, it is the lowest cost strategy overall.
- The Innovation strategy, which emphasizes emerging technologies, is generally the highest cost strategy.

3.7.2 Risk Informed

When evaluating portfolios, it is helpful to assess execution and financial risk. Execution risk is driven by technology type and emphasis in each portfolio, along with load growth. Financial risk can be measured using the risk/benefit ratio and risk exposure metrics. These metrics provide insights into the full range of potential costs for a portfolio as key uncertainties such as load and fuel prices vary. Risk/benefit ratio measures the potential for higher than estimated costs divided by the potential for lower than estimated costs for a given portfolio, while risk exposure measures the potential for higher than estimated costs.

The charts below compare risk/benefit ratio and risk exposure results for each strategy within the three scenarios (lower is good). Additional information on risk informed metrics can be found in Appendix I.

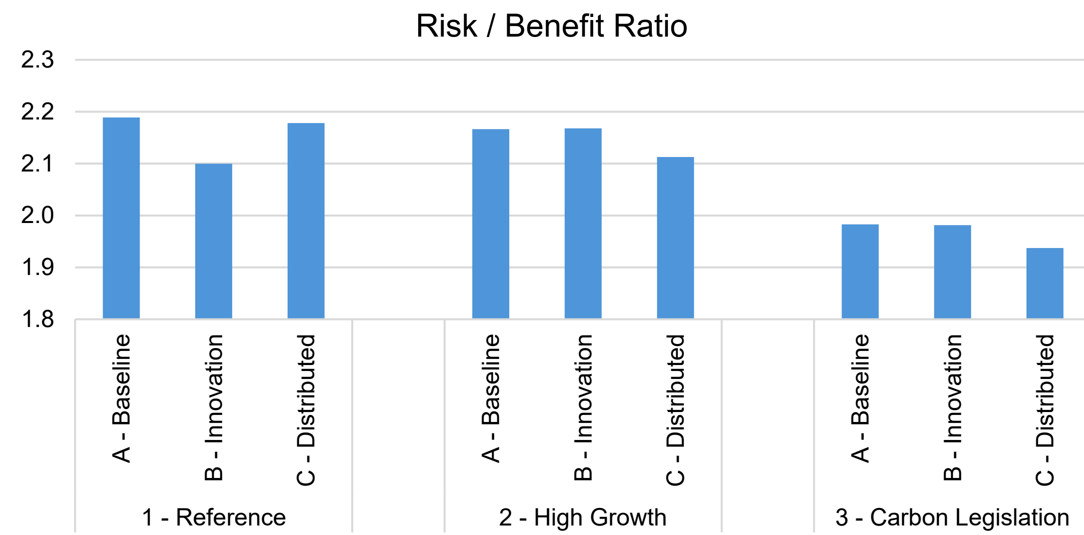


Figure 3-25: Risk/Benefit Ratio

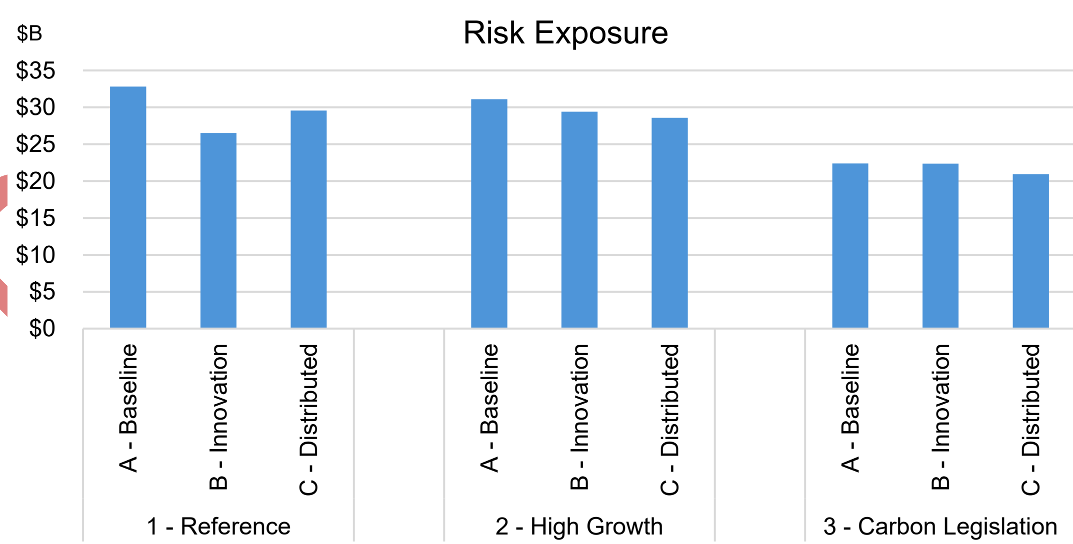


Figure 3-26: Risk Exposure

Key takeaways from evaluating risk performance across the portfolios include:

- Financial risk exposure is highest in the Reference scenario which has the highest variable cost generation, and it is generally lowest in the Carbon Legislation scenario which has the most fixed cost generation.
- The Innovation strategy, which emphasizes new nuclear resources, has a more favorable risk/benefit ratio than the Baseline Utility Planning strategy based on lower fuel volatility exposure.
- The Distributed strategy, which includes higher amounts of renewable, demand-side, and distributed generation, generally has the lowest financial risk exposure based on lower fuel requirements.
- While the risk informed metrics seek to quantify financial risk, all strategies also include timeline, technological, transmission, and/or market depth uncertainty and execution risks, which are amplified by load growth, reliance on emerging technologies, and regulatory impacts; timeline risks are greatest in the High Growth scenario, technological risks are greatest in portfolios with more reliance on emerging energy technologies such as the Innovation strategy, and transmission risks are greatest in portfolios with the largest solar buildouts such as the Distributed strategy.

3.7.3 Environmental Responsibility

Five metrics related to environmental responsibility are included in the IRP analysis – land use intensity, water consumption intensity, waste intensity, carbon dioxide (CO_2) direct emissions, and CO_2 intensity. Intensity expresses environmental impacts in terms of how they relate to average total energy for each portfolio, which allows for a better comparison across all portfolios.

Waste intensity measures production of coal ash and gypsum waste and is very similar across all strategies within a scenario, since all cases utilize the same expectations for coal end of life. The charts below compares land use intensity in 2050, water consumption intensity, and CO_2 intensity for each strategy within the three scenarios (lower is good). Additional information on environmental responsibility metrics can be found in Appendix J.

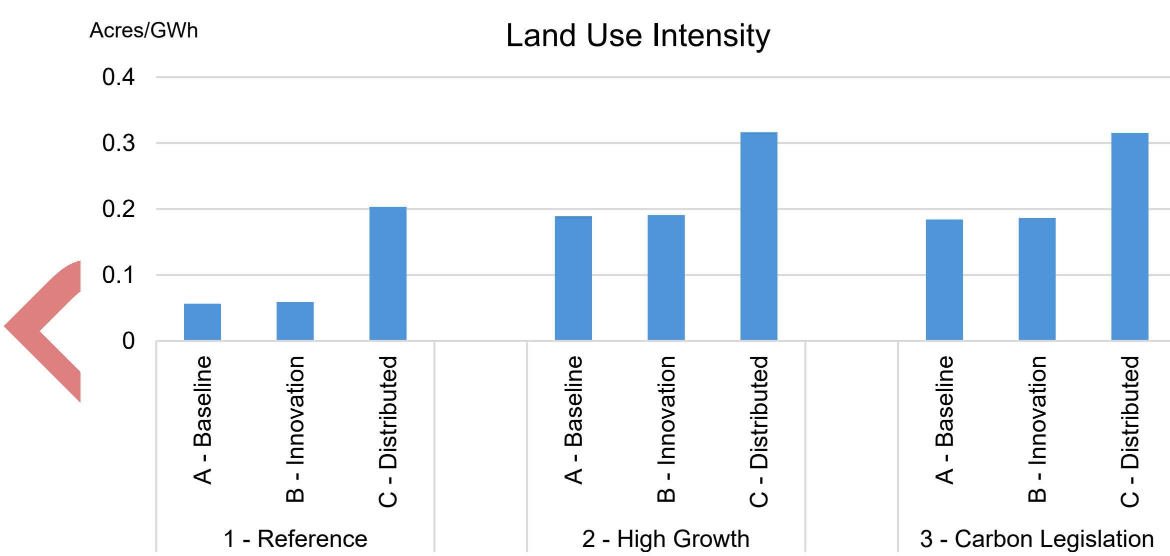


Figure 3-27: Land Use Intensity (2050)

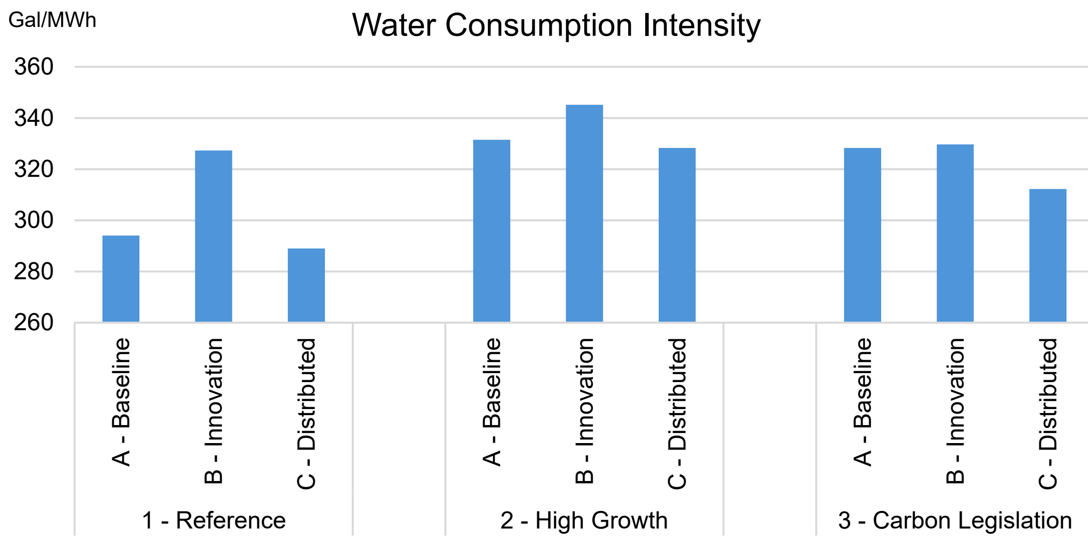


Figure 3-28: Water Consumption Intensity (2026-2050)

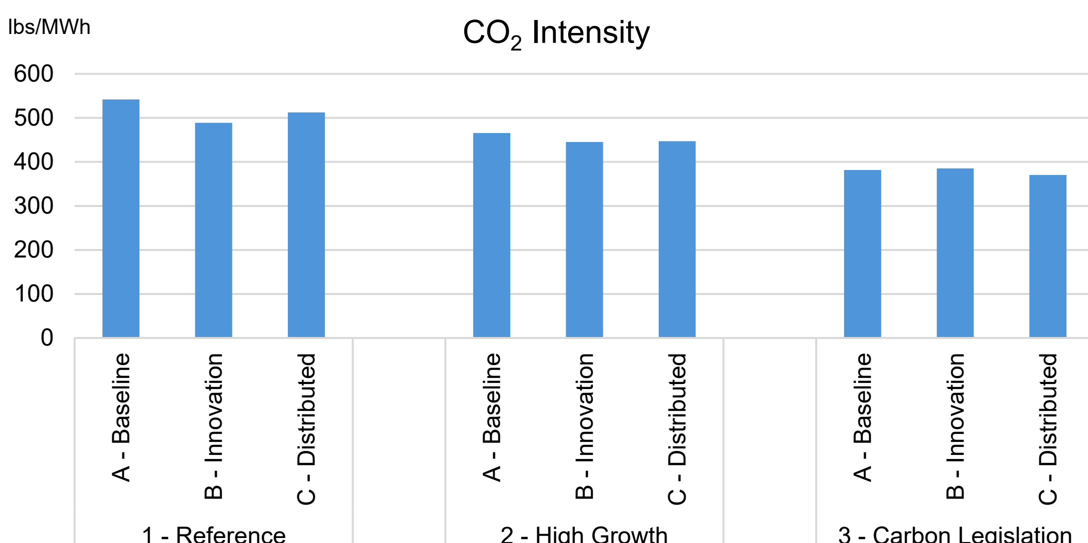


Figure 3-29: Average CO_2 Intensity (2026-2050)

Key takeaways from evaluating environmental performance across the portfolios include:

- The Baseline Utility Planning and Innovation strategies result in very similar land use
- The Distributed strategy, which emphasizes demand-side, distributed, and renewable generation, has the highest land use and lowest water consumption
- The Innovation strategy, which emphasizes nuclear additions, has the highest water consumption
- The Baseline Utility Planning strategy, which features the highest natural gas additions has the highest CO_2 emissions and intensity, while the Innovation and Distributed strategies have similar, lower CO_2 emissions and intensity

- Overall, the strategies feature environmental tradeoffs, such as the Distributed strategy having the highest land use, the Innovation strategy having the highest water consumption, and the Baseline Utility Planning strategy having the highest carbon emissions

3.7.4 Diverse, Reliable, and Flexible

Operational metrics help gauge impacts of resource additions on the diversity, reliability, and flexibility of the portfolio as a whole. Metrics include operating cost stability, P95 average unserved energy ratio, and energy curtailment ratio. Additional information on operational metrics can be found in Appendix K.

Operating cost stability measures the variability of operating costs as load, fuel prices, and other key assumptions fluctuate. Diverse portfolios generally have less variance in operating costs and can help improve resiliency. The chart below compares operating cost stability for each strategy within the three scenarios (lower is good).

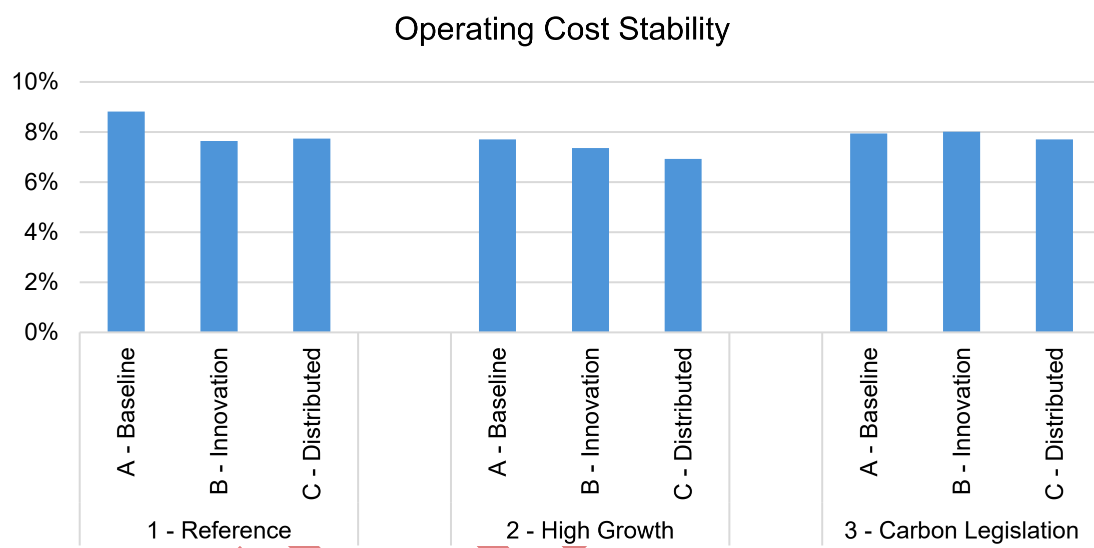


Figure 3-30: Operating Cost Stability

With the differences in resource mix among the three strategies, ensuring the flexibility and availability of resources to meet the hour-to-hour changes in demand is increasingly important. Energy curtailment will increase as the share of energy generation from inflexible or non-dispatchable generation sources increases. The chart below compares expected energy curtailment ratio for each strategy within the three scenarios (lower is good)

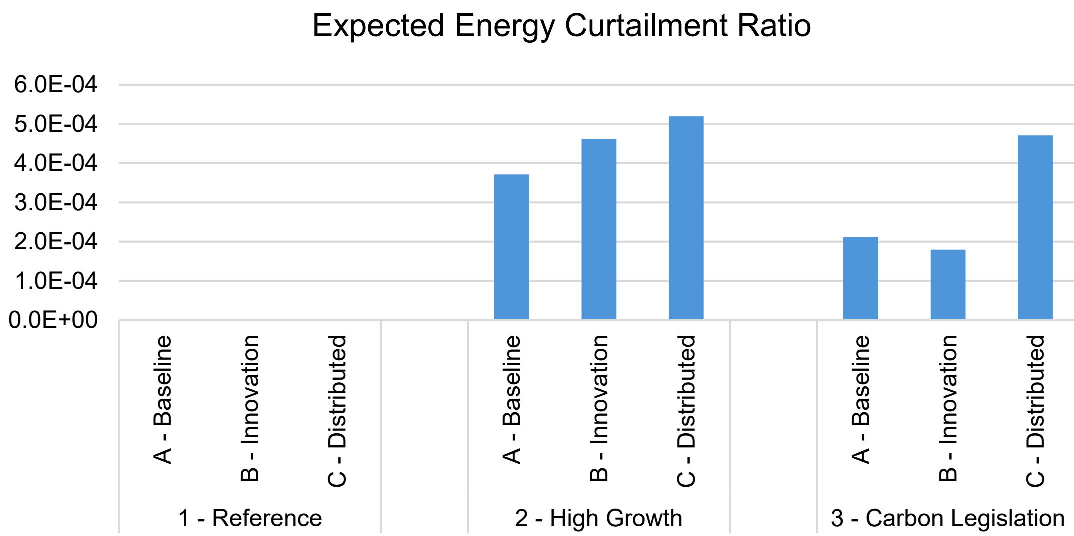


Figure 3-31: Expected Energy Curtailment Ratio

Key takeaways from evaluating operational metric performance across the portfolios include:

- Baseline Utility Planning strategy portfolios tend to have slightly lower stability in operating costs due to higher natural gas fuel requirements.
- Distributed strategy portfolios have more stability in operating costs on average across scenarios.
- Expected energy curtailment across all cases is small; scenarios with a higher share of energy from inflexible or non-dispatchable resources like nuclear or solar see the greatest potential for energy curtailment.
- All strategies perform well in operational metrics on an absolute basis and would continue to result in a reliable and resilient system.

3.7.5 Key Tradeoffs

With an understanding of strategy performance within metric categories, key tradeoffs across metric categories can then be assessed. Evaluating tradeoffs between cost, risk, environmental, and operational profiles, helps inform strategic direction.

Cost and Risk Tradeoffs

In resource planning and specific asset decisions, cost and risk tradeoffs should be considered.

- Baseline Utility Planning (A) performs best in cost metrics across all scenarios but tends to have higher risk exposure based on potential for higher natural gas prices.
- Innovation (B) tends to be the most expensive due to construction costs associated with nuclear expansion but performs relatively well in risk metrics based on lower fuel price volatility.
- Distributed (C) tends to have median cost performance while performing well in risk metrics based on lower fuel price volatility.

Environmental Tradeoffs

In resource planning and specific asset decisions, environmental tradeoffs should be considered.

- Baseline Utility Planning (A) performs well in land use and water consumption but typically features highest CO_2 intensity.
- Innovation (B) performs well in land use and CO_2 intensity but requires higher water consumption to serve higher nuclear expansion.
- Distributed (C) performs well in water consumption and CO_2 intensity but requires the highest volume of land use to serve higher solar expansion.
- All strategies feature similar waste intensity due to minor variations in coal plant operations across strategies.

Operational Tradeoffs

In resource planning and specific asset decisions, operational tradeoffs should be considered.

- All strategies perform well in operational metrics on an absolute basis and would continue to result in a reliable and resilient system.
- Baseline Utility Planning (A) performs well in unserved energy and curtailment metrics but tends to feature higher variation in operating costs due to higher natural gas expansion.
- Innovation (B) typically performs well in operating cost stability due to lower fuel price volatility and features median performance in unserved energy and curtailment metrics.
- Distributed (C) performs well in operating cost stability due to lower fuel price volatility but has the worst performance in unserved energy and curtailment metrics due to higher volumes of intermittent resources.

3.7.6 Key Takeaways by Strategy

Key findings, summarized by strategy, include:

Strategy A (Baseline Utility Planning): As Strategy A applies no resource promotions, it is the lowest cost strategy overall, though its higher reliance on natural gas generation results in higher financial risk exposure than alternative strategies. Strategy A portfolios have the highest natural gas generation and the lowest land use on average across the strategies.

Strategy B (Innovation): Strategy B is the most expensive overall, as it would require significant investments in nuclear expansion. Land use is comparable to Strategy A, but water consumption is highest in this strategy. Technological risks are greatest in portfolios with more reliance on emerging energy technologies, and Strategy B portfolios have the highest amount of new nuclear. This strategy performs well in operational metrics with low variation in operating cost due to lower fuel price volatility, and it features median performance in unserved energy and curtailment metrics.

Strategy C (Distributed): Strategy C is generally the median in cost. Strategy C portfolios have the highest renewable and storage additions on average. With the largest solar buildouts under this strategy, transmission risks and land use are greatest. Water consumption intensity is lowest as higher renewable generation displaces thermal generation. Operationally, higher reliance on intermittent renewable generation increases the risk of unserved energy or energy curtailment.

3.8 Scorecard Results

Fully populated scorecards are included in this section with two views presented – by scenario and by metric. Metrics are calculated based on the optimization results for the nine core portfolios. Metrics cover the 2026-2050 study period, except for one metric that focuses on 2050, as noted. See Chapter 2 for a discussion on metrics development and Appendices I-K for further details on cost, risk, environmental, and operational metrics.

3.8.1 Scorecard Results by Scenario

Scorecard results by scenario, shown in the tables below, compare how the three strategies performed across all metrics within each scenario modeled in the IRP. Lower is better for all metrics.

Table 3-2: Scenario 1 Scorecard (Reference)

Scenario 1 – Reference		Strategies		
Category	Metric	A	B	C
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$189	$200	$194
	System Average Cost ($/MWh)	$78	$83	$80
	Total Resource Cost ($B)	$190	$201	$195
Risk Informed	Risk / Benefit Ratio	2.19	2.10	2.18
	Risk Exposure ($B)	$32.8	$26.5	$29.6
Environmentally Responsible	Land Use Intensity in 2050 (Acres/GWh)	0.06	0.06	0.20
	Water Consumption Intensity (Gallons/MWh)	294	327	289
	Waste Intensity (Tons/GWh)	8.5	8.8	8.7
	CO_2 Direct Emissions (Million Tons)	52	47	49
	CO_2 Intensity (lbs/MWh)	542	489	513
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation)	8.82%	7.64%	7.74%
	P95 Average Unserved Energy Ratio	2.2×10^{-5}	4.9×10^{-5}	7.6×10^{-5}
	Expected Average Energy Curtailment Ratio	1.0×10^{-9}	8.7×10^{-9}	0

Table 3-3: Scenario 2 Scorecard (High Growth)

Scenario 2 – High Growth		Strategies		
Category	Metric	A	B	C
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$257	$262	$261
	System Average Cost ($/MWh)	$96	$98	$98
	Total Resource Cost ($B)	$258	$263	$263
Risk Informed	Risk / Benefit Ratio	2.17	2.17	2.11
	Risk Exposure ($B)	$31.1	$29.4	$28.6
Environmentally Responsible	Land Use Intensity in 2050 (Acres/GWh)	0.19	0.19	0.32
	Water Consumption Intensity (Gallons/MWh)	331	345	328
	Waste Intensity (Tons/GWh)	9.1	9.0	9.1
	CO_2 Direct Emissions (Million Tons)	49	46	46
	CO_2 Intensity (lbs/MWh)	466	445	447
	Operating Cost Stability (% Variation)	7.71%	7.36%	6.92%

Scenario 2 – High Growth		Strategies		
Category	Metric	A	B	C
Diverse, Reliable, and Flexible	P95 Average Unserved Energy Ratio	6.2×10^{-5}	5.5×10^{-5}	6.8×10^{-5}
	Expected Average Energy Curtailment Ratio	3.7×10^{-4}	4.6×10^{-4}	5.2×10^{-4}

Table 3-4: Scenario 3 Scorecard (Carbon Legislation)

Scenario 3 – Carbon Legislation		Strategies		
Category	Metric	A	B	C
Low Cost	Present Value of Revenue Requirements (PVRR, $B)	$218	$218	$219
	System Average Cost ($/MWh)	$93	$94	$94
	Total Resource Cost ($B)	$218	$219	$221
Risk Informed	Risk / Benefit Ratio	1.98	1.98	1.94
	Risk Exposure ($B)	$22.4	$22.4	$20.9
Environmentally Responsible	Land Use Intensity in 2050 (Acres/GWh)	0.18	0.19	0.32
	Water Consumption Intensity (Gallons/MWh)	328	330	312
	Waste Intensity (Tons/GWh)	6.2	6.5	6.4
	CO_2 Direct Emissions (Million Tons)	35	35	33
	CO_2 Intensity (lbs/MWh)	382	385	370
Diverse, Reliable, and Flexible	Operating Cost Stability (% Variation)	7.94%	8.01%	7.70%
	P95 Average Unserved Energy Ratio	3.6×10^{-8}	1.1×10^{-5}	2.0×10^{-5}
	Expected Average Energy Curtailment Ratio	2.1×10^{-4}	1.8×10^{-4}	4.7×10^{-4}

3.8.2 Scorecard Results by Metric

Scorecard results by metric, shown in the table below, compare how the three strategies performed across all scenarios for each metric. Lower is better for all metrics.

Table 3-5: Scorecard Metrics by Scenario and Strategy

Metric / Scenario	Strategy		
	A	B	C
Present Value of Revenue Requirements (PVRR, $B)			
1 - Reference	$189	$200	$194
2 - High Growth	$257	$262	$261
3 - Carbon Legislation	$218	$218	$219
System Average Cost ($/MWh)			
1 - Reference	$78	$83	$80
2 - High Growth	$96	$98	$98

Metric / Scenario	Strategy		
	A	B	C
3 - Carbon Legislation	$93	$94	$94
Total Resource Cost ($B)			
1 - Reference	$190	$201	$195
2 - High Growth	$258	$263	$263
3 - Carbon Legislation	$218	$219	$221
Risk/Benefit Ratio			
1 - Reference	2.19	2.10	2.18
2 - High Growth	2.17	2.17	2.11
3 - Carbon Legislation	1.98	1.98	1.94
Risk Exposure ($B)			
1 - Reference	$32.8	$26.5	$29.6
2 - High Growth	$31.1	$29.4	$28.6
3 - Carbon Legislation	$22.4	$22.4	$20.9
Land Use Intensity in 2050 (Acres/GWh)			
1 - Reference	0.06	0.06	0.20
2 - High Growth	0.19	0.19	0.32
3 - Carbon Legislation	0.18	0.19	0.32
Water Consumption Intensity (Gallons/MWh)			
1 - Reference	294	327	289
2 - High Growth	331	345	328
3 - Carbon Legislation	328	330	312
Waste Intensity (Tons/GWh)			
1 - Reference	8.5	8.8	8.7
2 - High Growth	9.1	9.0	9.1
3 - Carbon Legislation	6.2	6.5	6.4
CO_2 Direct Emissions (Million Tons)			
1 - Reference	52	47	49
2 - High Growth	49	46	46
3 - Carbon Legislation	35	35	33
CO_2 Intensity (lbs/MWh)			
1 - Reference	542	489	513
2 - High Growth	466	445	447
3 - Carbon Legislation	382	385	370
Operating Cost Stability (%)			
1 - Reference	8.82%	7.64%	7.74%
2 - High Growth	7.71%	7.36%	6.92%

Metric / Scenario	Strategy		
	A	B	C
3 - Carbon Legislation	7.94%	8.01%	7.70%
P95 Average Unserved Energy Ratio			
1 - Reference	2.2x10^{-5}	4.9x10^{-5}	7.6x10^{-5}
2 - High Growth	6.2.x10^{-5}	5.5x10^{-5}	6.8x10^{-5}
3 - Carbon Legislation	3.6x10^{-8}	1.1x10^{-5}	2.0x10^{-5}
Expected Average Energy Curtailment Ratio			
1 - Reference	1.0x10^{-9}	8.7x10^{-9}	0
2 - High Growth	3.7x10^{-4}	4.6x10^{-4}	5.2x10^{-4}
3 - Carbon Legislation	2.1x10^{-4}	1.8x10^{-4}	4.7x10^{-4}

3.9 Sensitivity Analysis Summary

When analyzing core portfolio results and considering stakeholder and public input, TVA identified questions warranting further evaluation related to key assumptions that could influence results. TVA used sensitivity analysis to assess potential impacts, varying a key assumption to isolate the impact of that change on portfolio results. For additional insights, TVA performed sensitivity analysis focused in the following areas:

- Electricity demand changes
- Resource costs and availability
- Natural gas commodity prices

In general, sensitivity results fell within the capacity expansion bounds for resource selection within the nine core portfolios with the exception of Higher EE Availability and Deployment and Supercharged Growth. Additionally, earlier and later coal end of life cases were evaluated and show very little variation in incremental capacity by 2040; rather, it is the timing of resource additions that differs.

The following figure and tables show the incremental capacity by 2040 for all sensitivities compared to their baseline case as well as capacity expansion impacts by resource type by 2040 and by 2050 for all sensitivities (increases in green, decreases in red). Reference case 1A is the baseline cases unless otherwise noted. The impacts to the PVRR is noted in the 2050 table (lower values in green, higher values in red). A discussion of each sensitivity is included in the following section. The results of sensitivity analysis, along with the results of the nine core portfolios and the EIS, were considered in developing the IRP recommendations.

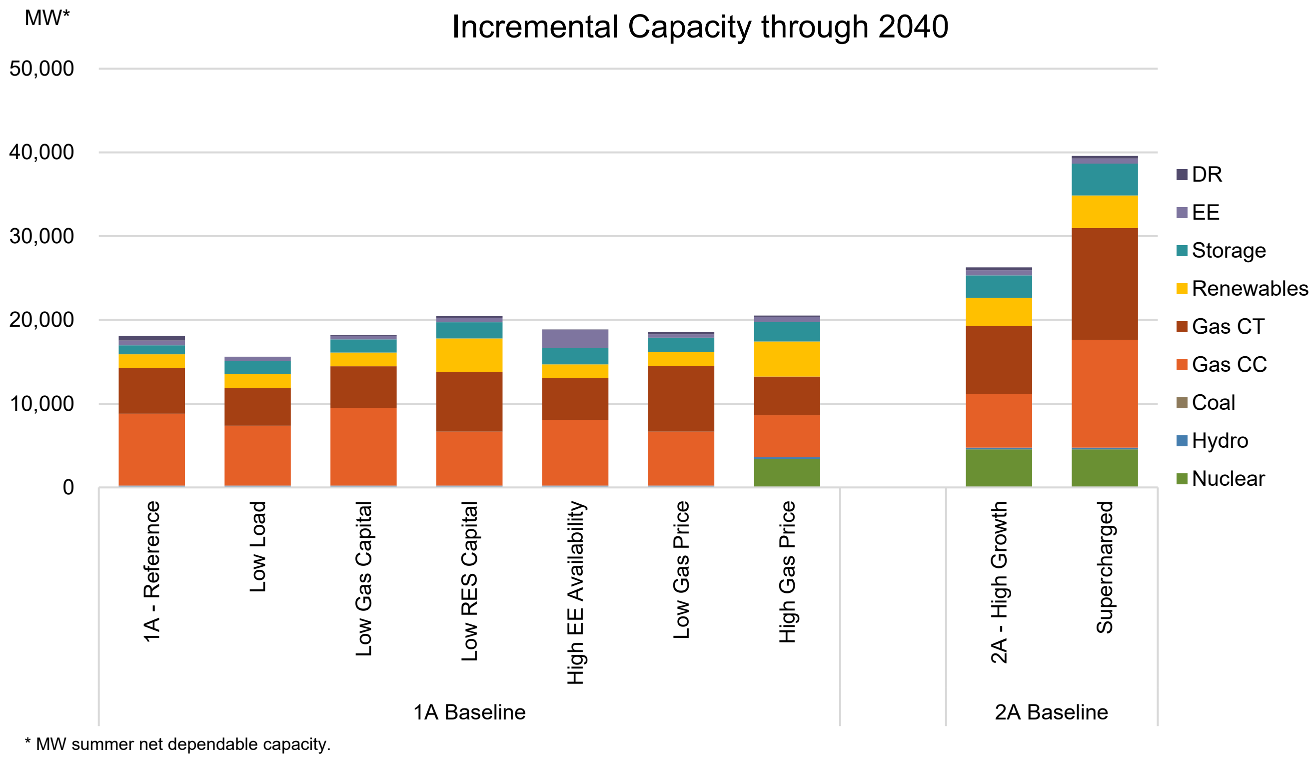


Figure 3-32: Sensitivity Incremental Capacity through 2040

Table 3-6: Summary of Sensitivity Analysis – Impacts through 2040 (GW Summer NDC)

SENSITIVITY ANALYSIS Reference case 1A is the baseline unless otherwise noted	CAPACITY EXPANSION IMPACTS THROUGH 2040 (GW) INCREASE / DECREASE						
	Nuclear	Gas CC	Gas CT	Solar	Wind	Storage	EEDR
Electricity Demand Changes							
Supercharged Growth (2A)		+6.4	+5.3	+0.5		+1.1	Minor Impacts
Low Growth		-1.4	-0.9			+0.5	-0.6
Resource Costs and Availability							
Lower renewable and storage costs		-2.1	+1.7	+2.3		+0.7	-0.4
Lower gas resource costs		+0.7	-0.5			+0.5	-0.6
Earlier/later coal end of life	Minor Impacts						
Higher EE availability and deployment		-0.7	-0.5			+0.9	+1.1
Natural Gas Commodity Prices							
Higher natural gas prices	+3.4	-3.6	-0.8	+2.4	+0.2	+1.3	-0.4
Lower natural gas prices		-2.1	+2.4			+0.7	-0.5

Table 3-7: Summary of Sensitivity Analysis – Impacts through 2050 (GW Summer NDC)

SENSITIVITY ANALYSIS Reference 1A is the baseline unless otherwise noted	CAPACITY EXPANSION IMPACTS THROUGH 2050 (GW) INCREASE / DECREASE							COST FAVORABLE / UNFAVORABLE
	Nuclear	Gas CC	Gas CT	Solar	Wind	Storage	EEDR	PVRR* ($B)
Electricity Demand Changes								
Supercharged Growth (2A)		+10.0	+7.5	+0.1	+0.1	+1.1	Minor Impacts	+$56.7
Low Growth		-1.4	-1.4	-0.7		-0.8	-0.4	-$8.1
Resource Costs and Availability								
Lower renewable and storage costs		-3.6	+3.4	+3.2		+0.4	-0.3	-$1.7
Lower gas resource costs		+1.4	-0.5	-0.5		-0.8	-0.4	-$5.0
Earlier/later coal end of life	Minor Impacts							-$1.1 (later) to +$1.6 (earlier)
Higher EE availability and deployment			-0.9	-1.0		-0.4	+2.1	+$9.8
Natural Gas Commodity Prices								
Higher natural gas prices	+5.4	-7.2	+1.7	+3.1	+0.2		Minor Impacts	+$44.9
Lower natural gas prices		-1.4	+2.1	-0.9		-0.6	-0.2	-$23.6

*PVRR for Reference case 1A is $189B.

3.10 Sensitivity Analysis Discussion

3.10.1 Electricity Demand Changes

Electricity demand is an important driver of portfolio expansion in resource planning. During review of the draft IRP, questions surfaced during IRP Working Group discussions and the public comment period about the potential for even higher load growth than is included in the High Growth scenario, especially related to electrification potential as well as data centers and other industrial loads that could have a significant impact on electricity demand. Conversely, economics or other market factors, such as widespread adoption of market-driven energy efficiency, could lead to a prolonged period of stagnant growth. To address both of these possibilities, TVA created upper and lower bounding sensitivities for load growth.

The chart below compares electricity demand forecasts for the three scenarios and the two load sensitivity cases.

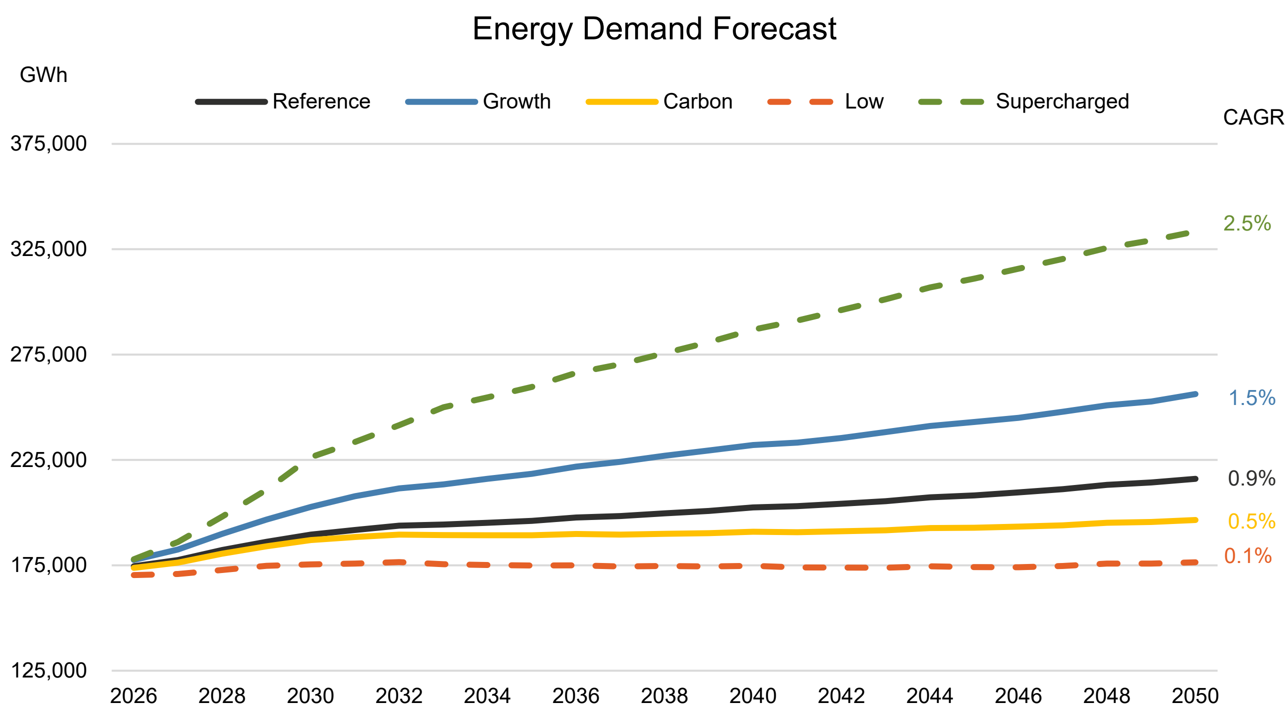


Figure 3-33: Energy Demand Comparison of IRP Scenarios and Load Growth Sensitivities

Supercharged Growth

The electric load forecasts for the IRP scenarios reflect assumptions for economic, demographic, and other key drivers. The Reference case (Scenario 1) and the High Growth case (Scenario 2) do include forecasted growth in electric demand from all sectors, including industrial growth, which includes data centers. During review of draft results, IRP Working Group members and public comments raised questions about more extreme growth in electrification potential, data centers, and other electricity-intensive industries. To address this, TVA conducted a sensitivity that assumes more rapid and sustained growth in electricity demand above what is already included in the High Growth scenario.

To support the higher load growth, additional nuclear, gas CC, gas CT, storage, and solar capacity is added by 2040. This need for additional capacity resources of all types continues through 2050. These changes in the resource mix increase PVRR by $56.7 billion. Changes in electricity demand would also correspond with an increase in sales, resulting in a modest increase in system average cost of approximately $5/MWh.

Low Growth

Wanting to understand the impacts of lower load growth, the IRP analysis included a sensitivity that looked at nearly flat loads for the duration of the plan. These lower loads could be driven by one or a combination of factors such as widespread adoption of market-driven energy efficiency, regulatory drivers, economic stagnation, etc. By 2040 and 2050, analysis indicates that capacity additions are primarily needed to replace expiring contracts or units reaching expected end of life; these additions come primarily from a mix of gas CC, gas CT, and storage. These changes in the resource mix decrease PVRR by $8.1 billion. Changes in electricity demand would also correspond with a decrease in sales, resulting in a modest decrease in system average cost of approximately $1/MWh.

3.10.2 Resource Costs and Availability

Estimated resource costs were a key driver of results for the nine core portfolios. TVA utilizes a combination of direct experience with recent projects, market-based request for proposal responses, industry expertise working with equipment manufacturers, and industry forecasts to inform baseline resource costs. The IRP Working Group and other stakeholders had questions about how different the results would look if future resource cost trajectories were higher or lower than estimated for key resource types. Some public comments also highlighted a desire to understand the potential impact if the market depth and adoption of energy efficiency programs were higher than estimated.

Lower Renewable and Storage Costs

Future resource costs for renewable and storage technologies could be lower than estimated if costs to build or procure trend lower or if tax credits were to be reestablished and extended. For this sensitivity, TVA extended the impacts of a 30% investment tax credit for renewables and storage through 2050 and increased some base cost declines to simulate additional manufacturing efficiencies or other market improvements. The figures below compares IRP baseline costs, including ITC impacts, to those assumed in this sensitivity. By 2040, gas CC capacity is replaced by a combination of increased solar, storage, and peaking gas CTs. By 2050, this trend continues and accelerates as additional solar, storage, and peaking gas CTs replace gas CC expansion. No wind is selected in this sensitivity due to cost and portfolio fit challenges. These changes in the resource mix decrease PVRR by $1.7 billion.

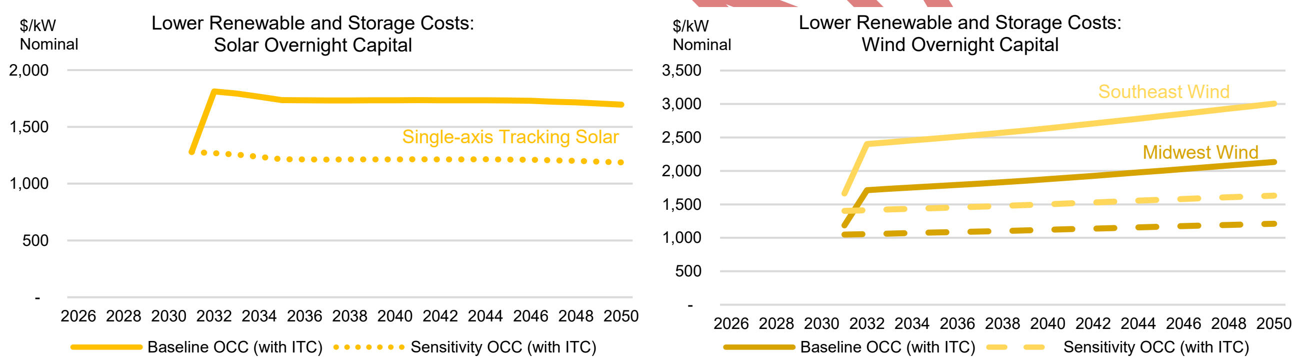


Figure 3-34: Renewable Overnight Capital Costs (with ITC) - Lower Renewable and Storage Costs Sensitivity

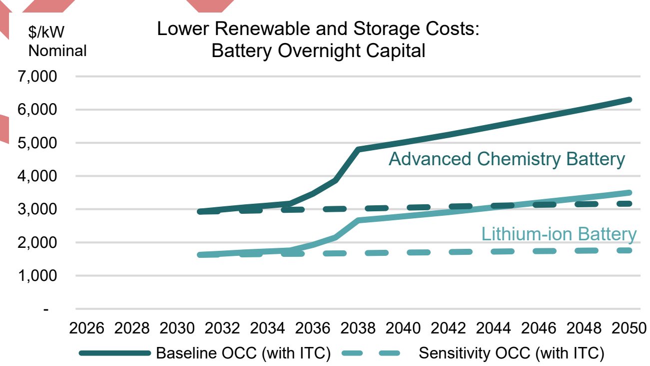


Figure 3-35: Storage Overnight Capital Costs (with ITC) - Lower Renewable and Storage Costs Sensitivity

Lower Gas Resource Costs

The cost to construct new gas-fired generation is a significant driver of potential future resource portfolio mixes. These costs have seen significant recent escalation based off inflationary pressures and increased gas turbine demand driven by increased load growth nationally. It remains unclear if recent increases in gas construction costs will remain elevated, or if the impacts are transitory. To evaluate the potential impact of lower than forecasted gas capital costs, TVA ran a sensitivity assuming recent cost escalation eases and overnight capital costs align more closely to the Draft 2025 IRP. By 2040, additional gas CC and storage capacity is added, displacing some gas CT and energy efficiency and demand response (EEDR) capacity. By 2050, additional gas CC capacity is added, displacing some gas CT, solar, storage, and EEDR capacity. These changes in the resource mix decrease PVRR by $5.0 billion.

Earlier or Later Coal End of Life

An increase in power demand and associated system reliability concerns prompted TVA to recently re-evaluate and approve taking steps to continue operation of TVA's coal-fired fleet to reduce total system costs and address system reliability risks. The 2026 IRP includes planning assumptions for coal plant end of life based on anticipated regulatory requirements, age, and/or material condition. As these dates are subject to permitting requirements as well as further evaluation, environmental review, and TVA Board approval, sensitivities evaluating both earlier and later coal end of life dates were studied. The earlier case assumed a staggered, full coal fleet end of life by 2034, while the later case assumed operation of all existing coal units through the end of 2039. Results show minor impacts to incremental capacity by 2040 and 2050; rather, it is the timing of resource additions that differs. The earlier coal end of life case increased PVRR by $1.6 billion while the later coal end of life case decreased PVRR by $1.1 billion.

Higher EE Availability and Deployment

TVA leveraged insights from the 2022 Energy Programs Potential Study and subsequent market experience to develop the EE program tiers modeled in the IRP. Some stakeholders asked about the potential to achieve greater levels of EE, especially in the commercial and industrial sectors. Industrial sector potential is particularly challenging to estimate, as solutions are often custom in nature and can be economic for industrial customers to pursue without utility incentives. To evaluate the potential impacts of greater EE market depth beyond what was modeled in the draft IRP cases, TVA assumed significantly increased maximum annual energy efficiency program potential was available with corresponding increases in costs which may be required to achieve them. This increased potential was spread across residential, commercial, and industrial sectors, and adoption was forced at highest level each year. By 2040, additional EE capacity is added along with storage, displacing some gas CC and gas CT capacity. By 2050, additional EE capacity is added, displacing some gas CT, solar, and storage capacity. These changes in the resource mix increase PVRR by $9.8 billion.

3.10.3 Natural Gas Commodity Prices

Natural gas generation makes up a significant part of TVA's existing fleet, and several types of gas generation are offered as expansion options. Changes in natural gas commodity prices change the variable cost of gas units and may change the economics of gas expansion options relative to other resources. To understand the potential impact of higher and lower natural gas price trajectories, TVA evaluated the difference in expansion plans at two standard deviations above and below forecasted prices in the Reference scenarios.

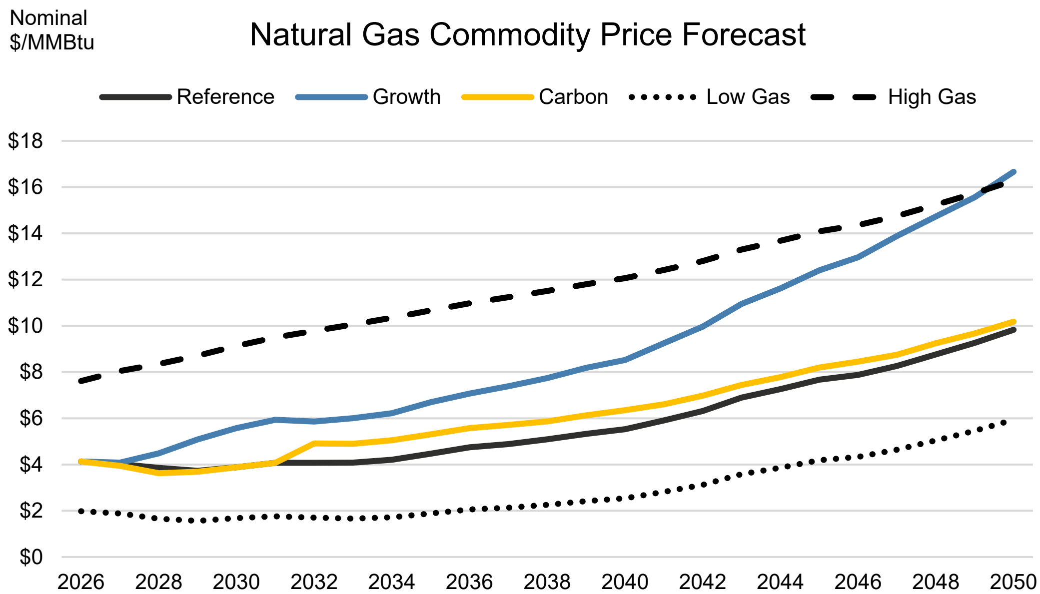


Figure 3-36: Natural Gas Price Forecast – Scenario and Sensitivity Ranges

Higher Natural Gas Prices

Higher natural gas prices increase the cost of gas generation, making competing resources relatively more valuable. By 2040, analysis indicates that additional nuclear, storage, and solar capacity is added, displacing some CC and CT capacity. By 2050, additional nuclear and solar capacity is added, and gas CTs also displace some CC capacity. These changes in the resource mix increase PVRR by $44.9 billion.

Lower Natural Gas Prices

Lower natural gas prices improve the economics of gas generation relative to other resource options. By 2040, analysis indicates that additional CT and storage capacity is added, displacing primarily gas CC capacity. By 2050, additional CC and CT capacity is added, displacing some renewable and storage capacity. These changes in the resource mix decrease PVRR by $23.6 billion.

3.11 Conclusion

The results of the nine core resource portfolios, coupled with the sensitivity analysis that explores the impacts of changes in key assumptions, provide insights into how the future power system might evolve to meet the region's future energy needs. The full set of results were considered in developing the IRP recommendations discussed in the next chapter.

4 Recommendations and Implementation

The Tennessee Valley is one of the fastest growing regions in the nation. The 2026 IRP evaluates potential electricity demand growth, evolving regulations, and different strategic emphasis to identify a long-range resource plan that is grounded in least-cost planning and performs well in a constantly changing business environment. Throughout the process, TVA engaged external stakeholders to gather their views, challenge assumptions, and strengthen the analysis and outcomes. The IRP recommendations provide strategic direction for the future power system, establishing a strong planning foundation and informing TVA's next long-range financial plan.

4.1 Developing IRP Recommendations

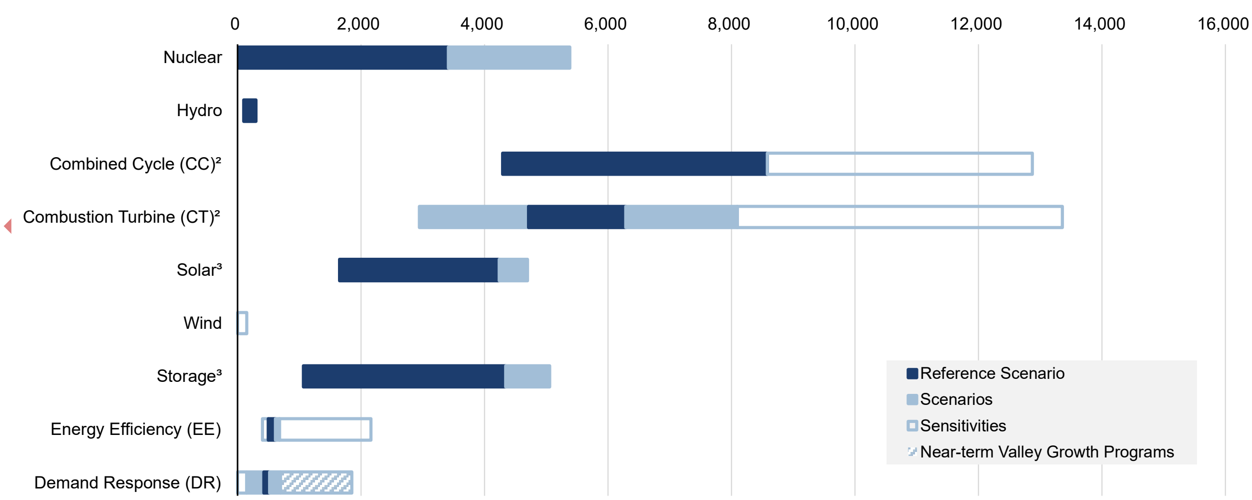
IRP results – including the nine core portfolios, metrics, sensitivities, and EIS – provide robust analysis to consider in forming IRP recommendations. The analysis offers insights into potential power supply mix ranges and impacts to customer priorities of power cost, reliability, resiliency, and environmental responsibility over the long term.

To develop IRP recommendations, TVA first summarized the power supply mix ranges by resource type from the comprehensive IRP analysis. Next, a strategic portfolio direction was developed, including a set of recommended actions. Finally, TVA identified the key signposts to monitor to understand potential implications to recommended actions and evolution of the power system over the long term.

4.2 Power Supply Mix Ranges

Exploring potential scenarios and strategies in the IRP is fundamental to ensuring TVA is well prepared to meet the region's energy needs however the future unfolds. The chart below shows the power supply mix ranges – or incremental additions – from now through 2040. The ranges encompass the full set of results, with reference scenario results shown in the dark blue bars, and alternative scenario and sensitivity results outside of the reference ranges shown in the light blue bars and outline-only bars, respectively. Generally speaking, the upper end of most ranges is set by the High Growth scenario or the Supercharged Growth sensitivity.

Range of MW[1] Additions, 2027 through 2040



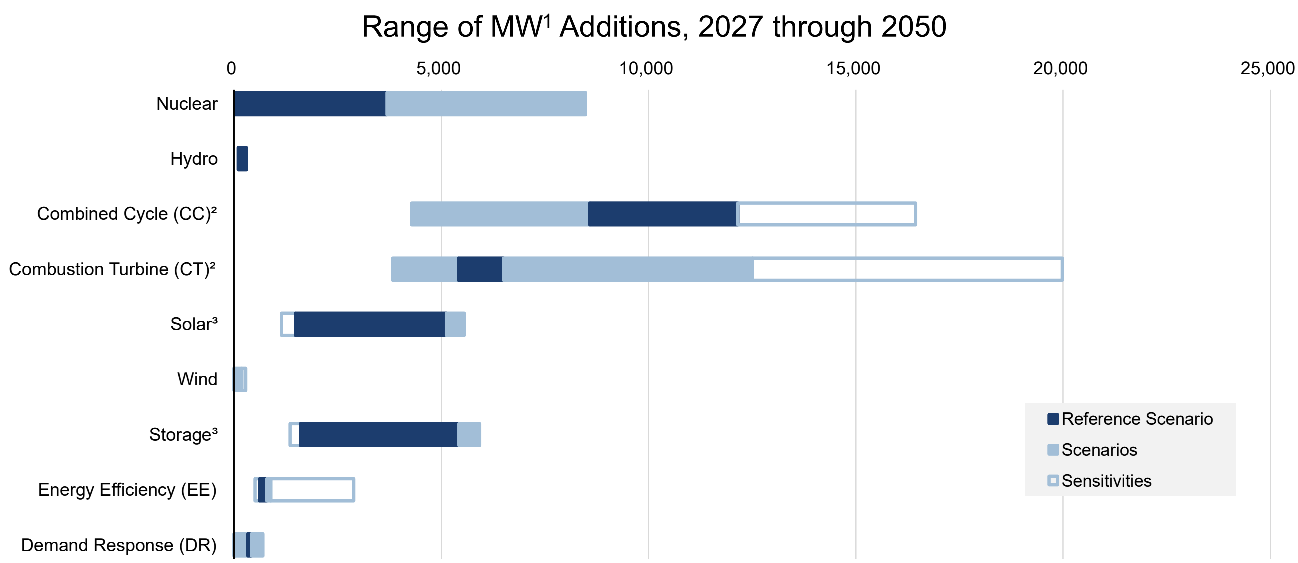
[1] MW capacity expressed in summer net dependable capacity.

[2] CC and CT additions could include control technologies, such as carbon capture and sequestration, alternative fuel co-firing (e.g., hydrogen), or gas re-firing of existing coal burners.

[3] Solar and storage include utility-scale and distributed resource additions.

Figure 4-1: Power Supply Mix Ranges through 2040

The chart below shows the power supply mix ranges – or incremental additions – from now through 2050. Uncertainty in electricity demand, environmental regulations, resource costs, and available technologies increases as the forecast horizon extends further into the future. The IRP analyzes potential ways the resource portfolio might evolve between now and 2050 to respond to changes in these key drivers, and insights gained from evaluating the entire planning horizon were used to inform the strategic portfolio direction.



[1] MW capacity expressed in summer net dependable capacity.
[2] CC and CT additions could include control technologies, such as carbon capture and sequestration, alternative fuel co-firing (e.g., hydrogen), or gas re-firing of existing coal burners.
[3] Solar and storage include utility-scale and distributed resource additions.

Figure 4-2: Power Supply Mix Ranges through 2050

4.3 Strategic Portfolio Direction

TVA's IRP analysis reaffirms the importance of adhering to least-cost planning principles to ensure the continued delivery of affordable, reliable, and resilient power to the Tennessee Valley. The results underscore that no single resource will fully meet future system needs; rather, maintaining a diverse portfolio remains essential. In the near-term, TVA should prioritize the addition of firm, dispatchable resources, particularly natural gas and storage, to address capacity requirements. TVA should also continue collaborating with industry and federal partners to prepare for the potential deployment of firm, dispatchable advanced nuclear technologies, which could support long-term load growth while mitigating fuel volatility and regulatory risks. Finally, complementary deployment of solar, demand-side, and distributed generation resources should be used to satisfy capacity requirements, provide economic energy, and/or meet customer needs.

4.3.1 Recommended Actions

The 2026 IRP's strategic portfolio direction includes the following recommended actions:

Existing Resources

- Invest in the hydro and nuclear fleets and pursue nuclear license extensions to maintain low-cost generation
- Invest in the gas and storage fleets to maintain reliability
- Continue operation of the coal fleet, subject to regulatory requirements, to reduce total system cost and reliability risk

Supply-side Resource Additions

- Add firm, dispatchable gas to maintain system reliability and enhance flexibility
- Add firm, dispatchable storage to maintain system reliability and improve system efficiency
- Pursue solar to reduce total system costs or meet customer needs
- Suspend wind additions given cost and portfolio fit challenges

Demand-side Resource Additions

- Utilize demand response and behind-the-meter resources to enable near-term interconnection of new industrial loads
- Partner with customers to leverage cost-effective energy efficiency and demand response
- Collaborate with local power companies on the evolution of distributed generation programs

Grid and Innovation Enablement

- Prepare for Gen III+ and Gen IV nuclear to support load growth and reduce fuel volatility and regulatory risks while pursuing external funding opportunities
- Pursue transmission system enhancements to deliver low-cost generation resources
- Collaborate with industry partners to evaluate emerging technologies, such as fusion and long-duration storage

Figure 4-3: Strategic Portfolio Direction – Recommended Actions

4.3.2 Planned Actions for Existing Resources and Mature Resource Additions

The table below outlines the IRP ranges, current actions in progress, and planned actions through 2040 for existing resources and mature resource additions including supply-side and demand-side resources. A combination of resource additions is needed to ensure the region continues to have affordable, reliable, and resilient power. Additions will vary within the ranges based on movements in key signposts, which are discussed later in this chapter.

Table 4-1: Strategic Portfolio Direction – Planned Resource Actions through 2040

Resource Type	GW through 2040	Actions in Progress	Planned Actions through 2040
Nuclear	Up to 5 GW	Pursuing license extensions for and investing in the existing nuclear fleet; evaluating advanced nuclear options	Continue investing in the existing nuclear fleet and cost-effective opportunities to increase output; potential for advanced nuclear deployment
Hydro	Up to 1 GW	Ongoing investments in the Hydro Life Extension (HLE) program, leveraging cost-effective ways to increase output	Continue investing in the existing hydro fleet, maximize cost-effective uprate potential, and evaluate market opportunities
Coal	Expected to reach end of life by 2040	Continuing operation of coal fleet, subject to regulatory requirements, as an immediate, cost-effective option to reduce total system cost and system reliability risk	Evaluate existing fleet, as needed, considering material condition, system reliability, system cost, regulatory requirements, and replacement generation
Gas Combined Cycle (CC)	4 to 13 GW	2 GW of CC capacity being added by 2028 to address capacity requirements and provide grid support	Continue investing in the existing fleet and evaluate future CC additions and market opportunities for system reliability needs

Resource Type	GW through 2040	Actions in Progress	Planned Actions through 2040
Gas Combustion Turbine (CT)	3 to 13 GW	2 GW of Frame and Aero capacity being added by 2028 to address capacity requirements, provide grid support, and enhance system flexibility	Continue investing in the existing fleet and evaluate future CT additions and market opportunities for system reliability, flexibility, and resiliency needs
Solar	2 to 5 GW (3 to 12 GW nameplate)	3 GW (nameplate) of Green Invest, self-directed, and Generation Flexibility solar projects contracted to come online by 2030	Evaluate solar additions to either lower system costs or meet customer needs utilizing regular procurement cycles
Wind	<1 GW (Up to 1 GW nameplate)	Screening wind offers through request for proposal processes for cost-effectiveness and system fit	Monitor wind proposals to determine if cost and system fit challenges are improving
Storage	1 to 5 GW (1 to 8 GW nameplate)	0.7 GW of Green Invest, self-directed, and Generation Flexibility battery projects contracted to come online by 2030; evaluating pumped storage option	Continue investing in the existing pumped storage fleet and evaluate storage options to support reliability, resiliency, and system flexibility; potential for additional pumped storage deployment
Energy Efficiency (EE)	1 to 2 GW	Investing in residential, commercial, and industrial EE programs using insights from the potential study	Partner with customers to realize cost-effective EE program potential, reducing power generation resource needs
Demand Response (DR)	Up to 2 GW	Investing in residential, commercial, and industrial DR programs to enable interconnection of new industrial loads and to serve system needs	Collaborate with customers to realize cost-effective DR program potential, reducing power generation resource needs

A portion of resource additions will be driven by local power companies through flexible generation options or the evolution of contractual arrangements. Also, TVA will continue to evaluate future market offers received on a one-off basis in the context of least-cost planning and the IRP's strategic direction.

Additions of new energy resources of all types typically require additional investments in the transmission system. Generally, these investments include optimizing existing infrastructure through projects such as reconductoring transmission lines and upgrading substations, along with building new transmission infrastructure such as transmission lines, substations, and other devices that support system reliability and stability. Where possible, TVA prefers to utilize brownfield sites with existing infrastructure and easements. TVA is also expanding its use of grid-enhancing and grid-supporting technologies, such as advanced conductors and STATCOMS, as well as exploring dynamic line ratings, to greater leverage the existing transmission system when adding new generation and storage to the system.

Additions of new gas-fired resources typically require new or expanded gas pipeline infrastructure. The TVA region has a robust gas pipeline network, and future siting efforts will seek to leverage existing pipelines and minimize the need for infrastructure expansion to the extent possible. To support reliability of gas-fired plants, TVA typically contracts for a high level of fuel delivery priority and/or invests in a backup fuel source on site, depending on the expected operations profile of a particular plant.

4.3.3 Planned Actions to Advance Emerging Technologies

Based on insights from the IRP analysis, the table below provides general direction on actions to advance the potential deployment of emerging technologies through 2040 and beyond to support long-term load growth while mitigating fuel volatility and regulatory risks. The table includes details on in-progress and planned actions.

Table 4-2: Strategic Portfolio Direction – Planned Actions to Advance Emerging Technologies

Emerging Technology	Actions in Progress	Planned Actions through 2040
Advanced Nuclear	Collaborating with industry partners to advance light water SMR design at Clinch River Site for next milestone evaluation	Potential deployment of light water SMR if future milestones are met, leveraging partnerships that reduce cost and risk
	Analyzing lessons learned from advanced large reactor deployment (e.g., Georgia Power's Plant Vogtle) and other recent technology advancements	Evaluate the potential option for future deployment of advanced large reactors to support long-term load growth while mitigating fuel volatility and regulatory risks
	Partnering with Oak Ridge National Laboratory, Kairos Power, and Type One Energy to accelerate the next generation of cost-effective nuclear power	Continue industry partnerships to advance the development of next-generation nuclear technologies, including Generation IV reactors and fusion energy systems
Advanced Storage	Exploring emerging long-duration storage through participation in utility collaborations	Evaluate additional opportunities to enable future advanced storage deployment

Based on the evolution of current and future policy or regulatory requirements, it may become necessary to evaluate additional environmental controls at existing or future generation facilities, particularly for coal and gas units. Options to meet future regulatory requirements could include technologies such as carbon capture and sequestration, alternative fuel co-firing (such as hydrogen), or natural gas co- or re-firing of existing coal burners. TVA should continue to monitor advancements in these technologies and evaluate their potential future use if needed to meet regulatory requirements or as a cost-effective method of preserving existing infrastructure (i.e., co- or re-firing of existing coal burners with natural gas).

4.4 Key Signposts and Implications

TVA identified key signposts to monitor that will provide insights into potential impacts to recommended actions between now and 2040 and will ultimately guide future portfolio decisions. The key signpost themes relate to changing market conditions, evolving policy and regulations, and emerging technologies. Movement in key signposts can signal potential shifts in the portfolio mix and indicate the appropriate timing for the next IRP.

Theme	Signpost
Changing Market Conditions	Electricity demand
	Natural gas prices
	Customer needs
	Resource costs
Evolving Policy and Regulations	Shifts in U.S. energy policy
	Tax credits and incentives
	Regulatory requirements
	Permitting and siting challenges
Emerging Technologies	Advanced nuclear technologies
	Advanced storage technologies

Figure 4-4: Key Signposts

4.4.1 Changing Market Conditions

Changing market conditions related to electricity demand, natural gas prices, customer needs, and resource costs have the potential to influence implementation of planned resource additions through 2040, as described in the table below. Movement also indicates directional changes in longer-term resource plans.

Table 4-3: Changing Market Conditions – Key Signposts and Implications

Signpost	2040 Trajectory vs. Reference Case	Implications to Reference Case through 2040
Electricity Demand	Higher electricity demand	More firm capacity additions; likely a mix of more gas, solar, storage, and/or nuclear
	Lower electricity demand	Less firm capacity additions; likely a mix of less gas, solar, and storage
	Note: 10% increase in 2040 electricity demand requires an ~5 GW increase in firm capacity need	
Natural Gas Prices	Higher natural gas prices (long-term fundamentals)	More solar, storage, and/or nuclear expansion; likely offsetting gas expansion (particularly CC)
	Lower natural gas prices (long-term fundamentals)	More gas expansion; likely offsetting solar and/or storage
Customer Needs	Higher clean energy program demand	More programmatic solar and storage, potential to expand existing programs, and/or potential for advanced nuclear partnerships; likely offsetting gas expansion (particularly CC)
Resource Costs	Higher than forecasted costs and/or lower annual capability	Less expansion of higher cost resources which will be offset by relatively lower cost resources
	Lower than forecasted costs and/or higher annual capability	More expansion of lower cost resources which will offset relatively higher cost resources

4.4.2 Evolving Policy and Regulations

Shifts in U.S. energy policy can impact tax incentives and policy and regulatory requirements, which can have downstream impacts on the regulatory processes related to bringing new energy resource assets online. Federal energy policy continues to evolve, such as recent Executive Orders and Environmental Protection Agency actions. The following table directionally describes the potential influence of evolving policy and regulations on planned resource additions through 2040. Trends in these signposts also can indicate directional changes in longer-term plans.

Table 4-4: Evolving Policy and Regulations - Key Signposts and Implications

Signpost	2040 Trajectory vs. Reference Case	Implications to Reference Case through 2040
Tax Credits and Incentives	Lower tax credits and incentives	Higher effective costs for applicable resources, likely reducing their expansion relative to alternative resources
	Higher tax credits and incentives	Lower effective costs for applicable resources, likely increasing their expansion relative to alternative resources
Policy and Regulatory Requirements	Relaxed policy and regulatory requirements	Likely more gas expansion and lower solar expansion; lower impetus to advance emerging technology development
	Increased policy and regulatory requirements	Likely more solar and storage expansion and lower gas expansion; higher impetus to advance emerging technology development
Permitting and Siting Challenges	Relaxed permitting and siting challenges	Potential for faster pace of resource additions of all types, along with associated economic development benefits
	Increased permitting and siting challenges	Potential for slower pace of resource additions and constraints on annual deployment capability of certain resource types

4.4.3 Emerging Technologies

TVA's strategic partnerships play a key role in keeping a pulse on and accelerating advancements in emerging technologies. The pace of progress in advanced nuclear and advanced storage technologies will impact deployment potential between now and 2040 and influence longer-term plans, as described below.

Table 4-5: Technology Advancements – Key Signposts and Implications

Signpost	2040 Trajectory vs. Reference Case	Implications to Reference Case through 2050
Advanced Nuclear Technologies	Faster progress in technology and adoption readiness or decreasing resource costs driven by advancements or third-party funding	Increased probability of adding new nuclear (Gen III+, Gen IV, or fusion), likely offsetting a mix of solar, storage, and gas
	Slower progress in technology and adoption readiness or increasing resource costs	Decreased probability of adding nuclear over the long term, potentially increasing the need for gas, solar, and storage

Signpost	2040 Trajectory vs. Reference Case	Implications to Reference Case through 2050
Advanced Storage Technologies	Faster progress in technology and adoption readiness or decreasing resource costs driven by advancements or third-party funding	Increased mix of solar and storage over the long term, likely offsetting some gas additions
	Slower progress in technology and adoption readiness or increasing resource costs	Decreased mix of solar and storage over the long term, offset by more gas and/or emerging energy resources

Based on the evolution of U.S. energy policy and current or future regulatory requirements it may become necessary to leverage technology advancements in environmental control technologies, such as carbon capture and sequestration or alternative fuel co-firing (such as hydrogen). When constructing new gas generation facilities, TVA will consider ways to preserve the future option to potentially retrofit facilities with carbon capture or alternative fuel co-firing capabilities.

4.5 Implementation

This section outlines some of the next steps and key considerations and challenges TVA faces in implementing the recommendations of the 2026 IRP.

4.5.1 Next Steps

In finalizing the IRP and EIS and developing the IRP recommendations, TVA considered the input received throughout the process, including from the IRP Working Group, Regional Energy Resource Council, and during the public comment period. Any actions taken by the Board and TVA with respect to the IRP will comply with requirements of the Administrative Procedure Act and NEPA.

A key next step in implementing the IRP recommendations is translating the IRP's strategic direction into an executable asset strategy from an operational, commercial, and financial perspective. A successful asset strategy also relies on partnering with TVA customers, especially on the distributed and demand-side aspects of the plan, and with other key stakeholders. Site-specific aspects of actions that are later proposed to implement the IRP strategic direction will be addressed and considered in tiered environmental reviews and subject to any required TVA Board approvals.

4.5.2 Monitoring Key Signposts

Going forward, TVA will monitor the key signposts related to changing market conditions, evolving policy and regulations, and emerging technologies. Changes in these key signposts will inform ongoing execution efforts and guide portfolio decisions over the long term. Movement in signposts can signal potential shifts in the portfolio mix and also indicate the appropriate timing for the next IRP.

4.5.3 Implementation Considerations

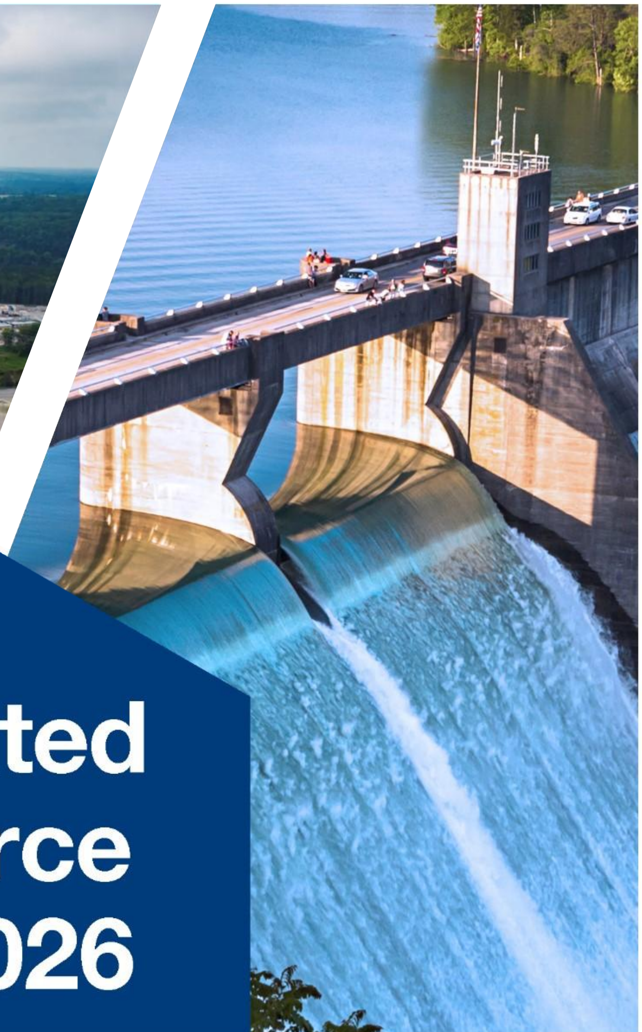
Implementing a plan with significant power generation resource additions over the next decade presents some considerations and challenges. Prior to the publication of the Final 2026 IRP and EIS, TVA will meet with the RERC to present preliminary recommendations and seek an official advice statement for TVA Board consideration.

For more information, visit the RERC website at www.tva.gov/rerc.

As the asset strategy is developed and refined, TVA will consider and work to address implementation considerations and other risks identified through monitoring movement in key signposts.

4.6 Conclusion

The IRP provides strategic guidance for the region's future energy system. The full IRP and EIS provide additional information on planning the future system, stakeholder engagement, process and methodology, portfolio results and assessments, and recommendations and implementation, along with an environmental impacts analysis. TVA greatly appreciates the input, review, and insights provided by the IRP Working Group and the RERC, along with the comments received from other stakeholders and the public that have strengthened the analysis and recommendations. TVA looks forward to continued stakeholder and public involvement as the IRP recommendations are implemented, paving the way for affordable, reliable, and resilient energy in the region through 2040 and beyond.



Integrated Resource Plan 2026

VOLUME 1 / APPENDIX

PRELIMINARY FINAL
JUNE 2026

TENNESSEE VALLEY AUTHORITY

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Appendix A – Integrated Resource Planning Fundamentals

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Appendix A – Integrated Resource Planning Fundamentals

Integrated resource planning is a complex process that considers numerous inputs to produce potential resource plans for meeting the power supply needs of the TVA region, providing guidance for business decisions. This appendix covers the fundamentals of integrated resource planning, including descriptions of key concepts and steps in the process. The process involves forecasting electricity demand, determining capacity needs, identifying resource options, producing and testing resource plans, and analyzing business decisions.

A.1 Objectives of Resource Planning

Resource planning at TVA is grounded in the following least-cost principles:

- Low Cost
- Risk Informed
- Environmentally Responsible
- Reliable and Resilient
- Diverse
- Flexible

TVA applies these principles, in alignment with Section 113 of the Energy Policy Act of 1992, to develop plans for providing affordable, reliable, and resilient energy to the region over the long term.

A.2 Resource Planning Process

Resource Planning is a common practice in the utility industry to identify the optimal solution to meet customer demand over a planning horizon, typically 20 years. TVA conducts an Integrated Resource Plan (IRP) to determine power supply mix ranges, which serve as guardrails, along with recommendations for strategic portfolio direction. Between IRP cycles, which is typically every four to five years, TVA annually updates plans based on current forecasts for key assumptions and analyzes sensitivities and stochastics to better understand risk. The IRP and annual plan updates provide information needed to initiate and evaluate site-specific asset decisions. Resource planning follows a similar process for the IRP and annual plan updates:

Forecast Electricity Demand	Project customer demand for electricity in the future
Determine Capacity Needs	Compare capacity needs to existing resources to determine gaps
Identify Resource Options	Identify viable supply and demand-side resource options
Produce and Test Plans	Produce least-cost resource plan and test bounds and risks
Analyze Business Decisions	Analyze specific asset needs and strategic investments

A.3 Capacity and Energy Definitions

Before stepping through the resource planning process, it is important to understand the difference between capacity and energy. Power system peaks are measured in terms of capacity, or the highest one-hour power requirement placed on the system. Resource planning ensures that there are sufficient resources to reliably meet that peak demand. As resource options are considered, the ability of a given resource to contribute to meeting peak demand is identified.

Capacity for a resource is the instantaneous maximum amount of energy that can be supplied by that generating unit. For long-term planning purposes, capacity is primarily referred to in two ways:

- Nameplate capacity – the theoretical design value or intended maximum megawatt (MW) output of a generator at the time of installation.
- Net dependable capacity – the maximum dependable capacity at seasonal peak demand times less all known adjustments, such as transmission restrictions, station service needs, and fuel derates. In resource planning, it is also referred to as firm capacity.

Net dependable capacity, which is used in capacity planning models, is typically determined by performance testing during the respective season, because weather conditions and peak coincidence affect generating capability. For variable energy resources like solar and wind, net dependable capacities for each season are determined by looking at the historical output at typical seasonal peak times (late afternoon in the summer and early morning in the winter) as a percentage of nameplate capacity. TVA uses both summer and winter net dependable capacities of units in resource planning analysis, given the dual-peaking nature of the system.

While capacity measures power supplied at a given peak time, energy refers to the amount of power supplied over a given time. Overall power system production over a given period of time, such as a day or year, is called energy or generation and is measured in terms of megawatt-hours (MWh). The example below describes a generating unit that produced its maximum net dependable capacity of 100 MW at the peak hour and generated a total of 1,800 MWh over a 24-hour period.

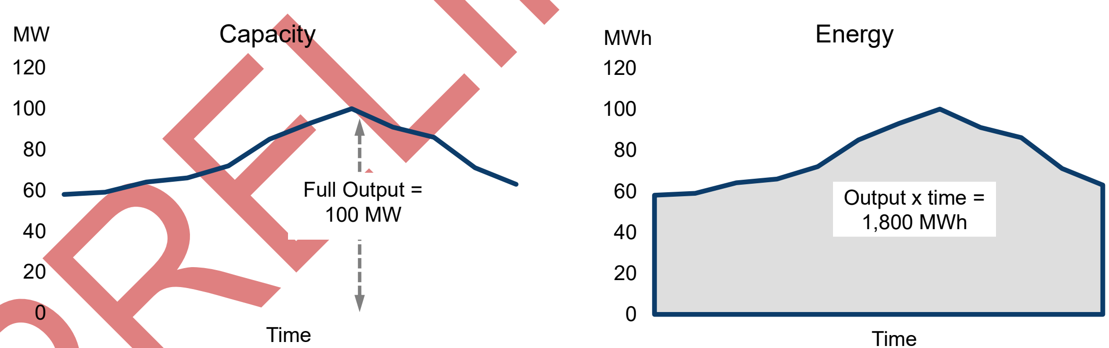

Figure A-1: Capacity and Energy Illustration

A.4 Forecasting Electricity Demand

The primary purpose of long-term resource planning is to determine the optimal mix of resources to supply power to the Valley region over the next 20-plus years and inform decision making. The process starts with estimating future electricity demand, sometimes also referred to as the load forecast.

In resource planning, electricity demand forecasts project the peak demand and energy requirements of the system on an hourly, daily, and annual basis for the next 20 years. Forecasts are typically expressed in terms of normal weather conditions. TVA normalizes the load forecast for weather based on data from 23 weather stations located across the region with proportional load weights. Normalizing for typical weather conditions allows load forecasters to identify the relationship between trends in electricity demand and long-term drivers, including economic activity, population changes, and climate trends. The TVA system is dual peaking, meaning that forecasted peak demand for summer and winter is roughly the same, so electricity demand forecasts are developed for both seasons.

Economic and Demographic Drivers

To inform electricity demand forecasts, TVA first develops forecasts for economic and demographic variables that are key drivers of demand. Key macroeconomic variables include U.S. Gross Domestic Product (GDP) and measures of inflation, such as the U.S. GDP – Implicit Price Deflator and U.S. Treasury rates. To develop a consensus forecast, TVA looks at several sources including Moody's Analytics, the Congressional Budget Office (CBO), the Federal Reserve, the Conference Board, and other publicly available sources. Only Moody's and CBO provide long-term forecasts, while other sources inform the short-term outlook. Only Moody's provides regional and county level data projections. Key regional demographic and economic variables include population, number of households, and employment. TVA utilizes Moody's forecasts at the regional and county level, adjusted for recent Bureau of the Census updates, to forecast demographic trends for districts within the TVA region and for the region as a whole. In some cases, regional projections are adjusted to be consistent with consensus macroeconomic forecasts and to reflect TVA economic development customer expansions.

Electricity Demand Forecasting Methodology

To forecast electricity demand, TVA uses statistical and mathematical models that link electricity sales to several key drivers, including growth in overall economic activity, changes in underlying demographics, energy substitution, changes in consumer usage through technology, and weather trends. The forecast also considers factors such as regulations, electrification adoption across all sectors, and energy efficiency codes and standards. The system forecast is aggregated from individual forecasts by the major consuming sectors, including residential, commercial, industrial, and directly served customers. The hourly energy and daily peak forecasts are inputs into the resource planning and commodity forecasting models.

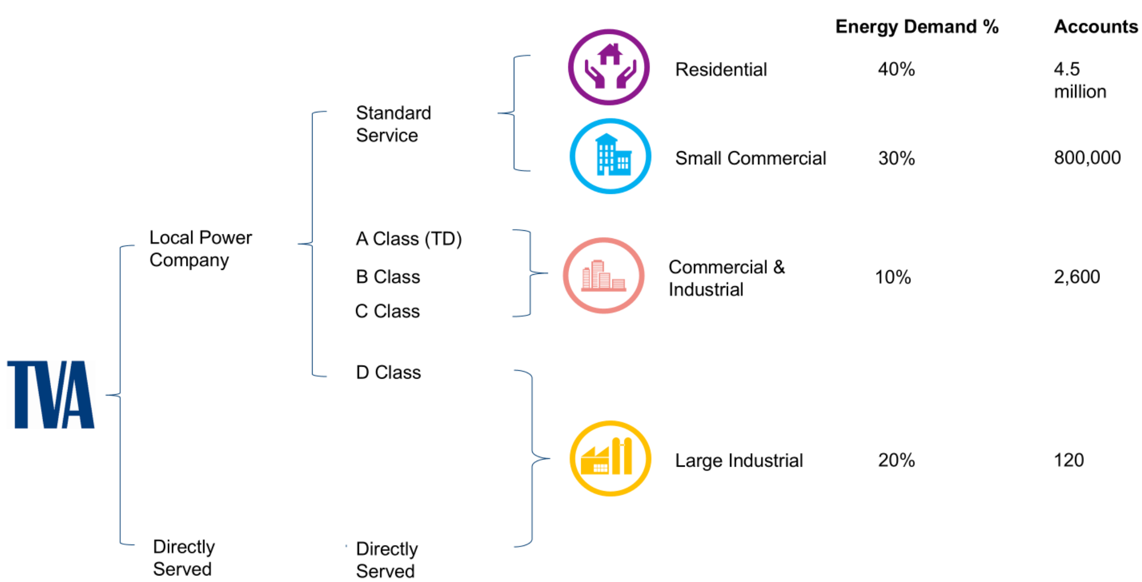

Figure A-2: Current Snapshot of Load Forecast Sectors

The load forecast is one of the most critical inputs to the planning process. Underestimating load growth can result in insufficient resources to meet electricity demand, while overestimating load growth can result in unnecessary or stranded assets.

A.5 Determining Capacity Needs

The next step in the resource planning process is determining capacity needs for both winter and summer. Capacity requirements represent the megawatts (MW) needed to serve forecasted electricity demand plus required planning reserve margins in each season. Capacity requirements can be compared to existing resources to identify the need for new capacity.

Planning Reserve Margin and Firm Requirements

To maintain reliability, power providers must have more generating capacity available than required to meet projected demand. This additional capacity accounts for uncertainty in the amount of forecasted demand and available generating capacity on a future peak day. Future demand is uncertain due to variations in weather conditions, and electric generators can experience unplanned outages due to equipment failure. TVA conducts a reserve margin study to understand the amount of excess generation required to reliably maintain its power system. The reserve margin study is based on a probabilistic analysis that considers the uncertainty of weather, demand, and generator performance.

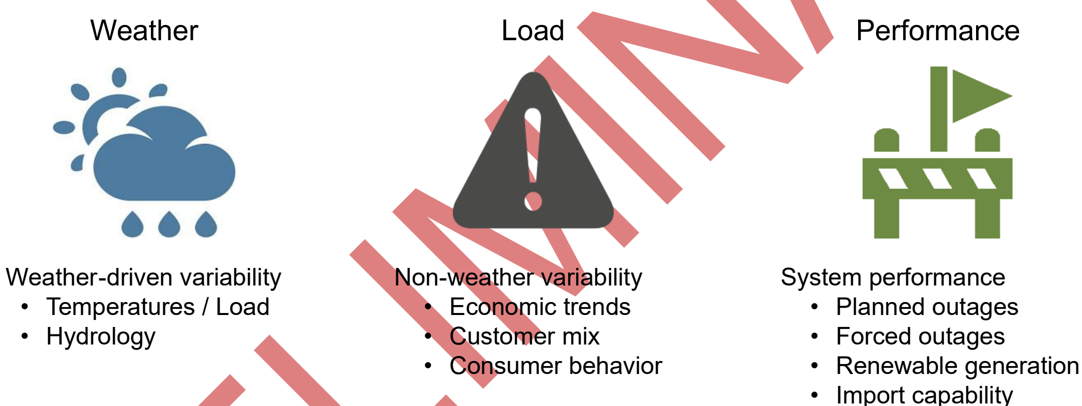

Figure A-3: Reserve Margin Study Elements

While forecasted peak demand for summer and winter is similar, uncertainty and risks vary with the seasons. Weather is a key driver of demand, and the variability of weather during winter is much greater than in summer in TVA's service territory. Generating unit performance also varies by season due largely to ambient temperatures and conditions, and the amount of rainfall. To reliably serve customers, TVA must have sufficient resources to meet the peak demand in both seasons, accounting for changes in weather, generating unit availability, and other factors. Additional information on the reserve margin study can be found in Appendix D – Key Modeling Assumptions.

Based on the last reserve margin study, TVA established planning reserve margins for summer and winter that targeted industry best-practice levels of reliability. TVA's current planning reserve margin is 18% above peak demand requirements in the summer and 26% above peak demand requirements in the winter. Planning reserve margin targets are added to the forecast of electricity demand to derive firm requirements needed to reliably serve the power needs of TVA customers.

Capacity Gap

Simply put, a capacity gap is the difference between projected electricity demand and generating capacity supply. Calculating the capacity gap begins with forecasting baseline firm supply from existing resources, which declines over time due to contract expirations and end of life expectations for existing plants. Then firm capacity requirements, which reflect projected electricity demand plus required planning reserve margins in each season, are compared to capacity supply from existing resources. The difference between the two represents the capacity gap – or the need for incremental power resources, as illustrated below.

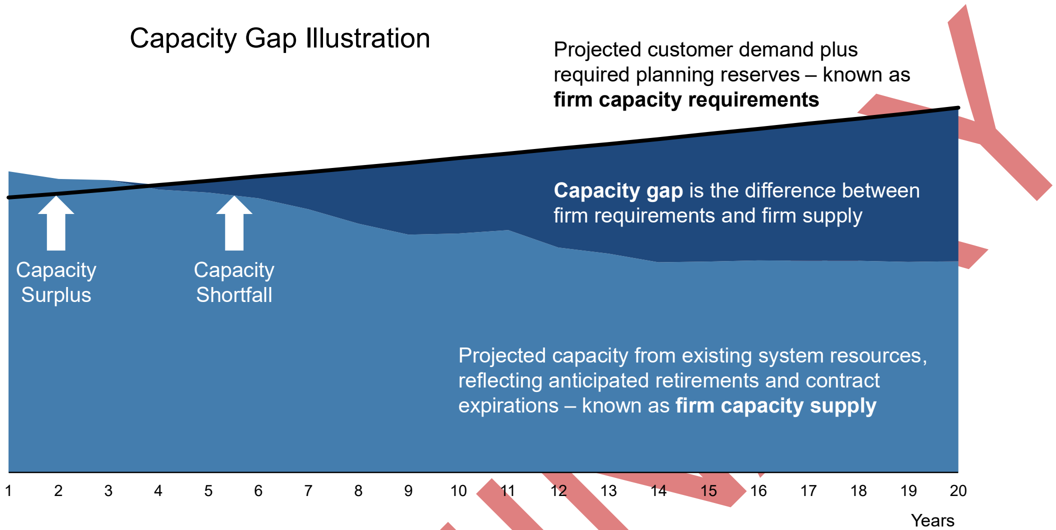

Figure A-4: Capacity Gap Illustration

A.6 Identifying Resource Options

Maintaining the diversity of energy resources is fundamental to TVA's ability to provide affordable, reliable and resilient electric power to Valley residents, businesses and industries. For this reason, and consistent with Section 113 of the Energy Policy Act of 1992, TVA considers the addition of a wide range of supply-side generating resources as well as energy efficiency and other demand-side resource options to fill capacity gaps. TVA's power supply consists of existing TVA-owned resources, existing power purchase agreements, and approved projects such as new plant additions and upgrades to existing assets.

Commodity Price Forecasts

Commodity price forecasts are a key input when evaluating resource options. Commodity prices refer to the price of natural gas, coal, oil, imported electricity, and carbon dioxide (CO_2). The natural gas price forecast represents the market clearing price of a competitive market subject to infrastructure constraints. To create this forecast, TVA uses an industry standard gas model (GPCM) that simultaneously considers data such as pipeline capacity and transportation costs, expected consumption by sector, and cost of supply by basin. The modeling approach starts with near-term market costs, blending into a fundamental forecast driven by the underlying drivers, and also considers other industry forecast benchmarks. Changes in natural gas prices change the variable cost of gas units and may change the economics of different types of gas capacity relative to other resource options. TVA uses another industry standard model (Aurora) to forecast imported electricity prices, considering the interdependency of the gas and electricity markets. CO_2 prices are typically based on current policy and regulations, and alternative scenarios may evaluate potential future regulatory conditions. Higher carbon prices can influence the selection of more carbon-free capacity.

Resource Options

Electric generating assets are generally categorized in two ways – by technology type and by dispatch role. Resource technology type generally refers to fuel source, including nuclear, hydro, coal, natural gas, solar, wind, storage, and demand-side management. Dispatch role refers to whether a resource option is generally used to meet power demands around the clock, through a portion of the day, or during peak demand hours.

Dispatch roles are:

- Baseload: Due to their lower operating costs and high availability, baseload resources are used primarily to provide continuous, reliable power over long periods of uniform demand. Large nuclear plants are a prime example of a baseload resource.
- Variable: Renewable energy sources are variable resources, as generation is available when the sun is shining, the wind is blowing, and the water is flowing. Renewable generation has patterns that can be reasonably forecasted based on historical data and incorporated into resource planning models.
- Intermediate: Intermediate resources are used primarily to fill the gap in generation between baseload and peaking needs. They also provide backup and balance the supply of energy from intermittent wind and solar generation. Natural gas combined cycle units are well suited to an intermediate dispatch role.
- Peaking: Typically used infrequently for short-duration, high demand periods, peaking resources play a key role in maintaining system reliability. For example, natural gas combustion turbines can start up quickly to meet sudden changes in demand or supply. Storage resources serve a similar function but use lower-cost, off-peak electricity to store energy for generation at peak times.

The figure below illustrates how a mix of different resources "stack up" together to help meet system demand over the course of a typical, hot summer day.

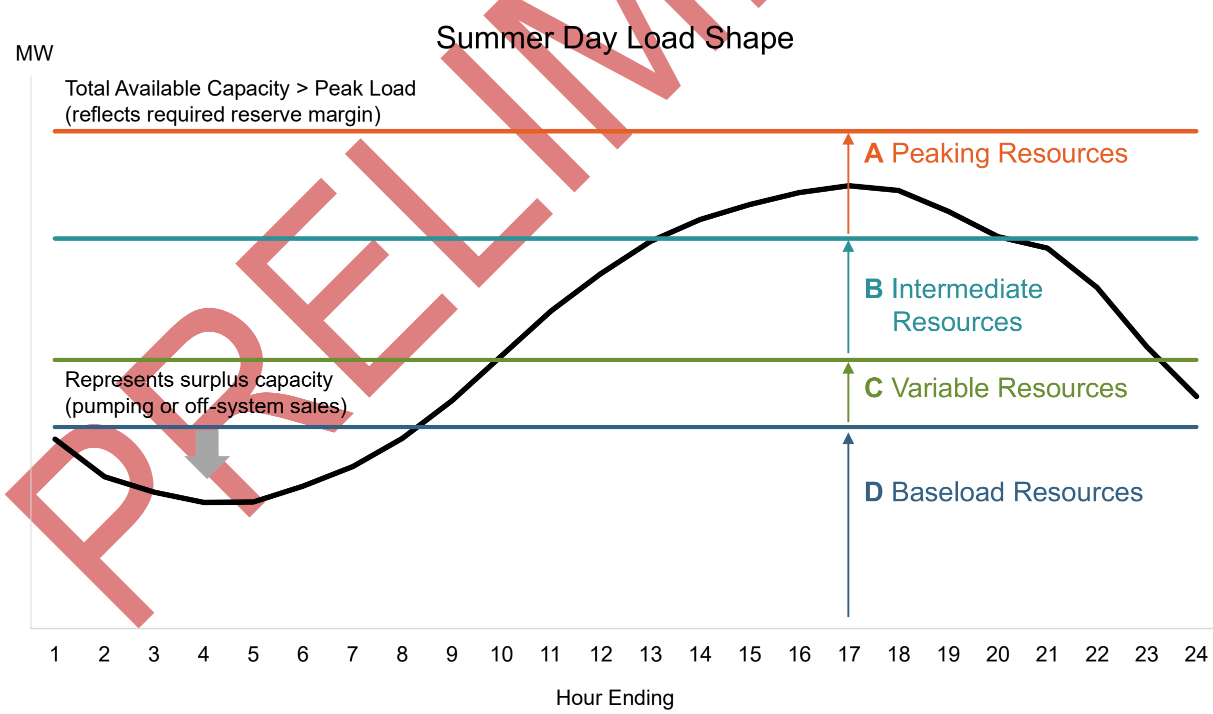

Figure A-5: Illustration of Resource Dispatch Roles

The figure below shows the actual dispatch of the TVA power system on a typical, hot summer day, categorized by resource type. Nuclear provides reliable, low fuel cost, baseload power across the day. Variable resources like hydro, solar, and wind have no fuel cost, but are either limited by water availability, in the case of hydro, or are weather or time dependent, in the case of solar and wind. Excess off-peak generation is stored for later use at peak times. Intermediate resources like natural gas combined cycle units have medium fuel costs, and they can ramp up or down to meet generation needs as electric load changes throughout the day. Peaking resources like natural gas combustion turbine units, which have higher fuel costs, and storage are dispatched for short durations to meet peak demand, and they also provide reserve capacity that can start up quickly if needed.

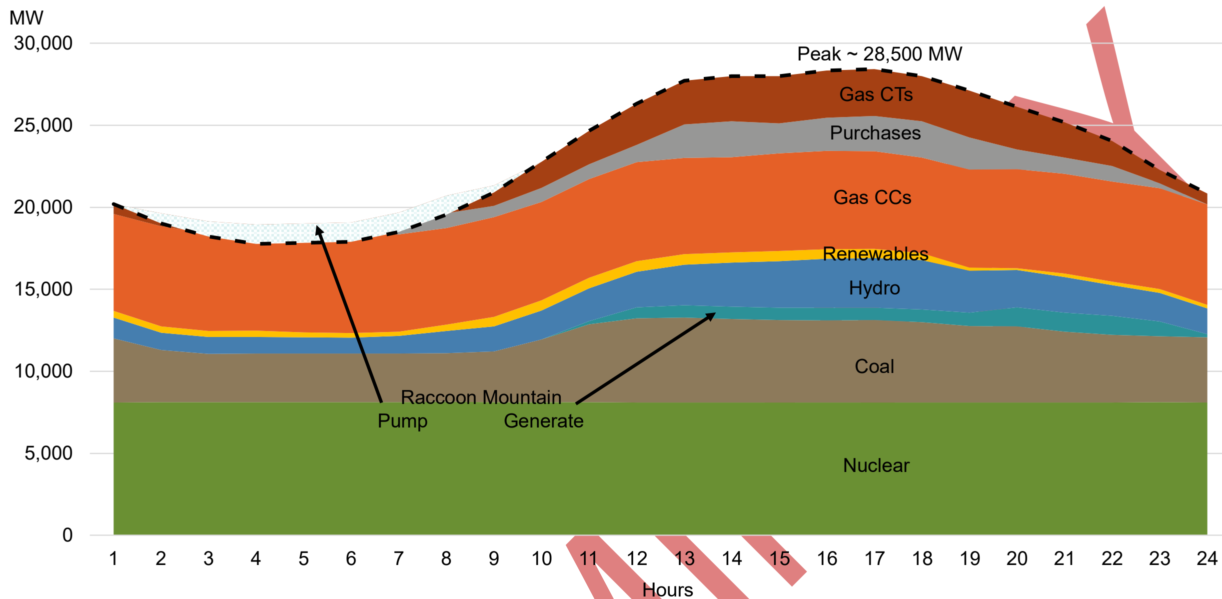

Figure A-6: TVA Power System Dispatch for Typical Hot Summer Day

Resource Characteristics

To objectively compare resource options, it is important to have consistent data regarding the cost and operating characteristics of each option. A description of the characteristics typically used to model resource options is included in the following tables. Additional information on resource costs and characteristics used in the 2026 IRP can be found in Appendix E – Utility Scale Resources Methodology, Appendix F – Distributed Generation Resources Methodology, and Appendix G – Demand-side Resources Methodology.

Table A-1: Cost Characteristics

Cost Characteristic	Description
Capital expenditures ($/kilowatt [kW])	Capital expenditures represent the total "overnight" costs for each project addition, including transmission costs, typically expressed in today's dollars in relation to unit capacity.
Capital escalation rates (%)	Capital costs typically increase over time, escalating at the forecasted rate of inflation. For energy technologies that are rapidly evolving such as solar and battery storage, declining costs for these resources are typically assumed for some period of time.
Construction annual profile	This input represents the allocation of capital spending to construct a project to the years preceding the in-service date, aligned to a typical construction schedule for that resource.
Fixed operating and maintenance costs, or FOM ($/kW-year)	FOM is independent of hours of operation or energy generated, and it includes operating and maintenance labor, plant support equipment, administrative expenses, and regulatory fees. FOM is typically expressed as an annual cost per kW.

Cost Characteristic	Description
Variable operating and maintenance costs, or VOM ($/MWh)	VOM is dependent on hours of operation, and it includes consumables like raw water, chemicals and reagents, and waste and water disposal expenses. VOM is typically expressed in relationship to generation, and it does not include fuel expenses.
Fuel costs ($/million British thermal units [MMBtu])	Fuel is the material consumed to generate electricity, such as uranium, coal, natural gas, and biomass. Fuel costs are expressed in terms of the heat content of the fuel, and they cover the fuel needed for operations, starts, and shutdowns and delivery charges.

Table A-2: Operating Characteristics

Operating Characteristic	Description
Book life (years)	Book life represents the number of years a new resource is expected to be in service for accounting purposes, and it determines the financial payback period and depreciation rate. License extensions beyond original asset life are not assumed with new generating options.
Unit availability (year)	Availability specifies the year a new unit would be available for operation, determined by technical feasibility, commercial availability, and permitting and construction times. For example, if it takes five years to build a new unit, availability would be five years from now.
Annual build limits	Annual limits model the practical ability to construct or procure new resources. Limits are based on recent experience designing, permitting, constructing, and interconnecting new generating assets and procuring new resources through Request for Proposal processes. These should be viewed as long-term, average annual limitations as unique circumstances or future project timing may allow TVA to exceed these limits in some years during implementation of TVA's Asset Strategy.
Net dependable capacity, or firm capacity (MW)	Each unit must have a summer and winter net dependable capacity, which represents the expected output of that unit under summer and winter peak load conditions.
Effective Load Carrying Capability (ELCC) (% of nameplate)	For variable energy resources like solar, wind, and storage, ELCC represents expected output at times of peak demand, expressed as a percentage of nameplate capacity. ELCC decreases as installation amounts of these variable resources increase on the system.
Full load heat rate (Btu/kWh)	Heat rate measures the consumption of fuel required to produce electricity at summer and winter full load conditions.
Annual outage rate (%)	Outage rate represents the percentage of time during the year where service interruptions are likely to occur for planned or unplanned maintenance.
Emissions Rates (lbs/MMBtu)	This input reflects the rate of carbon dioxide, sulfur dioxide, nitrous oxide, and mercury emissions that are released based on fuel usage.

A.7 Producing and Testing Resource Plans

The next step in the planning process is to produce and test resource plans. TVA utilizes an industry-standard model to consider a complex set of assumptions and solve for the lowest cost solution, and then plans are tested using stochastic and sensitivity analysis to evaluate uncertainty and risk.

Producing Resource Plans

TVA uses the EnCompass capacity expansion and production cost simulation package, licensed through Yes Energy, as the primary modeling tool for annual resource planning and IRP analysis. Based on the set of assumptions and constraints in an analysis, the EnCompass model seeks to determine the lowest cost resource plan. Assumptions include forecasts related to electricity demand, commodity prices, environmental regulations, and resource options, while constraints include planning reserve margin, operational limitations, and other factors. The resulting resource plan includes selected resources by year, expected energy output, and financial and operating data. The model can also be used to calculate metrics to inform business decisions. An illustration of how TVA utilizes industry-standard models in resource planning is shown below.

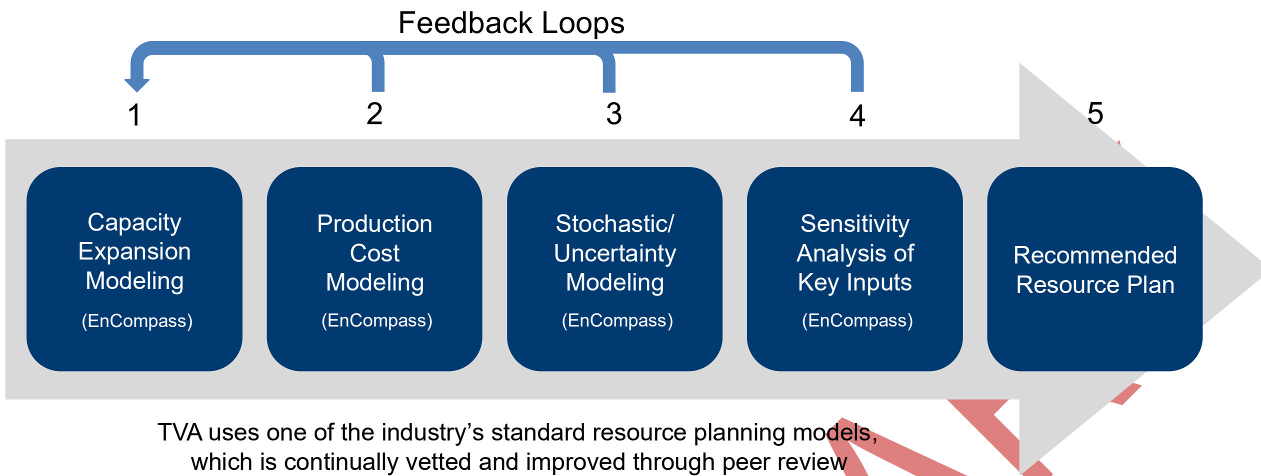

Figure A-7: Industry-standard Models Used in Resource Planning

Based on the assumptions and constraints provided, the model produces the lowest cost resource plan, and it can also help identify other resource plan options to evaluate that may be very similar in cost. Resource plans are not site-specific. They indicate the general type and timing of future resource needs at a system level, sending signals for future site-specific asset evaluations and decisions.

Testing Resource Plans

Fundamental forecasts for key variables, while useful in planning, will inevitably change over time. Variability is due to many factors such as weather, economic cycles, market conditions, supply/demand disruptions, evolving regulations, and technology improvements. Stochastic analysis and sensitivity analysis can provide insights to the impact of changes in key assumptions on resource plans.

Stochastic analysis evaluates the risk of uncertainty around multiple key assumptions and identifies the risk exposure inherent in long-term resource planning. A primary use of stochastic analysis is to quantify financial risk. The first step is to identify the key drivers of portfolio costs associated with electricity demand, fuel and market power prices, generating unit performance, and operating and capital costs. Then, a distribution around the fundamental forecasts for each of the drivers is developed using scalars based on historical variability. The stochastic model uses a Monte Carlo simulation (a form of repeated random sampling) to test the variability of key assumptions and understand the likely range of cost results, allowing for a comparison of financial risk across plans. Stochastic modeling can also be useful in evaluating non-financial risks.

The figure below illustrates a sample output from a stochastic analysis of the Present Value of Revenue Requirements (PVRR), comparing the cost results for two hypothetical portfolios. Where the two colors meet represents the expected PVRR result for each plan. The lighter colored bar to the right represents the potential risk exposure if assumptions change in an unfavorable direction overall, and the darker colored bar to the left represents the potential benefit if assumptions change in a favorable direction overall.

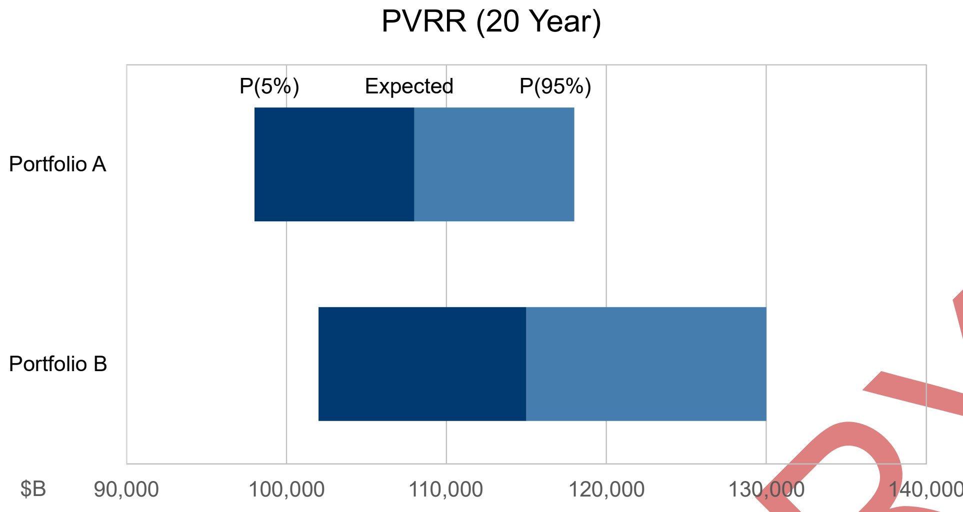

Figure A-8: Illustration of Stochastic Modeling Results

Sensitivity analysis is used in resource planning to isolate impacts of changes in a key assumption. One key assumption is varied at a time to study its impact on the outcome of the resource plan. For example, a sensitivity could be performed on higher natural gas prices to test changes in the resource plans and quantify associated cost risk.

In annual resource planning, TVA typically runs sensitivity analyses related to higher and lower natural gas prices, higher and lower electric demand loads, and potential regulatory changes. Stochastic analysis of the variability of loads and natural gas prices informs the changes modeled in those key assumptions. Exploring the impacts of changes in many or certain key assumptions through stochastic and sensitivity analyses provides insights that can be used in making business decisions.

A.8 Analyzing Business Decisions

Resource plans are useful tools to inform business decisions such as asset needs and strategic investments in transmission and developing technologies. As illustrated below, planning is an iterative process, evolving with tactical experience and market signals. The first five to 10 years of a long-term plan are more tactical, as there is more certainty in forecasts and available resource options. Beyond 10 years is more strategic, sending signals for possible future needs as forecasts and technologies evolve. Effective planning helps drive sound, tactical decisions in the near term, while considering system needs, opportunities, and risks in the long term.

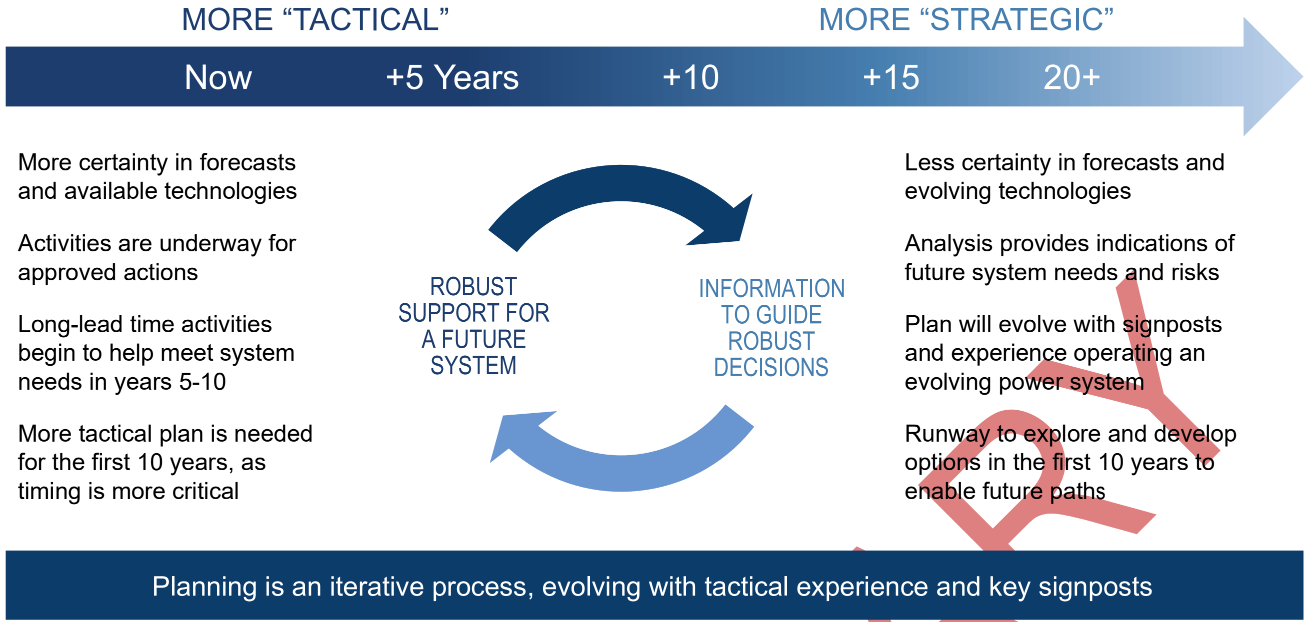

Figure A-9: Resource Planning Continuum

To test and implement strategy, TVA uses a variety of plans with different time horizons and methodologies to address uncertainty. The IRP provides guidance on long-term strategic direction for TVA. For example, the 2019 IRP signaled the need to modernize the existing gas fleet to maintain reliability and enhance system flexibility. TVA's long-term plans or annual planning processes are more specific and begin to signal build and end of life dates as they are identified. Business plans are used to establish and monitor near-term actions and targets. Environmental reviews are performed in accordance with NEPA to evaluate site-specific project options. The figure below demonstrates how each plan varies in purpose and certainty.

To develop and implement resource strategy, TVA uses a variety of plans with different time horizons, purposes, methodologies, and levels of uncertainty that increase with time.

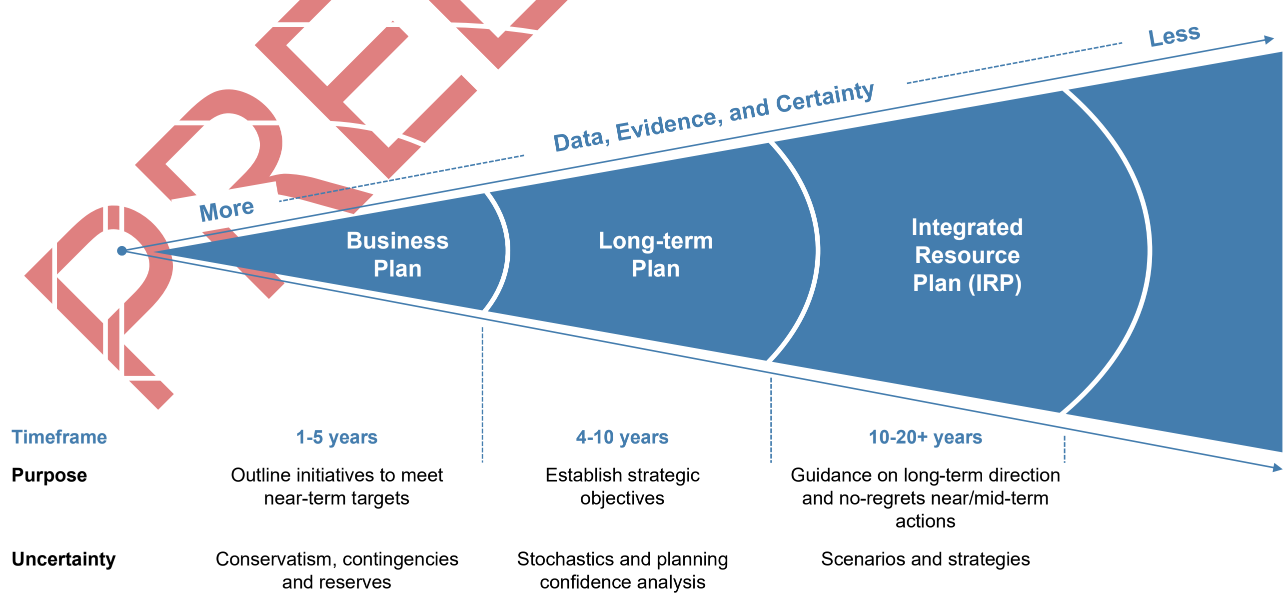

Figure A-10: Planning Horizons and Uncertainty

The IRP looks out 20-plus years and provides guidance on long-term strategic direction. The IRP establishes Board-approved guardrails for changes in the power supply mix and recommended near- to mid-term actions. Long-term plans, such as annual resource plan updates, leverage IRP direction and are used to initiate evaluations of specific asset needs, strategic investments, and associated environmental reviews. Business plans are used to outline initiatives to meet near-term targets that support strategic objectives.

B

Appendix B – Scenario Design and Forecasts

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Appendix B – Scenario Design and Forecasts

Generally defined, scenarios are a future world in which TVA may find itself operating. They are driven by factors outside of TVA's control but to which TVA must be prepared to respond. In the scenarios, key uncertainties were varied, such as electricity demand, environmental policy and regulations, macro-economic trends, and other factors. TVA strove for a set of possible futures to evaluate that are relevant, informative, and diverse. This appendix covers the details of scenario design and forecasts of key variables. Appendix A includes additional details on integrated resource planning fundamentals.

B.1 Scenario Development

The IRP analysis includes three distinct scenarios, focusing on how the future might be shaped by changes in key uncertainties such as economic trends, electricity demand, U.S. energy policy, and technology advancements. Scenario development sought to ensure that the scenarios:

- Reflected a possible future in which TVA might be operating between now and 2050
- Was unique from the other scenarios being studied
- Provided a robust foundation for analyzing a range of resource selections
- Encompassed the relevant interests of key stakeholders

The three scenarios are as follows:

SCENARIOS

1	**Reference** Represents TVA's current forecast that reflects moderate population, employment, and industrial (primarily data center) growth, weather-normal trends, growing electrification, and increasing efficiencies
2	**High Growth** Reflects a technology-driven increase in U.S. productivity growth that stimulates the national and regional economies, resulting in substantially higher demand for electricity
3	**Carbon Legislation** Reflects the impact of potential future carbon legislation designed to reduce power sector emissions.

Figure B-1: Scenario Narratives

B.2 Varying Uncertainties in Scenario Design

Each scenario represents a fundamentally different potential future. In designing these worlds, forecasted uncertainties were altered to explore a wide range of realistically possible and differentiated futures. For all scenarios, the uncertainties represent a correlated set of variables that combine to create a cohesive forecast. The table below shows how the key uncertainties were varied in the alternative scenarios relative to the Reference for each forecasted uncertainty.

Table B-1: Scenario Key Uncertainties

Scenario Name	Load Forecast	Gas Price Forecast	Carbon Price Assumption
Reference	Base	Base	N/A
High Growth	Higher	Higher	N/A
Carbon Legislation	Lower (higher electricity cost)	Near Base (includes offsetting factors)	Higher (~$50/ton in 2032 increasing to ~$75/ton in 2037

Generally, scenario design began with forecasting broad economic and demographic conditions, which in turn influenced electricity demand and commodity price forecasts. Then, forecasts of potential policy or regulatory changes were developed, which also had the potential to impact electricity demand.

B.3 Economic and Demographic Forecasts

Economic trends in the TVA region are highly correlated to the macroeconomic trends in the U.S. However, the large manufacturing base in the region tends to create potential for greater downward moves during periods of economic slowdown or recession. Similarly, demographic trends reflect this same volatility, where significant shifts in economic conditions directly influence population growth, household formation, and employment levels.

The economic measures utilized in creating the scenarios include:

- U.S. and TVA Region Real Gross Domestic Product
- U.S. Productivity (output per worker hour)
- Gross Domestic Product – Implicit Price Deflator
- Consumer Price Index
- TVA Region Total Population
- TVA Region Working-age Population
- TVA Region Households
- TVA Region Employment

Highlights of key economic forecasts for the scenarios are discussed below.

Gross Domestic Product

Historically, economic growth in the Valley region has an 84% correlation with U.S. economic growth. A key measure of economic growth is Gross Domestic Product (GDP). GDP represents the total monetary value of finished goods and services produced in the nation in a given time period. Movement in factors such as energy prices, productivity, and regulations can influence GDP, and GDP is a primary driver of industrial growth in the TVA region. Each scenario reflects a unique forecast for GDP.

- **Reference**: Reflects short-term volatility in GDP as the Federal Reserve adjusts interest rates to rein in inflation, but real growth in long-term U.S. and TVA region GDP is expected to be about 2%.
- **High Growth**: This scenario reflects a 90% confidence interval around the reference GDP forecast, extrapolated using a Monte Carlo simulation based on the historical variance in U.S. GDP growth over the past 30 years.

- **Carbon Legislation**: Reflects the impacts of potential future decarbonization policies that drive higher electricity prices, which reduces national productivity and TVA's regional cost advantages and results in higher inflation, and a moderately lower national and regional GDP forecast relative to the reference case.

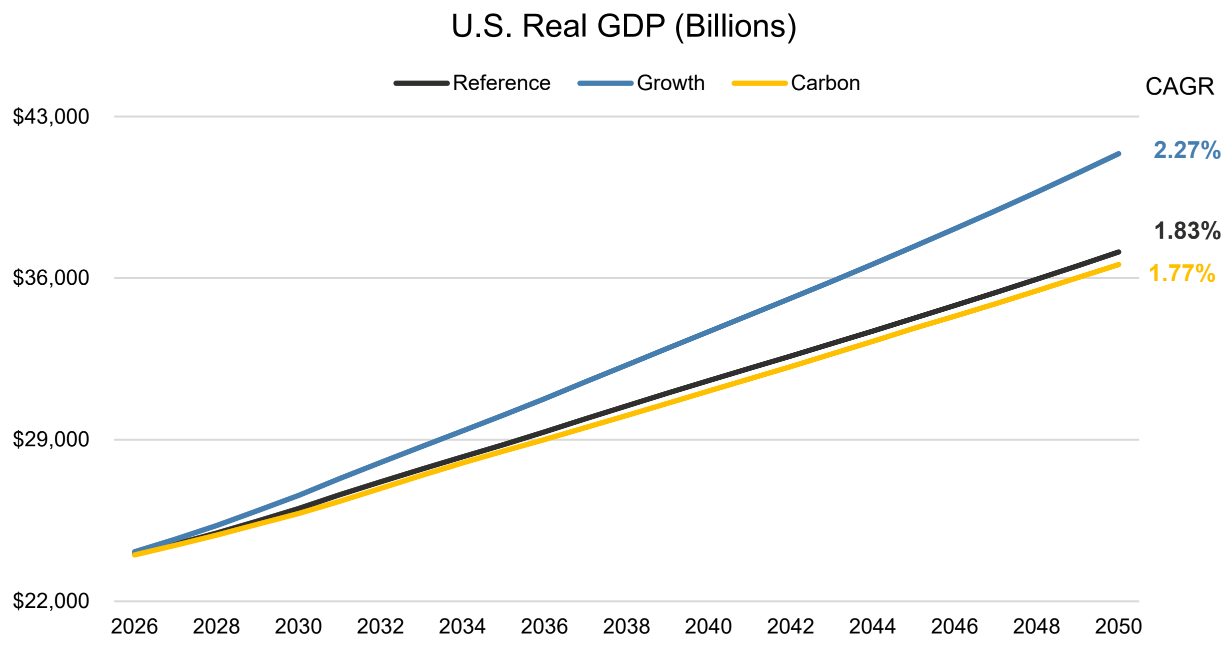

Figure B-2: U.S. GDP Forecasts ($B 2017$)

Inflation

Another key economic measure is inflation, which can be expressed in terms of the U.S. GDP – Implicit Price Deflator. Inflation represents the rate of increase in prices, or decline in the purchasing power of money, over a given period of time. Inflation impacts the outlook for all sectors, including residential, commercial, and industrial. Forecasts for inflation across the scenarios vary, as described below.

- **Reference**: Reflects a return to the long-term Federal Reserve 2% inflation target beginning in 2026.
- **High Growth**: This scenario reflects a 90% confidence interval around the Reference scenario inflation forecast, extrapolated using a Monte Carlo simulation based on the historical variance over the past 30 years.
- **Carbon Legislation**: Reflects efforts to decarbonize the electricity sector, resulting in increased energy prices and generally higher inflation forecasts.

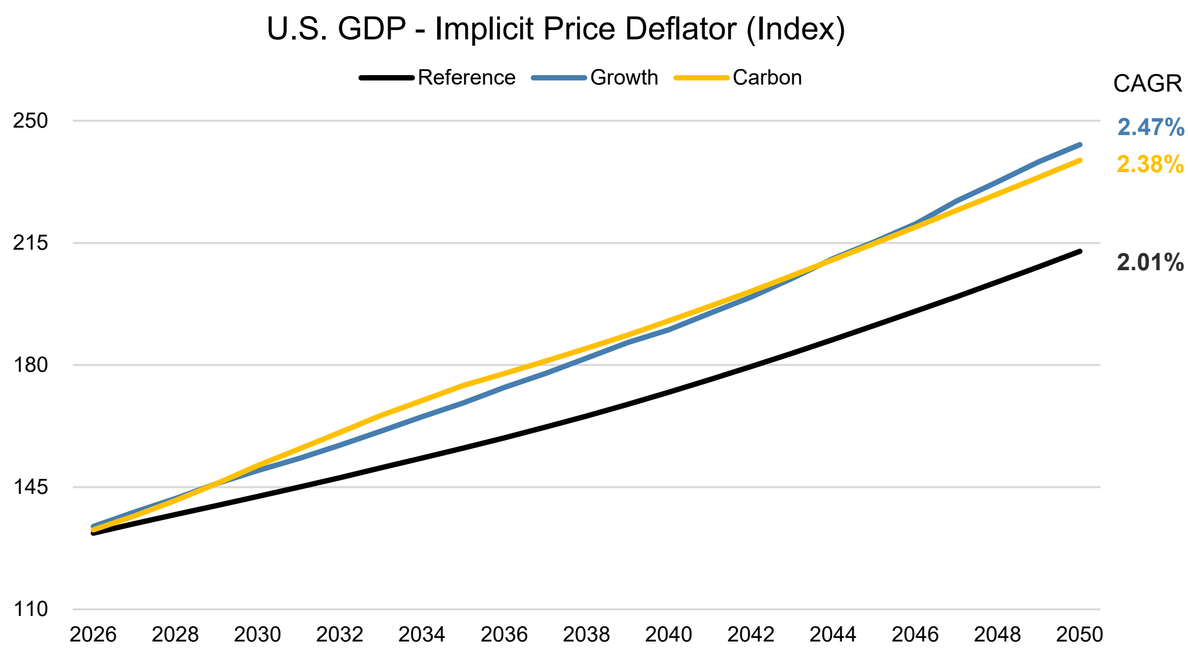

Figure B-3: U.S. GDP – Implicit Price Deflator (Index, 2017 = 100)

TVA Region Demographics

Key regional demographic measures include households and employment. Projected growth in households and employment levels are the primary drivers of local power company load growth in TVA's forecast models. Forecasts for demographics across the scenarios vary, as described below.

- **Reference**: Reflects continued growth in population and household formation, with a near-term boost in the working age population and a decline in household size over time; economic growth and in-migration to the region is anticipated to lift employment levels.
- **High Growth**: This scenario reflects a 90% confidence interval around the Reference scenario forecast for households and employment, extrapolated using a Monte Carlo simulation based on the historical variance over the past 30 years.
- **Carbon Legislation**: Reflects lower productivity growth and higher inflation that results in slower economic growth, which in turn translates into lower growth in households and employment levels.

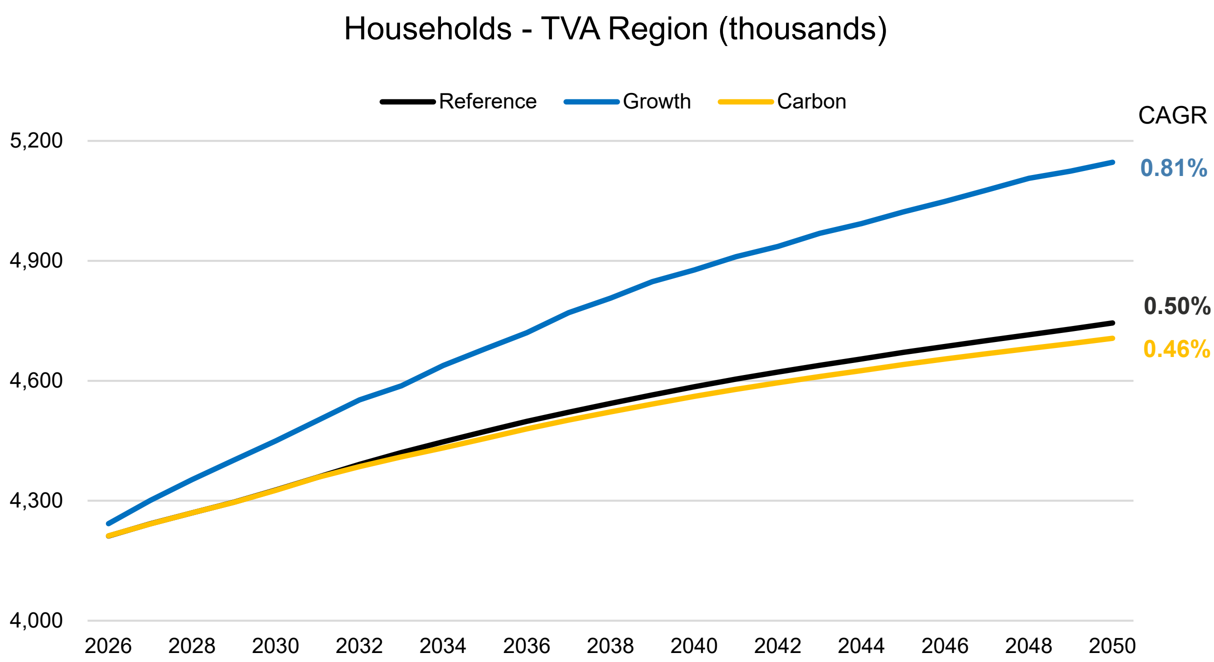

Figure B-4: Households – TVA Region

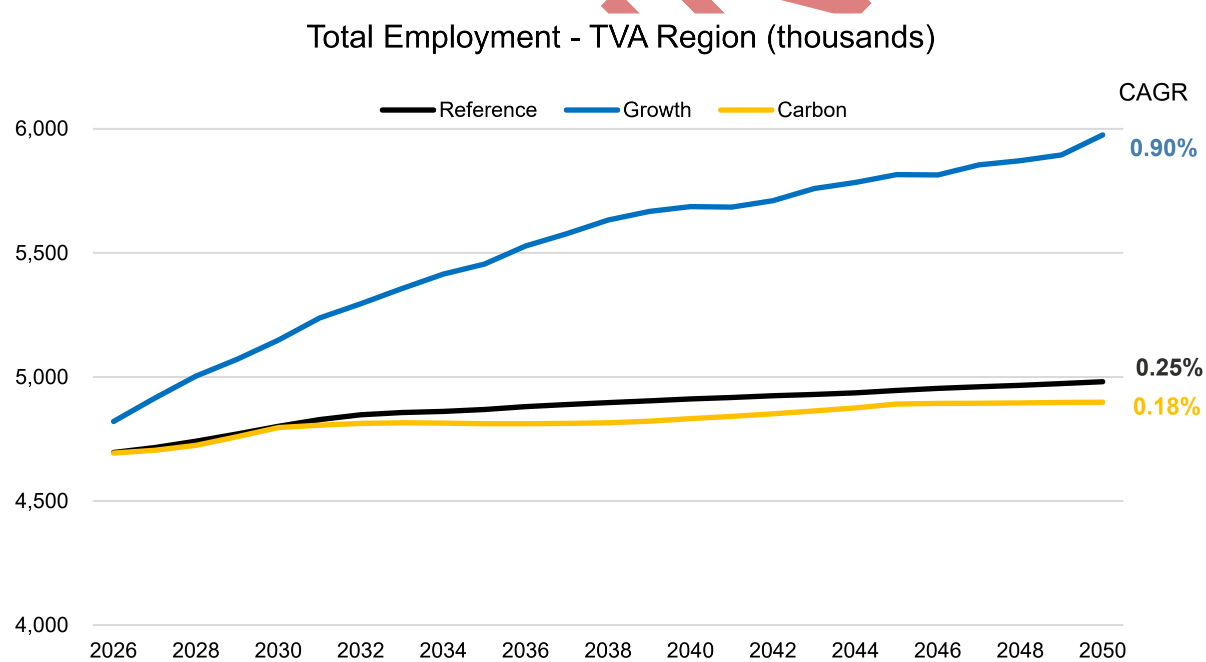

Figure B-5: Total Employment – TVA Region

B.4 Electricity Demand Forecasts

Forecasts for economic conditions and demographics in the region have a direct impact on electricity demand from TVA. The load forecast represents the region's future energy needs under normal weather conditions. In creating load forecasts, TVA uses a number of best-in-class forecasting techniques, including:

- Weather data from stations across the region

- County level economics and demographics
- Residential and commercial end-use intensities and saturations
- Appliance efficiency codes and standards
- Light and medium/heavy duty electric vehicle (EV) adoption with usage data and charging patterns
- Behind-the-meter solar adoption and technical specifications
- Discrete customer forecasts for directly served industrial customers
- Large industrial customer expansions and additions
- Hourly, regional, and customer level load data capturing behavioral patterns, levels, and trends

Trended Weather-Normal Forecasting

Weather is a key driver of electric load. Electricity demand forecasts are typically expressed in terms of normal weather conditions. Normalizing for typical weather conditions allows load forecasters to identify the relationship between trends in electricity demand and long-term drivers, including economic activity, population changes, and climate trends. TVA normalizes the load forecast for weather based on data from 23 weather stations located across the region with proportional load weights. The weather normalization process accounts for regional trends that show an increase in Cooling Degree Days (CDD) and a decrease in Heating Degree Days (HDD) over the period from 1960 to 2020. CDD and HDD represent the total number of degrees above 65°F or below 65°F, respectively, across all days for a given period, which drives space conditioning needs. This trend is incorporated in all IRP scenarios.

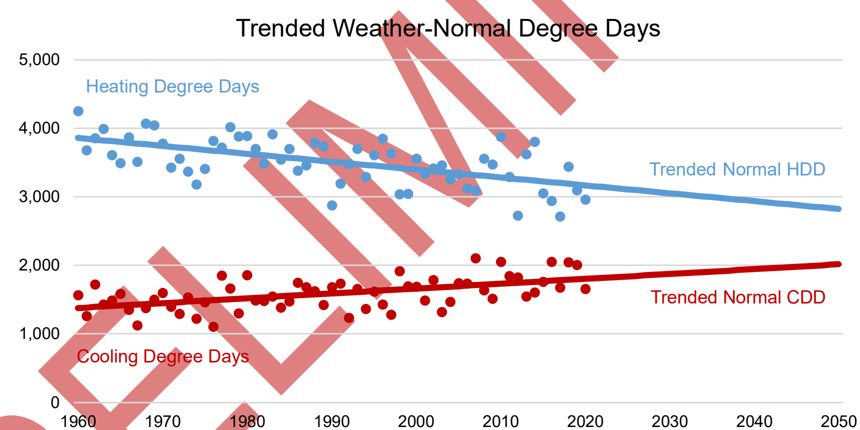

Figure B-6: Trended Weather-Normal Load Forecasting (Degree Days)

Load Forecast

Utilizing the data elements listed above combined with trended weather-normal expectations, TVA developed a load forecast for each of the modeled scenarios. These forecasts included annual expectations for energy and peak demand and hourly projections for 2026-2050. Load forecasts vary across scenarios, as described below. Additionally, TVA performed two sensitivities, “Low Growth” and “Supercharged Growth” to simulate potential upper and lower bounds of load growth, which are also displayed on the figure using dashed lines.

- **Reference**: After a decade of flat loads followed by post-pandemic growth, TVA expects moderate load growth of 0.8% on average per year driven by higher employment and population forecasts, industrial expansions and additions, data centers, and electrification adoption across all sectors. Increasing efficiency standards and behind-the-meter solar adoption had a slightly moderating effect on load growth.

- **High Growth**: In the High Growth scenario a technology-driven increase in U.S. productivity growth stimulates the national and regional economies, resulting in a higher load growth of 1.4% on average per year. This higher load growth encompasses higher demand for electricity across all customer segments.
- **Carbon Legislation**: This scenario foresees legislation assigning a cost for CO_2 emissions in the electricity sector via a carbon tax, which is the primary motivation for load changes in this case. As a result of this tax, higher national electricity costs impact economic growth, natural adoption of energy efficiency, and potential for fuel-switching which dampens load growth to a rate of 0.5% on average per year.

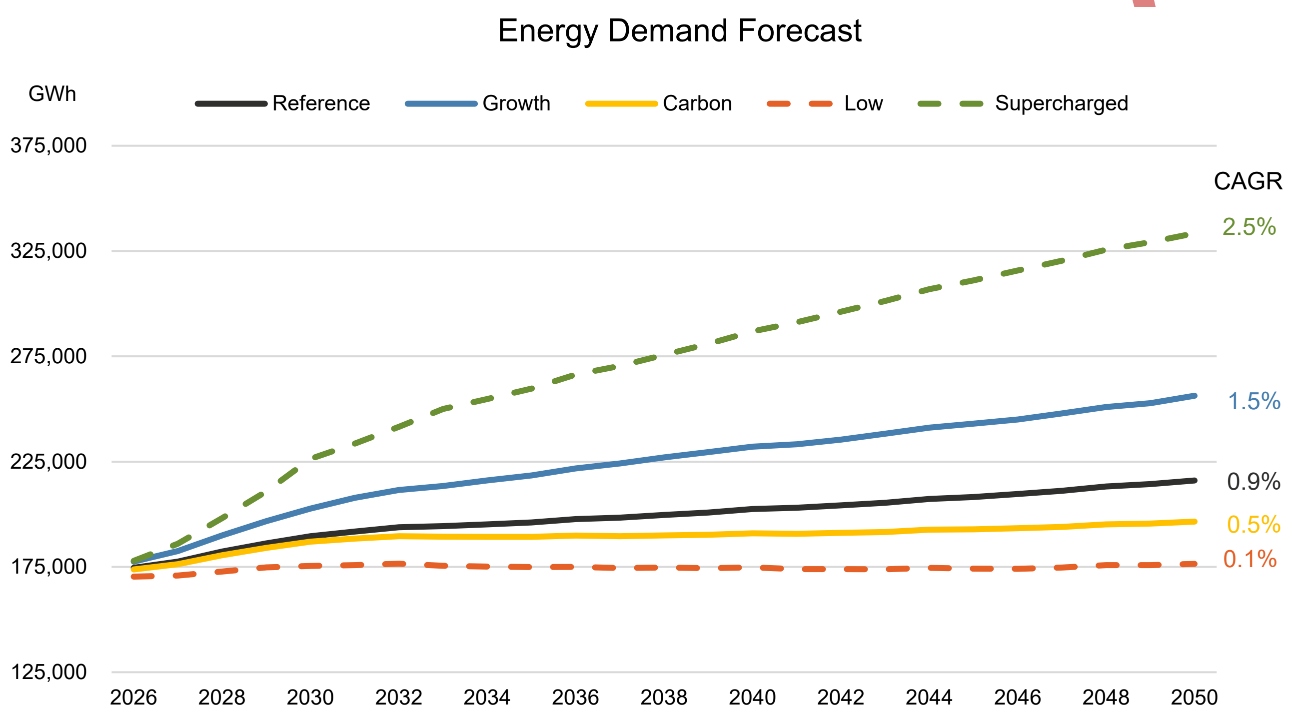

Figure B-7: Energy Demand Comparison of IRP Scenarios and Load Growth Sensitivities

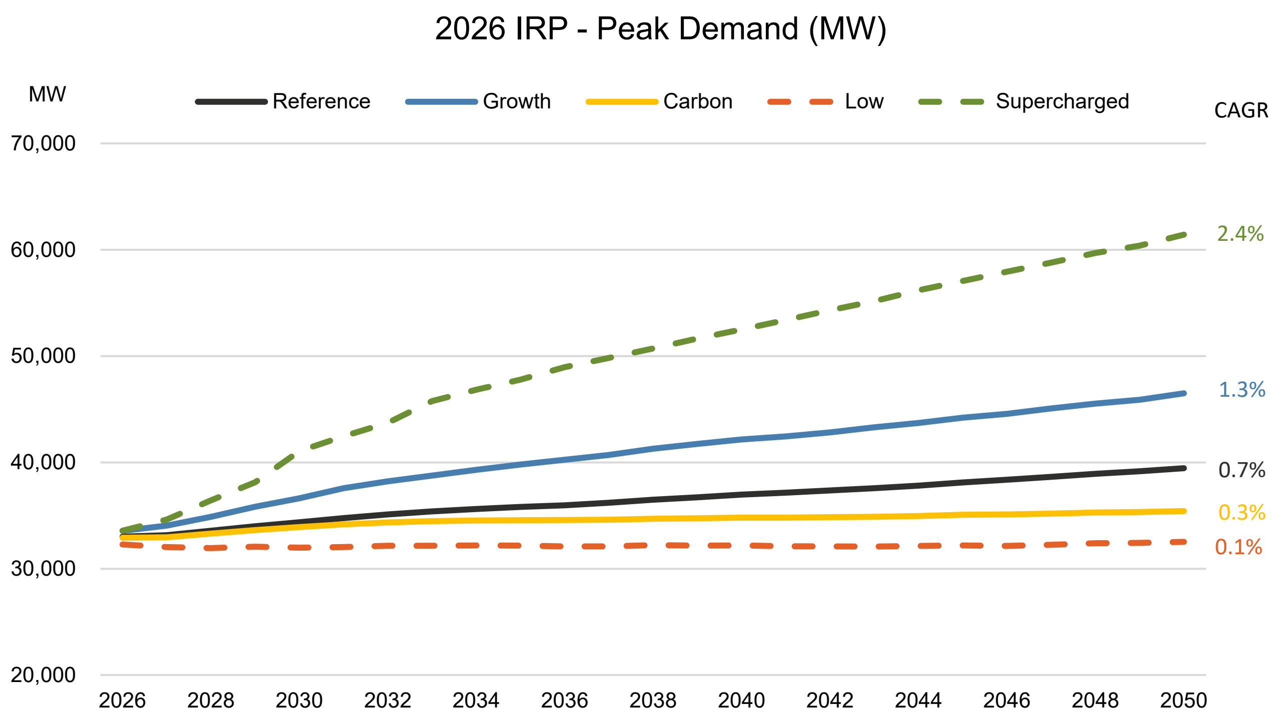

Figure B-8: Forecasted Annual Peak Demand

Load Forecast Tables

The following tables provide energy and peak demand forecasts by year for all scenarios:

Table B-2: Scenario Energy Demand Forecasts (GWh)

Year	Reference	High Growth	Carbon Legislation
2026	174,586	177,529	173,803
2027	177,497	182,556	176,267
2028	182,265	189,969	180,566
2029	186,141	196,743	184,019
2030	189,550	202,737	186,990
2031	191,788	207,818	188,445
2032	193,838	211,521	189,601
2033	194,389	213,442	189,361
2034	195,189	216,050	189,281
2035	196,088	218,414	189,251
2036	197,704	221,809	189,902
2037	198,389	224,119	189,609
2038	199,677	226,988	189,954
2039	200,843	229,540	190,247
2040	202,461	232,109	190,950
2041	203,064	233,240	190,755
2042	204,249	235,412	191,173

Year	Reference	High Growth	Carbon Legislation
2043	205,450	238,222	191,594
2044	207,288	241,104	192,679
2045	208,157	242,998	192,818
2046	209,635	245,024	193,345
2047	211,135	247,855	193,968
2048	213,198	250,923	195,187
2049	214,307	252,755	195,552
2050	216,047	256,278	196,517
CAGR	0.9%	1.5%	0.5%

Table B-3: Scenario Seasonal Peak Demand Forecasts (MW)

Year	Reference		High Growth		Carbon Legislation	
	Winter	Summer	Winter	Summer	Winter	Summer
2026	33,014	32,776	33,559	32,776	32,913	32,133
2027	33,151	32,681	34,055	33,580	32,956	32,499
2028	33,570	33,115	34,881	34,414	33,299	32,868
2029	33,988	33,555	35,830	35,351	33,633	33,240
2030	34,363	33,995	36,629	36,204	33,921	33,604
2031	34,764	34,438	37,571	37,168	34,174	33,906
2032	35,109	34,830	38,224	37,861	34,351	34,134
2033	35,388	35,151	38,763	38,437	34,477	34,302
2034	35,618	35,431	39,305	39,041	34,538	34,407
2035	35,818	35,717	39,794	39,613	34,564	34,506
2036	35,970	35,971	40,243	40,171	34,548	34,575
2037	36,122	36,202	40,690	40,707	34,519	34,604
2038	36,253	36,496	41,094	41,282	34,487	34,705
2039	36,386	36,711	41,462	41,734	34,477	34,741
2040	36,486	36,972	41,694	42,160	34,427	34,808
2041	36,585	37,153	41,901	42,445	34,388	34,810
2042	36,745	37,361	42,226	42,815	34,429	34,853
2043	36,854	37,570	42,609	43,308	34,432	34,880
2044	37,104	37,811	43,042	43,714	34,579	34,950
2045	37,288	38,109	43,408	44,210	34,644	35,076
2046	37,501	38,366	43,698	44,565	34,720	35,114
2047	37,702	38,637	44,144	45,080	34,792	35,179
2048	37,977	38,929	44,587	45,529	34,956	35,280
2049	38,138	39,161	44,870	45,889	35,023	35,330
2050	38,538	39,451	45,606	46,498	35,319	35,423
CAGR	0.6%	0.8%	1.2%	1.4%	0.3%	0.4%

B.5 Commodity Price Forecasts

Another key element in scenario design is the forecast for commodity prices. For the IRP, commodity price forecasts were developed for natural gas, coal, and wholesale market power prices. These forecasts represent significant uncertainties that TVA will face, and they can vary significantly by scenario.

Natural Gas Prices

Natural gas is an important fuel source for U.S. power generation, and it is also exported to other countries. Forecasts for gas prices are driven by many factors, such as supply and demand, inflation, and export volumes. TVA also performed two sensitivities "Low Gas" and "High Gas" that represent the upper and lower bounds of natural gas prices that can be reasonably expected. For additional information on how commodity prices are forecasted, refer to Appendix A, section A.6.

- **Reference**: Industrial demand and growing export volumes are the primary drivers of nominal natural gas price increases in this scenario, while prices adjusted for inflation remain relatively stable.
- **Higher Growth**: All things being equal, increases in economic activity will lead to increases in demand for energy of all types. This scenario evaluates a higher gas price environment driven by substantial economic growth.
- **Carbon Legislation**: A carbon tax leads to a slight increase in natural gas demand over as utilities utilize more natural gas-fired generation to replace coal fired generation. Higher gas demand and higher levels of inflation relative to the reference case lead to higher nominal gas prices in this scenario.

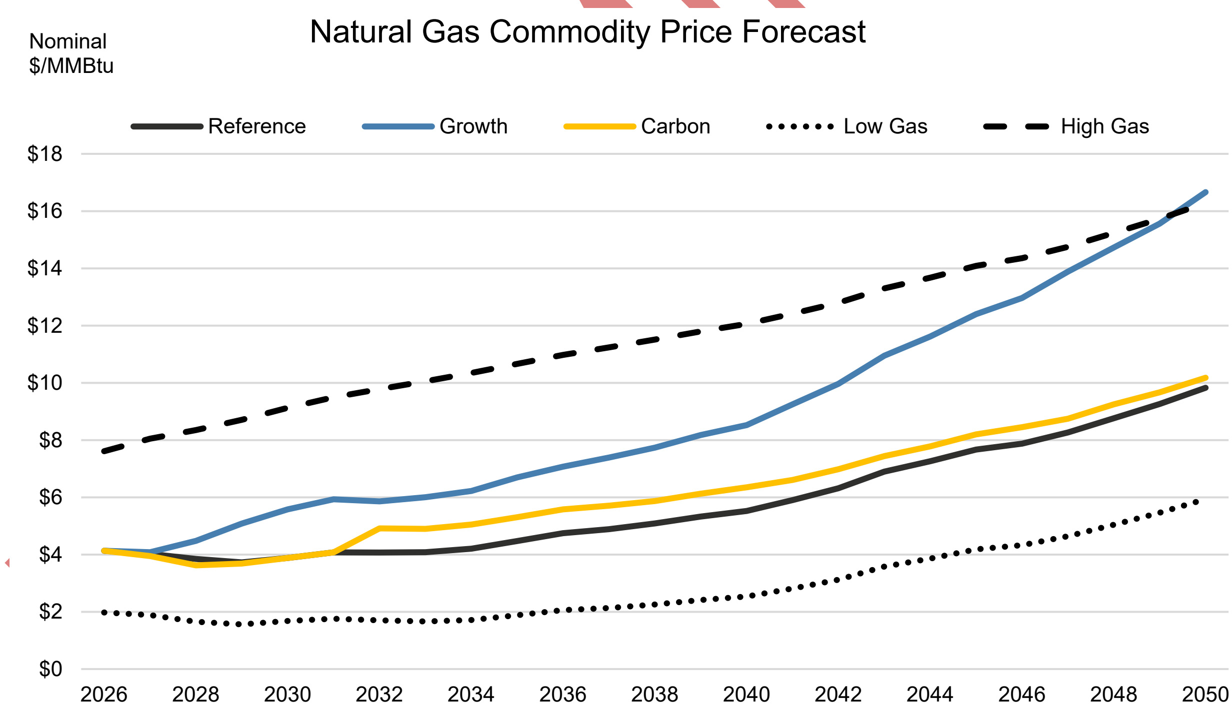

Figure B-9: Natural Gas Price Forecast – Scenario and Sensitivity Ranges

Wholesale Market Power Prices

Wholesale market power prices are an important input and a key uncertainty in scenario modeling. These prices represent the forecasted price TVA would pay to purchase power from neighboring utilities on the spot market. Annual trends in market power prices are largely a function of the price of natural gas, as natural gas-fired generation is frequently the marginal generator that sets the price of energy on the market.

- **Reference**: The trend in market power prices mirrors the trend in natural gas prices in this scenario.
- **Higher Growth**: Higher market power prices are driven by higher gas prices in this scenario.
- **Carbon Legislation**: A carbon tax leads to a slight increase in natural gas demand as utilities utilize more natural gas-fired generation to replace coal fired generation. Higher gas demand and higher levels of inflation relative to the reference case lead to higher market power prices

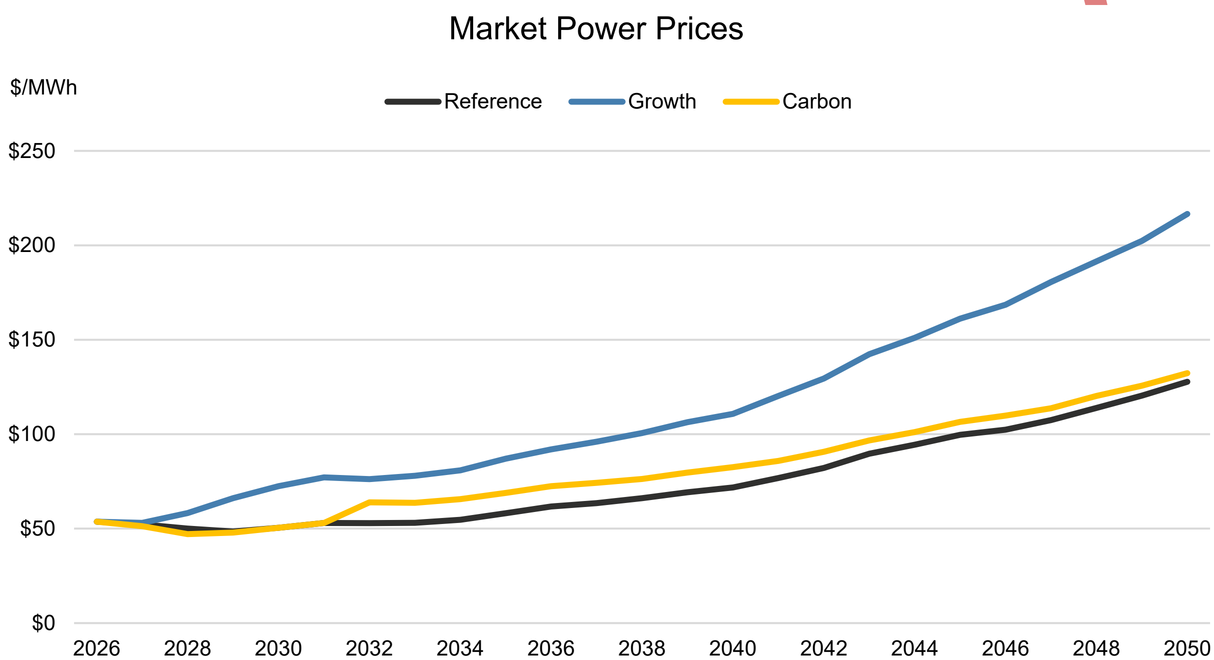

Figure B-10: Forecasted Market Power Prices, Annual Average All Hours

Coal Prices

Forecasted prices for coal varied across the IRP scenarios, primarily driven by projections for load growth and inflation.

- **Reference (without GHG Rule)**: This reference case forecast for both ILB and PRB coal prices is relatively stable throughout the forecast period.
- **Higher Growth**: The relatively higher load in this scenario drives a higher coal price forecast.
- **Carbon Legislation**: Stricter national regulations on CO_2 emissions drive coal prices lower as demand for coal falls in this scenario. Higher levels of inflation increase nominal prices over time.

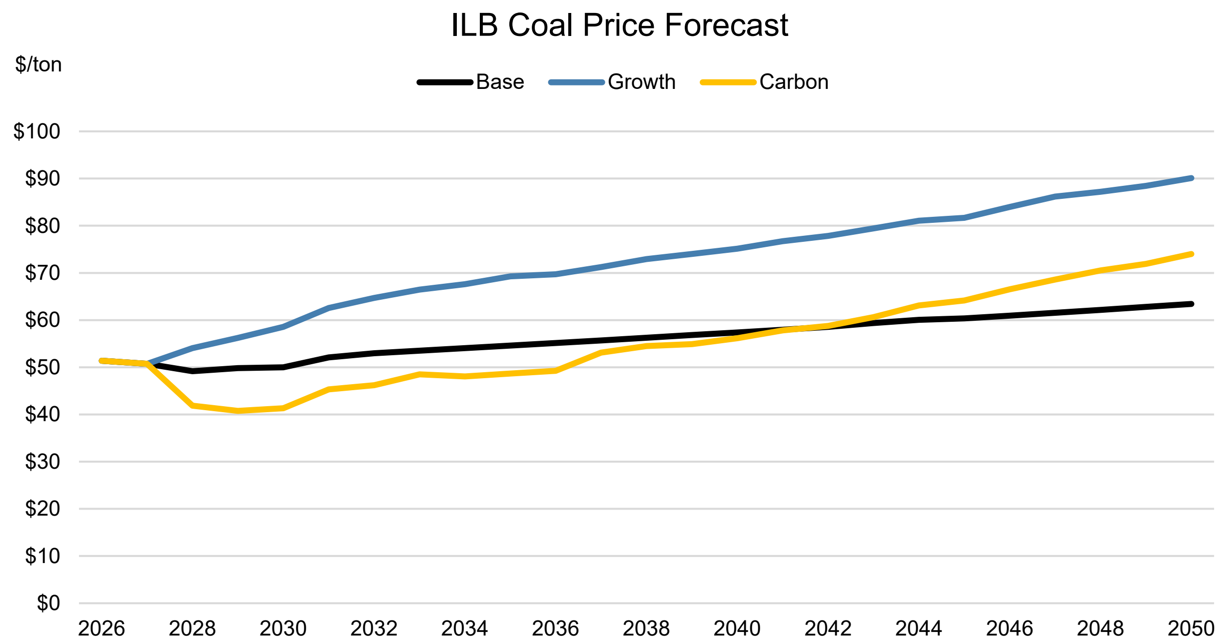

Figure B-11: Forecasted Illinois Basin (ILB) Coal Prices

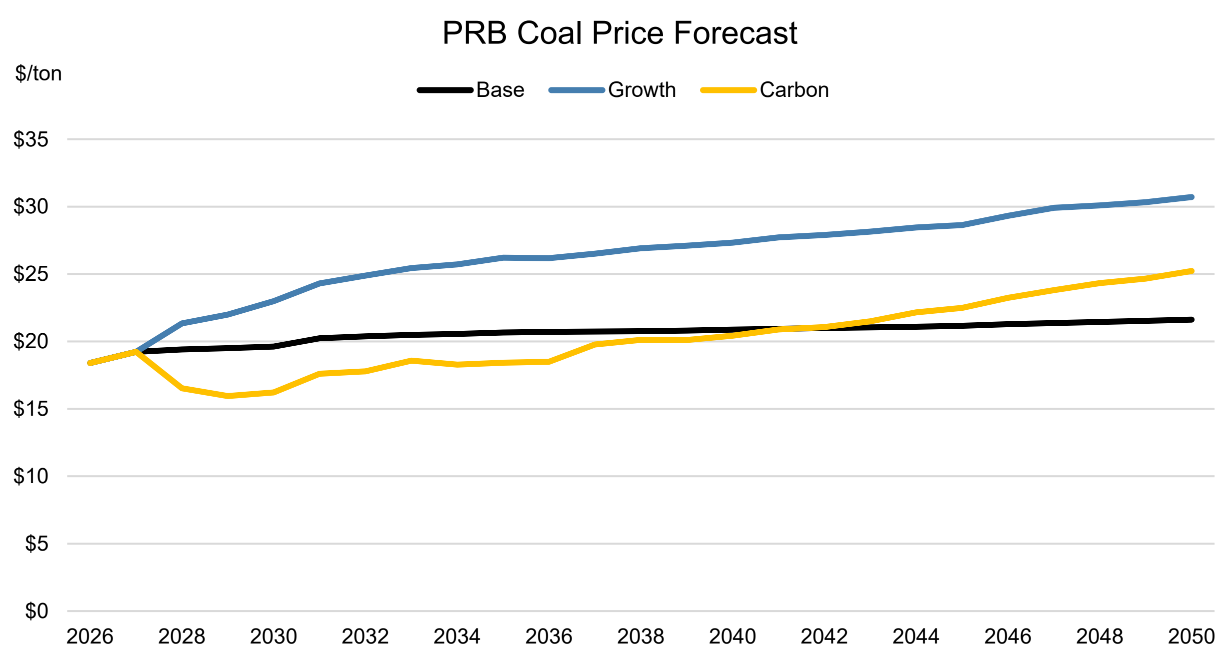

Figure B-12: Forecasted Powder River Basin (PRB) Coal Prices

Nuclear Fuel Prices

TVA's nuclear fuel is obtained predominantly through long-term uranium concentrate supply contracts, contracted conversion services, contracted enrichment services, or a combination thereof, and contracted fuel fabrication services. The supply markets for uranium concentrates and certain nuclear fuel services are subject to price fluctuations and availability restrictions. Nuclear fuel prices used across the IRP scenarios are based on TVA's existing supply contracts and may differ from current supply market conditions. As these contracts are commercially sensitive, nuclear fuel price assumptions are not included in this appendix.

B.6 Regulatory Forecasts

The changing U.S. energy policy landscape represented another key uncertainty in scenario design. All IRP scenarios reflect the impacts of the One, Big, Beautiful Bill Act (OBBB) on resource costs and national and regional energy prices. Additionally, Scenario 3 (Carbon Legislation) includes a forecasted carbon tax to serve as a proxy for current and potential future legislation and/or regulatory actions seeking to reduce greenhouse gas emissions.

One, Big, Beautiful Bill Act (OBBB)

OBBB included updates to investment tax credit (ITC) opportunities available for renewable, storage, and nuclear resources. The figure below shows the level of ITC assumed in the IRP modeling of scenarios and resource cost assumptions. TVA generally assumed a 30% ITC for nuclear, renewable, and storage resources with phaseouts based on commercial operations date (COD), or in-service date, as illustrated in the chart below. The OBBB allows up to a 50% ITC if wage and apprenticeship standards, domestic content guidelines, and siting criteria (in an energy or low-income community) are met. To account for potential cost increases to meet requirements, siting challenges, and other risk factors, the IRP analysis applies a 30% ITC. TVA will seek to maximize ITC value on a project-specific basis during the implementation of future applicable projects.

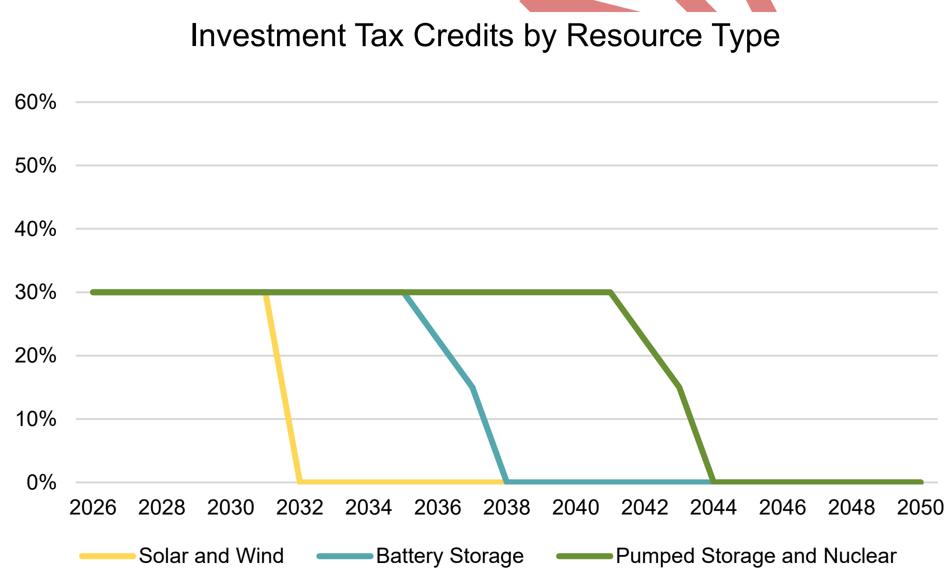

Figure B-13: Investment Tax Credits by Resource Type and Commercial Operations Date

Carbon Tax

Over the past several decades, a number of legislative proposals have been made and regulatory actions undertaken in an effort to reduce greenhouse gas emissions from the electric power sector, such as the Clean Power Plan and Greenhouse Gas Rule. While recent actions have been undertaken to repeal or revise these rules and provide regulatory relief, utilities must still account for the possibility that current regulatory efforts are stalled or new legislation or regulatory actions will be taken in the future. To account for this, Scenario 3 - Carbon Legislation includes a forecasted carbon tax to serve as a proxy for current and potential future legislation and/or regulatory actions seeking to reduce greenhouse gas emissions. The carbon tax assumptions used in the Carbon Legislation scenario are not based on any specific forecasts, regulations, or legislative proposals. Rather, the carbon tax forecast uses the same trajectory studied in TVA's 2019 IRP (from the Double Decarbonization sensitivity), with adjustments to start in 2032 and ramp-up five years later.

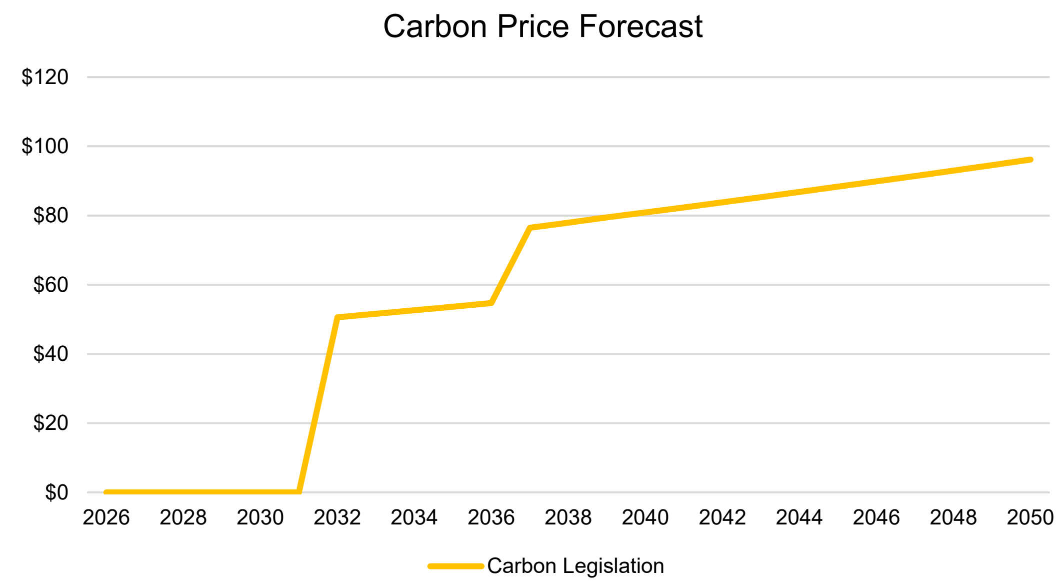

Figure B-14: Forecasted Carbon Tax for Carbon Legislation Scenario (Nominal $/Ton)

TVA

C

Appendix C – Strategy Design and Application

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Appendix C – Strategy Design and Application

The IRP analysis includes three strategies to be evaluated: Baseline Utility Planning, Innovation, and Distributed. Where scenarios describe the potential futures TVA may find itself operating in, strategies depict business approaches TVA could employ to meet energy demand in these future worlds. The IRP analysis compares baseline utility planning with alternative strategies that emphasize certain resource types to evaluate tradeoffs. This appendix covers the details of strategy design and how they were applied in the analysis.

C.1 Strategy Narrative Development

Baseline Utility Planning represents fundamental least-cost planning, and all strategies apply a planning reserve margin to provide sufficient resources to account for variations in load and generating unit availability. The alternative strategies emphasize specific themes – from promotion of new nuclear to an emphasis on distributed energy resources such as battery storage, renewables, and demand side programs.

STRATEGIES

A	**Baseline Utility Planning** Represents TVA's current outlook based on least-cost planning, incorporating existing programs and a planning reserve margin target. This reserve margin target applies in all strategies
B	**Innovation** Emphasizes emerging, firm and dispatchable technologies such asadvanced nuclear and long-duration storage through innovation, continued R&D, and partnerships.
C	**Distributed** Emphasizes distributed technologies such as batteries, renewables, and demand-side programs to reduce reliance on central station generation and utilize virtual power plants

Figure C-1: Strategy Narratives

Strategy A: Baseline Utility Planning

Baseline Utility Planning represents fundamental least-cost planning. No specific resource types are emphasized beyond existing programs. Resources are modeled and chosen economically to meet the reserve margin constraint for reliability. Planning reserve margins are included for both summer and winter peak seasons, and they apply in all strategies. These targets are developed separately from the IRP and employ an industry best-practice 1-in-10-year loss-of-load expectation level of reliability (see Appendix D – Key Modeling Assumptions for more information on planning reserve margins).

Strategy B: Innovation

Under the Innovation strategy, TVA focuses on developing emerging technologies that are firm and dispatchable, meaning that they can be reliably and predictably turned on and off to meet demand. These technologies include advanced nuclear and long duration storage. Under this strategy, TVA would increase efforts in research and development to advance and deploy these new technologies. This could be executed through partnerships with the federal government or other organizations, such as universities, research labs, and startups, to share resources and expertise.

Strategy C: Distributed

The Distributed strategy emphasizes resources that are more geographically dispersed in nature, both at utility and distribution scale. At the utility scale, this strategy would emphasize battery storage and smaller natural gas generators, such as aeroderivative combustion turbines and reciprocating internal combustion engines, which are more modular and can be sized and adapted to meet both local and system needs. This strategy also emphasizes utility scale solar where individual solar farms are often smaller in capacity compared to traditional thermal generation and are therefore more distributed across the service territory. Finally, this strategy includes increased incentives to encourage customers to install distributed generation and participate in demand-side management (DSM) programs. Distributed generation includes distributed solar and storage while DSM options include energy efficiency and demand response programs. This strategy would require the use of existing and potentially expanded customer partnerships and programmatic solutions to increase uptake of these distributed resources. Program design would need to ensure that the incentive structure is balanced and fair, so that it does not disrupt grid reliability or lead to higher costs for other non-participating customers.

C.2 Strategy Design and Evaluation

The IRP analysis compared Baseline Utility Planning with the alternative strategies to evaluate tradeoffs based on least-cost planning principles. At a high level, the steps in the strategy design and evaluation process were:

- Develop Baseline Utility Planning cases for all scenarios (no resources promoted)
- Identify emphasis of resource types to achieve objectives in each strategy
- Run cases with resource emphases for alternative strategies in all scenarios
- Evaluate tradeoffs across all scenarios and strategies using metrics based on planning principles

All resource options were available to be selected in each strategy, including those with no emphasis, allowing the model to select and optimize the resource portfolio from the full suite of available resources.

C.3 Resource Emphasis

Required minimum additions is the modeling mechanism used to apply emphasis in the strategy design of this IRP. Minimum amounts can be defined by either required annual additions or a total required addition amount by a specified date.

C.3.1 Strategy Design Matrix

A strategy design matrix was developed to indicate the levels of emphasis for resource types within each strategy. Each resource was assigned either base (no promotion) or emphasize (promotion) to drive differentiation across the strategies.

The Strategy Design Matrix below provided the roadmap for how resource emphasis was applied in the strategies. Resource types are shown across the top, grouped by utility scale and distributed and demand-side, and the rows indicate the emphasis level by resource for each strategy. This matrix begins to translate the strategy narratives into a plan for modeling. All resource types were available for selection in all strategies.

STRATEGY	UTILITY-SCALE RESOURCES							DISTRIBUTED AND DEMAND-SIDE RESOURCES			
	Nuclear	Coal	Gas CC and Frame CT	Aero CTs and RICE	Renewables	Battery Storage	Long-duration Storage	Distributed Solar	Distributed Storage	Energy Efficiency	Demand Response
A Baseline	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base	Base
B Innovation	Emphasize	Base	Base	Base	Base	Base	Emphasize	Base	Base	Base	Emphasize
C Distributed	Base	Base	Base	Emphasize	Emphasize	Emphasize	Base	Emphasize	Emphasize	Emphasize	Emphasize

Figure C-2: Strategy Design Matrix

C.3.2 Promotion Levels for Utility Scale Resources

The figure below outlines the detailed emphasis schemes for utility-scale resources. The model was free to choose volumes above the minimum if cost-effective. Additionally, to account for the larger capacity gap in Scenario 2, High Growth, minimum requirements in this scenario were set approximately 25% higher than the values shown in the figure below.

STRATEGY*	Nuclear	Coal	Gas CC and Frame CT	Aero CT and RICE	Renewables	Battery Storage	Long-Duration Storage
A Baseline Utility Planning	Base	Base	Base	Base	Base	Base	Base
B Innovation	Emphasize 3,400 MW by 2040	Base	Base	Base	Base	Base	Emphasize 1,200 MW by 2040
C Distributed	Base	Base	Base	Emphasize 1 GW by 2040	Emphasize 400 MW/yr solar minimum 2031-2050 (8,000 MW)	Emphasize 300 MW/yr minimum 2031-2050 (6,000 MW)	Base

Figure C-2: Strategy Design: Utility Scale Promotion Levels

C.3.3 Promotion Levels for Distributed and Demand-side Resources

The figure below provides the detailed emphasis schemes for distributed and demand-side resources. Distributed storage was modeled at a 15% capacity match to distributed solar at a base level, with a higher capacity match applied for the Distributed strategy. Energy efficiency and demand response are divided into three tiers representing distinct price points and associated volumes. For the Reference and Distributed scenarios, strategic emphasis entailed a minimum annual requirement of Tier 2 of higher volumes, whereas the High Growth scenario increased this requirement to Tier 3 annually.

STRATEGY	Distributed Solar	Distributed Storage	Energy Efficiency	Demand Response
A Baseline Utility Planning	Base	Base: 15% solar capacity match	Base	Base
B Innovation	Base	Base: 15% solar capacity match	Base	Emphasize: Tier 2 or higher required
C Distributed	Emphasize: 100% of the marginal cost incentive	Emphasize: 50% solar capacity match	Emphasize: Tier 2 or higher required	Emphasize: Tier 2 or higher required

Figure C-3: Strategy Design: Distributed and Demand-side Resource Promotion Levels

D

Appendix D – Key Modeling Assumptions

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Appendix D – Key Modeling Assumptions

TVA utilized an industry-standard model for the IRP that applies a planning reserve margin and other key assumptions, forming the modeling framework for the analysis. Other key assumptions included Net Dependable Capacity (NDC) and integration costs for solar and wind resources, flexibility benefits for storage resources, and achievable potential for energy programs. Collectively, these assumptions provided the framework necessary to plan for a reliable system and an actionable set of programs. This appendix discusses recent studies on these topics that informed the key modeling assumptions used in the IRP analysis.

D.1 Planning Reserve Margin Study

D.1.1 Overview and Background

The planning reserve margin is the excess capacity that TVA maintains beyond forecasted peak load to provide reliable service to customers while keeping rates low. Maintaining additional capacity accounts for uncertainty in the amount of load and available generation on a future peak day.

In real time, operating reserve capacity must be large enough to cover the loss of the largest single operating unit (contingency), be able to respond to instantaneous changes in system load (regulating) and be able to replace the largest operating unit should it fail (replacement). A planning reserve margin is the amount of generation capacity above forecasted peak loads that a utility plans to have in the future, which must include the contingency, regulating, and replacement reserves, as well as be sufficient to cover unplanned unit outages, severe weather events, and other variations in load. For example, a reserve margin of 15% means that a utility plans to have dependable peak-day generation equal to 115% of its forecasted future peak load.

TVA has a dual-peaking power system, meaning that peak demand for electricity is roughly the same in winter and in summer. While forecasted peaks are similar, weather and asset performance uncertainties vary by season, so seasonal reserve margins are used to account for this. TVA's planning reserve margins have changed over time as the power system and the load it serves have evolved. The most recent reserve margin study indicates that the primary reliability risk to TVA's system is during the winter months. TVA's current planning reserve margins are 18% during the summer and 26% during the winter.

D.1.2 2024 Reserve Margin Study

TVA conducted a planning reserve margin study in 2024 with the assistance of Astrapé Consulting. Periodically, TVA conducts a study reflecting the latest data on electricity demand and the power system to establish updated planning reserve margin targets. Higher reserve margins increase the reliability of the system but come at a cost, and an effective study evaluates and balances these considerations.

Study Scope and Approach

TVA partnered with Astrapé Consulting to determine the appropriate reserve margin for its power system. Astrapé Consulting used its proprietary Strategic Energy and Risk Valuation Model (SERVM) to facilitate this analysis. SERVM is a widely used industry model that employs a probabilistic view of costs and risks. Reserve margin studies typically look ahead about five years to allow time for utilities to make any necessary changes to the amount of reserves held. The 2024 reserve margin study focused on a 2029 year. The results of TVA's reserve margin analysis were primarily driven by weather uncertainty, load forecast error, generator availability, and market import capability.

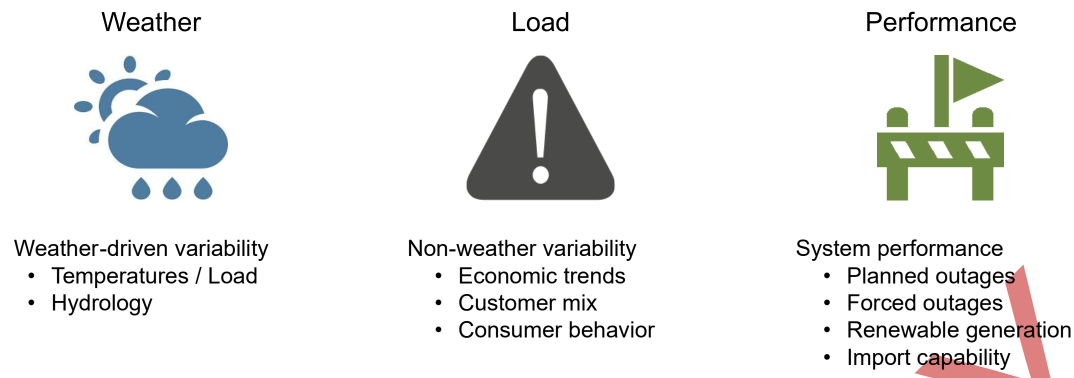


Figure D-1: Key Uncertainties in the Reserve Margin Study

The objective of the study was to determine reserve margin targets that support an industry best practice level of reliability in both summer and winter. Industry best practice reliability is typically expressed as one loss of load event (LOLE) every ten years, or 0.1 LOLE for one year.

Summary of Inputs

SERVM is a resource adequacy and production cost model that captures the key drivers of electric load and available generation. The primary model inputs are:

- Load: 40-plus years of load shapes developed from historical weather that are adjusted for current and projected relationships between load and weather.
- Demand-side Resources: TVA's demand-side program capacities, contractual constraints, and dispatch rules; typical constraints for demand response programs include hours per day, week, month, season, year, and call duration.
- Supply-side Resources: TVA-owned and contracted generating assets, including nuclear, hydro, coal, natural gas, renewables, and storage; recent generating unit outage experience and the potential for reliability purchases during peak system conditions are also considered.
- Hydro Availability: Hydro generation is an energy constrained resource, meaning that the peak output and amount of energy it can produce is subject to hydrologic conditions and watershed management considerations; inputs include monthly capacity, energy, and minimum and maximum flows.
- Ancillary Services and Operating Reserve Requirements: These grid requirements support a continuous, reliable power supply by maintaining grid frequency, ensuring generation is available to follow load, and assuring available backup generation in the event of unplanned outages.
- Transmission: Physical import and export constraints of the transmission network between TVA and its neighboring utilities.

SERVM uses a probabilistic, Monte Carlo approach that randomly samples historical weather years and future economic conditions to create potential load scenarios, along with sampling unit outages, to predict the probability of a loss of load event. Over 40 years of weather history are combined with five potential non-weather sensitive load forecast errors to create over 200 possible load scenarios, each with an associated probability. The amount of available generation is also subject to a random outage probability. All generating resources are assigned a probability to fail as a function of temperature. These random unit outage draws are then run across all 200-plus load cases to create over 16,000 simulations of load-unit outage combinations, resulting in a probabilistic estimate of system reliability. More details of these steps are provided in the following sections.

43 Weather Years (Equal Probability) X 5 Load Forecast Error Points (Associated Probabilities) = 215 Load Scenarios (Associated Probabilities)

Over 215 Load Scenarios X 75 Unit Outage Draws = Over 16,000 8760-Hour Simulations

Figure D-2: SERVM Model Probabilistic Approach

Accounting for uncertainty requires a probabilistic assessment of the inputs, including the expected value of each input and to what extent it can vary from expectations based on historical experience. The table below summarizes the key uncertainties for model inputs that influence reserve margins. The uncertainties relate to variability in weather-related load drivers, non-weather-related load drivers such as changes in the economy, generating asset performance, and availability of market purchases during times of system stress.

Table D-1: Key Uncertainties in the Reserve Margin Study

Model Input	Key Uncertainty Drivers
Weather	40-plus years of hourly temperatures for five regional cities, indicating peak load variability up to -6% to +7% in summer and -11 to +25% in winter
Load Forecast Error	Peak load impact up to +/- 4% from non-weather-related load drivers
Hydro	40-plus years of historical hydro generation correlated to weather year, adjusted for the past five years of unit performance
Renewables	40-plus years of historical patterns of solar and wind correlated to weather year
Generating Unit Outages	Five recent years of North American Electric Reliability Corporation (NERC) Generator Availability Data System (GADS) forced outage information
Import Capability	Recent experience importing market purchases at times of peak demand

Weather-related Load Uncertainty

Weather is a key driver of electric load, primarily due to heating and cooling requirements for buildings. Utilities model the relationship between outside temperature and electric load and develop a baseline peak load forecast based on an average winter or summer, otherwise known as a “weather normal” forecast.

The study evaluated weather-driven variability around peak loads, as shown in the figure below. The analysis projects seasonal peak loads as if the TVA system experienced the weather from any of the 40-plus historical weather years, calibrated to recent load response behaviors. The results have been expanded to include through 2022 and have been sorted from mildest to most extreme weather years. While summer peak loads have varied from -6% to +7% around normal weather conditions, winter peak loads have varied from -11% to +25%. Winter peak loads are influenced by the region’s relatively high share of electric heat. Weather uncertainty – and consequently the required reserve margins to ensure reliability – are greater in winter.

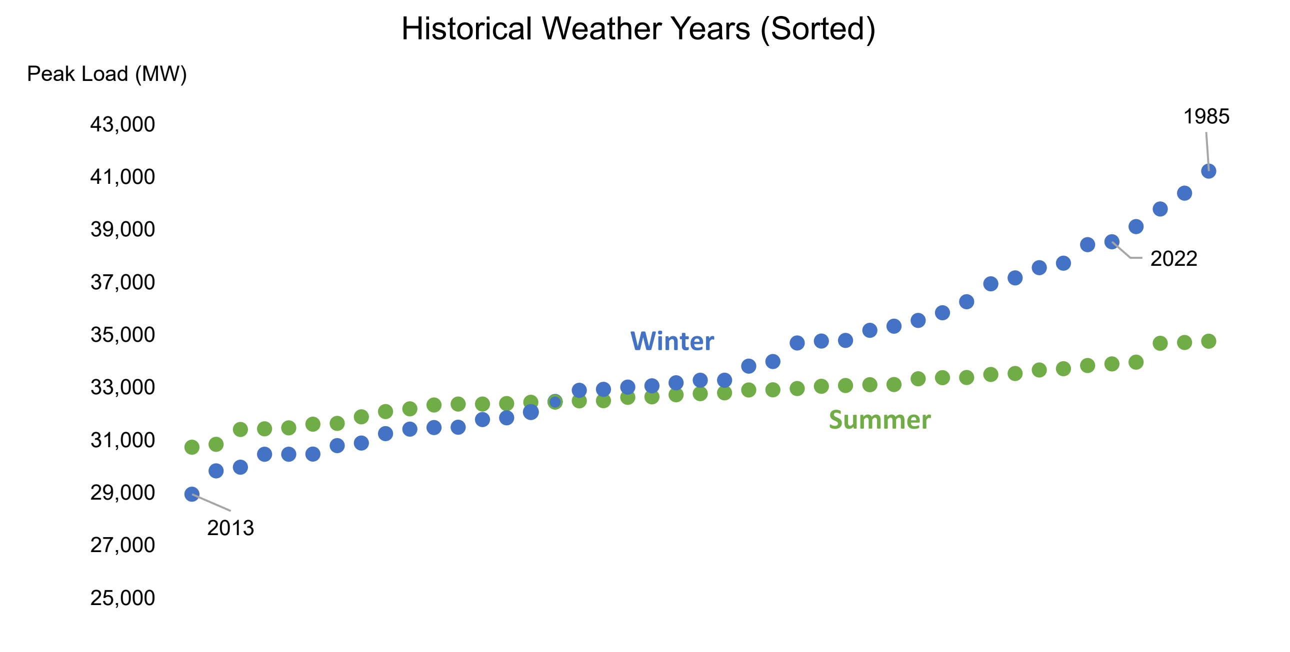


Figure D-3: Seasonal Weather-driven Peak Variability

Non-Weather-Related Load Uncertainty

While weather is a key uncertainty in estimating future peak loads, not all loads that TVA must serve are weather sensitive. A primary example of this is industrial customer load, which is not particularly weather sensitive and is more closely associated with macroeconomic conditions and other factors. The reserve margin study estimates the potential load forecast error for non-weather sensitive load using the uncertainty in economic forecasts.

The probability and magnitude of future economic load forecast error can be estimated using the Congressional Budget Office's historical forecasts for Gross Domestic Product (GDP). Five load forecast error multipliers were developed to simulate the expected probability that peak demand would differ due to changes in the forecast for economic growth. The study assumed peak demand sensitivity to changes in GDP of approximately 0.4% per 1% change in GDP, indicating a peak load uncertainty range of -4% to 4% due to economic factors.

Asset Performance

Generating asset performance varies with the seasons. All resource types except for solar have higher winter capacity. Thermal units (nuclear, coal, and gas) operate more efficiently in cooler temperatures and hydro generation is typically higher in the winter. Solar output is relatively high at the time of the summer peak that typically occurs in late afternoon, but there is often little to no solar output at the time of the winter peak that typically occurs early in the morning. More information on the contribution of renewable resources to meeting peak demand is discussed in the section on the Effective Load Carrying Capability Study.

Although thermal units generally operate more efficiently in cooler temperatures, extreme winter conditions can have detrimental impacts on generator performance. For instance, freezing temperatures can create shortages in the fuel supply or cause control equipment to fail. TVA's fuel supply is highly resilient due to a diverse generation fleet, firm gas supply and storage contracts, and fuel oil backup at combustion turbine sites. Asset performance is impacted by temperature, but there are steps utilities can take to improve performance. During 2023, TVA invested nearly $123 million and completed 3,400 winter readiness activities to harden the system and enhance reliability and resiliency at its coal, gas and hydro facilities that improved future performance, especially during subsequent winter storms in 2024 and 2025 that set new peak records.

The SERVM tool takes a probabilistic approach to generation outages in the reserve margin study. Potential unit failures are modeled by estimating a range of equivalent forced outage rates based on historical experience captured by NERC's Generating Availability Data System (GADS) and an incremental probability of failure as a function of temperature.

Market Purchases

A robust transmission network can increase reliability and lower costs for consumers. Utilities often buy and sell power from one another to help maintain electric reliability and for economic reasons. When utilities are not experiencing peak demand, they may have spare generating capacity to sell to other utilities. Weather patterns and generating unit performance will generally vary for TVA and its neighboring utilities. As a result, there may be some amount of spare capacity on the bulk power system that can be utilized to meet peak demand.

In addition to TVA's owned and contracted resources, SERVM models neighboring utilities and the transmission network. Neighboring utilities were modeled at planning reserve margin levels. The study considered the available import capability for market purchases based on historical experience at peak times. The distribution of market purchases ranged from 1,000 to 4,750 MW during the summer and 0 to 4,500 MW during the winter, with the quantity drawn randomly in each simulation. The figure below shows the schematic used in SERVM to capture the regional transmission network.

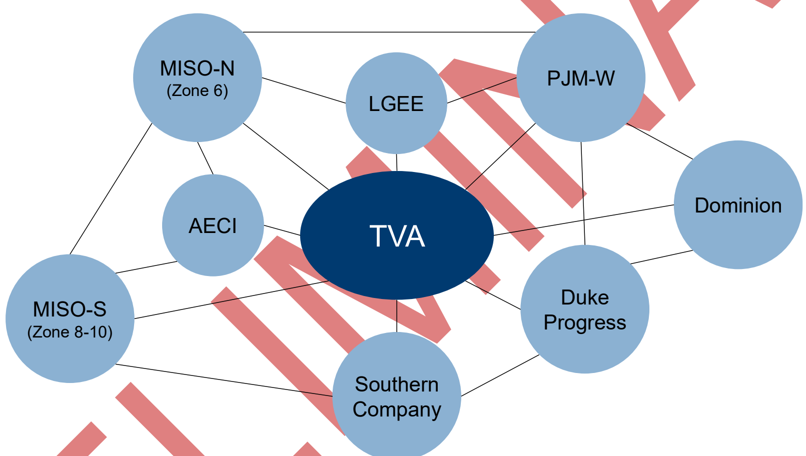


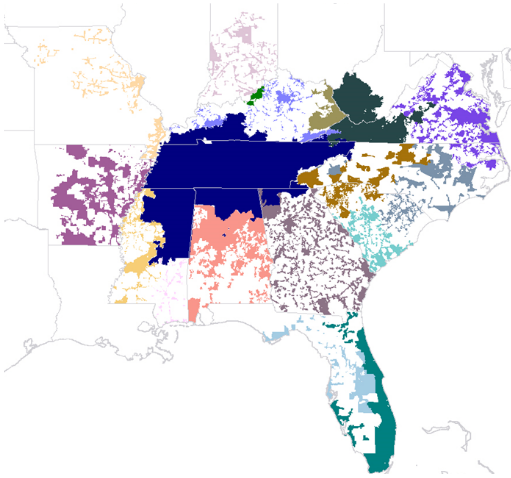
Figure D-4: Schematic of Regional Transmission Network

Study Results

As mentioned above, the goal of the reserve margin study was to estimate the amount of reserves TVA should maintain to meet the industry best practice of one loss of load event every ten years, or 0.1 LOLE per year. Applying a probabilistic approach, the study randomly sampled inputs from the key areas of uncertainty, including weather-related load, non-weather-related load, asset performance, and market purchases. This process produced over 16,000 simulations that informed the analysis.

The 2024 study results indicated that TVA should target an 18% summer reserve margin and 26% winter reserve margin to provide a seasonally balanced, industry best-practice level of reliability.

TVA's reserve margin targets are in line with industry peers. Notably, the planning reserve margins of many other regional utilities have increased over time. Higher winter reserve margins in surrounding regions show a shift towards winter risk, which could result in less available market assistance during extreme winter conditions.



Utility Company	Summer	Winter	Average Fleet Age (Years)
Kentucky Utilities	23.00%	29.00%	43
Louisville Gas & Electric	23.00%	29.00%	29
Duke Energy Carolinas	22.00%	22.00%	40
Duke Energy Progress	22.00%	22.00%	36
Alabama Power	20.00%	26.00%	42
Georgia Power	20.00%	26.00%	37
Duke Energy Florida	20.00%	20.00%	25
Florida Power & Light	20.00%	20.00%	18
Tennessee Valley Authority	**18.00%**	**26.00%**	**41**
Mississippi Power	16.25%	26.00%	36
Dominion Energy South Carolina	15.00%	20.10%	38
Appalachian Power	14.90%	14.90%	54
Virginia Electric & Power *	14.80%	14.80%	29
Entergy Mississippi	12.69%	12.69%	35
Entergy Arkansas	9.00%	27.40%	38
Kentucky Power	8.90%	8.90%	56
Ameren Missouri *	7.90%	18.90%	42
Duke Energy Indiana	5.60%	16.80%	38

Figure D-6: Reserve Margin Benchmark Comparisons

D.2 Net Dependable Capacity Study

Overview and Background

TVA periodically analyzes the reliability contribution of renewable and storage resources. It is important to account for solar and wind generation profiles when planning to serve peak load. Solar and wind output varies hourly and seasonally, and daily load profiles vary throughout the year, so it is essential to understand the relationship between renewable generation and hourly load. Solar output is relatively high at the typical summer peak late in the afternoon but is substantially less at the typical winter peak early in the morning. Wind generation is more variable overall and is generally higher in winter than in summer. Storage resources are considered energy limited resources. It is important to understand the complex interactions of storage with the bulk power system to ensure that the system has adequate energy during high demand periods.

Study Approach

In 2023, TVA performed a study to determine the net dependable capacity (NDC) of solar, wind, and storage resources. NDC is a measurement of a resource's ability to produce energy at times of peak demand, expressed as a percentage of nameplate capacity. The seasonal NDC of intermittent and storage resources can be determined by evaluating historical generation patterns and/or an Effective Load Carrying Capability (ELCC) study.

To determine the NDC for solar and wind, TVA utilized the historical generation method. TVA used 43 years of hourly historical generation for utility-scale solar and wind installations in the region, similar to the reserve margin study. For the historical summer and winter peak months, the study looked at the peak hour of the top six days to determine the expected solar and wind generation at summer and winter peak times as a percentage of nameplate, based on a 50% confidence level.

To determine the NDC for storage, TVA applied the ELCC method using Astrape's SERVM reliability model. Storage capacity is added to a reference case while dispatchable peaking capacity is removed until the loss of load expectation (LOLE) is equal to the reference case. ELCC is reported as the ratio of dispatchable peaking capacity removed to the storage capacity added to achieve the same LOLE estimated in the model. ELCC calculations are complex because a resource's effectiveness to help meet peak load also depends on the existing system and the amount of the intermittent or storage resources already present on the system.

Study Results

As mentioned above, the goal of the NDC study was to estimate the contribution of solar, wind, and storage resources to meeting peak demand as a percentage of nameplate. Highlights of study results include:

- NDC for incremental solar resources at the beginning of the study period was 68% in summer and 15% in winter, and NDC declines as installation of solar resources on the system increases.
- NDC for incremental wind resources at the beginning of the study period was 19% in summer and 33% in winter, and NDC declines as the installation of wind resources on the system increases.
- NDC for incremental 4-hour battery storage begins at 100% for up to 500 MW, falls to about 80% by 1,500 MW, and decreases further as installation increases.
- NDC for incremental 8-to-10-hour storage assumes significant installation of 4-hour battery storage, begins at 67% by 6,000 MW of total storage installation, and decreases as installation increases.

As solar, wind, and storage installation increases, the system peak net of renewables shifts and the ability of incremental additions to contribute to meeting peak demand decreases. Based on study results, the expected peak contributions for solar, wind, and storage as installation of each resource increases are shown below:

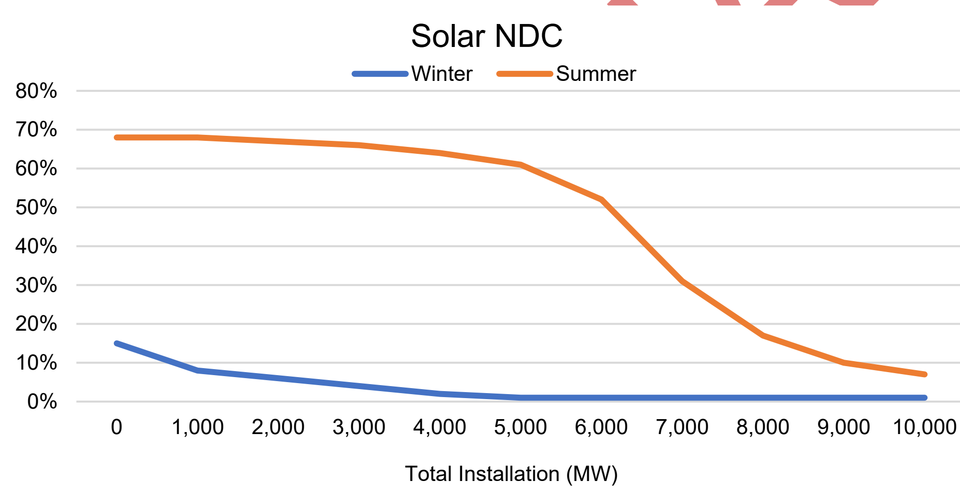


Figure D-8: Solar NDC at Increasing Installation Levels (% of Nameplate)

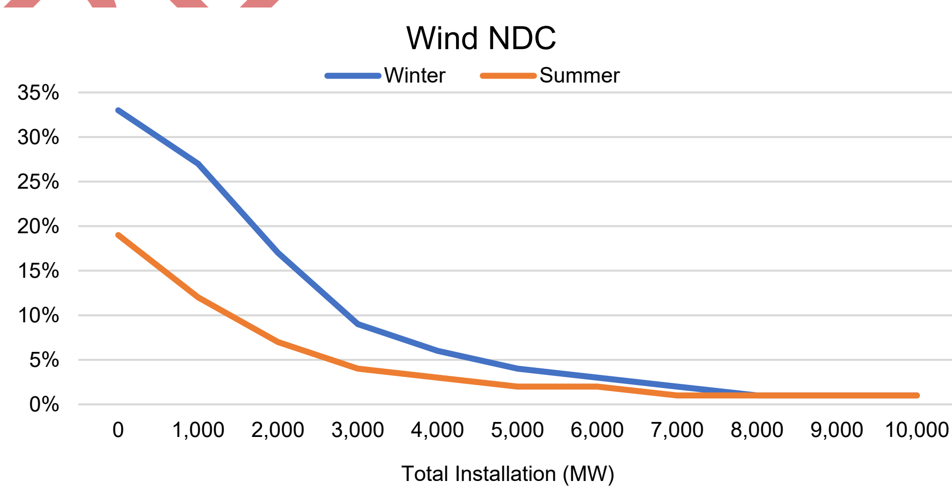


Figure D-9: Wind NDC at Increasing Installation Levels (% of Nameplate)

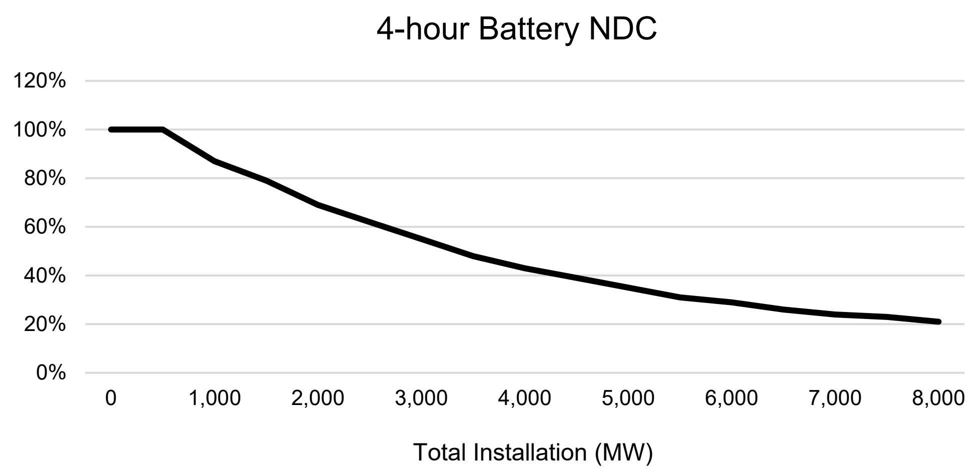


Figure D-10: 4-Hour Battery NDC at Increasing Installation (% of Nameplate)

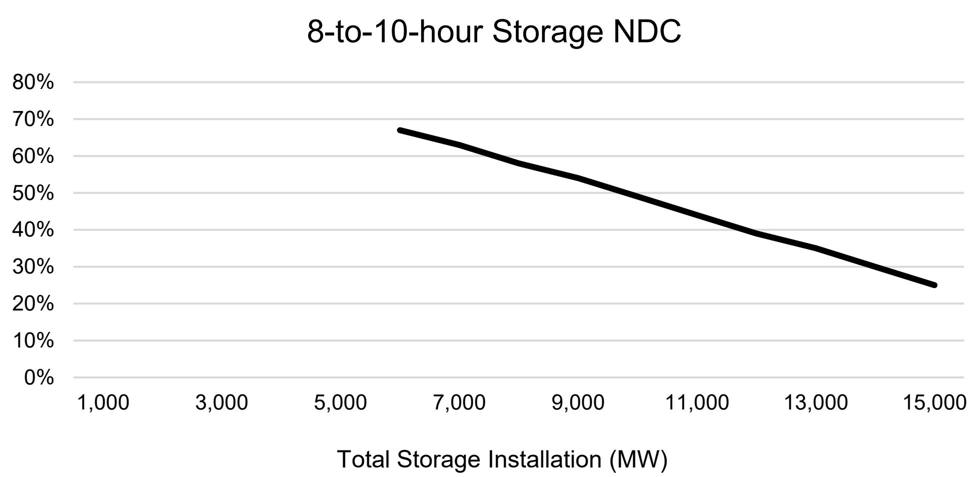


Figure D-11: 8-to-10-Hour Storage NDC at Increasing Installation (% of Nameplate)

TVA applied these NDC study results in IRP modeling to reflect the contribution of solar, wind, and storage resources to meeting peak demand over the planning horizon.

D.3 Flexibility Cost / Benefit Study

Overview and Background

Intermittent resources alter the operations of the power system, so it is important to understand the full cost and value of these resources. Solar and wind intermittency requires other resources to provide additional load following and cycling to absorb fluctuations in renewable generation. Clear days have lower solar volatility, cloudy days have higher solar volatility, and wind generation is more variable overall. Increasing renewable volumes generally have a smoothing effect due to locational diversity. Conversely, storage adds operational flexibility to absorb intermittency impacts. While the EnCompass model effectively captures the hourly impacts of renewable and storage additions, a study was needed to evaluate the sub-hourly impacts for modeling. The sub-hourly impact of renewable and storage is expressed as flexibility cost or benefit, respectively.

Study Approach

The Flexibility Cost / Benefit Study focused on 2026 and evaluated the sub-hourly impacts of intermittent and storage resource additions on operating costs and maintenance costs, explained further below. Intermittent solar and wind resource additions increase these costs, with the net change representing a flexibility cost. Storage resource additions reduce these costs, with the net change representing a flexibility benefit.

- Operating costs – costs incurred from additional load following, curtailments, and cycling of gas, hydro, and storage resources to maintain system balance with sub-hourly variations in intermittent generation.
- Maintenance costs – costs incurred for maintenance on equipment such as turbines, generators, boilers, and switchyards from the additional cycling of resources that help maintain system balance.

Impacts were studied at increasing levels of solar, wind, and storage installation on the system:

- Incremental solar capacity at 4,000 MW, 8,000 MW, and 13,000 MW installation levels
- Incremental wind capacity at 1,000 MW and 3,000 MW installation levels
- Incremental storage capacity at 200 MW, 1,000 MW, and 2,000 MW installation levels, studied with 4,000 MW, 8,000 MW, and 13,000 MW of solar installation

For intermittent resources, historical generation data (five-minute granularity) from TVA contracted solar and wind sites and from larger non-TVA solar portfolios was used to assess the intra-hour volatility of solar and wind generation, as illustrated below.

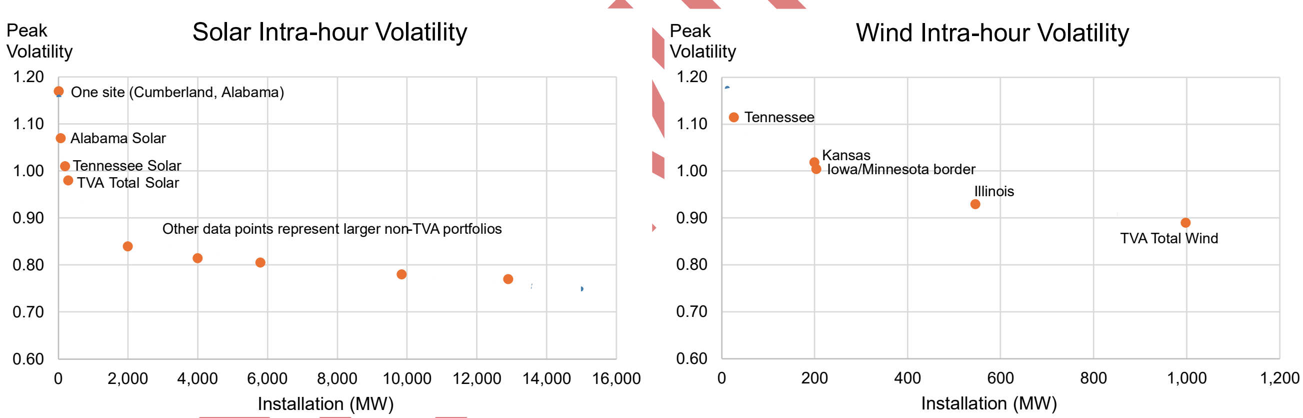


Figure D-12: Solar and Wind Generation Intra-hour Volatility

The sub-hourly flexibility impact of storage additions was evaluated in comparison to a gas frame combustion turbine (CT). Key assumptions are shown in the table below. Compared to a frame CT, storage has a broader operating range, faster ramp rate, and no start costs.

Table D-2: Key Study Parameters for Frame CT and Storage

Parameter	Gas Frame CT (4 units)	Lithium-ion Battery (4-hour)	Advanced Chemistry Battery (8-hour)	Pumped Storage (12-hour)
Maximum Capacity (MW)	884	50	50	1,600
Operating Capacity Range (%)	27% to 100%	-100% to 100%	-100% to 100%	-107% to -77% (pumping) 37% to 100% (generating)
Storage Efficiency (%)	N/A	85	85	81
Ramp Rate (MW/minute)	5	15	15	10
Start Costs ($/start – cold / hot)	14,790 / 6,322	0	0	0
Variable Operating and Maintenance ($/MWh)	0.00	0.00	0.00	2.80
Fixed Operating and Maintenance ($/kW-year)	5.50	46.61	46.61	20.64

The study calculates the impact of renewable and storage additions on operating and maintenance costs at sub-hourly and hourly levels, and the cost difference between the two levels represents the sub-hourly flexibility cost or benefit, respectively.

Study Results

As mentioned above, the goal of the study was to estimate the sub-hourly flexibility cost of intermittent solar and wind resources and the sub-hourly flexibility benefit of storage resources. Incremental impact results were derived from average impact assessments in the study.

Study results for incremental solar and wind flexibility cost at various installation levels are summarized below. Solar flexibility cost is relatively small at $3/MWh up to 4,000 MW of solar additions, increasing to $8/MWh for 8,000 MW or more of solar additions. Wind flexibility cost is $2/MWh up to 3,000 MW of wind additions. Values hold at higher volumes, as solar and wind locational diversity smooths out intermittency impacts.

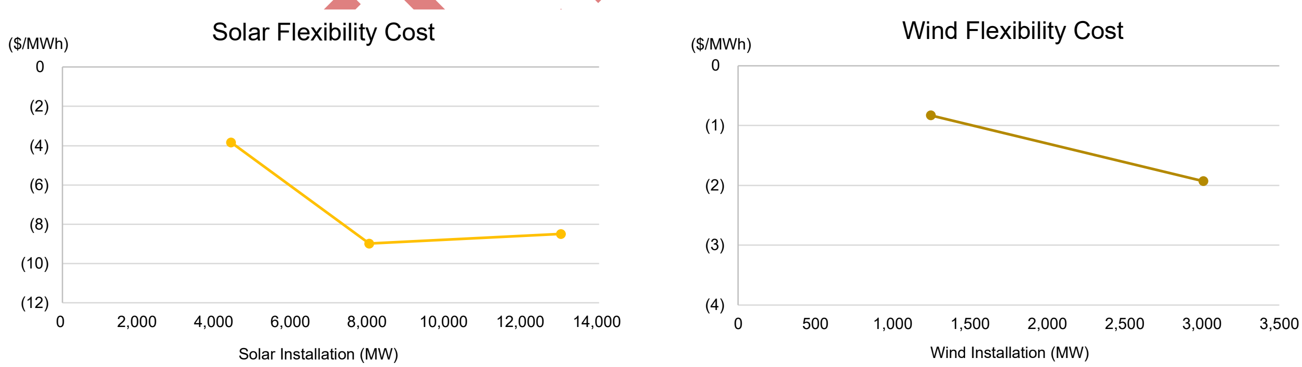


Figure D-13: Incremental Solar and Wind Flexibility Cost

Study results for incremental storage flexibility benefit at varying levels of storage and solar installation are shown below. Initial storage additions provide the greatest flexibility benefit. Short-duration battery storage is likely to be added first and be used to manage sub-hourly fluctuations in intermittent generation. Sub-hourly flexibility benefits for 4-hour batteries increase as solar installation grows from 4,000 MW to 8,000 MW, and then decrease as solar locational diversity expands. At higher levels of renewable and storage installation when peaks become flatter, longer-duration storage provides value over multiple hours, and this value is effectively captured in the hourly EnCompass model. For up to 2,000 MW of 4-hour battery additions, the sub-hourly flexibility benefit averages about $12/kW-year. For up to 2,000 MW of 8-hour storage additions, assuming similar installation of 4-hour battery storage, the sub-hourly flexibility benefit averages about $6/kW-year.

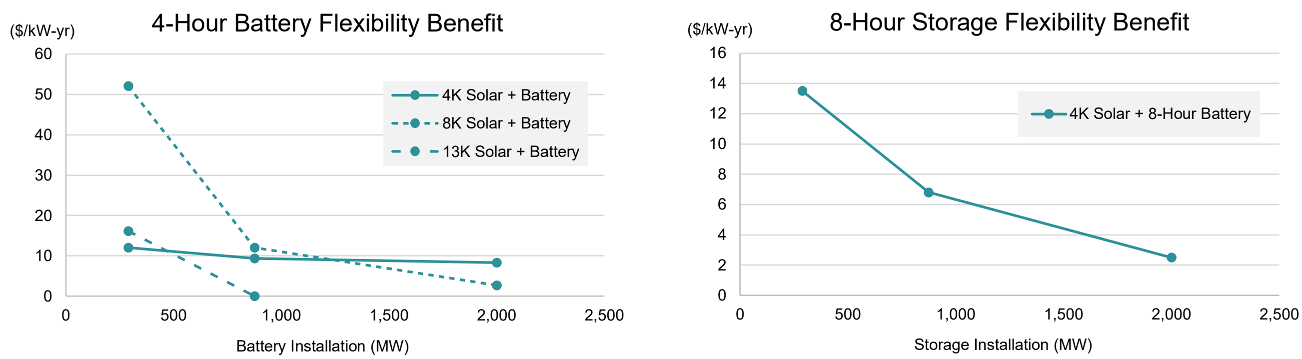


Figure D-14: Incremental Storage Flexibility Benefit

Applying Flexibility Study Results in the IRP

In EnCompass and other resource planning models, it is difficult to model assumptions like flexibility cost and benefit that dynamically change with the installation of certain resources. Given this limitation, TVA used the study results to estimate annual values for the incremental sub-hourly flexibility cost of intermittent resources and flexibility benefit of storage based on expected installation through time. Solar flexibility cost increases with anticipated installation. Wind flexibility cost remains relatively constant as existing wind contracts expire, and the potential to shape some future wind contracts would reduce intermittency impacts. Storage flexibility benefit increases with higher renewable installation. The storage benefit is applied to both battery and pumped storage resources, as new pumped storage options are assumed to have variable speed pumps.

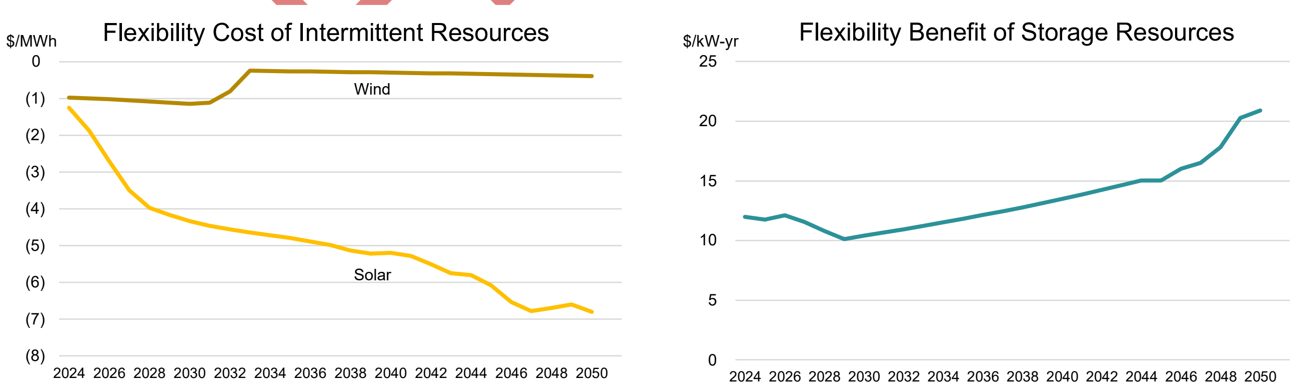


Figure D-15: Incremental Flexibility Cost/Benefit of Intermittent and Storage Resources

TVA applied these incremental sub-hourly values in IRP modeling to more fully capture the flexibility cost of intermittent resources and the flexibility benefit of storage resources over the planning horizon.

D.4 Energy Programs Potential Study

Overview and Background

The 2019 IRP recommended that TVA conduct a market potential study for energy efficiency and demand response. TVA's previous potential study was completed in 2012 and was outdated due to changes in codes and standards, as well as technology advancements since that time. In 2021, TVA initiated a new potential study leveraging third-party support and analysis conducted by DNV. Study results were used to inform program development and system planning projects, including the IRP. A potential study offers a detailed snapshot of regional opportunities for influencing electric load through various utility programs. This snapshot is the first step in program planning, and it helps identify high-value opportunities for further exploration and development.

Study Scope and Approach

The Energy Programs Potential Study considers three resource types – energy efficiency, demand response, and electrification. The objective of the analysis was to estimate the range of possibilities for the three resource types in the TVA region for each of the primary sectors – residential, commercial, and industrial. The project team assessed the potential for each resource at multiple levels:

- Technical Potential – Includes all available technology with no cost considerations and assumes consumer willingness to adopt all measures.
- Economic Potential – Is a subset of technical potential that includes measures that are cost-effective when compared to supply-side alternatives and considers consumer costs.
- Achievable Potential – Is best described as realistic potential, or what would occur in response to specific program funding, marketing, and incentive levels. Achievable potential takes into consideration market and program barriers, impacts of evolving codes and standards, and naturally occurring market adoption that would have happened without programs.

The analysis began with the collection of model input data and the creation of a baseline market characterization, leveraging region-specific building and economic data. Measure-level analysis was conducted using accepted cost estimates and region-specific impacts. Technical and economic potential were then calculated, followed by estimations of naturally occurring and achievable potential. This approach was used for all resource types, considering costs and nuances specific to each resource type and overlapping measures between resources.

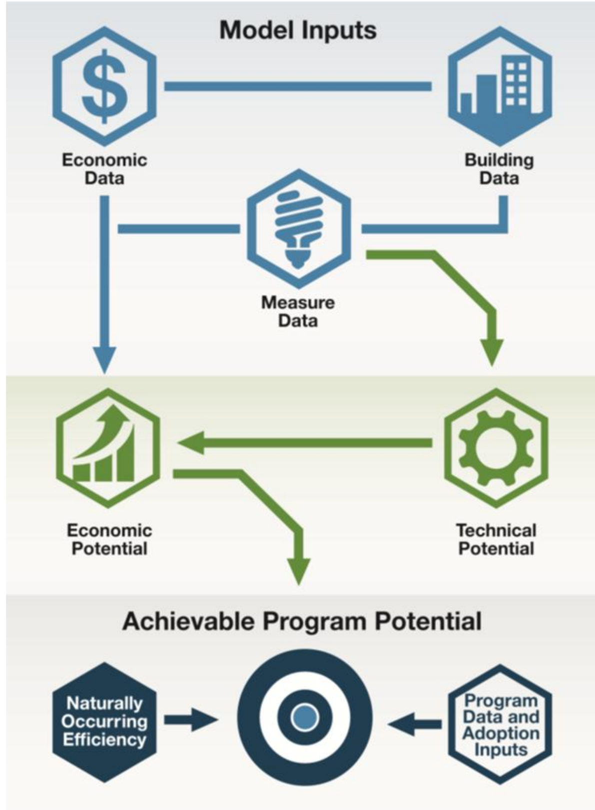


Figure D-16: Energy Program Potential Study Approach

Study Results

Study results cover achievable potential for the three resource types. As electrification is explored in the IRP scenarios, this discussion of study results will focus on energy efficiency and demand response, which are offered as resource options in the IRP analysis.

The study indicated a 10-year potential for regional energy efficiency gains ranging from 2-7% of base sales and 2-9% and 4-16% of summer and winter peak demand, respectively. The residential sector accounts for most of the potential, particularly homes utilizing electric heating. Potential in the less weather-sensitive commercial and industrial sectors is driven by linear fluorescent and high-intensity discharge lighting applications.

Highlights from the energy efficiency portion of the study were:

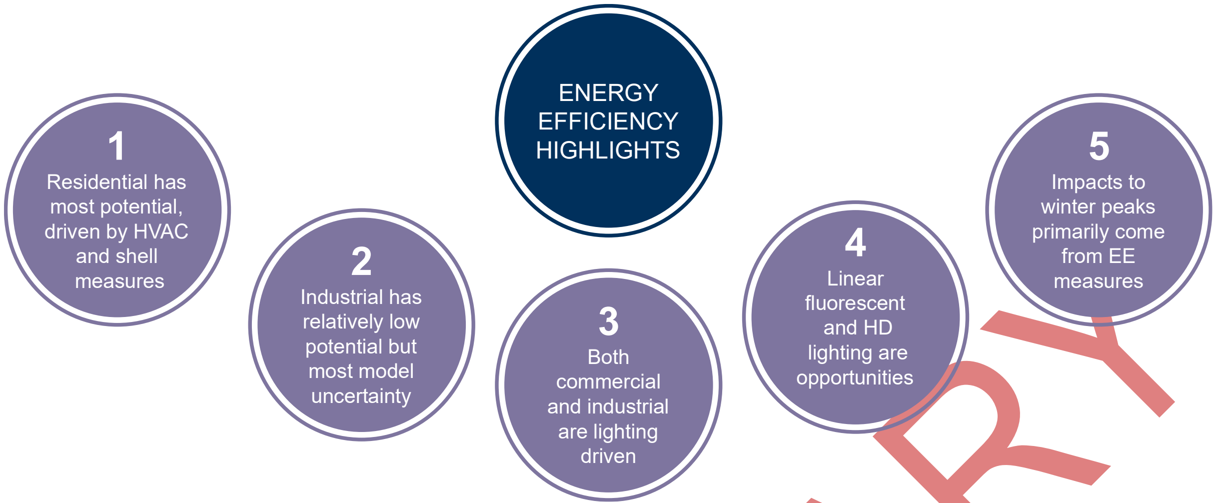


Figure D-17: Energy Efficiency Highlights from the Potential Study

Highlights from the demand response portion of the study were:

Figure D-18: Demand Response Highlights from the Potential Study

The study was used to inform energy program resource options in the IRP. More information on the Energy Programs Potential Study can be found on the energyright.com website.

E

Appendix E – Utility Scale Resource Methodology

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Appendix E – Utility Scale Resource Methodology

Maintaining diversity in the resource mix is fundamental to TVA's ability to provide affordable, reliable, and resilient energy to the residents, businesses, and industries in the region. A diverse portfolio reduces fuel price risk and reliability risks associated with single modes of failure. To facilitate this, the IRP analysis considered the addition of a wide range of supply-side generating resources, distributed generation resources, and demand-side management resources.

When evaluating how to best meet future needs for electricity, TVA optimizes decisions using least-cost planning models. These models require inputs such as capacity amounts, upfront capital costs, asset life, fuel usage parameters, ongoing operating and maintenance costs, and many others. The model integrates all the variables associated with the scenarios (demand projections, fuel prices, regulatory environments, etc.) and strategies (resource emphases) with all the variables associated with the resource options to select the mix of expansion units that meet overall portfolio needs at the lowest system cost. The model considers annual limits for each resource option as a method for simulating the practical ability to construct or procure new resources. Annual build limits listed within sections E.3 through E.9 apply in all modeled cases except Scenario 2 - High Growth and the Supercharged Growth sensitivity which feature annual limits that are approximately 50% higher than the standard limit. The following sections provide the assumptions for key operating characteristics for the various resource options modeled in the IRP (see Appendix A – Integrated Resource Planning Fundamentals for definitions of operating characteristics).

E.1 Overnight Resource Costs

A key assumption contributing to resource selection is the cost to construct a particular resource. Overnight capital costs represent the total estimated cost to build a given resource in the first year available, restated in 2026 dollars and divided by its capacity in kilowatts ($/kW). For utility-scale options, TVA utilizes a combination of direct experience with recent projects, market-based request for proposal responses, industry expertise working with equipment manufacturers, and industry forecasts to inform resource costs. For example, informed by direct experience exploring designs for potential small modular reactors (SMRs) at the Clinch River Nuclear Site, TVA used refined forecasts for new nuclear resources that reflect all-in costs plus risk contingencies and may be higher than some industry estimates. The refined nuclear forecasts utilize information from preliminary estimate determination efforts. Hydro expansion costs were based on internal estimates specific to opportunities across the TVA power system. Gas and hydro pumped storage expansion estimates were based on recent project experience and discussions with equipment manufacturers. Solar and battery storage costs in the near-term are based on market offers submitted through recent, competitive requests for proposal, with long-term forecasts including adjustments for continued technological advancements. Finally, wind expansion costs were sourced from the 2024 NLR Annual Technology Baseline and incorporate transmission wheeling estimates to deliver this energy.

The table below summarizes overnight capital costs for the utility scale resource options considered in the IRP.

Table E-1: Overnight Capital Costs (2026 $/kW before tax credits)

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2026 $/kW)
Nuclear	Advanced Pressurized Water Reactor (APWR)	1,100	14,235
	Small Modular Reactor – Light Water (First-of-a-Kind)	285	17,263
	Small Modular Reactor – Light Water (Nth-of-a-Kind)	285	8,743
	Small Modular Reactor – Gen IV with Integrated Storage (500 MW w/ storage)	500	9,751

Resource Type	Resource Technology	Summer NDC or Nameplate (MW)	Overnight Capital Cost (2026 $/kW)
Hydro	Hydro Uprates	200	1,818
Coal	Coal Supercritical Pulverized	650	3,482
	Coal Supercritical Pulverized with Carbon Capture and Sequestration	650	4,905
Natural Gas	Combined Cycle – 3x1x1*	2,145	2,148
	Combined Cycle with Carbon Capture and Sequestration – 2x1x1	1,430	3,635
	Frame Combustion Turbine – 4x*	884	1,161
	Aeroderivative Combustion Turbine – 20x*	1,060	2,513
	Reciprocating Internal Combustion Engine – 12x*	216	2,305
Solar (nameplate)	Solar Single-Axis Tracking	50	1,698
Wind (nameplate)	Wind – Midwest	200	1,574
	Wind – Southeast High-Hub	200	2,205
Storage (nameplate)	Pumped Storage	1,212	3,191
	Battery – Lithium-ion 4-Hour	50	2,158
	Battery – Advanced Chemistry	50	3,886
EE and DR	Energy Efficiency and Demand Response Programs	Varies by program – refer to Appendix G for program options and details	
Distributed Generation	Distributed Solar, Storage, and Combined Heat and Power	Varies by resource – refer to Appendix F for modeling details	

* Smaller configurations of these resources were also offered as available options.

E.2 Technology and Adoption Readiness

The ability to successfully deploy a technology is dependent upon the maturity of the technology itself, as well as the readiness to adopt that technology throughout its entire value chain. To better assess adoption readiness, the Department of Energy (DOE) has developed a Commercial Adoption Readiness Assessment Tool (CARAT) that establishes an Adoption Readiness Level (ARL) framework to complement the existing Technology Readiness Level (TRL) framework. Taken together, they provide a more complete view of the readiness to deploy various generating and storage technologies in the energy sector.

In DOE's framework, technology readiness assesses the level of technological breakthroughs required and developmental challenges to overcome. Technology readiness is assessed with a 1 to 9 TRL score that ranges from research to development and demonstration to commissioning and operations, as described below.

Table E-2: DOE Technology Readiness Level Scale

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Operations	TRL 9	Actual system operated over the full range of expected conditions	Actual operation of the technology in its final form, under the full range of operating conditions. Examples include using the actual system with the full range of wastes.

Relative Level of Technology Development	Technology Readiness Level	TRL Definition	Description
System Commissioning	TRL 8	Actual system completed and qualified through test and demonstration	Technology has been proven to work in its final form and under expected conditions. In almost all cases, this TRL represents the end of true system development. Examples include developmental testing and evaluation of the system with real waste in hot commissioning.
System Commissioning	TRL 7	Full-scale, similar (prototypical) system demonstrated in a relevant environment	Prototype full-scale system. Represents a major step up from TRL 6, requiring demonstration of an actual system prototype in a relevant environment. Examples include testing the prototype in the field with a range of simulants and/or real waste and cold commissioning.
Technology Demonstration	TRL 6	Engineering/pilot-scale, similar (prototypical) system validation in a relevant environment	Representative engineering scale model or prototype system, which is well beyond the lab scale tested for TRL 5, is tested in a relevant environment. Represents a major step up in a technology's demonstrated readiness. Examples include testing a prototype with real waste and a range of simulants.
Technology Development	TRL 5	Laboratory scale, similar system validation in a relevant environment	The basic technological components are integrated so that the system configuration is similar to (matches) the final application in almost all respects. Examples include testing a high-fidelity system in a simulated environment and/or with a range of real waste and simulants.
Technology Development	TRL 4	Component and/or system validation in laboratory environment	Basic technological components are integrated to establish that the pieces will work together. This is relative "low fidelity" compared with the eventual system. Examples include integration of "ad hoc" hardware in a laboratory and testing with a range of simulants.
Research to Prove Feasibility	TRL 3	Analytical and experimental critical function and/or characteristic proof of concept	Active research and development is initiated. This includes analytical studies and laboratory-scale studies to physically validate the analytical predictions of separate elements of the technology. Examples include components that are not yet integrated or representative. Components may be tested with simulants.
Research to Prove Feasibility / Basic Technology Research	TRL 2	Technology concept and/or application formulated	Invention begins. Once basic principles are observed, practical applications can be invented. Applications are speculative, and there may be no proof or detailed analysis to support the assumptions. Examples are still limited to analytic studies.
Basic Technology Research	TRL 1	Basic principles observed and reported	Lowest level of technology readiness. Scientific research begins to be translated into applied research and development (R&D). Examples might include paper studies of a technology's basic properties.

The ARL framework establishes a rubric for evaluating the commercial factors related to a technology's value proposition, market acceptance, resource maturity, and license to operate, resulting in an overall 1 to 9 ARL score that reflects a readiness level across the adoption value chain. Descriptions of the 17 risk dimensions across four core areas included in the assessment are summarized in the table below. In ARL scoring, each risk dimension receives a rating of low, medium, or high risk using fact-based parameters. Further information on DOE's Adoption Readiness Levels and the CARAT tool can be found here.

Table E-3: DOE Commercial Adoption Readiness Assessment Tool (CARAT) Risk Dimensions

Adoption Risk Core Areas	Dimensions of Adoption Risk	Description
Value Proposition	Delivered Cost	Risks associated with achieving delivered cost competitiveness when produced at full scale, including amortization of incurred development and capital costs, and accounting for switching costs (if any).
	Functional Performance	Risks associated with the ability of the technology solution to meet or exceed the performance and feature-set of incumbent solutions or create new end-use markets.
	Ease of Use / Complexity	Risks associated with operational switching costs; the ability of a new user (individual, company, system integrator) to adopt and operationalize the technology with limited training, few new requirements, or special resources (e.g., tools, workforce, contract structures).
Market Acceptance	Demand Maturity / Market Openness	Risks associated with demand certainty and access to standardized sales and contracting mechanisms (if required), as well with natural (e.g., network effects, first-mover-advantages) and/or structural (e.g., existing monopolies / oligopolies) barriers to entry in the market(s) to which the technology solution can be applied.
	Market Size	Risks associated with the overall size of the market that can be served by the technology, and the level of uncertainty with which it will materialize.
	Downstream Value Chain	Risks associated with the projected path to get the product from a producer to a customer along the value chain (e.g., considering split incentives, technology acceptance, business model changes).
Resource Maturity	Capital Flow	Risks associated with the availability of capital needed to move the technology solution from its current state to production at scale, including total investment required, availability of willing investors, availability of associated financial and insurance products, and the speed of capital flow.
	Project Development, Integration, and Management	Risks associated with the existence of processes and capabilities to successfully and repeatably execute projects using the technology solution.
	Infrastructure	Risks associated with the physical and digital large-scale systems that need to be in place to support, enable, or facilitate deployment at full scale (e.g., pipelines, transmission lines, roads and bridges, etc.)
	Manufacturing and Supply Chain	Risks associated with all the entities and processes that will produce the end-product, including integrators, component, and sub-component manufacturers and providers.
	Materials Sourcing	Risks associated with the availability of critical materials required by the technology (e.g., rare earth and other limited availability materials).
	Workforce	Risks associated with the human capital and capabilities required to design, produce, install, maintain, and operate the technology solution at scale.
License to Operate	Regulatory Environment	Risks associated with local, state, and federal regulations or other requirements/standards that must be met to deploy the technology at scale.
	Policy Environment	Risks associated with local, state, and federal government policy actions that support or hinder the adoption of the technology at scale.
	Permitting and Siting	Risks associated with the process to secure approvals to site and build equipment and infrastructure associated with deploying the technology at scale.
	Environmental and Safety	Risks associated with the potential for hazardous side effects or adverse events inherent to the production, transport, or use of the technology solution or end product in the absence of sufficient controls.
	Community Perception	Risks associated with the general perception by global and local communities of the technology solution and its risks or impact, whether founded or unfounded.

Using the low, medium, and high scores for each risk dimension, an overall ARL score is developed for each technology based on the following criteria established by DOE.

Table E-4: DOE Overall Adoption Readiness Scoring Table

Overall Adoption Readiness Score		Number of High Risk Dimensions								
		0	1	2	3	4	5	6	7	8+
Number of Medium Risk Dimensions	0	9	8	7	5	3	1	1	1	1
	1	8	7	6	4	2	1	1	1	1
	2	8	7	6	4	2	1	1	1	1
	3	7	6	5	3	1	1	1	1	1
	4	7	6	5	3	1	1	1	1	1
	5	6	5	4	2	1	1	1	1	1
	6	5	4	3	1	1	1	1	1	1
	7	3	2	1	1	1	1	1	1	1
	8+	1	1	1	1	1	1	1	1	1

TVA assessed the technology and adoption readiness of the resource technology options in the IRP analysis using DOE's TRL and ARL rubrics and tools. TVA referenced industry-led risk registers to help identify technology-specific risk types and levels. For the ARL assessment, TVA considered production, transportation, and distribution infrastructure in a 3-to-5-year commercialization window. A summary of the TRL and ARL assessment results can be found in Chapter 2, section 2.6.3.

Further information on DOE's Technology and Adoption Readiness Levels and the detailed CARAT tool scoring parameters can be found here.

E.3 Nuclear Resource Modeling

Existing Nuclear Resources

TVA operates seven nuclear reactors – three at Browns Ferry Nuclear Plant, two at Sequoyah Nuclear Plant, and two at Watts Bar Nuclear Plant. These plants have a combined generating capability of 8,302 MW. The three units at Browns Ferry have license expiration dates of 2053, 2054, and 2055, respectively. The two units at Sequoyah are licensed for operation through 2040 and 2041, respectively, and TVA plans to apply for second license renewal. Watts Bar Units 1 and 2 are licensed for operation through 2035 and 2055, respectively (initial 40-year licenses), and TVA plans to apply for license renewal. TVA has an Early Site Permit to potentially construct and operate small modular reactors (SMRs) at TVA's Clinch River Nuclear Site in Oak Ridge, Tennessee. In 2022, the TVA Board approved a programmatic approach to exploring advanced nuclear technology.

Nuclear Resource Options

In the IRP analysis, three nuclear expansion options are available to fill the expected capacity gap:

- Advanced Pressurized Water Reactor (APWR)
- Light Water SMR (first and nth-of-a-kind)
- Gen IV SMR

SMRs are a new type of nuclear reactor in which the components are manufactured in a factory and then assembled onsite. The individual units are smaller in size, allowing for increased flexibility in installation and use. New units could be located at existing nuclear sites or at other sites beneficial to the transmission system and local resiliency. Two SMR options are included. The first option is a light water-cooled SMR that leverages proven technology and is furthest along from a licensing perspective. The second option is a Gen IV SMR that is non-water-cooled (e.g., liquid sodium, molten salt) with an integrated thermal energy storage system. Both APWR and Light Water SMR options are considered to be Gen III+ nuclear reactors.

The table below shows the key operating characteristics used to model the nuclear expansion options.

Table E-5: Nuclear Expansion Options and Key Assumptions

Key Assumptions	APWR	Light Water SMR	Gen IV SMR
Summer Net Dependable Capacity (MW) – without / with storage	1,110	285	345 / 500[1]
Unit Availability (First Year)	2039	2033	2041
Standard / High Growth Annual Build Limit (Units)	1 / 1	1 / 2[2]	1 / 1
Book Life (Years)	60	60	60
Overnight Capital Cost (2026$/kW) – first / nth-of-a kind	14,235	17,263 / 8,743	9,751
Summer Full-load Heat Rate (Btu/kWh)	10,132	10,713	8,308
Annual Outage Rate (%)	5	5	15
Variable Operating and Maintenance (2026$/MWh)	1.40	1.18	4.49
Fixed Operating and Maintenance (2026$/kW-year)	136.44	157.42	290.52

[1]Base reactor capacity of 345 MWe with 155 MW of integrated storage (~5.5 hours) for combined output of 500 MW
[2]In High Growth, limit 1 unit per year for first four units then 2 units per year thereafter

Numerical values for nuclear resource options were developed internally based on TVA's estimated range of all-in costs using information from preliminary estimate determination efforts.

Values in the table above and figure below show the trend in overnight capital costs for the nuclear resource options including the impact of inflation and any applicable investment tax credits.

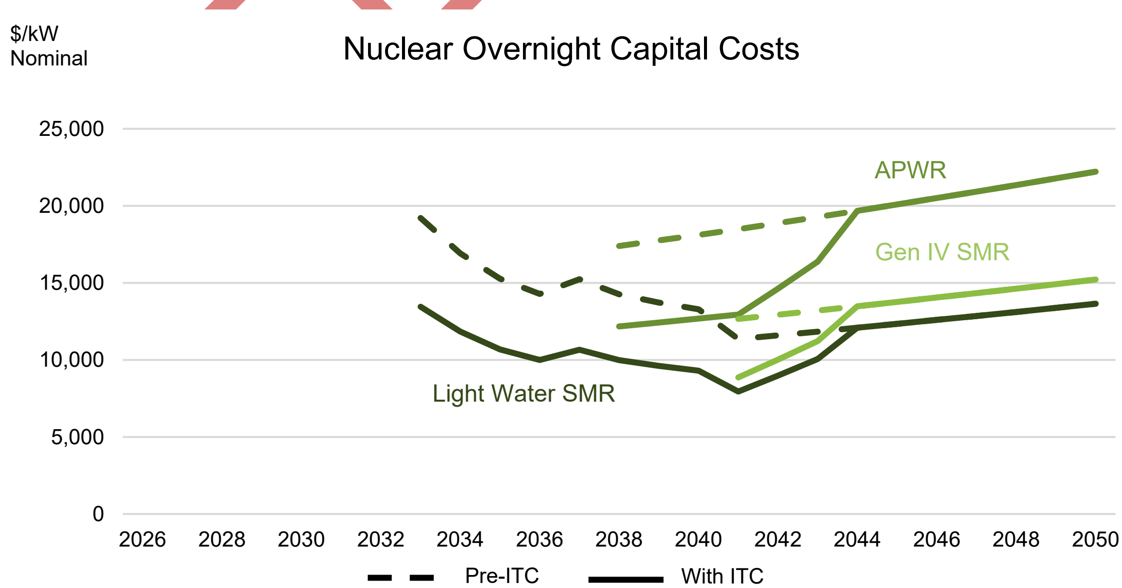

Figure E-1: Nuclear Overnight Capital Costs

E.4 Hydro Resource Modeling

Existing Hydro Resources

TVA operates 109 conventional hydro generating units at 29 dams with a generating capability of 3,783 MW of electricity. All IRP portfolios reflect investing in and maintaining TVA's existing hydro fleet. Through its Hydro Life Extension program, TVA plans to modernize two to three units per year, and the program is perpetual in nature to maintain capacity over time. Based on a model that simulates the operation of the river system and the operational constraints of the hydro units, TVA anticipates about 70% of the combined hydro capability to be available at the summer peak hour. Also, TVA has long-term power purchase agreements for output from multiple dams on the Cumberland and Tennessee River systems. These facilities provide 779 MW of capability.

Hydro power is not dispatched based on price alone, because water releases in the Tennessee River system also are required for municipal and industrial uses, navigation, flood damage reduction, recreation, water quality, and other purposes. To account for this, TVA includes a fixed amount of monthly energy in the model for conventional hydro units, and the model shapes the available hydro energy to level the total load shape served by other units within high-level constraints, resulting in total hydro generation that approximates if it were modeled as a collection of individually linked resources.

Hydro Resource Options

In the IRP analysis, one hydro expansion option is available to fill the expected capacity gap:

- Hydro Uprates

The hydro uprates expansion option was developed based on TVA's Hydro Life Extension (HLE) program assessments and is specific to opportunities across the TVA system. HLE projects provide the best opportunity to take advantage of the limited water supply by increasing the productivity of the existing hydroelectric dams. While performing activities required to maintain existing capacity, opportunities to improve upon original design capabilities with incremental capital were identified and modeled as a resource. The incremental capacity available and incremental spend above the cost of the base HLE program became the cost basis. While cost synergies are tied to uprate work being performed at the same time as HLE work, the model has some latitude to shift the timing of the uprates to achieve the best overall fit in each portfolio.

The table below shows the key operating characteristics used to model the hydro expansion option.

Table E-6: Hydro Expansion Options and Key Assumptions

Key Assumptions	Hydro Uprates
Summer Net Dependable Capacity (MW)	200
Unit Availability (First Year)	2031
Cumulative Build Limit (Units)	1
Book Life (Years)	30
Overnight Capital Cost (2026$/kW)	1,818
Variable Operating and Maintenance (2026$/MWh)	2.61
Fixed Operating and Maintenance (2026$/kW-year)	N/A

As hydro uprates expand the capacity of existing units, there is additional variable but no additional fixed operating and maintenance costs. Since hydro plants do not use fuel, a heat rate is not needed for modeling.

The figure below shows the trend in overnight capital costs for the hydro resource option including the impact of inflation and any applicable investment tax credits.

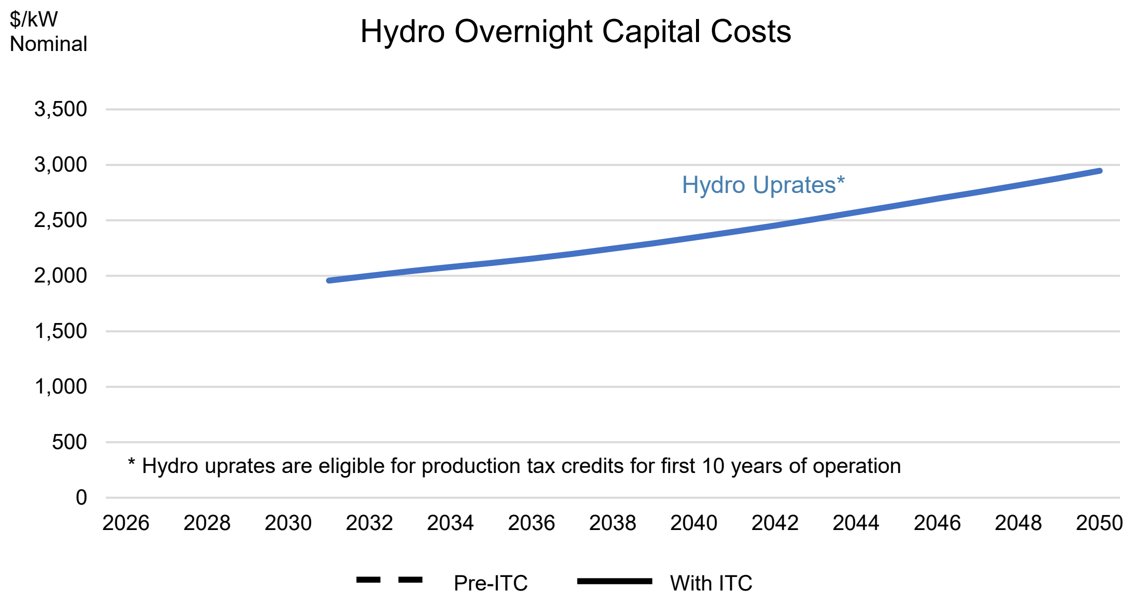

Figure E-2: Hydro Overnight Capital Costs

E.5 Coal Resource Modeling

Existing Coal Resources

TVA operates four coal-fired plants with 24 active generating units and a total capability of 5,815 MW. In planning, TVA uses a number somewhat lower than the capability of a resource, based on expected output at the summer and winter peaks (net dependable capacity). In February 2026, TVA issued Supplemental EISs for continued operation of the Cumberland and Kingston fossil plants to meet rapidly increasing demand for electricity and address associated reliability concerns in the TVA region. Based on recent evaluations, TVA concluded that continued operation of Cumberland and Kingston fossil plants are cost-effective and recommended taking actions to continue operation to reduce total system cost and reliability risks, subject to compliance with applicable permitting and regulatory requirements. For planning purposes, existing coal plants are expected to reach end of life by 2039, subject to TVA Board approval and further environmental review.

In addition to TVA's four coal plants, TVA has access to the output from a coal-fired plant in Mississippi with a generating capability of 440 MW through a long-term power purchase agreement that expires in 2032.

Coal Resource Options

In the IRP analysis, two coal expansion options are available to fill the expected capacity gap:

- Supercritical Pulverized Coal
- Supercritical Pulverized Coal with Carbon Capture and Sequestration (CCS)

The table below shows the key operating characteristics used to model the coal expansion options.

Table E-7: Coal Expansion Options and Key Assumptions

Key Assumptions	Supercritical Pulverized Coal	Supercritical Pulverized Coal w/CCS
Summer Net Dependable Capacity (MW)	650	650
Unit Availability (First Year)	2032	2033
Standard / High Growth Annual Build Limit (Units)	2 / 3	1 / 1
Cumulative Build Limit (Units)	-	11
Book Life (Years)	30	30
Overnight Capital Cost ($/kW)	3,482	4,905
Summer Full-load Heat Rate (Btu/kWh)	10,548	10,548
Annual Outage Rate (%)	25	25
Variable Operating and Maintenance ($/MWh)	0.62	24.94
Fixed Operating and Maintenance ($/kW-year)	105.05	295.24

Cost estimates for new coal units were derived from the NLR Annual Technology Baseline (ATB). For coal with CCS, TVA applied the cost estimates developed for CCS systems for CC units to a conventional coal unit to reflect the additional cost of CCS technology. Coal units typically have a CO_2 emissions rate of 205 pounds per million BTUs of coal burned. CCS technology capturing 90% of the emissions would reduce the CO_2 rate to 20.5 pounds per million BTUs of coal burned. In the Carbon Legislation scenario, the modeled coal units incur emissions charges based on a dollar-per-ton emission penalty.

The figure below shows the trend in overnight capital costs for the coal resource options including the impact of inflation and any applicable investment tax credits.

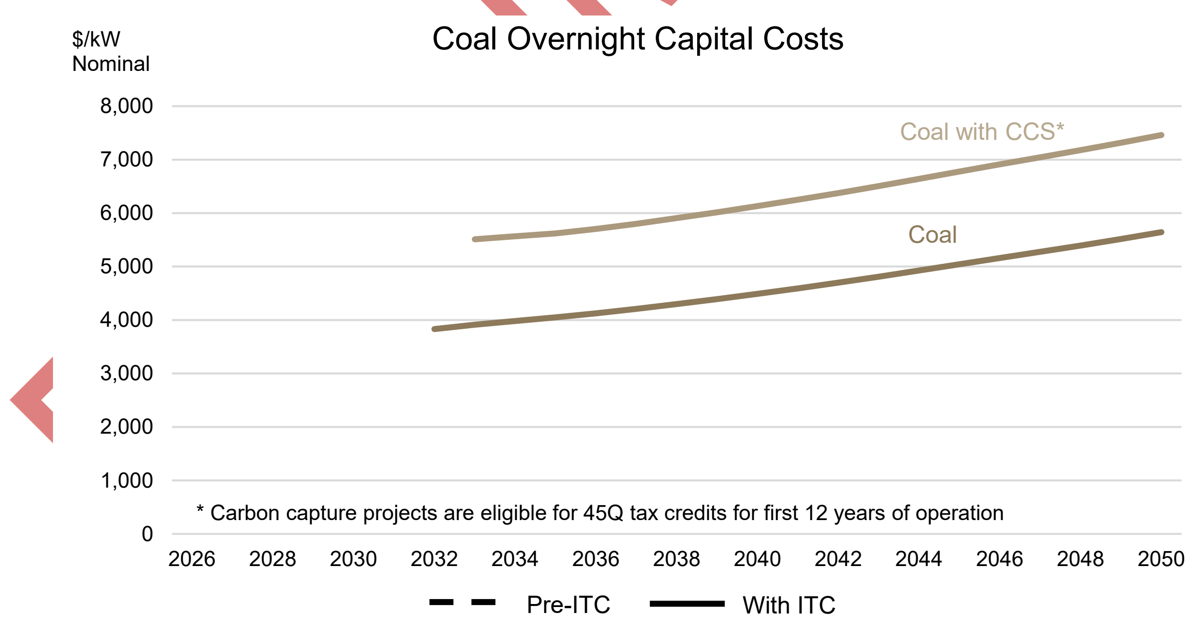

Figure E-3: Coal Overnight Capital Costs

E.6 Natural Gas Resource Modeling

Existing Natural Gas Resources

TVA operates 68 natural gas-fired combustion turbines (CT) at ten power plants with a combined generating capability of 5,619 MW (excluding co-generation), 14 combined cycle (CC) units at eight power plants with 6,958 MW of generating capability, and one co-generation unit with a generating capability of 66 MW. TVA has power purchase agreements with merchant gas-fired plants for 3,609 MW of capability, with current agreements expiring in the mid-2020s to early 2030s.

Natural Gas Resource Options

In the IRP analysis, five gas expansion options are available to fill the expected capacity gap:

- Combined Cycle (CC) – 3x1x1 and 2x1x1 (two sets of one gas turbine and one steam generator)
- CC with Carbon Capture and Sequestration (CCS) – CC with CCS capturing 90% of CO_2 emissions
- Frame Combustion Turbine (Frame CT) – 3x and 4x
- Aeroderivative Combustion Turbine (Aero CT) – 2x, 4x, 10x, 20x
- Reciprocating Internal Combustion Engine (RICE) – 2x, 6x, 12x

Frame CTs are available with three or four turbines, Aero CTs are available in packages of two, four, ten or twenty turbines, and RICE are available in packages of two, six, or twelve turbines (largest configurations shown in the table below).

Table E-8: Gas Expansion Options and Key Assumptions

Key Assumptions	CC	CC w/CCS	Frame CT	Aero CT	RICE
Summer Net Dependable Capacity (MW)	2,145	1,430	884	1,060	216
Unit Availability (First Year)	2032	2033	2032	2032	2032
Standard / High Growth Annual Build Limit (Units)	2 / 3	1 / 1	2 / 3	2 / 3	2 / 3
Cumulative Build Limit (Units)	-	11	-	-	-
Book Life (Years)	30	30	30	30	30
Overnight Capital Cost ($/kW)	2,148	3,635	1,161	2,513	2,305
Summer Full-load Heat Rate (Btu/kWh)	6,665	7,832	10,087	9,392	8,607
Annual Outage Rate (%)	14.2	14.2	2.2[1]	2.2[1]	2.0[1]
Variable Operating and Maintenance ($/MWh)	1.01	5.04	Start-based	9.07	7.11
Fixed Operating and Maintenance ($/kW-year)	45.69	188.75	5.95	23.72	43.91

[1]Simple-cycle gas expansion options also include annual energy limits based on typical permitting requirements

Cost estimates for gas units are based on recent project experience and discussions with equipment manufacturers. Variable costs for Frame CTs are modeled using a start cost mechanism. The CO_2 emissions rate for a typical gas unit is 117 pounds per million BTUs of gas burned. CCS technology capturing 90% of the emissions would reduce the CO_2 rate to 11.7 pounds per million BTUs of gas burned. In scenarios that include a carbon tax, the modeled gas units incur emissions charges based on a dollar-per-ton emission penalty. Incremental CCS costs include capture equipment, transportation, and storage with these components accounted for across overnight capital, variable operating and maintenance and fixed operating and maintenance cost categories. A total cumulative build limit has also been included for CC with CCS based on current expectations for storage availability in or around the Tennessee Valley. The figure below shows the trend in overnight capital costs for the gas resource options including the impact of inflation and any applicable investment tax credits.

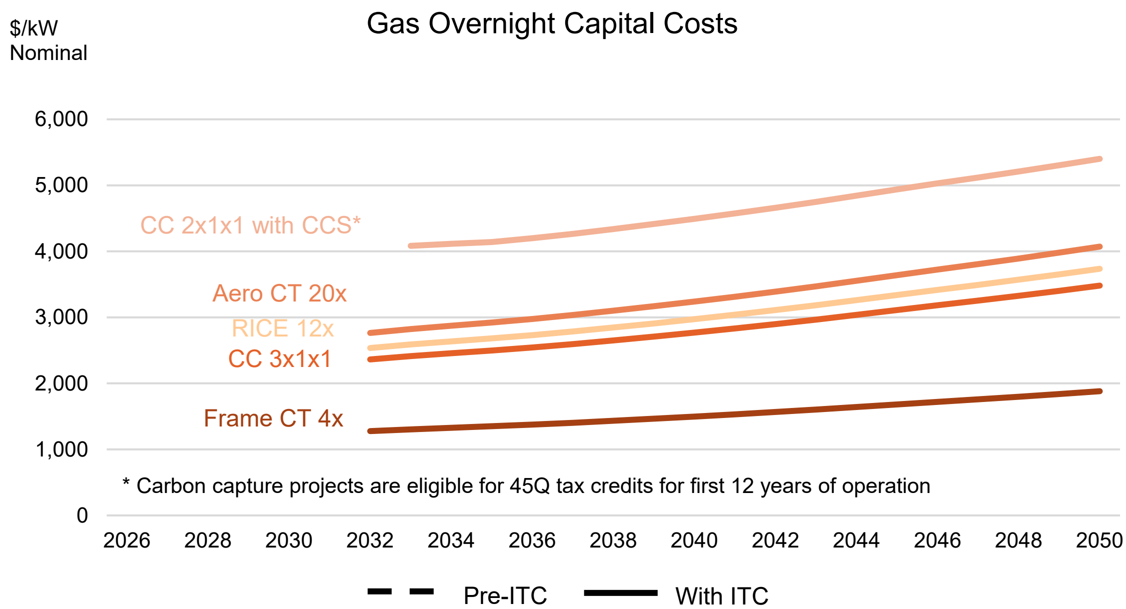

Figure E-4: Gas Overnight Capital Costs

E.7 Solar Resource Modeling

Existing Solar Resources

Through several programs, TVA purchases renewable power (primarily solar, some biomass) totaling 301 MW of capability. As of FY26, TVA has long-term power purchase agreements for 1,438 MW of operating solar nameplate capacity and has contracted for an additional 2,528 MW of solar nameplate capacity expected to come online over the next few years, bringing the total solar amount contracted (operating and in development) to approximately 4,250 MW. Operating solar installations were included in existing assets for the IRP analysis. TVA obtains renewable energy credits from these sites, and existing agreements extend through the mid-2030s to early 2040s. TVA also owns approximately 1 MW of solar capability across nine operating solar installations.

Solar Resource Options

In the IRP analysis, one utility-scale solar expansion resource option is available to fill the expected capacity gap:

- Single-axis Tracking Solar

Single-axis tracking solar allows the solar panels to follow the sun. Solar generation is weather and location dependent, and solar is an energy and capacity limited resource. TVA uses an hourly energy production profile to dispatch solar to reflect the amount of solar generation expected to occur across daylight hours for each season. The figure below illustrates how seasonal load shapes and solar generation compare. Solar output in the TVA region is lower than in some other regions in the U.S. due to lower overall levels of solar irradiance, which is driven by factors such as the number of sunny days and humidity levels. TVA also applies a capacity credit since only a portion of the nameplate capacity of a solar unit can be expected at the time of the system peak. Currently, TVA anticipates 68% and 15% of initial incremental solar nameplate capacity to be available to meet summer and winter peak requirements, respectively, and these amounts decrease as solar installation on the system increases (see Appendix D.2 for more information on solar capacity contribution).

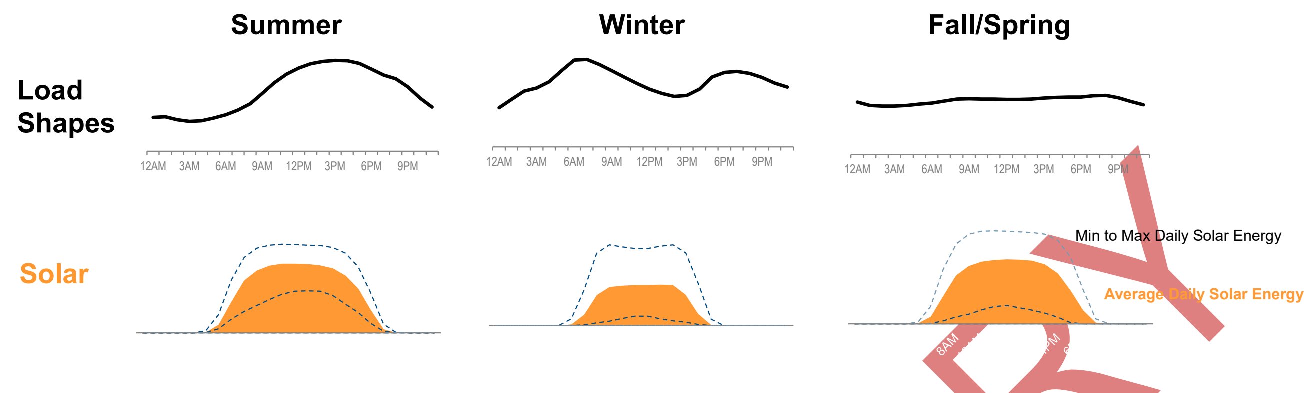

Figure E-5: Illustration of Load and Solar Generation Profiles

The table below shows the key operating characteristics used to model the solar expansion option. This option is modeled as a power purchase agreement, but TVA could choose to pursue a combination of contracted solar expansion and self-directed solar builds. All capacities are stated in alternating current terms.

Table E-9: Solar Expansion Options and Key Assumptions

Key Assumptions	Single-Axis Tracking
Nameplate Capacity (MW)	50
Summer Net Dependable Capacity (first 500 MW at 68% NDC, declines thereafter)	34
Winter Net Dependable Capacity (first 500 MW at 15% NDC, declines thereafter)	7
Capacity Factor (%)	25
Unit Availability (First Year)	2031
Standard / High Growth Annual Limit (MW)	1,000 / 1,500
Book Life (Years)	20
Overnight Capital Cost ($/kW)	1,698

Solar resource costs are based on the costs in recent market-based requests for proposal for solar PPAs, with a learning rate applied based on NLR's 2024 annual technology baseline. Effectively, this learning rate offsets the impacts of inflation over the long-term. As solar resource options were modeled as power purchase agreements (PPA), operating and maintenance costs are included in the PPA cost.

The figure below shows the trend in overnight capital costs for the solar resource option including the impact of the learning rate, inflation, and any applicable investment tax credits.

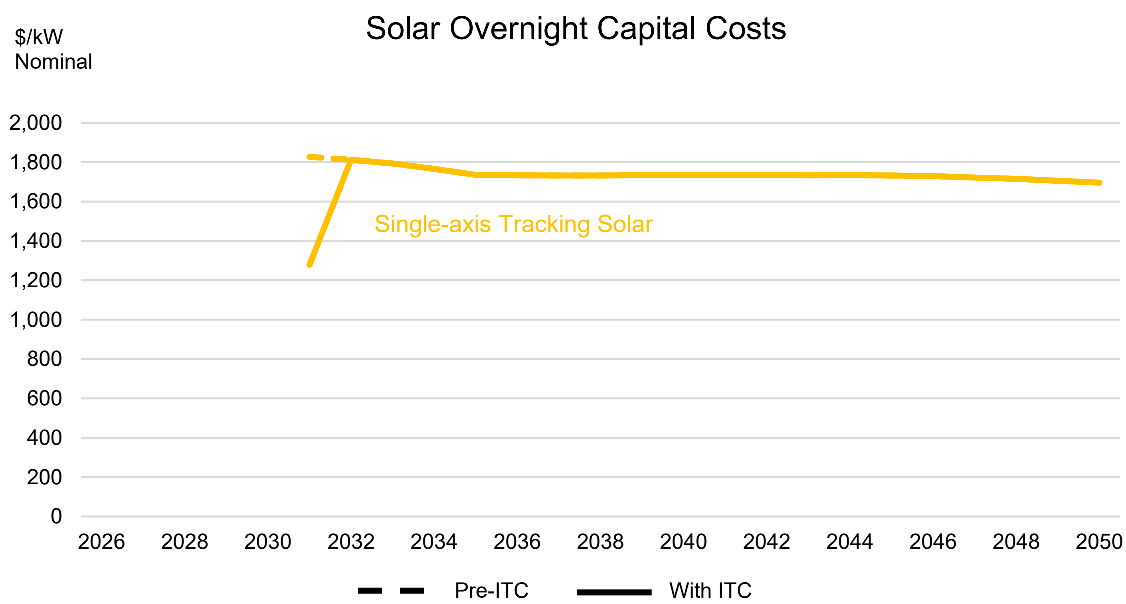

Figure E-6: Solar Overnight Capital Costs

E.8 Wind Resource Modeling

Existing Wind Resources

TVA has long-term power purchase agreements with seven wind farms, all located in the Midwest, which expire by the early 2030s. These facilities provide 920 MW of nameplate capacity.

Wind Resource Options

In the IRP analysis, three wind expansion options are available to fill the expected capacity gap:

- Midwest Wind
- Southeast High-hub Wind

Midwest Wind is sourced from neighboring service territories, requiring wheeling across one or more transmission areas into TVA's system. This option serves as a general proxy for importing wind from other regions, recognizing that costs will vary somewhat depending on the specific location. For the Southeast option, higher hub heights are necessary due to relatively lower wind speeds in the region, and this local option does not incur transmission wheeling costs.

Wind generation is also weather and location dependent, and it is more variable across all hours than solar. As wind is an energy and capacity limited resource, TVA uses an hourly energy production profile to dispatch wind energy to reflect the amount of wind generation expected to occur across the day for each season. This "wind shape" for existing sites is based on actual data for those sites, and TVA assumed somewhat higher overall output for future generation to reflect the newer technology of wind turbines. The figure below illustrates how seasonal load shapes and wind generation compare. TVA also applies a capacity credit since only a portion of the total nameplate capacity of a wind turbine can be expected at the time of the system peak. Currently, TVA anticipates 19% and 33% of initial incremental wind nameplate capacity to be available to meet summer and winter peak requirements, respectively, and these amounts decrease as wind installation on the system increases (see Appendix D.2 for more information on wind capacity contribution).

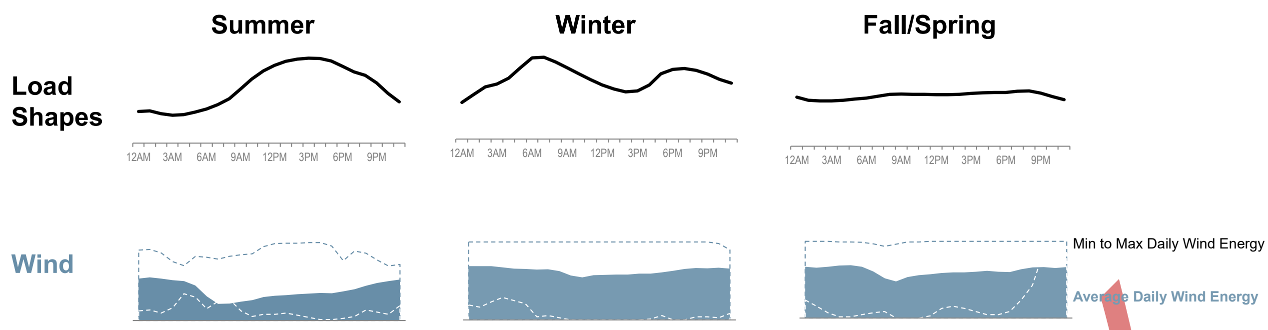

Figure E-7: Illustration of Load and Wind Generation Profiles

The table below shows the key operating characteristics used to model the wind expansion options. The Midwest option is modeled as a power purchase agreement while the Southeast high hub option is modeled as a self-directed build, but could ultimately be contracted as well.

Table E-10: Wind Expansion Options and Key Assumptions

Key Assumptions	Midwest Wind	Southeast High-hub Wind
Nameplate Capacity (MW)	200	200
Summer Net Dependable Capacity (first 500 MW at 19%)	38	38
Winter Net Dependable Capacity (first 500 MW at 33%)	66	66
Capacity Factor (%)	40	30
Unit Availability (First Year)	2031	2031
Standard / High Growth Annual Limit (MW)	1,000 / 1,400	1,000 / 1,400
Book Life (Years)	20	20
Overnight Capital Cost ($/kW)	1,574	2,205
Fixed Operating and Maintenance Cost ($/kW-year)	98.60	33.00

Midwest and Southeast high-hub estimates were developed from the NLR 2024 ATB conservative case. Costs to import Midwest Wind to the TVA region are included in fixed operating and maintenance costs.

The figure below shows the trend in overnight capital costs for the wind resource options including the impact of inflation and any applicable investment tax credits.

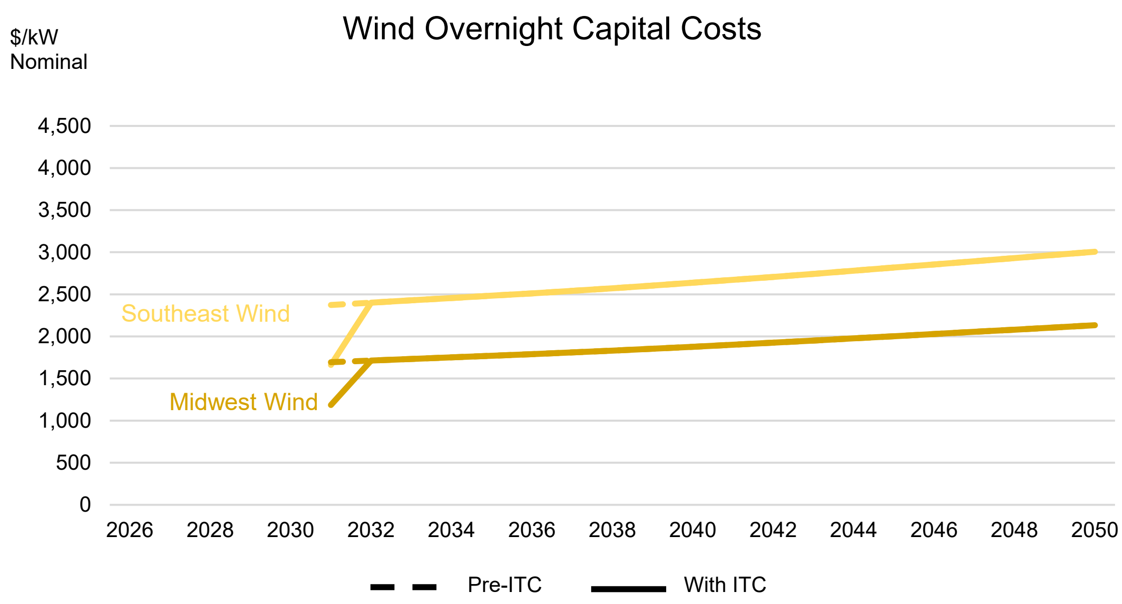

Figure E-8: Wind Overnight Capital Cost

E.9 Storage Resource Modeling

Existing Storage Resources

TVA operates one large storage facility. The Raccoon Mountain Pumped Storage Plant has four generating units with a capability of 1,715 MW, providing critical flexibility to the TVA system by storing water at off-peak times for use when demand is high. In conjunction with several solar contracts, TVA has also contracted for battery storage, with 100 MW currently operating and an additional 270 MW expected to come online over the next few years. Also, TVA is building a 20 MW battery facility in Vonore, Tennessee, to gain direct experience with battery storage construction and operation.

Storage Resource Options

In the IRP analysis, three utility-scale storage expansion options are available to fill the expected capacity gap:

- Pumped Storage
- Lithium-ion Battery (4-hour)
- Advanced Chemistry Battery (8-hour)

The pumped storage option would use reversible turbine generators to pump water up to a higher altitude reservoir during periods of excess power and use water flowing from the upper to lower reservoir to power the turbines when energy is needed. Two different types of battery storage technologies were modeled. Lithium-ion is the prevalent technology today, and it is best suited for shorter durations, so a four-hour version was modeled. Advanced chemistry battery storage technologies are developing that would enable longer durations of storage, so an 8-hour version was modeled. Storage efficiency is modeled for all of these options due to the energy losses inherent in the conversion process and the loss of water during storage. Storage efficiency represents the efficiency of one cycle (i.e., pumping/releasing water, charging/releasing battery power).

The table below shows the key operating characteristics used to model the storage expansion options.

Table E-11: Storage Expansion Options and Key Assumptions

Key Assumptions	Pumped Storage	Lithium-ion Battery (4-hour)	Advanced Chemistry Battery (8-hour)
Nameplate Capacity (MW)	1,212	50	50
Unit Availability (First Year)	2035	2031	2031
Standard / High Growth Annual Build Limit (MW)	1,212 / 1,212	500 / 750	500 / 750
Cumulative Build Limit (Units)	1	-	-
Book Life (Years)	100	20	20
Overnight Capital Cost ($/kW)	3,191	2,158	3,886
Storage Efficiency (%)	81	85	85
Annual Outage Rate (%)	5	5	5
Variable Operating and Maintenance ($/MWh)	0.00	0.00	0.00
Fixed Operating and Maintenance ($/kW-year)	12.17	44.87	80.33

Pumped storage cost estimates were developed using information from the evaluation of potential pumped storage sites. Lithium-ion battery cost estimates were derived from recent request for proposal offers. Effectively, this learning rate offsets some of the impacts of inflation over the long-term. Advanced chemistry batteries are used as a proxy for a number of mature and emerging longer-duration battery technologies. Costs for advanced chemistry batteries were set based on a proportional increase in 4-hour to 8-hour lithium-ion battery costs in the NLR 2024 ATB. TVA will monitor developments in alternative long-duration storage technologies to inform future planning. Batteries are modeled as fixed augmentation and maintenance agreements, so anticipated variable operating and maintenance costs are negligible.

The figure below shows the trend in overnight capital costs for the storage resource options including the impact of inflation and any applicable investment tax credits.

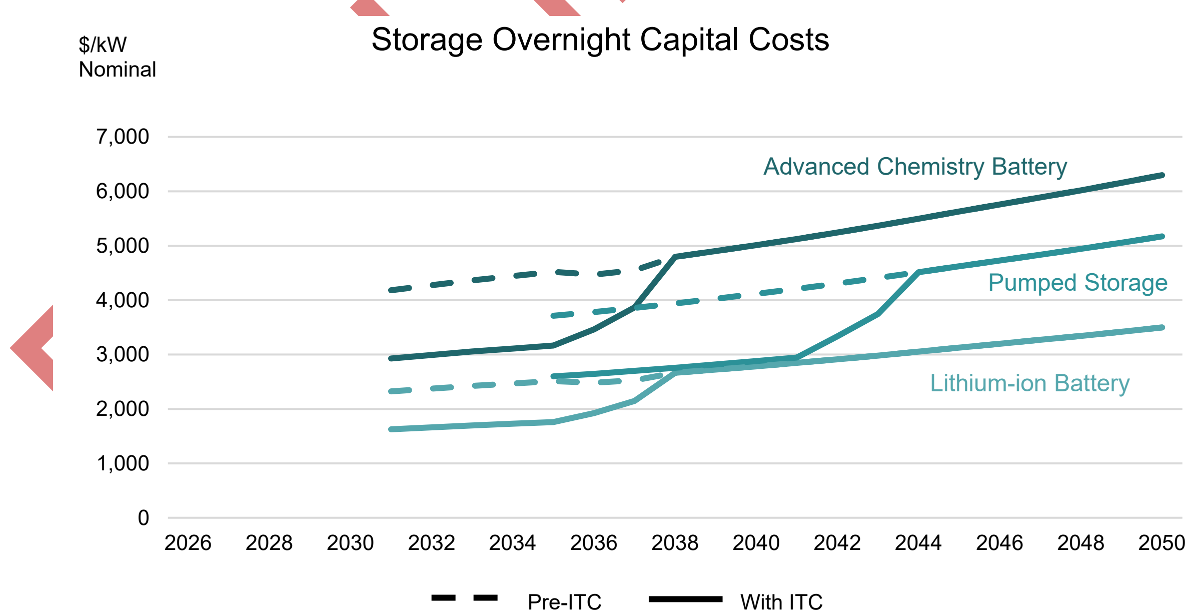

Figure E-9: Storage Overnight Capital Cost

E.10 Environmental Parameters for Resource Options

To analyze the environmental impacts of the supply-side resource options evaluated in the IRP, assumptions for rate of fuel usage, emissions, and land requirements are needed. The table below provides the assumptions for these factors by resource type and technology.

Table E-12: Environmental Parameters for Resource Options

	Resource Option	Summer NDC or Nameplate (MW)	Summer Full-Load Heat Rate (Btu/kWh)	Storage Efficiency (%)	CO_2 Emissions (lbs/MWh)	SO_2 Emissions (lbs/MWh)[1]	NOx Emissions (lbs/MWh)	Hg Emissions (lbs/MWh)	Process Water Use (Gallons/MWh)	Process Water Consumption (Gallons/MWh)	Facility Land Requirements (Acres/MW)	Facility Land Requirements Permanently Disturbed (Acres)
Nuclear	APWR	1,110	10,132	-	-	-	-	-	1,289	859	0.40	460
	SMR – Light Water (First-of-a-Kind)	285	10,296	-	-	-	-	-	719	539	0.63	180
	SMR - Light Water (Nth-of-a-Kind)	285	10,296	-	-	-	-	-	719	539	0.63	180
	SMR - Gen IV (reactor / with storage)	345/500	8,308	-	-	-	-	-	719	539	0.63/ 0.08	229
Hydro	Hydro Uprates	200	-	-	-	-	-	-	-	-	-	-
Coal	Coal Supercritical Pulverized	650	10,548	-	1,160	0.333	1.194	2.98E-09	82,445	329	0.69	449
	Coal Supercritical Pulverized with CCS	650	10,548	-	116	0.333	1.194	2.98E-09	82,445	329	0.69	449
Gas	CC – 3x1x1	2,145	6,665	-	397	-	0.081	-	250	195	0.08	114
	CC with CCS – 2x1x1	1,430	7,832	-	40	-	0.081	-	250	195	0.08	114
	Frame CT– 4x	884	10,087	-	590	-	0.363	-	130	130	0.10	88
	Aero CT – 20x	1,060	9,392	-	548	-	0.337	-	130	130	0.08	85
	RICE – 24x	426	8,607	-	504	-	0.310	-	130	130	0.15	64
Solar	Solar Single-Axis Tracking	50	-	-	-	-	-	-	-	-	7.30	365
Wind	Wind - Midwest	200	-	-	-	-	-	-	-	-	0.80	160
	Wind – Southeast High-hub	200	-	-	-	-	-	-	-	-	1.00	200
Storage	Pumped Storage	1,212	-	81	-	-	-	-	-	-	0.88	1,408
	Battery – Lithium-ion (4-hour)	50	-	85	-	-	-	-	-	-	0.08	4
	Battery – Advanced Chemistry (8-hour)	50	-	85	-	-	-	-	-	-	0.08	4

[1]Trace amounts of SO2 emissions (US EPA default emission rate of 0.0006 lb/mmBtu) associated with sulfur-containing odorants added to pipeline-delivered natural gas not included.

F

Appendix F – Distributed Generation Resource Methodology

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Appendix F – Distributed Generation Resource Methodology

In addition to utility scale resources, the IRP also considers distributed generation (DG) resource options. Recent technology advancements and consumer preference have led to increased interest in DG. The IRP focuses on two sources of DG – distributed solar and storage. The IRP analysis includes baseline forecasts for DG adoption for each scenario and forecasts for higher levels of adoption when emphasized in an alternative strategy. To complement Chapter 2 that summarized key assumptions for the resource options, this appendix covers the evolution of TVA's DG programs and the modeling approach for DG in the IRP analysis.

F.1 Overview and Background

At TVA, DG was introduced through the Dispersed Power Program (DPP) in 1981 to comply with provisions of the Public Utility Regulatory Policies Act of 1978. DPP's primary aim was to allow commercial and industrial customers the ability to sell back excess generation to the grid. Over time, TVA's DG programs have evolved with the maturity of the technology and the marketplace. Today, TVA offers several programs, such as the mid-scale Generation Flexibility program which facilitates local power company (LPC) community solar offerings for TVA's long-term partners, a more convenient and cost-effective alternative to rooftop installations for consumers to support DG.

TVA utilizes an adoption model to forecast the growth of DG technologies over time. First, the base level of market installation for each distributed resource type is calculated based on assumptions present in the various scenarios. Next, the level of incentives that will apply in certain strategies to reduce payback on investment is determined. Then, an adoption curve approach is used to simulate higher installation levels achieved through improved economics. Next, these new adoption levels are applied in the capacity expansion model as a required resource. Finally, the capacity planning model optimizes the remainder of the resource portfolio in a least cost manner. This DG methodology allows TVA to gain insights into the roles DG could have on the TVA system under a variety of different futures. The individual steps are discussed in greater detail in the following sections.

Figure F-1: Distributed Generation (DG) Resources Modeling Process

F.2 Step 1: Model Base Level of Adoption in Each Scenario

Distributed generation is expected to continue to grow, due to increasing customer demand for energy choice, improved pricing, or both. Likely levels of distributed solar and distributed battery installation were forecasted across the various IRP scenarios. These scenarios include levels of DG that would occur in the market based on unique scenario assumptions before any TVA strategies are employed. For example, a scenario with higher average electric rates driven by regulatory factors would result in improved economics for distributed solar and likely lead to higher adoption by residential, business, and LPC customers. The Higher Growth scenario shows the highest levels of forecasted DG, whereas the Reference scenario shows the lowest levels of DG. The figure below shows projected base levels of DG, by resource type, deployed by 2040 and 2050 in each scenario, prior to any additional TVA incentives.

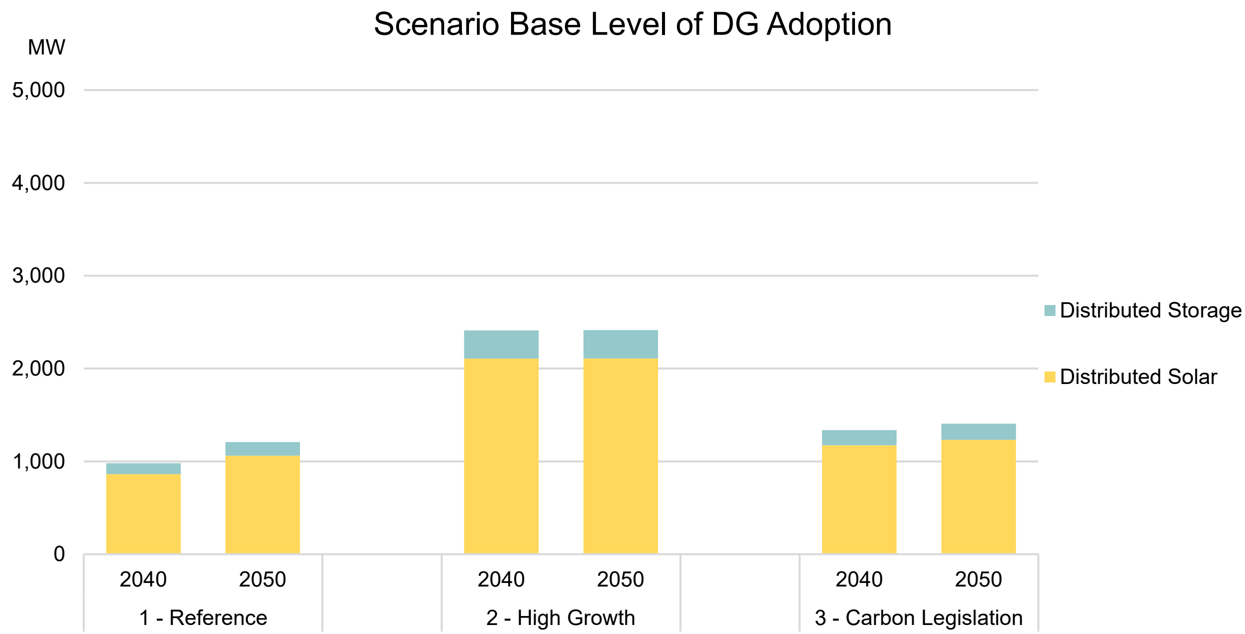

Figure F-2: Base Levels of DG in Each Scenario by 2040 and 2050

See Appendix B – Scenario Design and Forecasts for further information on how unique assumptions around DG were developed for each scenario. As each strategy is applied in a scenario, the base level of adoption in each scenario sets the baseline comparison.

F.3 Step 2: Determine Incentive Level to Apply in a Strategy

The Distributed strategy emphasizes increased DG uptake using a monetary incentive to increase adoption of distributed solar by reducing its payback period, or the number of years to recoup the upfront investment of installation. While resources can provide energy and capacity, IRP modeling takes a simplified approach to use the marginal energy cost in each scenario to determine the amount of distributed solar incentives. Distributed storage is modeled using a percentage capacity match to distributed solar, as they are often paired for improved resiliency and economics. A base incentive level aligns to no additional incentive beyond existing programs. At a base level, distributed storage is assumed to be installed at a 15% capacity match. This means that for every 100 MW of distributed solar, an additional 15 MW of battery storage is included. Incentives are used to emphasize DG and for distributed solar are modeled at 100% of the scenario's baseline (Strategy A) marginal energy cost, and distributed storage is assumed to be installed at a 50% capacity match of the distributed solar capacity.

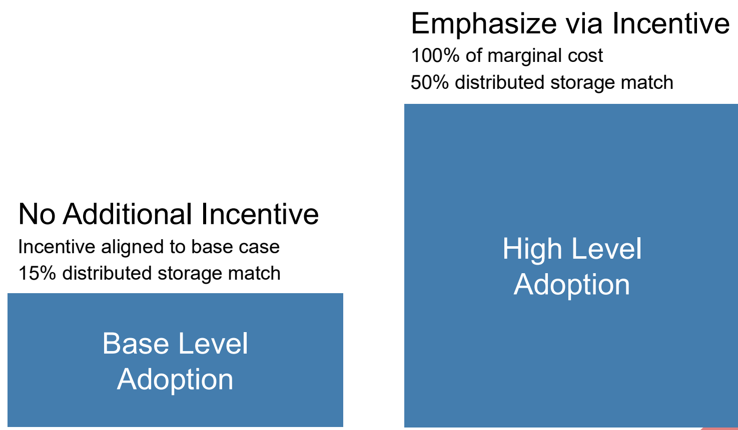

Figure F-3: Description of DG Promotion Levels

Applying an incentive in the Distributed strategy allows TVA to test the impacts of increased DG installation. The matrix below shows the incentive levels by DG resource type for each strategy.

Table F-1: Distributed Generation Promotion Levels by Strategy

Strategy	Distributed Solar	Distributed Storage
Baseline	Base	Base
Innovation	Base	Base
Distributed	Emphasize	Emphasize

For additional information on strategy development, see Appendix C – Strategy Design and Application.

F.4 Step 3: Develop New Adoption Level based on Economics

Base and high installation levels for DG resources were determined using an adoption curve approach. The approach used is similar to the National Laboratory of the Rockies' (NLR's) (formerly the National Renewable Energy Laboratory or NREL) Distributed Market Demand Model, which simulates potential adoption of a given resource as a function of payback period. Factors specific to each scenario and strategy combination were fed into a TVA-developed DG model to create a unique adoption level for each resource for the long-term planning horizon.

The key elements in NLR's model are the payback period, maximum market share and adoption curve. The payback period determines the maximum market share, or depth, for a DG technology. It also influences the pace of adoption. The concept behind the NLR model is illustrated below, and a simplified application of this model in the IRP is further explained in the following sections.

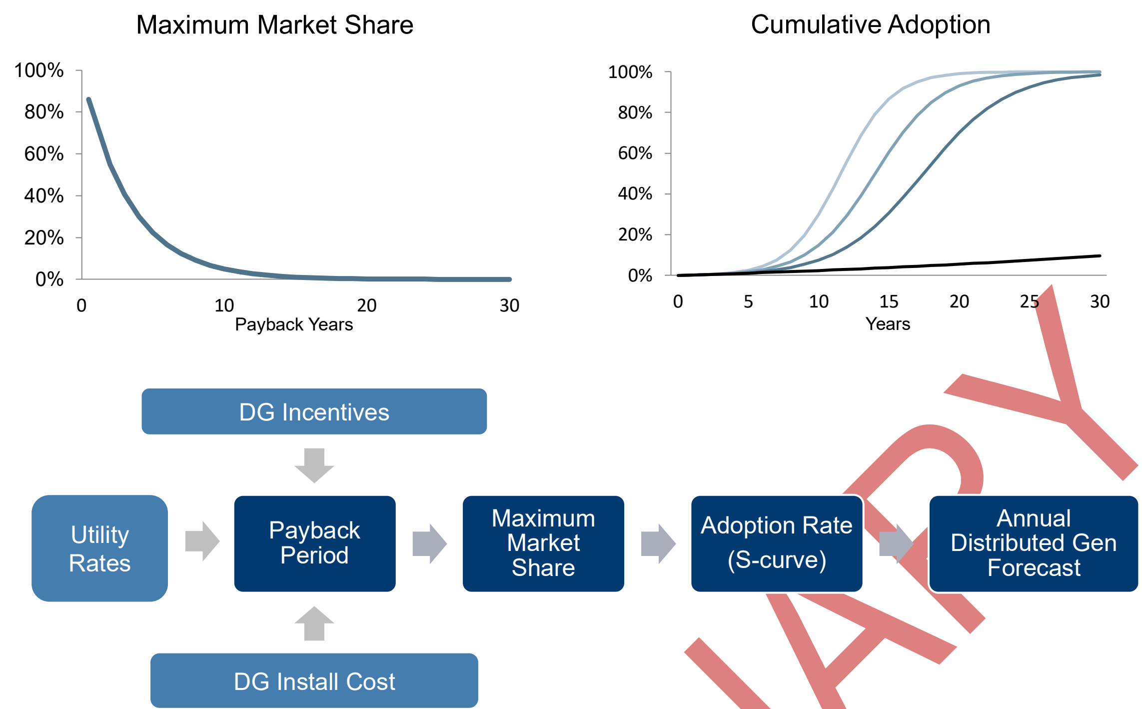

Figure F-4: Concept Illustration of NLR's Distributed Market Demand Model

Payback Period

A key element in the model is the payback period, which is simply the number of years required for a consumer to recoup the upfront costs of an investment. Ignoring discount rates, an example project requiring an upfront capital investment of $10,000 that saves a net $1,000/year will have a payback period of 10 years. The shorter the payback period, the greater the market depth, as more Valley residents see value in adopting a particular technology. Even with an acceptable payback period, not all consumers will adopt the technology at the same time. This occurs for a variety of reasons. Some consumers are more comfortable using new technologies than others and are likely to adopt sooner, while others will wait. Also, a consumer must have access to the capital required to cover the initial costs of the technology investment. Even with the necessary capital, whether or when a consumer purchases a technology depends on competing uses for the funds and other practical considerations. All these factors impact the pace of DG adoption, which happens over the course of years or decades and is generally faster with quicker payback periods.

Payback Components

There are two primary components in calculating payback for a DG installation – electricity bill savings and the required investment. To estimate electricity bill savings, forecasts for residential and commercial average effective rates were applied to the average annual energy output of a DG system. Next, it was necessary to estimate projected prices for distributed solar systems. Pricing information for DG resources was derived from NLR projections found in the 2024 ATB.

Escalation rates for DG resources can vary by scenario, driven by assumptions around tax policy and macroeconomic growth projections. The figure below shows assumptions for distributed solar cost projections. Cost projections are listed in real 2022 dollars, as this is the format provided in the 2024 NRL ATB.

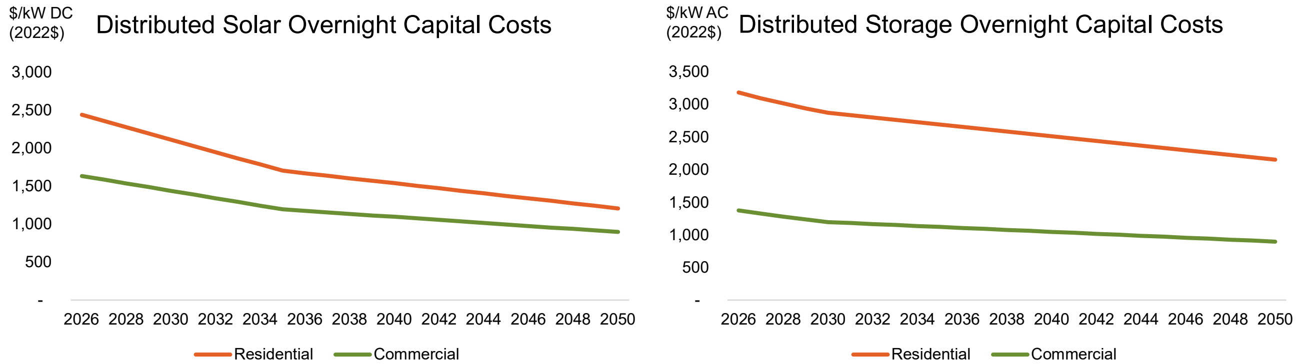

Figure F-5: Distributed Solar and Storage Price Forecast

Adoption Levels

Using the calculated payback period, and considering assumptions unique to each scenario and strategy combination, the DG model provides forecasts for the following:

- Base levels of DG in each scenario, considering TVA programs and payback period without additional incentives
- Levels of DG with high incentives in each scenario

An example of the DG model output illustrating the resulting levels of DG adoption through time for the Reference scenario is shown in the figures below.

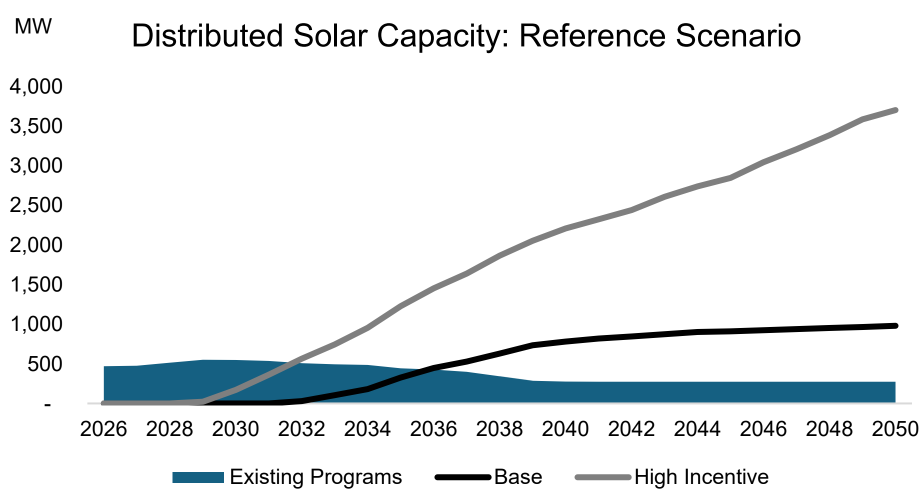

Figure F-6: Distributed Solar Capacity, Reference Scenario

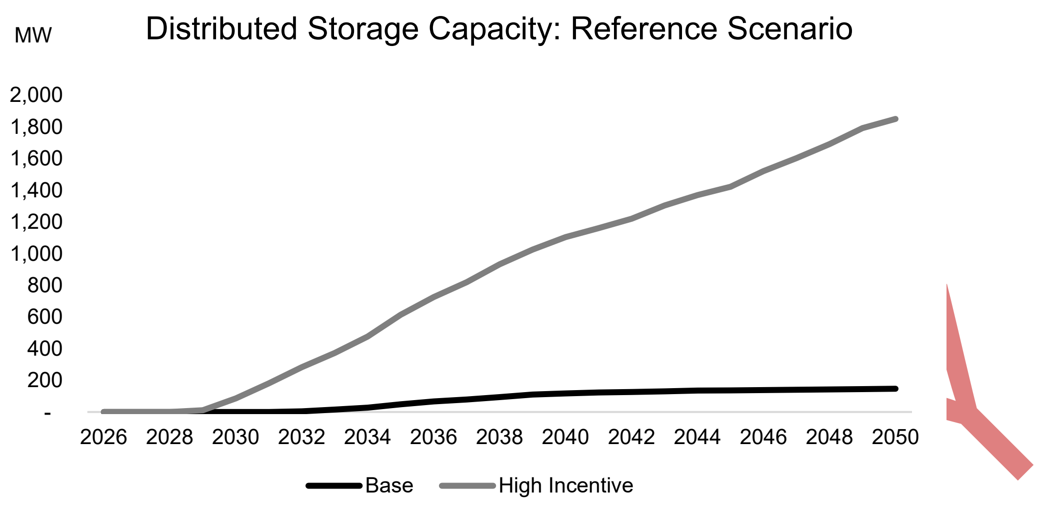

Figure F-7: Distributed Storage Capacity, Reference Scenario

F.5 Step 4: Apply New Adoption Level in Expansion Model

Once the DG adoption curves are created for distributed solar and distributed storage, they are imported into the expansion model. A unique set of DG adoption levels is fed into the expansion model for each scenario and strategy combination. The DG adoption levels are treated as required resources, or effectively a constraint the model considers prior to optimization of other resources. Forecasted DG adoption by resource type for all nine core portfolios by 2050 is shown below.

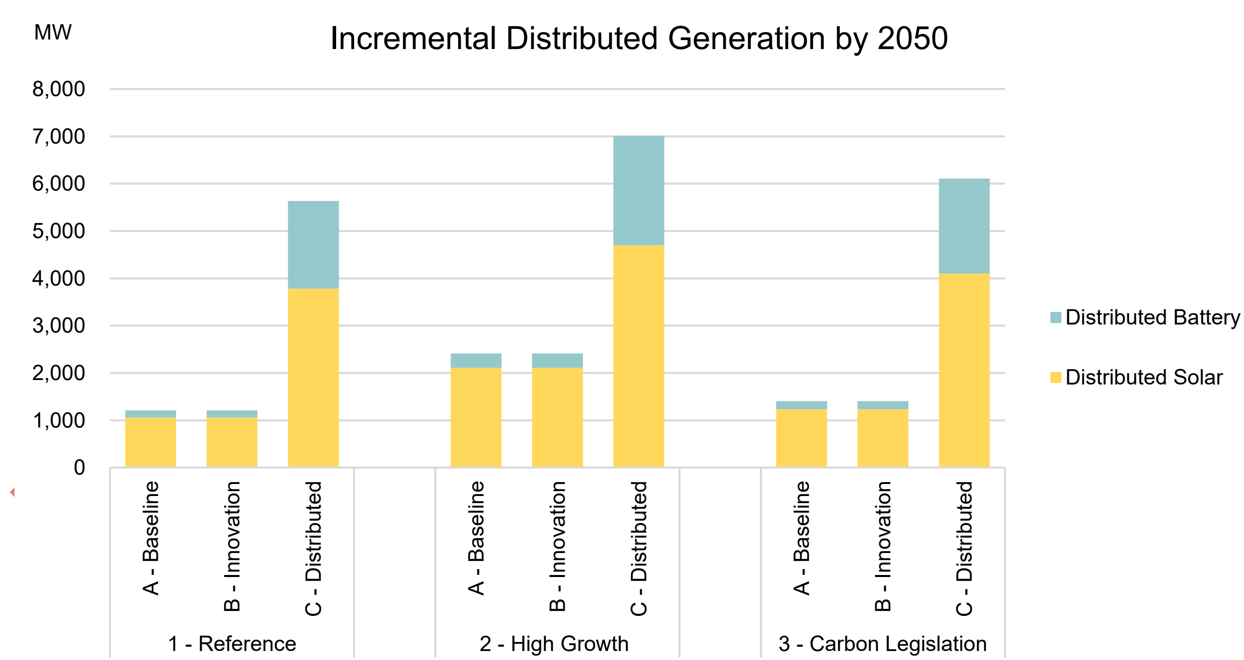

Figure F-8: Distributed Generation Capacity by 2050

F.6 Step 5: Optimize Balance of Resources for the Portfolio

After the DG adoption curves for distributed solar and distributed storage are imported into the expansion model as required resources, the expansion model will then be run to optimize the remainder of the portfolio. This action is performed for each scenario and strategy combination, considering the aims and bounds of the strategy and all available generation and programmatic resources. The reserve margin is an important consideration in this step, ensuring that the expansion path chosen results in a portfolio that meets or exceeds seasonal reserve margin requirements to support a reliable system at the lowest feasible cost for a given strategy.

F.7 Conclusion

TVA's 2026 IRP utilizes the innovative methodology first used in the 2019 IRP to forecast the impact of alternative strategies on DG installation across various future scenarios. The method simulates the effect of monetary incentives reducing payback period and driving higher adoption of DG technologies. Results from the model provide insights into the impact that DG could have on the TVA system under a variety of different futures. These insights will inform future planning and program design as part of the region's future energy system.

TVA

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Appendix G – Demand-side Resource Methodology

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Appendix G – Demand-side Resource Methodology

In addition to utility scale and distributed generation resources, the IRP also considers demand-side options. Demand-side resource options evaluated in the IRP include energy efficiency (EE) and demand response (DR) programs. These offerings can include incentive programs, pricing products, and educational efforts to encourage informed consumer choice and reduction in energy usage. Leveraging the latest potential study and recent market experience, the IRP evaluates a set of EE and DR program options, with programs promoted in alternative strategies. To complement Chapter 3 that summarized key assumptions for the resource options, this appendix discusses the evolution of TVA's energy programs and the modeling approach used for EE and DR in the analysis.

G.1 Background

TVA's EE and DR programs are offered under the EnergyRight® brand spanning the residential, commercial, and industrial sectors. Over the years, TVA programs evolved to suit the changing energy landscape, as depicted in Figure G-1. For over 30 years, TVA has offered DR programs that incent commercial and industrial customers to reduce loads during periods of high demand. Since the mid-2000s, TVA has facilitated EE programs that incentivize energy efficiency across all sectors.

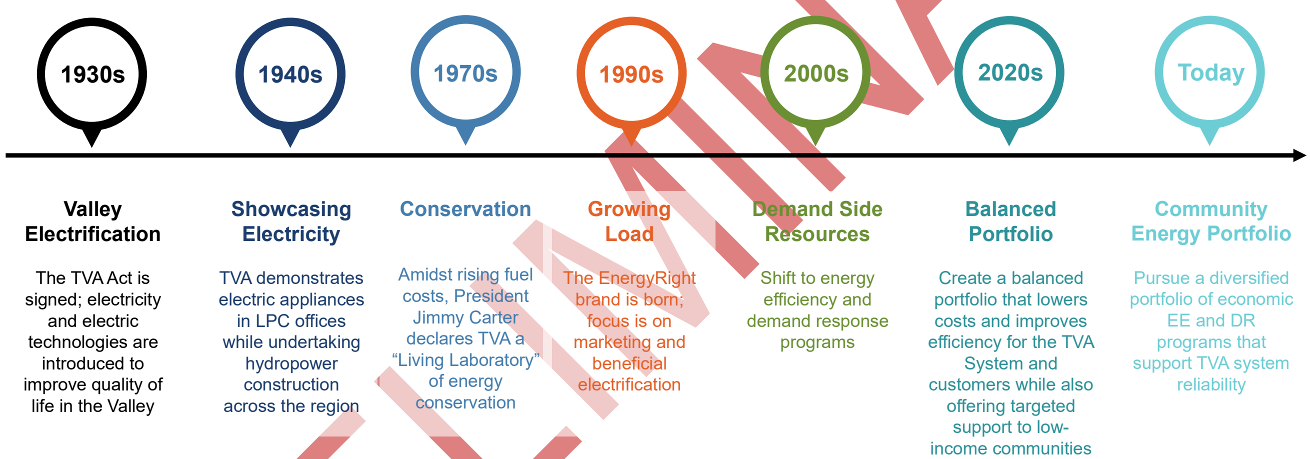

Figure G-1: TVA Energy Programs, A History of Consumer Engagement

G.2 Demand-side Resource Overview

EE programs target efficiency upgrades and improvements to reduce system load across many hours. Programs provide incentives or educational opportunities to spur consumers to make efficiency improvements in their homes or businesses above and beyond current codes and standards. DR programs reduce system load at peak hours and potentially offset or delay the need for more expensive peaking capacity or power purchases.

Over the past several years, TVA has significantly expanded its demand-side resource portfolio to help meet growing forecasted energy and capacity needs across the Valley. In 2023, TVA announced a major expansion of energy efficiency and demand management efforts, supported by over $1.5 billion in dedicated funding through FY 2028. This investment strengthens TVA's ability to manage long-term system needs, reduce peak demand, and provide cost-effective alternatives to new generation.

Building on this commitment, TVA has launched and scaled a suite of new and reinvigorated EE offerings over the past nearly three years. These programs reintroduced incentives across residential, commercial, and industrial sectors; expanded midstream and retail pathways; and enhanced customer engagement through the EnergyRight® platform. As these offerings have grown, TVA has seen increasing customer uptake and measurable energy and demand reductions, with additional momentum accelerating in 2025 as market participation strengthened.

Demand response resources continue to evolve as well, with TVA growing programs for industrial, commercial and residential customers—including the 2025 launch of the Smart Thermostat Reward program, which enables customers to reduce heating, ventilation, and air conditioning (HVAC) usage during peak events and enhances TVA's flexibility to maintain system reliability.

While TVA's demand-side portfolio serves customers across all segments, TVA also maintains targeted support for households and communities with higher energy burdens. TVA introduced its Home Uplift program in 2018, in partnership with local power companies and communities. By FY 2019, about 1,300 Valley residences were retrofitted with more energy efficient technology for heating and cooling, water heating, and insulation. This number grew to about 7,900 retrofitted residences by the end of FY 2025, reducing system energy needs by more than 28,000 megawatt hours, benefitting low-income households. TVA provides matching funds for local power companies and local communities to support this program. Additionally, the School Uplift program provides education and efficiency improvements to schools within TVA's service territory, which has especially benefited low-income communities. These initiatives complement TVA's broader EE strategy and remain part of TVA's base-level EE investments.

Together, these expanded EE and DR offerings form the foundation of TVA's demand-side resource analysis in the 2026 IRP. The strategies, assumptions, and modeling approach in this appendix reflect both the significant program momentum achieved in recent years and the role of demand-side resources in meeting TVA's long-term system needs.

G.3 Tiered Approach to Modeling Demand-Side Program Options

To model demand-side program options for the IRP, TVA leveraged an updated potential study and subsequent market experience to estimate load changes and costs of potential EE and DR programs. In 2022, TVA partnered with industry expert DNV to create an updated Energy Programs Potential Study to inform TVA on the achievable potential of EE and DR programs within the Valley. TVA also partners with third-party Evaluation, Measurement & Verification vendors to evaluate, measure, and verify program impacts, and provide insights on the potential impacts of new programs based on their experience working with TVA and other utilities. Additionally, TVA typically conducts a Residential Saturation Survey and a Commercial Saturation Survey every other year to understand market depth and potential reach of programmatic efforts, which vary from region to region. TVA is also an active participant in and member of multiple industry trade organizations that specialize in energy programs, including the Electric Power Research Institute, Association of Energy Services Professionals, and others. Since 2023, TVA has reintroduced incentives across customer segments and significantly increased its presence in the EE and DR markets. Due to inflationary pressures and the unique partnership arrangement between TVA and the LPCs, customer uptake of EE programs has been slower and more costly than anticipated in the 2022 Energy Programs Potential Study though momentum began to increase in 2025 and the portfolio remains cost-effective.

Energy program adoption by customers varies based on a number of factors, with a key driver being the level of financial incentive offered. In the potential study, higher levels of EE adoption or DR participation were forecasted when financial incentives to participate were increased. To simulate this effect in modeling, TVA created several tiers, or buckets, of EE and DR program levels that included increasing numbers of participants along with increasing incentives required to achieve these higher levels of participation. The tiered program offerings are described in the figure below. In each year, the model could select an appropriate level of program participation above Tier 0, or base level, based on TVA's system needs. Alternative strategies explored the impact of increased emphasis on demand-side resources by implementing higher tiers over the study period.

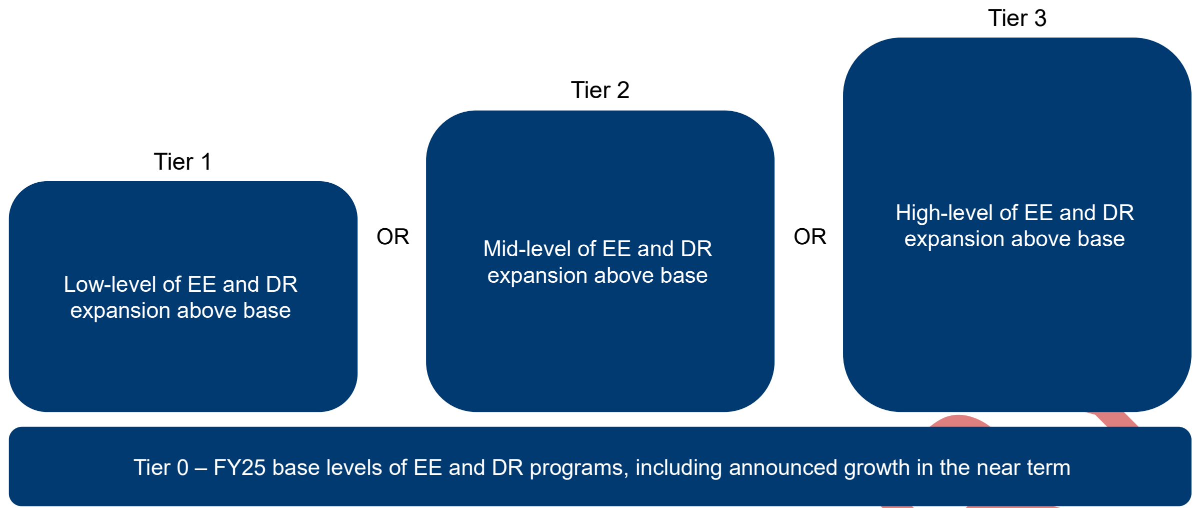

Figure G-2: Programmatic EE and DR Three-Tiered Structure

Tier 0 reflects base levels of demand-side programmatic engagement that are expected to continue into the future, regardless of the strategy employed. Tier 0 includes EE programs that are focused on educational resources, base levels of low-income program funding, and smaller levels of targeted incentives for the highest value programs. Also, Tier 0 reflects TVA's current DR portfolio of approximately 1,800 MW and forecasted near-term growth related to short-term load growth programs. The load growth programs were created as economic development vehicles to facilitate faster interconnection of large commercial and industrial customers prior to new, firm generation resources being constructed. TVA does not anticipate that all of these customers will want to continue with these DR contracts once new firm, dispatchable generation comes online over the next few years.

Tier 1 offerings represent the first tranche of optional EE and DR expansion above the base level. Each successive tier aims to increase participation through increased marketing efforts or increased pricing. At a Tier 3 level, EE and DR program achievable potentials are maximized, based on recent potential study findings and subsequent market experience.

G.4 Demand-side Resource Promotion in IRP Strategies

Strategy design applies a base or increased emphasis aligned to each strategy narrative. The table below summarizes the level of EE and DR promotion applicable in each strategy. A base level of promotion assumes continuation of Tier 0 programs, while a high level of emphasis layers on additional incentives to increase program participation. In all cases, the model is given the flexibility to select higher tiers, if economical. High emphasis generally models the impacts of TVA investment in EE and DR at a Tier 2 or higher level across the entire study period. Emphasis within the Higher Growth scenario (Scenario 2) explores the impact of maximizing TVA investment in EE and DR programs at the Tier 3 level across the entire study period in order to further offset the impacts of the higher demand in this scenario.

Table G-1: Demand-side Resource Promotion by Strategy

Strategy	Energy Efficiency	Demand Response
Baseline Utility Planning	Base	Base
Innovation	Base	Emphasize
Distributed	Emphasize	Emphasize

G.5 TVA Program Characteristics

G.5.1 Energy Efficiency (EE)

EE programs span all customer segments and focus on reducing overall electrical consumption. Since temperature is the largest driver of peak loads, particularly in the residential sector, many EE programs focus on space conditioning (HVAC) and weatherization improvements. Programs may also include more efficient lighting, variable frequency drives, and other custom options tailored to a specific industry.

TVA's residential EE programs are administered through the Residential Services suite of offerings. EnergyRight.com serves as a centralized online resource for residential customers to explore available rebates, as an educational tool, and to build and reinforce consumer trust. Additionally, consumers can use this platform to ensure their contractor has been trained and approved and that their installation has been performed to program standards. Residential customers can also set up appointments for home energy evaluations. Following a home energy evaluation or inspection, the customer will receive a detailed report, including pictures of problem areas and recommendations. Contractor search and validation enables customers to find contractors who have been vetted and trained by TVA, providing peace of mind when selecting a contractor for home improvements. Tiers 1, 2, and 3 in the IRP all include financial incentives to encourage end-use participation. These incentives are generally in the form of rebates following verification that approved home efficiency projects were completed by TVA-vetted contractors or point-of-sale or manufacturer rebates to those purchasing efficient technologies, such as Heat Pump Water Heaters.

TVA's low-income EE programs are an important component of residential EE offerings. Since 2009, TVA has partnered with the state of Tennessee's Weatherization Assistance Program (TN WAP) to provide home energy audit and upgrade services to families with incomes less than or equal to 200% of the federal poverty level for the household size. The DOE provides funding for this program, which is then administered locally by the state of Tennessee. TVA continues to provide administrative and technical support to TN WAP to ensure the state takes advantage of all available DOE funds. TVA's Home Uplift initiative, which was expanded Valley-wide in 2020, augments TN WAP by working with LPCs and local communities to create a sustainable program for making weatherization improvements in low-income households. TVA matches the funds contributed by LPCs, local governments, and non-profit agencies. Continued support for Home Uplift is included in base EE spending.

Commercial and industrial (C&I) EE programs include standard rebates and options for more customized solutions. Tier 0 includes continued support of Strategic Energy Management (SEM), which provides a forum to allow companies to work together to identify and develop solutions for common energy efficiency challenges and implement behavioral energy-saving strategies. For example, a company might discuss the advantages and lessons learned from installing smart thermostats at their facility. SEM has traditionally focused on the industrial sector but is being expanded to include the commercial sector. Tiers 1, 2, and 3 include incentives for C&I programs. Example programs include, but are not limited to, LED lighting retrofits, variable frequency drives, and HVAC upgrades. Industrial projects tend to be highly customized based on a given customer's use case. For custom projects, the customer would provide TVA with a proposed plan, obtain approval for the plan, implement improvements, and receive rebates following verification for completed projects and demonstrated savings.

The impact of EE programs on TVA's load will vary by customer segment, season, and time of day, as illustrated below. Residential EE programs tend to have the greatest impact in late afternoon summer hours when residents are returning home from work, and in early winter morning hours when preparing for the day. Generally, these times align with the highest hours of cooling or heating load. Commercial EE load impacts are typically higher during traditional business hours. Due to round-the-clock shifts, industrial EE impacts are generally more consistent throughout all hours. Sector impacts also vary depending on whether a program targets HVAC, lighting, other equipment, or a combination of these aspects.

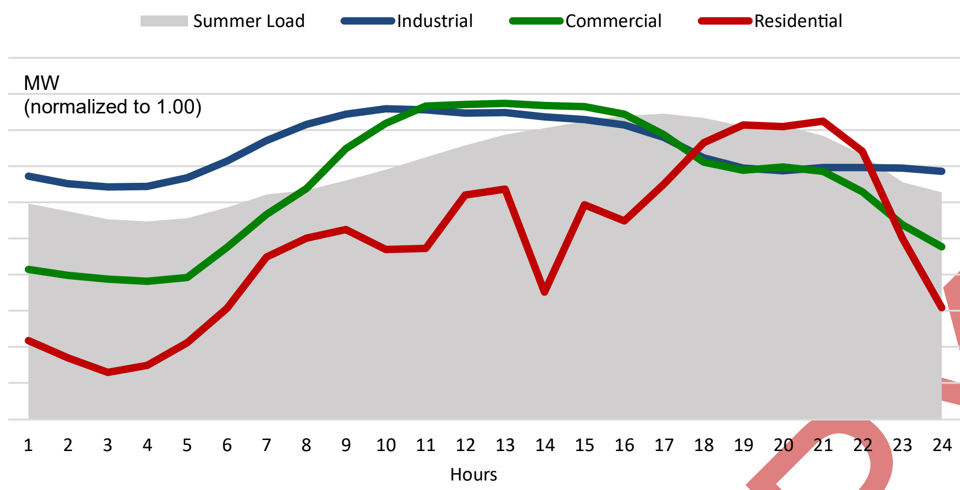

Figure G-3: Illustrative Energy Efficiency Summer Load Shapes (normalized)

G.5.2 Demand Response (DR)

DR resources reduce system load at peak hours. Figure G-4 illustrates summer and winter load shapes, and typical peak or near-peak demand hours around which DR is most likely to be called upon for economic or reliability reasons.

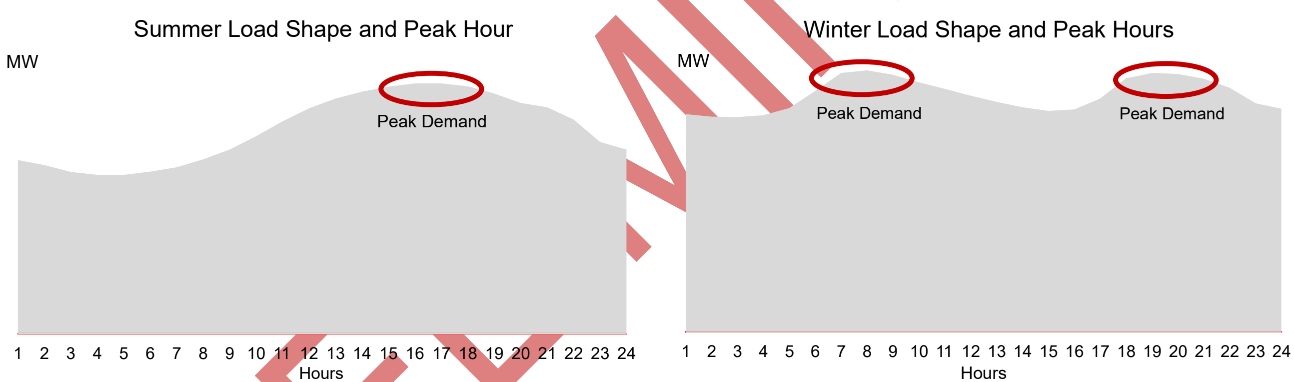

Figure G-4: Seasonal Load Shapes and Typical Peak Demand Hours

Current TVA DR programs include PowerFlex, Interruptible Power (IP), Peak Rewards, Dispatchable Voltage Regulation, load growth programs, and Smart Thermostat Rewards. The IRP assumes existing programs will continue through their respective program lives.

PowerFlex is a pay-for-performance program and is TVA's largest DR program. Large commercial and industrial customers allow TVA to call on them to reduce their electric load when supply is tight or costly, in exchange for financial credits. When called upon, participants in the PowerFlex Emergency-only option are given 5-, 30-, or 60-minutes notice to reduce their load to a specified amount according to their contract. The Emergency-only option may be used for system reliability reasons at TVA's sole discretion without limits. Participants in the PowerFlex Emergency+Capacity option are given 5-, 30-, or 60-minutes' notice to reduce their load to a specified amount for emergency reasons and 30-minutes, four-hours, or 12-hours' notice to reduce for capacity reasons. Participants contract for a maximum number of capacity hours each TVA fiscal year when they initially enroll, ranging from 24 hours to 96 hours or more. PowerFlex currently supplies around 890 MW of load reduction. These programs evolve over time to meet system and customer needs.

IP currently includes the IP30 and IP5 options and is a pay-for-performance program. Large industrial customers allow TVA to call on them to reduce their electric load when supply is tight or costly, in exchange for financial credits. When called upon, participants in the IP30 program are given 30-minutes' notice to reduce their load to a specified amount. The IP30 program may be used for capacity and economic reasons up to 12 hours per TVA fiscal year or for reliability reasons without limits. Participants in the IP5 program are given 5-minutes' notice to reduce their load to a specified amount. The IP5 program can only be used for system reliability. IP currently supplies about 530 MW of load reduction. These programs are no longer enrolling new participants.

Peak Rewards utilizes a third-party program administrator to aggregate smaller commercial and industrial customers to meet load reduction targets. While similar in concept to PowerFlex, Peak Rewards is smaller and currently supplies about 40 MW of net load reduction. The Peak Rewards program may be used for economic or system reliability reasons.

The DVR program works in partnership with LPCs to lower the voltage on their respective systems to the lower half of the acceptable voltage range. Assumptions around the updated version of the program are included in the IRP study.

Load growth programs provide flexible solutions for new and growing load on the TVA system. These programs evolve over time to meet system and customer needs. The IRP includes assumptions on the volume of near-term growth, the lifespan of these load growth programs, and the possibility for terms, such as number of capacity hours, to change over time.

Finally, the IRP study also includes a smart thermostat program. Tier 0 includes spending associated with lower volumes of smart thermostat deployment, while Tiers 1-3 include the potential for further expansion of this program. TVA launched the Smart Thermostat Rewards program to residential participants in early 2025 and expanded the program to include small commercial customers in 2026.

G.6 Model Inputs and Assumptions

For demand-side programs to be offered for selection in the optimization model, certain characteristics must be defined that are comparable to supply-side resources, such as:

- Capacity and energy – typically a known size in MW and MWh, respectively
- Installation cost – typically non-site specific $/kW
- Construction lead time – years to build from initial project consideration
- Operational characteristics – variable energy cost $/MWh, capacity factor, etc.
- Service life – years

Demand-side program characteristics must be developed that are comparable to supply-side resources. Traditional supply-side characteristics are modified to meet the unique attributes of demand-side programs. For example, a traditional generating unit may have a service life of 30 years, whereas the lifespan of an energy efficiency program will be based on the lifespan of the individual measure elements included in that program. Characteristics for programs included in the IRP are further detailed in table G-3.

Characteristics of each program in each sector were developed for all tiers, including additional costs to expand delivery system infrastructures and encourage greater participation. Tier 0 programs generally represent costs for platform infrastructure and business as usual, and as such, have known costs. The steps in cost for Tiers 1 through 3 are similar to a supply stack concept, where programs with more potential are lower cost programs and programs with less potential are higher cost programs. As market depth is exhausted from the lower cost programs or tiers, the optimization model moves up the supply stack to the next lowest cost program or tier.

The figure below illustrates the range of costs for each segment and demand-side program type across all three tiers. C&I programs are typically lower cost on a $/MWh basis compared to residential programs due to economies of scale.

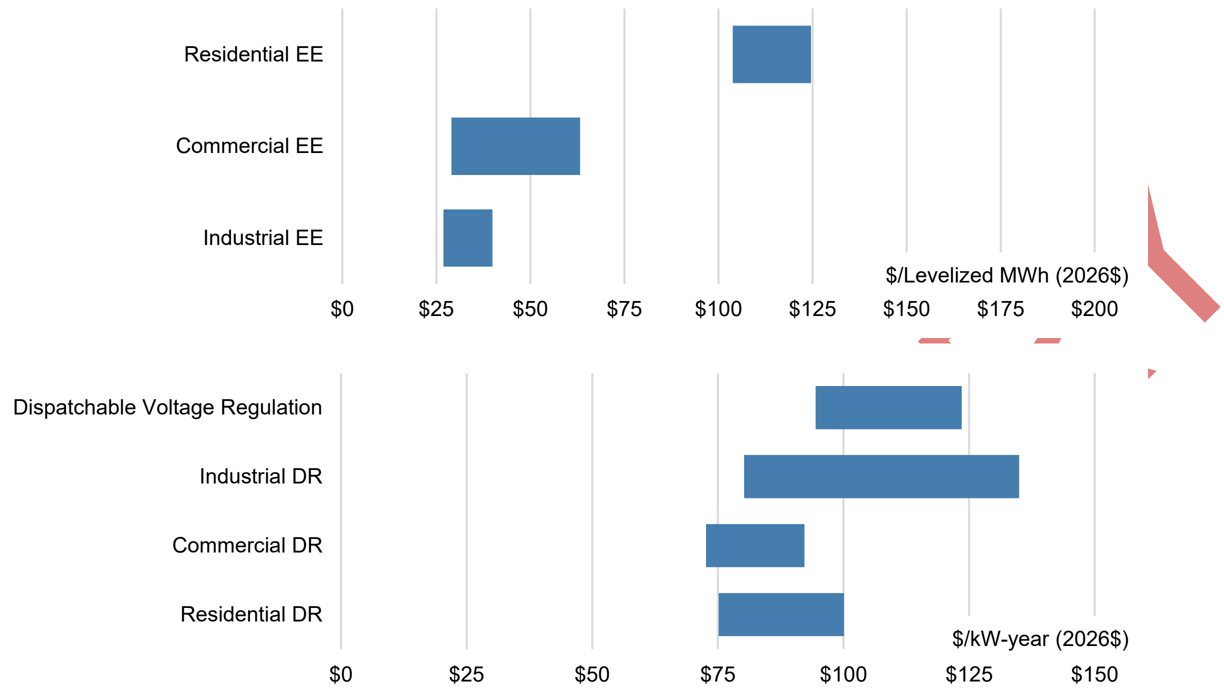

Figure G-5: Summary of Demand-side Program Options and Costs

Much like supply-side counterparts, demand-side programs also have operational-like limits on maximum energy reductions or additions. The limits are driven by program development, customer awareness, market adoption, participant acquisition, and other factors. Demand response capability is assumed to grow with the size of the system. TVA calculates an estimated participation rate for each program tier based on the incentives provided, using historical data and the recent potential study. The optimization model can select Tier 1, 2, or 3, based on which tier allows for the least-cost overall portfolio composition, with certain tiers enforced based on strategy design. New demand-side program resources are available for selection in the model starting in 2030. Details for the individually modeled programs are shown in the tables below.

Table G-2: Energy Efficiency Detailed Program Characteristics

Segment	Program Name	Tier	Life Span (years)*	Summer Firm Capacity (MW)	Winter Firm Capacity (MW)	Program Costs and Incentives ($000)	Energy (MWh)	$/Levelized MWh (2026$)
Residential EE	Residential Services	Tier 1	1-20	19.6	12.4	$56,786	78,168	$103.80
		Tier 2		24.0	15.8	$68,768	93,794	$104.92
		Tier 3		30.4	21.9	$102,672	125,085	$124.58
Commercial EE	Custom Commercial	Tier 1	10-15	4.8	3.6	$7,671	31,204	$29.02
		Tier 2		5.0	3.8	$9,229	33,071	$32.94
		Tier 3		5.3	4.0	$13,337	34,938	$45.06
	Standard Rebate Commercial	Tier 1	12-15	13.4	9.2	$55,294	121,726	$50.43
		Tier 2		14.3	9.8	$59,950	129,829	$51.27
		Tier 3		15.2	10.4	$78,542	137,932	$63.22

Segment	Program Name	Tier	Life Span (years)*	Summer Firm Capacity (MW)	Winter Firm Capacity (MW)	Program Costs and Incentives ($000)	Energy (MWh)	$/Levelized MWh (2026$)
Industrial EE	Custom Industrial	Tier 1-3	12-15	2.0	1.7	$5,537	15,874	$39.89
	Standard Rebate Industrial	Tier 1-3	12-15	7.6	5.2	$17,230	70,449	$26.89

* Range reflects lifespans of the shortest and longest individual measures included within the program

Table G-3: Demand Response Detailed Program Characteristics

Segment	Program Name	Tier	Contract Length	Capacity (MW)*	Annual Energy (MWh)	One-Time Cost (2026$)	Annual Fixed Cost ($/kW-year, 2026$)	Energy Cost ($/MWh, 2026$)
Residential DR	Smart Thermostat	Tier 1	5	65 / 35	6,000	$0	$90.02	$474
		Tier 2		95 / 50	8,721	$0	$75.15	$474
		Tier 3		125 / 66	11,475	$0	$100.11	$474
Commercial DR	Aggregated Commercial	Tier 1	1	50	1,600	$0	$72.64	$30
		Tier 2		90	2,880	$0	$73.69	$30
		Tier 3		150	4,800	$0	$92.21	$30
Industrial DR	Aggregated Industrial	Tier 1	5	55	4,644	$0	$80.21	$38
		Tier 2		150	6,192	$0	$112.03	$38
		Tier 3		275	20,625	$0	$134.97	$38
Local Power Company DR	Dispatchable Voltage Regulation	Tier 1	5	35	14,000	$45,000	$94.46	$25
		Tier 2		90	36,000	$45,000	$110.58	$25
		Tier 3		150	60,000	$45,000	$123.51	$25

* Smart Thermostat Capacity shown as "Summer / Winter"

G.7 Program Methodology in System Planning

Planning Approach

Since 2015, TVA has modeled EE and DR as selectable resources in its IRPs. Demand-side programs are modeled in a manner consistent with how supply-side resources are modeled, as applicable. Characteristics include a defined energy pattern similar to renewable resources, known as a load shape. The tiered approach (see Figure G-2) defines offerings, associated impacts, and costs at various levels of program uptake. This allows TVA to model selectable EE and DR resources for full optimization and promotion in certain strategies.

EE programs are non-dispatchable, meaning that system operators cannot directly control impacts based on system needs. Key input parameters are monthly avoided capacity, $/kW (cost divided by summer peak kW), and an hourly energy pattern. DR programs are dispatchable and can be called upon by system operators during peak periods or other times of system need. Typically, DR programs include an annual fixed capacity cost ($/kW-year) and an associated energy cost ($/MWh) used during event hours.

EE and DR programs have estimated energy and capacity impacts based on program load shapes. EE programs have a larger energy impact, and DR programs primarily have a capacity impact.

- Avoided energy calculation – Energy not consumed means fuel not burned, resulting in savings in variable costs. Since program impacts are realized at the consumer meter, they avoid transmission and distribution (thermal) losses, which can average 6.5% by the time energy reaches an end user.
- Avoided capacity calculation – Capacity is avoided, as reduced electricity demand translates into reduced need for incremental capacity additions.

For the 2026 IRP, planners took a “bottom-up” approach to modeling EE by first generating hourly demand profiles for individual program measures using engineering models, calibrated through program evaluation. An EE measure represents a specific energy reduction technology or customer behavior that can be combined with other measures to form a program. For example, a residential EE program might include a variety of individual measures addressing insulation, heating and cooling, window replacement, etc. Each measure has a unique energy reduction impact, as well as a uniquely defined lifespan based on its expected useful life. EE program inputs include 8,760 hourly profile shapes, which are regressed on weather and calendar variables, revealing the relationship between temperature, day of week, season, etc. EE program models then forecast forward using TVA weather and load forecasts as inputs. The final result is an hourly net energy reduction forecast synced to the TVA load forecast for each measure. Programs included in the IRP study represent a bundle of EE measures that represent total program impacts for a typical residential, commercial, or industrial customer.

Modeling Uncertainty

For supply-side resources in the IRP, unit performance is expected to be something less than 100%, and this delivery risk is captured in an outage rate for the unit. Demand-side programs do not have a comparable outage rate, meaning that program impacts are assumed to be available 100% of the time. Efficiency programs are dependent on variables such as equipment reliability and service life, operating conditions, and other factors that can impact operability, similar to an outage rate. Additionally, demand-side programs have other potential uncertainties that are not captured, such as variations in project costs and escalation rates.

The two major sources of uncertainty for demand-side programs are design and delivery. Design uncertainty is introduced by the creation of programs today that may have different costs, lifespans, or load shape impacts over time. Delivery uncertainty results from differences in estimated and evaluated energy savings, program implementation effectiveness though TVA’s 153 LPCs, and changes in codes and standards.

Example Sources of Uncertainty	
Energy Efficiency	Demand Response
Cost Variation	Claimed vs. Evaluated Impact
Measure Life	LPC Delivery Risk
Fixed Shape	Codes and Standards

Figure G-6: Design and Delivery Uncertainties

EE impacts manifest themselves in load, as do other variables such as forecasted adoption of distributed solar. Stochastic analysis, discussed earlier in the IRP document, will evaluate risks of load uncertainty driven by demand-side programs and many other factors.

G.8 Conclusion

TVA’s 2026 IRP evaluates a robust set of EE and DR program options. The options are modeled using a tiered approach of program offerings, informed by the recent potential study and subsequent market experience, and the tiers were also used to define levels of EE and DR promotion in some alternative strategies. Results from the model provide insights into the impact that demand-side resources could have on the TVA system under a variety of different futures. These insights will inform future planning and energy program design.

H

Appendix H – Capacity and Energy Plan Summaries

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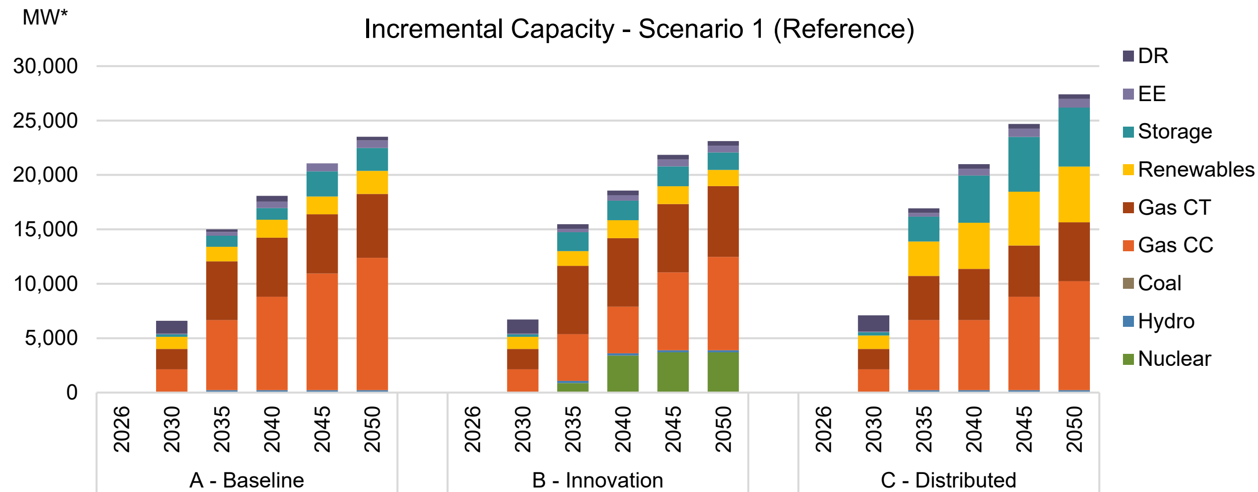
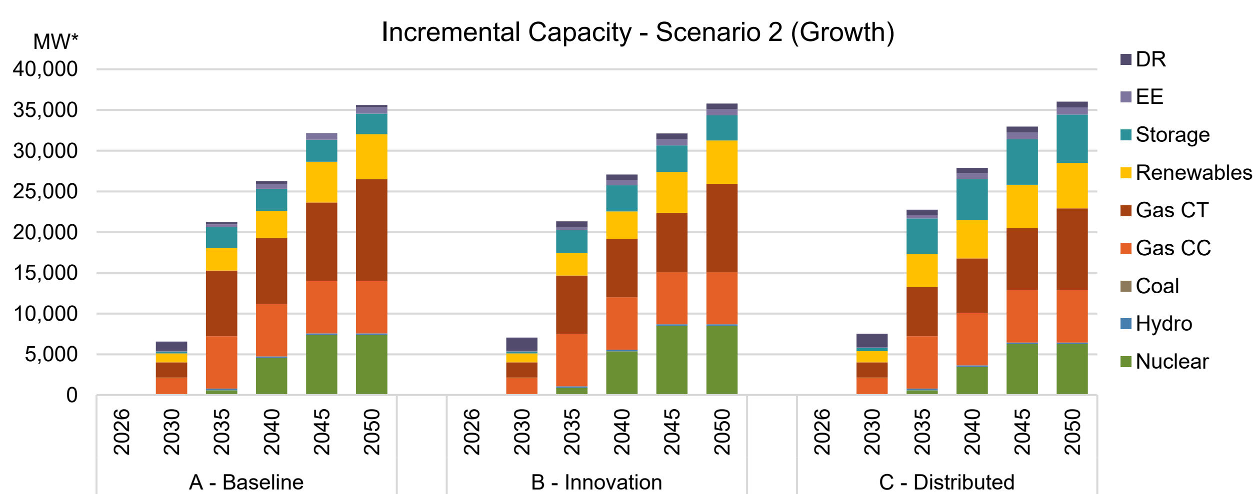
Appendix H – Capacity and Energy Plan Summaries

Combining the three external scenarios with the three business strategies modeled in the IRP resulted in nine core resource portfolios for evaluation. This appendix compares the portfolios on an incremental capacity, total capacity and total energy basis, along with forecasted summer and winter reserve margin positions. Additionally, incremental capacity, total capacity, and total energy details are included in tables for reference.

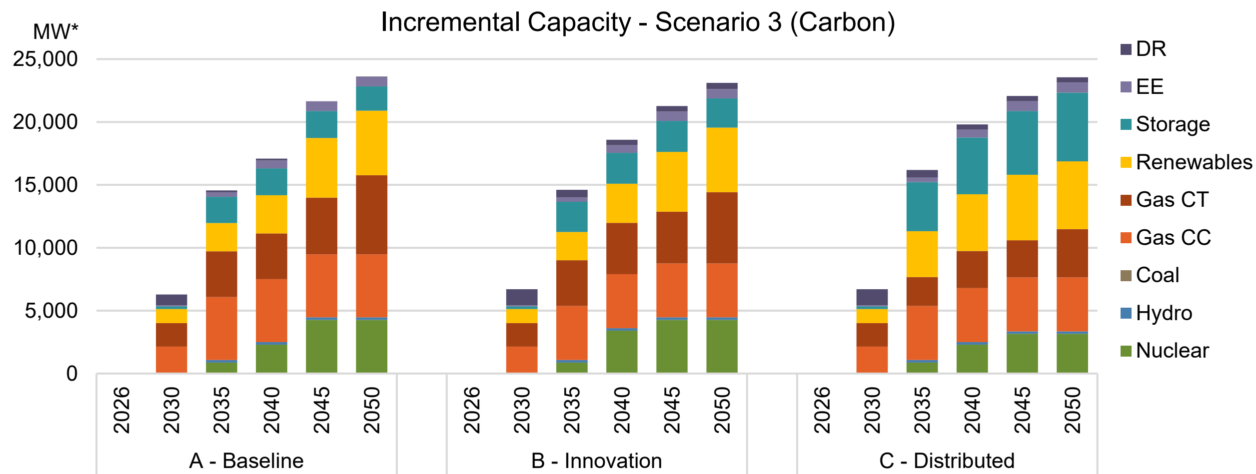
H.1 Incremental Capacity Plans



*MW summer net dependable capacity.



*MW summer net dependable capacity.

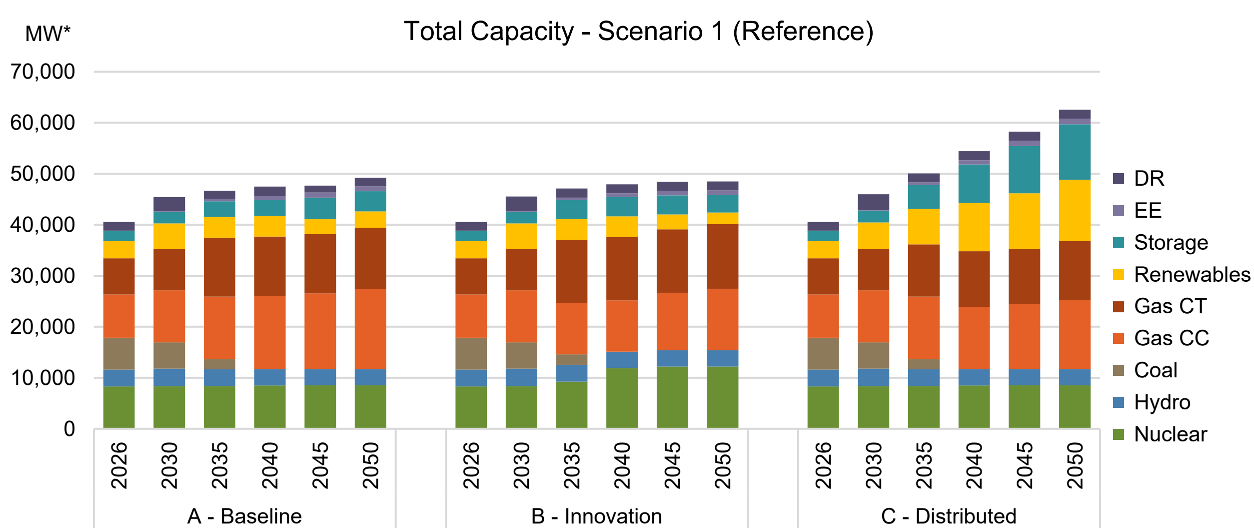


*MW summer net dependable capacity.

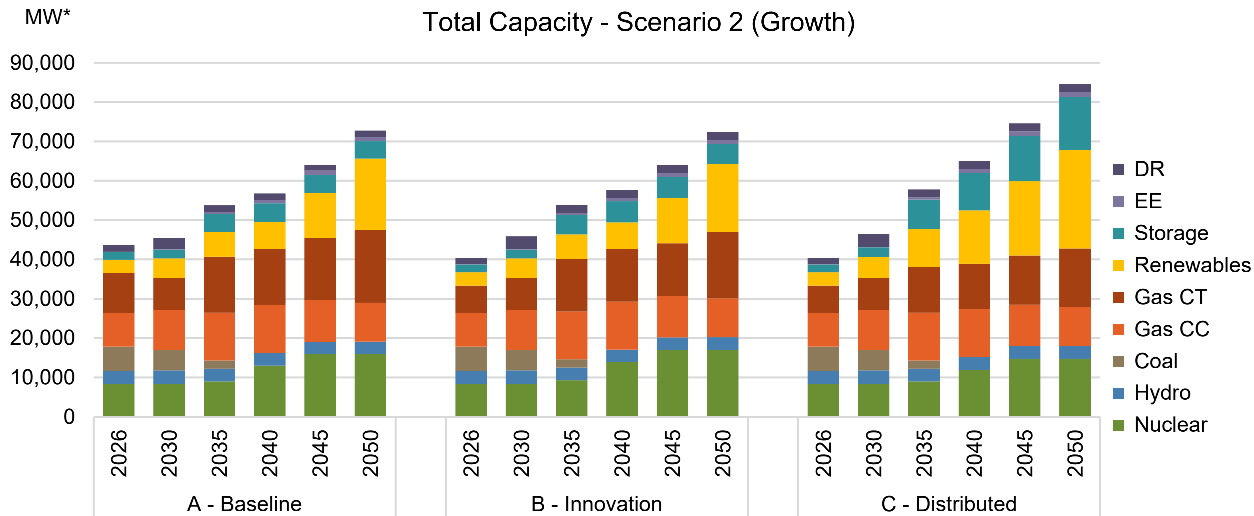
Figure H-1: Incremental Capacity Plans (Summer NDC)

H.2 Total Capacity Plans

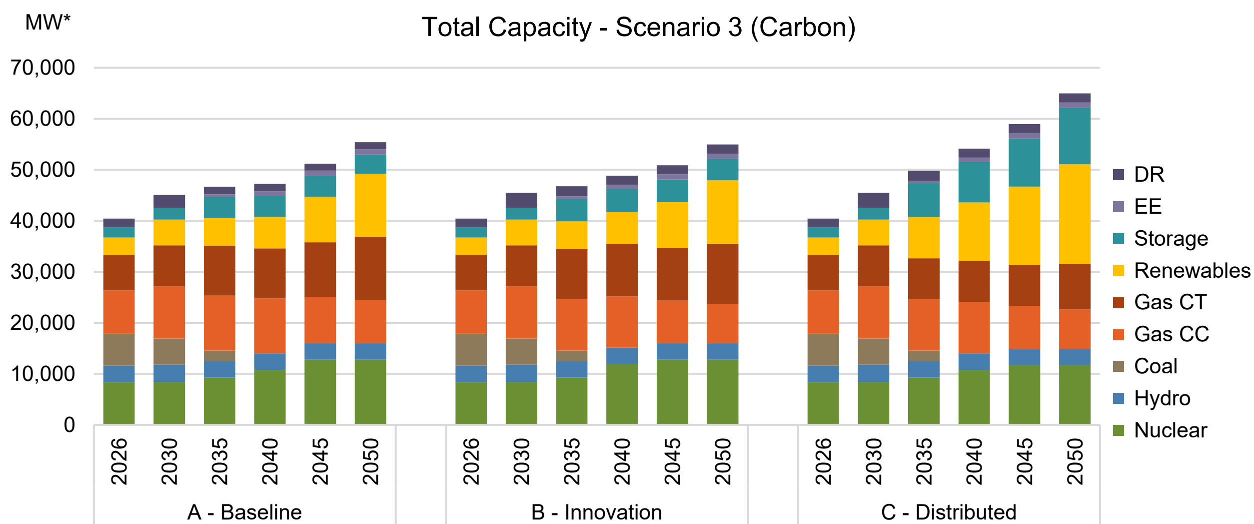
The capacity plans provided below reflect the results for each scenario for all three strategies. Results are grouped by resource type for time increments over the planning horizon. Capacity is shown in megawatts (MW) and is generally based on summer net dependable capacity, except for renewables and storage that are shown in nameplate capacity and energy efficiency which is shown as maximum summer reduction. The planning model considers summer and winter capacity needs and resource capabilities, as well as the pattern of energy needs across all hours, in portfolio optimization.



* MW summer net dependable capacity, except for renewables and storage shown in nameplate and energy efficiency shown as maximum summer reduction.



* MW summer net dependable capacity, except for renewables and storage shown in nameplate and energy efficiency shown as maximum summer reduction.



* MW summer net dependable capacity, except for renewables and storage shown in nameplate and energy efficiency shown as maximum summer reduction.

Figure H-2: Total Capacity Plans

H.3 Total Energy Plans

The energy plans provided below reflect the results for each scenario for all three strategies. Results are grouped by resource type for time increments over the planning horizon. Energy is shown in terawatt hours (TWh), which is equal to 1,000 gigawatt hours.

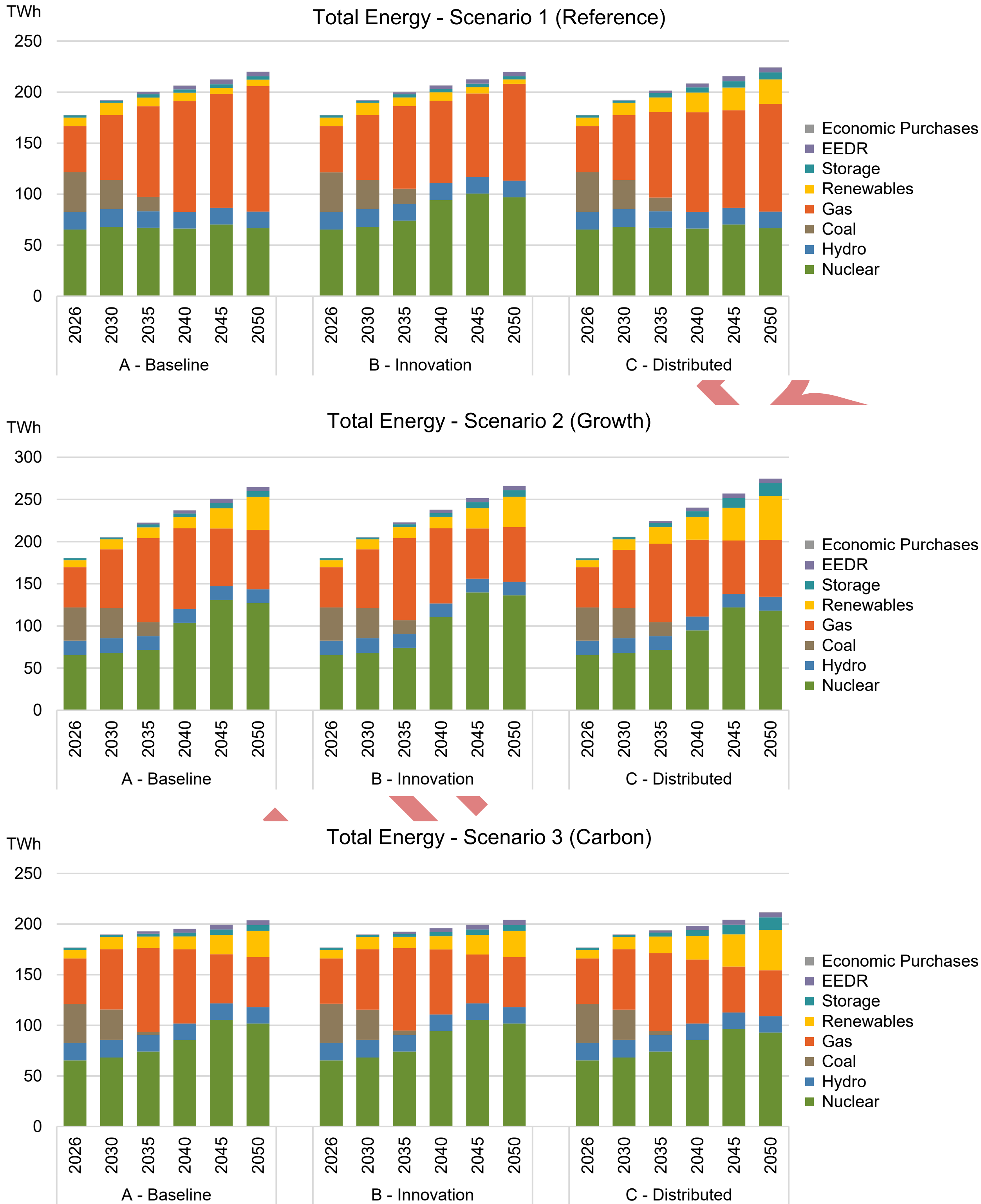


Figure H-3: Total Energy Plans

H.4 Reserve Margin Comparisons

The summer and winter reserve margin charts provided below correspond to the capacity plans. Results are grouped by scenario. For this IRP, TVA used an 18% reserve margin target for summer and a 26% reserve margin target for winter.

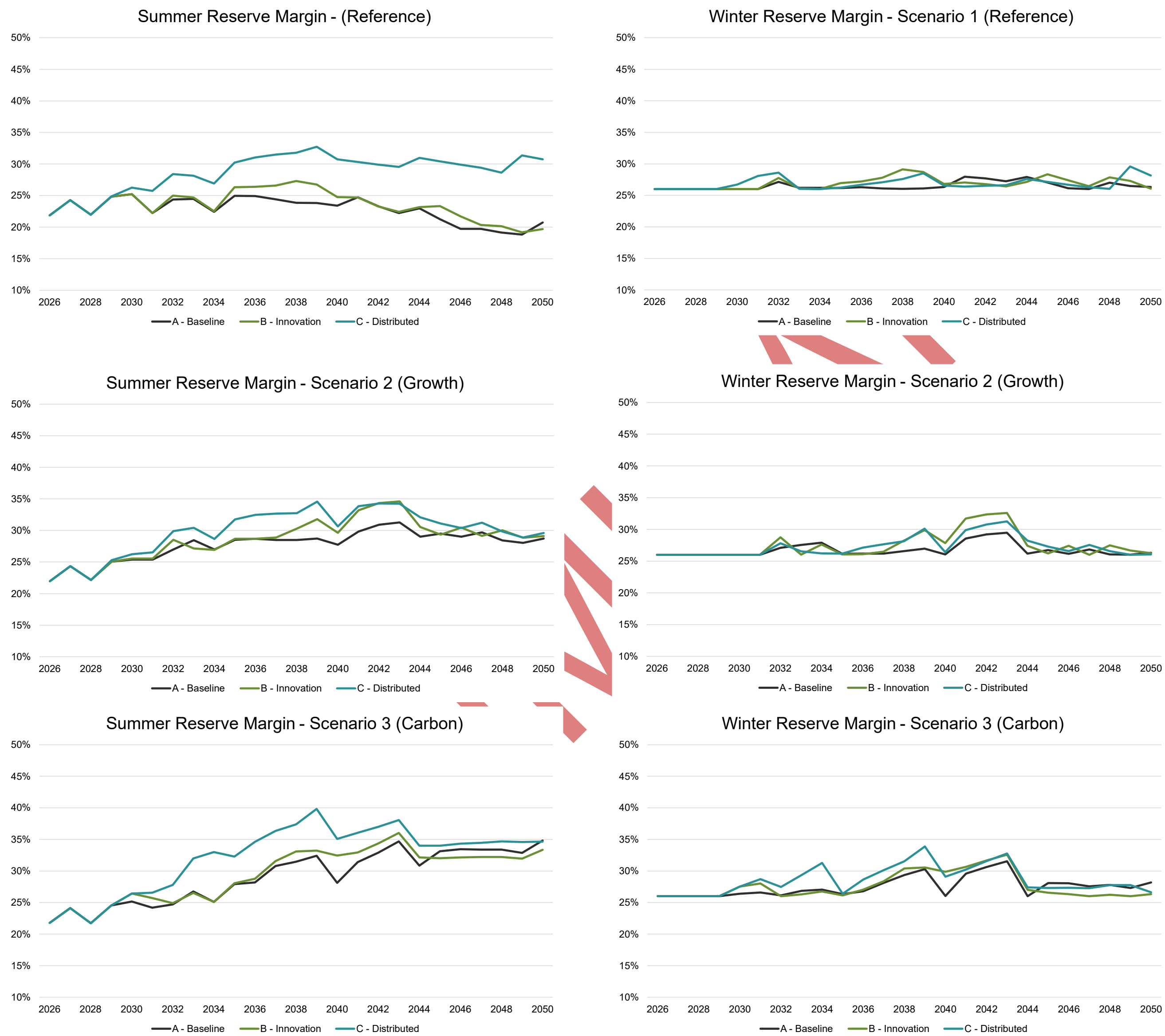


Figure H-4: Reserve Margin Comparisons

H.5 Incremental Capacity Changes

The tables provided below show incremental capacity for all nine core portfolios for 2026-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 3) and strategies by letter (A to C). Data is shown in summer net dependable gigawatts (GW SND).

Table H-1: Incremental Capacity Tables

1A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.1	4.3	4.3	6.4	6.4	6.4	6.4	6.4	8.6	8.6	8.6	8.6	10.7	10.7	10.7	10.7	12.2	12.2	12.2
CT	0.0	0.2	1.5	1.5	1.9	1.9	3.6	3.6	3.6	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.9
Renewables	0.0	0.3	0.7	0.9	1.1	1.1	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.6	1.3	1.5	2.1
Storage	0.0	0.0	0.0	0.1	0.2	0.3	0.3	0.3	0.6	1.0	1.0	1.0	1.0	1.1	1.1	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.1
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
DR	0.0	0.1	0.4	0.7	1.2	1.4	1.4	0.4	0.5	0.2	0.4	0.4	0.5	0.7	0.5	0.1	0.1	0.0	0.0	0.0	0.0	0.3	0.2	0.2	0.3
Total	0.0	2.0	4.8	5.4	6.6	7.2	9.0	10.3	10.7	15.0	15.4	15.5	15.7	16.0	18.1	18.9	19.0	18.9	21.1	21.1	21.1	21.4	22.3	22.5	23.5

1B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.4	2.0	2.0	3.4	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	6.4	7.2	7.2	7.2	8.6	8.6	8.6
CT	0.0	0.2	1.5	1.5	1.9	1.9	3.6	5.4	5.4	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.5
Renewables	0.0	0.3	0.7	0.9	1.1	1.1	1.1	1.2	1.2	1.3	1.4	1.5	1.5	1.6	1.7	1.7	1.7	1.7	1.7	1.6	1.6	1.4	1.1	1.1	1.5
Storage	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.5	1.7	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.6
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.4	0.4	0.5	0.5	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
DR	0.0	0.1	0.4	0.7	1.3	1.5	1.5	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	0.0	2.0	4.8	5.4	6.7	7.3	9.2	10.4	10.8	15.5	15.9	16.3	17.0	17.1	18.6	18.9	19.0	19.0	21.2	21.8	21.8	21.6	22.7	22.6	23.1

1C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	8.6	8.6	8.6	8.6	8.6	10.0	10.0
CT	0.0	0.2	1.5	1.5	1.9	1.9	2.8	4.1	4.1	4.1	4.1	4.1	4.3	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.7	4.8	5.4	5.4	5.4
Renewables	0.0	0.3	0.7	1.0	1.2	1.6	2.0	2.4	2.8	3.2	3.5	3.7	4.0	4.1	4.2	4.3	4.5	4.6	4.7	4.9	5.1	5.2	5.2	5.1	5.1
Storage	0.0	0.0	0.0	0.1	0.3	0.9	1.4	1.9	2.2	2.3	2.6	2.9	2.9	3.0	4.3	4.5	4.6	4.8	4.9	5.0	5.2	5.3	5.4	5.4	5.4
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.1	0.4	0.7	1.5	1.6	1.7	0.7	0.7	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.4	0.4
Total	0.0	2.0	4.8	5.5	7.1	8.5	10.4	11.6	12.4	16.9	17.7	18.2	18.8	19.5	21.0	21.3	21.7	21.9	24.3	24.7	25.0	25.2	26.1	27.3	27.4

2A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.2	1.7	2.3	2.9	4.6	6.2	6.8	7.4	7.4	7.4	7.4	7.4	7.4	7.4	7.4
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	4.3	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
CT	0.0	0.2	1.5	1.5	1.9	1.9	4.5	5.4	6.3	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.1	8.8	9.6	9.6	10.5	11.4	11.6	12.5
Renewables	0.0	0.3	0.7	0.9	1.1	2.2	2.3	2.4	2.5	2.7	2.9	3.1	3.2	3.3	3.4	3.4	4.0	4.4	4.7	5.0	5.2	5.3	5.3	5.3	5.5
Storage	0.0	0.0	0.0	0.1	0.2	0.9	0.9	0.9	1.0	2.6	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.5
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.2	0.4	0.8	1.1	1.4	1.4	0.3	0.2	0.3	0.3	0.2	0.2	0.2	0.3	0.0	0.0	0.0	0.2	0.1	0.2	0.2	0.2	0.3	0.3
Total	0.0	2.0	4.8	5.5	6.6	8.8	13.8	15.9	16.9	21.3	22.1	22.8	23.5	24.3	26.3	27.7	29.0	29.9	31.1	32.2	32.6	33.5	34.4	34.6	35.6

2B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.7	2.9	4.0	5.4	7.3	7.9	8.5	8.5	8.5	8.5	8.5	8.5	8.5	8.5
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
CT	0.0	0.2	1.5	1.5	1.9	1.9	2.8	4.5	5.4	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.3	7.3	8.2	8.2	9.9	9.9	10.8
Renewables	0.0	0.3	0.7	0.9	1.1	2.2	2.3	2.4	2.5	2.7	2.9	3.1	3.2	3.3	3.4	3.4	4.1	4.4	4.7	5.0	5.2	5.3	5.3	5.3	5.3
Storage	0.0	0.0	0.0	0.1	0.2	0.6	0.6	0.6	0.8	2.8	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.3	3.3	3.3	3.3	3.2	3.1
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.2	0.4	0.8	1.6	1.8	1.9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	0.0	2.0	4.8	5.5	7.1	8.9	14.3	15.4	16.9	21.3	22.1	22.9	24.3	25.5	27.1	29.1	30.4	31.4	31.8	32.1	33.2	33.3	35.1	35.0	35.8

2C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.6	1.2	1.7	2.3	2.9	3.4	5.1	5.7	6.3	6.3	6.3	6.3	6.3	6.3	6.3	6.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	4.3	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4	6.4
CT	0.0	0.2	1.5	1.5	1.9	1.9	3.6	3.6	3.6	6.1	6.1	6.1	6.1	6.7	6.7	6.7	6.7	6.7	7.6	7.6	7.6	8.5	9.1	9.1	10.0
Renewables	0.0	0.3	0.7	1.0	1.4	2.6	3.0	3.5	3.8	4.1	4.2	4.4	4.5	4.6	4.7	4.7	5.0	5.0	5.2	5.3	5.5	5.5	5.6	5.5	5.6
Storage	0.0	0.0	0.0	0.1	0.4	1.3	1.6	2.0	2.6	4.3	4.7	4.8	4.9	4.9	5.1	5.2	5.3	5.4	5.5	5.6	5.7	5.8	5.9	5.9	5.9
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.3	0.4	0.4	0.5	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	0.9	0.9	0.9	0.9	0.9
DR	0.0	0.2	0.4	0.8	1.6	1.8	1.9	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7	0.7
Total	0.0	2.0	4.8	5.6	7.5	10.0	14.9	16.8	17.7	22.8	24.0	24.8	25.7	27.1	27.9	29.8	30.7	31.5	32.7	33.0	33.2	34.2	35.0	35.0	36.0

3A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.4	1.7	2.0	2.3	3.7	4.0	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.9	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0	5.0
CT	0.0	0.2	1.5	1.5	1.9	1.9	1.9	1.9	1.9	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	4.5	4.5	4.5	5.4	5.4	6.3
Renewables	0.0	0.3	0.7	0.9	1.1	1.8	1.8	2.0	2.1	2.2	2.3	2.9	3.0	3.0	3.0	3.0	3.6	4.0	4.4	4.7	5.0	5.1	5.1	5.1	5.1
Storage	0.0	0.0	0.0	0.1	0.2	0.2	0.3	0.4	0.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.2	2.2	2.2	2.1	1.9
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.1	0.4	0.7	0.9	1.0	1.1	0.2	0.0	0.2	0.0	0.0	0.0	0.0	0.2	0.0	0.0	0.0	0.1	0.0	0.1	0.1	0.1	0.0	0.0
Total	0.0	2.0	4.8	5.4	6.3	7.3	8.3	10.1	10.4	14.6	14.8	15.7	16.2	16.6	17.1	18.4	19.3	20.0	20.4	21.6	22.1	22.1	23.1	22.9	23.6

3B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.4	2.0	2.0	3.4	3.7	4.0	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.2	1.5	1.5	1.9	1.9	1.9	1.9	1.9	3.6	3.6	3.6	3.6	3.6	4.1	4.1	4.1	4.1	4.1	4.1	4.1	4.1	5.0	5.0	5.7
Renewables	0.0	0.3	0.7	0.9	1.1	1.8	1.8	2.0	2.1	2.2	2.3	3.0	3.1	3.1	3.1	3.1	3.7	4.1	4.4	4.8	5.0	5.1	5.1	5.1	5.1
Storage	0.0	0.0	0.0	0.1	0.2	0.3	0.6	0.7	0.7	2.4	2.4	2.4	2.4	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.5	2.3
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.7
DR	0.0	0.1	0.4	0.7	1.3	1.4	1.5	0.5	0.4	0.6	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5
Total	0.0	2.0	4.8	5.4	6.7	7.8	8.4	10.0	10.5	14.6	15.0	16.0	16.8	16.9	18.6	18.9	19.8	20.5	20.9	21.3	21.6	21.7	22.7	22.5	23.1

3C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.6	0.9	1.2	1.4	1.7	2.0	2.3	2.6	2.9	3.2	3.2	3.2	3.2	3.2	3.2	3.2	3.2
Hydro	0.0	0.0	0.0	0.0	0.0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
Coal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	0.0	1.4	2.1	2.1	2.1	2.1	2.1	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3
CT	0.0	0.2	1.5	1.5	1.9	1.9	1.9	1.9	1.9	2.3	2.5	2.5	2.5	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	2.9	3.8	3.8	3.8
Renewables	0.0	0.3	0.7	0.9	1.1	1.8	2.3	2.8	3.3	3.7	3.9	4.2	4.3	4.4	4.5	4.6	4.8	4.9	5.0	5.2	5.4	5.4	5.4	5.4	5.4
Storage	0.0	0.0	0.0	0.1	0.2	0.6	1.2	1.8	2.3	3.9	4.2	4.2	4.3	4.4	4.5	4.6	4.7	4.8	5.0	5.1	5.2	5.3	5.4	5.4	5.5
EE	0.0	0.0	0.0	0.0	0.1	0.1	0.2	0.2	0.3	0.4	0.4	0.5	0.5	0.6	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8
DR	0.0	0.1	0.4	0.7	1.3	1.4	1.5	0.4	0.4	0.6	0.6	0.6	0.6	0.6	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Total	0.0	2.0	4.8	5.4	6.7	8.1	9.4	11.9	13.2	16.2	17.2	17.9	18.5	19.4	19.8	20.4	21.0	21.5	21.8	22.1	22.4	22.5	23.5	23.5	23.6

H.6 Total Capacity Plan Tables

The tables provided below show total capacity for all nine portfolios for 2026-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 3) and strategies by letter (A to C). Data is shown in summer net dependable gigawatts (GW SND), except for renewables and storage which are in nameplate and EE which is shown in maximum hourly reduction.

Table H-2: Total Capacity Plan Tables

1A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	10.5	11.9	11.9	13.4	13.4	13.4	13.4	13.4	15.7	15.7	15.7	15.7	16.2	16.2	16.2	16.2	17.1	17.1	17.1
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	11.3	11.3	11.3	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.2	13.7
Renewables	3.6	3.8	4.6	4.9	5.1	5.0	4.4	3.9	4.0	4.1	4.2	4.2	4.2	4.0	4.0	4.1	3.9	3.7	3.7	3.5	2.9	2.7	2.4	2.5	3.2
Storage	2.0	2.0	2.0	2.2	2.2	2.3	2.3	2.3	2.6	3.0	3.0	3.1	3.1	3.1	3.1	4.3	4.3	4.3	4.3	4.3	4.2	4.2	4.2	4.2	4.0
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.1	1.1	1.1
DR	1.9	2.0	2.4	2.7	2.9	3.0	2.9	1.8	1.8	1.6	1.8	1.8	1.9	2.0	1.9	1.4	1.4	1.4	1.4	1.4	1.4	1.7	1.5	1.5	1.7
Subtotal	44.3	45.8	47.8	48.0	48.9	49.4	49.9	49.4	49.8	50.2	50.7	50.8	51.0	51.0	51.3	52.1	52.0	51.8	52.4	52.1	51.5	51.5	51.9	51.9	53.1

1B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	9.0	9.2	9.5	9.9	10.2	10.7	10.7	12.2	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5	12.5
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	10.5	9.6	9.6	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.5	12.3	12.3	12.3	13.2	13.2	13.2
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	11.3	13.2	13.2	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.3
Renewables	3.6	3.8	4.6	4.9	5.1	5.0	4.4	3.9	4.0	4.1	4.2	4.2	4.2	4.0	4.0	4.1	3.9	3.7	3.7	3.5	2.9	2.4	2.1	1.8	2.3
Storage	2.0	2.0	2.0	2.2	2.2	2.3	2.4	2.5	2.5	3.7	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.7	3.7	3.7	3.7	3.5
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.6	0.6	0.7	0.7	0.8	0.8	0.9	0.9	1.0	1.0	1.0	1.0	1.0	1.0	0.9
DR	1.9	2.0	2.4	2.7	3.0	3.0	3.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Subtotal	44.3	45.8	47.8	48.0	49.0	49.4	50.1	49.4	49.7	50.5	51.0	51.3	52.0	51.8	51.3	51.7	51.6	51.4	52.0	52.5	51.9	51.3	51.8	51.5	52.0

1C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	8.7	8.7	8.7	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8	8.8
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	10.5	9.6	9.6	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.9	13.9	13.9	13.9	13.2	14.7	14.7
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	10.4	11.8	11.8	11.8	11.7	11.7	12.0	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	12.4	13.1	13.1	13.1
Renewables	3.6	3.8	4.6	5.0	5.2	5.7	5.8	5.8	6.3	7.0	7.6	8.1	8.6	8.9	9.5	10.0	10.3	10.6	11.2	11.4	11.4	11.5	11.7	11.7	12.0
Storage	2.0	2.0	2.0	2.2	2.3	2.9	3.5	4.1	4.6	4.7	5.3	5.7	5.9	6.0	7.5	7.9	8.3	8.6	9.0	9.3	9.7	10.0	10.6	10.8	10.9
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3
DR	1.9	2.0	2.4	2.7	3.2	3.2	3.2	2.1	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Subtotal	44.3	45.8	47.8	48.1	49.4	50.9	51.8	51.4	52.4	53.5	54.9	56.0	56.9	57.8	57.9	58.8	59.6	60.4	61.8	62.4	62.8	63.1	64.0	65.8	66.2

2A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	9.3	9.9	10.5	11.0	11.6	13.3	15.0	15.6	16.1	16.1	16.2	16.2	16.2	16.2	16.2	16.2
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	12.8	14.3	14.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	11.5	11.5	11.5	11.5	10.8	10.8	10.8
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	12.3	13.2	14.1	15.9	15.9	15.9	15.9	15.9	16.0	16.0	16.0	16.0	16.7	17.6	17.6	18.5	19.4	19.7	20.6
Renewables	3.6	3.8	4.6	4.9	5.1	6.6	6.2	5.8	5.9	6.3	6.5	6.7	6.8	6.7	6.8	6.8	7.9	9.2	10.7	12.0	12.9	13.9	15.1	16.0	18.2
Storage	2.0	2.0	2.0	2.2	2.2	2.9	2.9	2.9	3.0	4.6	4.7	4.7	4.8	4.8	4.8	4.8	4.8	4.8	4.8	4.7	4.7	4.6	4.6	4.6	4.4
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.2
DR	1.9	2.0	2.4	2.7	2.9	3.0	2.9	1.7	1.6	1.7	1.7	1.5	1.5	1.5	1.7	1.4	1.4	1.4	1.6	1.4	1.6	1.6	1.5	1.6	1.6
Subtotal	44.3	45.8	47.9	48.1	48.9	51.6	55.5	56.0	57.0	57.4	58.5	59.2	60.0	60.5	60.5	61.9	63.7	65.7	66.3	68.2	69.3	71.1	72.4	73.7	76.7

2B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	9.0	9.2	9.5	9.9	10.5	11.6	12.7	14.1	16.1	16.7	17.3	17.3	17.3	17.3	17.3	17.3	17.3	17.3
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	15.2	14.3	14.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	11.5	11.5	11.5	11.5	10.8	10.8	10.8
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	10.4	12.3	13.2	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.1	15.1	16.0	16.0	17.9	17.9	18.8
Renewables	3.6	3.8	4.6	4.9	5.1	6.6	6.2	5.8	5.9	6.3	6.5	6.7	6.8	6.7	6.8	6.8	8.0	9.3	10.8	12.1	13.0	14.0	15.2	16.1	17.3
Storage	2.0	2.0	2.0	2.2	2.2	2.6	2.6	2.6	2.8	4.9	5.3	5.3	5.4	5.4	5.4	5.4	5.4	5.4	5.4	5.3	5.3	5.2	5.2	5.2	5.0
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.6	0.7	0.8	0.9	1.0	1.0	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
DR	1.9	2.0	2.4	2.7	3.4	3.3	3.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Subtotal	44.3	45.8	47.9	48.1	49.4	51.6	56.2	55.4	56.9	57.4	58.5	59.4	60.7	61.8	61.3	63.3	65.3	67.2	67.0	68.2	70.1	70.9	73.2	74.1	76.1

2C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	8.7	8.7	9.3	9.9	10.5	11.0	11.6	12.2	13.9	14.5	15.0	15.0	15.0	15.0	15.0	15.0	15.0	15.0
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	12.8	14.3	14.3	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	13.4	11.5	11.5	11.5	11.5	10.8	10.8	10.8
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	11.3	11.3	11.3	13.8	13.8	13.8	13.8	14.5	14.5	14.5	14.5	14.5	15.4	15.4	15.4	16.3	17.0	17.0	17.9
Renewables	3.6	3.8	4.6	5.1	5.5	7.2	7.4	7.7	8.6	9.6	10.6	11.5	12.3	12.7	13.5	14.0	15.3	16.6	18.2	19.4	20.4	21.4	22.6	23.6	25.1
Storage	2.0	2.0	2.0	2.3	2.4	3.3	3.8	4.3	5.3	7.5	8.5	8.8	9.0	9.1	9.6	10.0	10.4	10.8	11.2	11.6	11.9	12.3	12.7	13.3	13.5
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.9	1.0	1.1	1.2	1.3	1.3	1.4	1.4	1.4	1.4	1.4	1.4	1.4
DR	1.9	2.0	2.4	2.7	3.4	3.3	3.4	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
Subtotal	44.3	45.8	47.9	48.3	50.0	53.0	57.2	57.8	59.7	62.0	64.8	66.5	68.2	70.0	69.9	72.6	74.9	77.2	78.3	80.0	81.3	83.6	85.3	86.9	89.5

3A, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	9.0	9.2	9.5	9.9	10.2	10.5	10.7	11.1	12.5	12.8	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	11.3	12.7	12.7	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	10.0	10.0	10.0	10.0	9.3	9.3	9.3
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	9.5	9.5	9.5	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	11.3	12.2	12.2	12.2	13.2	13.2	14.1
Renewables	3.6	3.8	4.6	4.9	5.1	6.0	5.4	5.1	5.3	5.5	5.5	6.4	6.4	6.2	6.2	6.2	7.0	7.8	8.8	9.5	10.0	10.4	11.1	11.5	12.3
Storage	2.0	2.0	2.0	2.2	2.2	2.2	2.3	2.4	2.4	4.1	4.1	4.1	4.1	4.2	4.2	4.2	4.2	4.2	4.2	4.1	4.1	4.0	4.0	4.0	3.8
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2
DR	1.9	2.0	2.3	2.7	2.6	2.5	2.6	1.6	1.4	1.5	1.4	1.4	1.4	1.4	1.5	1.4	1.4	1.4	1.4	1.4	1.5	1.5	1.5	1.4	1.4
Subtotal	44.3	45.8	47.8	48.0	48.6	49.8	49.5	49.6	49.9	50.0	50.4	51.6	52.0	52.2	50.6	51.9	53.1	54.2	53.5	55.1	55.6	56.0	56.9	57.2	58.7

3B, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	9.0	9.2	9.5	9.9	10.2	10.7	10.7	12.2	12.5	12.8	13.0	13.0	13.0	13.0	13.0	13.0	13.0	13.0
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	10.5	11.9	11.9	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	9.2	9.2	9.2	9.2	8.5	8.5	8.5
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	9.5	9.5	9.5	11.3	11.3	11.3	11.3	11.3	11.8	11.8	11.8	11.8	11.8	11.8	11.8	11.8	12.7	12.7	13.4
Renewables	3.6	3.8	4.6	4.9	5.1	6.0	5.4	5.1	5.3	5.5	5.5	6.5	6.6	6.3	6.3	6.3	7.1	7.9	8.9	9.6	10.1	10.5	11.2	11.6	12.4
Storage	2.0	2.0	2.0	2.2	2.2	2.3	2.6	2.7	2.7	4.4	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.5	4.4	4.4	4.4	4.4	4.4	4.2
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.2
DR	1.9	2.0	2.3	2.7	3.0	3.0	3.1	1.9	1.8	2.0	2.0	2.0	2.0	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Subtotal	44.3	45.8	47.8	48.0	49.0	50.3	49.5	49.4	49.9	50.0	50.5	51.9	52.6	52.5	52.2	52.5	53.6	54.8	54.0	54.7	55.2	55.6	56.5	56.9	58.2

3C, SND GW	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	8.6	8.6	8.6	8.6	8.6	8.6	8.7	9.0	9.2	9.5	9.9	10.2	10.5	10.7	11.1	11.4	11.6	11.9	11.9	11.9	11.9	11.9	11.9	11.9	11.9
Hydro	3.6	3.7	3.6	3.7	3.7	4.0	4.0	4.0	4.0	3.6	3.6	3.6	3.6	3.6	3.6	3.5	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6	3.6
Coal	6.6	6.1	5.1	5.4	5.4	5.4	5.4	5.0	5.0	2.1	2.1	2.1	2.1	2.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas CC	9.3	10.9	11.3	11.3	11.3	11.3	10.5	11.9	11.9	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	11.1	9.2	9.2	9.2	9.2	8.5	8.5	8.5
Gas CT	8.7	8.7	10.2	9.1	9.5	9.5	9.5	9.5	9.5	9.9	10.1	10.1	10.1	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	10.5	11.5	11.5	11.5
Renewables	3.6	3.8	4.6	4.9	5.1	6.1	6.2	6.4	7.3	8.1	8.7	10.0	10.6	10.9	11.5	12.5	13.3	14.1	15.2	16.0	16.6	17.3	18.1	18.6	19.5
Storage	2.0	2.0	2.0	2.2	2.2	2.6	3.2	3.9	4.7	6.6	7.1	7.3	7.5	7.6	8.0	8.3	8.6	8.9	9.2	9.5	9.9	10.2	10.5	10.9	11.1
EE	0.0	0.0	0.0	0.0	0.1	0.2	0.3	0.4	0.5	0.6	0.7	0.7	0.8	0.9	1.0	1.1	1.1	1.2	1.2	1.2	1.2	1.2	1.2	1.3	1.3
DR	1.9	2.0	2.3	2.7	3.0	3.0	3.0	1.8	1.8	2.0	2.0	2.0	2.0	2.0	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8	1.8
Subtotal	44.3	45.8	47.8	48.0	49.0	50.6	50.8	52.0	53.8	53.4	55.2	57.0	58.2	59.4	58.5	60.2	61.6	63.1	62.7	63.7	64.8	65.7	67.1	68.0	69.1

H.7 Total Energy Plan Tables

The tables provided below show total energy for all nine portfolios for 2026-2050. Results are grouped by scenario. Scenarios are represented by number (1 to 3) and strategies by letter (A to C). Data is shown in terawatt hours (TWh), which is equal to 1,000 gigawatt hours (GWh).

Table H-3: Total Energy Plan Tables

1A, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	68.9	65.8	67.0	68.6	67.4	66.5	69.7	66.3	68.4	69.2	67.8	67.0	70.3	66.7	68.2	69.4	67.8	66.7
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.3	16.2	16.3	16.3	16.4	16.3	16.3
Coal	38.9	31.0	28.6	28.2	28.6	29.6	28.6	23.3	27.7	14.0	14.3	15.1	15.4	15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	45.3	56.9	62.9	62.7	63.6	65.7	71.1	75.5	74.5	88.9	88.1	88.9	90.6	88.5	108.6	107.0	107.8	110.1	112.7	111.7	117.5	117.5	119.5	121.9	122.9
Renewables	8.3	9.0	10.4	11.4	11.8	11.3	9.6	8.2	8.3	8.4	8.6	8.5	8.3	8.2	8.2	8.2	7.5	7.4	7.3	6.0	5.1	5.0	3.9	4.4	6.3
Storage	2.3	2.1	2.4	2.1	2.2	2.4	2.5	3.0	2.8	3.3	3.3	3.0	2.7	3.1	3.2	3.7	3.6	3.3	3.5	3.4	3.1	3.2	3.5	3.2	3.3
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.2	2.5	2.8	3.1	3.5	3.7	4.0	4.2	4.4	4.7	4.7	4.7	4.7	4.6	4.5	4.5
Economic Purchases	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.1	0.1
Subtotal	177.4	180.1	185.3	188.7	192.3	194.8	196.9	198.1	198.6	200.0	201.7	202.1	203.0	204.6	206.3	207.5	208.7	209.4	211.5	212.3	213.4	215.0	217.4	218.2	220.0

1B, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	71.3	70.6	74.1	78.1	79.3	83.1	86.3	94.3	98.7	99.5	98.1	97.4	100.6	97.0	98.5	99.8	98.1	97.0
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.5	16.3	16.3
Coal	38.9	31.2	28.6	28.1	28.6	29.6	28.6	26.9	30.3	15.0	15.2	15.5	15.4	15.4	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	45.3	56.6	62.9	62.8	63.6	65.7	71.1	69.5	67.2	81.0	78.0	77.0	74.5	72.6	81.0	77.1	77.9	80.3	82.7	81.9	87.8	88.3	90.3	93.5	95.0
Renewables	8.3	9.0	10.4	11.4	11.8	11.3	9.6	8.2	8.3	8.4	8.6	8.5	8.3	8.2	8.2	8.2	7.5	7.4	7.3	6.0	5.1	4.4	3.2	2.9	4.3
Storage	2.3	2.1	2.4	2.1	2.2	2.4	2.6	2.6	2.3	3.1	3.5	3.2	3.0	3.4	3.3	3.5	3.4	3.2	3.3	3.6	3.4	3.2	3.7	3.2	3.1
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.0	1.4	1.6	2.0	2.2	2.5	2.7	3.0	3.3	3.6	3.8	4.0	4.2	4.2	4.2	4.3	4.3	4.3	4.2
Economic Purchases	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	177.5	180.0	185.3	188.7	192.3	194.8	197.0	197.6	198.0	199.9	201.9	202.3	203.3	205.0	206.5	207.3	208.5	209.4	211.4	212.5	213.9	215.1	217.7	218.3	219.8

1C, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	68.9	65.8	67.0	68.6	67.4	66.5	69.7	66.3	68.4	69.2	67.8	67.0	70.3	66.7	68.2	69.4	67.8	66.7
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.6	17.7	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.5	16.4	16.3
Coal	38.9	31.2	28.6	28.1	28.5	29.1	28.2	27.2	30.7	13.4	13.7	14.5	14.8	14.6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	45.3	56.7	62.9	62.8	63.4	64.8	68.9	68.0	66.7	83.9	82.0	81.9	82.6	79.7	97.7	95.1	94.9	96.2	97.8	95.8	100.5	100.1	100.7	103.4	105.6
Renewables	8.3	9.0	10.4	11.4	12.1	12.7	12.2	11.8	13.0	14.2	15.5	16.4	17.2	18.1	19.3	20.2	20.6	21.6	22.5	22.2	22.5	22.8	22.9	23.1	23.9
Storage	2.3	2.1	2.4	2.1	2.3	2.8	3.2	3.5	3.2	4.4	4.8	4.8	4.7	5.1	5.0	5.5	5.7	5.7	6.0	6.2	6.3	6.4	6.3	6.7	6.9
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.2	2.5	2.8	3.1	3.5	3.8	4.1	4.3	4.6	4.8	4.8	4.8	4.8	4.8	4.8	4.8
Economic Purchases	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.1	0.1	0.1	0.0	0.0
Subtotal	177.4	180.0	185.3	188.8	192.3	195.2	197.7	198.6	199.0	201.4	203.4	204.1	205.2	206.9	208.5	209.6	211.0	212.2	214.5	215.6	217.1	218.8	220.6	222.2	224.2

2A, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	68.9	65.8	71.8	78.1	81.7	85.5	93.4	103.8	119.5	125.0	128.4	127.8	130.9	127.3	128.8	130.1	128.4	127.2
Hydro	17.2	17.3	17.1	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.3	16.3	16.2	16.3	16.3	16.5	16.3	16.3
Coal	39.4	33.0	33.8	36.6	35.8	36.2	33.3	30.5	33.1	16.4	16.4	16.4	16.3	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	47.8	60.0	65.4	65.0	69.5	71.6	80.5	83.7	86.1	99.8	96.1	94.3	93.1	87.7	95.5	81.0	75.2	71.3	71.5	68.5	71.7	70.6	70.1	71.5	70.2
Renewables	8.3	9.0	10.4	11.4	11.8	14.7	13.2	12.0	12.3	12.8	13.2	13.4	13.3	13.3	13.5	13.3	15.8	18.9	22.0	23.9	26.3	28.8	30.9	33.2	39.3
Storage	2.3	2.2	2.5	2.3	2.2	2.7	3.1	3.7	3.1	3.4	4.0	3.7	3.4	4.2	4.1	4.8	5.5	5.7	5.9	6.2	6.3	6.7	6.7	6.6	6.8
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.2	2.5	2.8	3.1	3.5	3.8	4.1	4.3	4.6	4.8	4.8	4.8	4.8	4.9	4.8	4.9
Economic Purchases	0.1	0.1	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	180.4	185.2	193.0	199.5	205.4	211.1	215.3	218.0	219.9	222.5	226.7	228.6	231.1	234.7	237.1	239.1	242.2	245.2	248.3	250.6	252.8	256.1	259.1	260.9	264.7

2B, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	71.3	70.6	74.1	78.1	81.7	90.2	102.4	110.4	128.4	134.0	137.3	136.8	139.9	136.2	137.7	139.1	137.3	136.2
Hydro	17.2	17.3	17.1	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.3	16.2	16.3	16.3	16.5	16.3	16.3
Coal	39.4	33.1	33.9	36.5	35.8	36.2	31.8	30.3	32.8	16.4	16.4	16.4	16.3	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	47.7	59.9	65.4	65.0	69.5	71.5	82.0	81.5	81.6	97.5	96.1	94.4	88.5	78.9	89.1	72.3	66.1	62.2	62.4	59.5	62.8	61.7	61.2	62.7	64.9
Renewables	8.3	9.0	10.4	11.4	11.8	14.7	13.2	12.0	12.3	12.8	13.2	13.4	13.3	13.3	13.5	13.3	16.0	19.1	22.2	24.1	26.5	29.0	31.1	33.3	35.9
Storage	2.3	2.2	2.5	2.3	2.2	2.5	3.1	3.5	3.1	3.7	4.3	3.9	4.0	4.9	4.7	5.6	6.2	6.3	6.8	7.0	7.4	7.7	7.8	7.5	7.8
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.1	2.5	2.8	3.1	3.4	3.8	4.0	4.3	4.6	4.8	4.8	4.8	4.8	4.9	4.8	4.9
Economic Purchases	0.1	0.1	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	180.4	185.2	193.1	199.6	205.4	210.9	215.3	217.8	219.8	222.8	226.9	228.8	231.8	235.4	237.8	240.1	242.9	245.9	249.3	251.5	254.1	257.3	260.4	262.0	266.0

2C, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	68.9	65.8	71.8	78.1	81.7	85.5	93.4	94.9	110.5	116.1	119.4	118.8	121.9	118.3	119.9	121.2	119.4	118.3
Hydro	17.2	17.3	17.1	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.5	16.3	16.3
Coal	39.4	33.1	33.8	36.5	35.8	36.2	33.2	30.1	32.7	16.4	16.4	16.4	16.3	16.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	47.7	59.8	65.4	64.8	68.9	70.6	78.3	80.5	81.4	93.3	88.1	85.1	82.6	75.9	91.2	75.7	69.6	65.8	66.0	63.1	66.5	65.4	64.9	66.1	67.6
Renewables	8.3	9.0	10.4	11.6	12.4	15.7	15.5	15.7	17.3	19.3	21.3	22.8	24.1	25.3	26.9	27.9	30.5	33.6	36.8	38.8	41.2	43.7	45.9	48.4	51.8
Storage	2.3	2.2	2.5	2.3	2.3	2.9	3.7	4.7	4.5	5.1	6.0	6.3	6.4	7.1	6.9	8.3	9.5	10.1	11.0	11.7	12.6	13.5	14.1	14.6	15.4
EEDR	0.0	0.0	0.1	0.1	0.5	0.9	1.2	1.6	2.0	2.3	2.7	3.1	3.4	3.8	4.1	4.4	4.7	4.9	5.2	5.2	5.2	5.2	5.3	5.3	5.3
Economic Purchases	0.1	0.1	0.0	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	180.4	185.2	193.1	199.6	205.6	211.4	215.9	219.1	221.5	224.4	228.9	231.6	234.6	238.0	240.3	243.2	246.7	250.2	254.3	257.0	260.1	264.1	267.7	270.2	274.7

3A, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	71.3	70.6	74.1	78.1	79.3	80.8	86.3	85.3	98.7	101.8	102.8	102.2	105.3	101.7	103.3	104.5	102.8	101.7
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.7	17.7	16.2	16.2	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.4	16.3	16.3
Coal	38.6	30.8	25.9	27.7	30.0	30.0	12.3	4.9	7.5	3.2	2.9	0.4	0.4	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	44.8	55.8	63.9	61.1	59.6	59.9	80.5	83.8	81.1	82.7	79.4	78.2	77.0	71.9	73.4	60.0	55.5	52.6	52.2	48.6	51.3	49.0	47.8	48.7	49.4
Renewables	8.3	9.0	10.4	11.4	11.8	13.5	11.8	10.6	10.9	11.2	11.3	13.1	12.9	12.7	12.8	12.6	14.2	16.2	18.2	19.1	20.4	21.9	22.9	24.1	25.8
Storage	2.3	2.0	2.4	2.1	2.2	2.4	2.0	2.6	2.2	2.9	3.4	3.3	3.0	3.5	3.6	4.3	4.5	4.5	5.0	5.3	5.5	5.8	5.8	5.6	5.8
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.2	2.5	2.8	3.1	3.5	3.8	4.1	4.3	4.6	4.8	4.8	4.8	4.8	4.8	4.8	4.7
Economic Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.2	0.3	0.1	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	176.6	178.8	183.5	186.6	189.7	191.4	192.1	192.6	192.0	192.8	194.1	193.6	193.6	194.6	195.4	196.0	196.6	197.0	198.8	199.3	200.2	201.1	202.3	202.5	203.8

3B, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	71.3	70.6	74.1	78.1	79.3	83.1	86.3	94.3	98.7	101.8	102.8	102.2	105.3	101.7	103.3	104.5	102.8	101.7
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.6	17.6	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.5	16.3	16.3
Coal	38.7	30.7	25.8	27.7	29.9	30.0	14.5	6.8	9.8	4.4	3.7	0.7	0.6	0.5	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	44.7	56.0	64.0	61.1	59.8	59.9	78.2	81.9	78.7	81.4	78.5	77.4	74.0	71.2	64.3	59.6	55.3	52.4	52.0	48.4	51.1	48.8	47.6	48.5	49.2
Renewables	8.3	9.0	10.4	11.4	11.8	13.5	11.8	10.6	10.9	11.2	11.3	13.5	13.2	13.1	13.1	13.0	14.4	16.4	18.4	19.3	20.7	22.1	23.1	24.4	26.1
Storage	2.3	2.0	2.3	2.1	2.2	2.5	2.0	2.5	2.1	2.7	3.3	3.2	2.9	3.5	4.0	4.3	4.6	4.6	5.1	5.3	5.5	5.9	5.9	5.8	6.1
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.2	1.5	1.8	2.1	2.5	2.8	3.1	3.5	3.8	4.1	4.3	4.5	4.8	4.8	4.8	4.8	4.8	4.8	4.7
Economic Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.4	0.2	0.3	0.2	0.1	0.3	0.2	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	176.7	178.8	183.5	186.6	189.7	191.5	192.0	192.4	191.8	192.5	193.9	193.4	193.5	194.5	195.8	196.0	196.7	197.2	198.9	199.3	200.1	201.3	202.4	202.7	204.0

3C, TWh	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050
Nuclear	65.3	63.7	63.7	66.7	68.1	67.2	66.2	71.3	70.6	74.1	78.1	79.3	80.8	86.3	85.3	89.8	92.9	93.9	93.2	96.4	92.8	94.3	95.5	93.9	92.7
Hydro	17.2	17.3	17.2	17.5	17.5	17.7	17.8	17.6	17.7	16.2	16.3	16.3	16.3	16.2	16.3	16.3	16.3	16.4	16.4	16.2	16.3	16.3	16.5	16.3	16.3
Coal	38.6	30.7	26.0	27.8	29.9	30.1	14.0	6.0	8.1	4.1	3.3	0.6	0.7	0.3	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Gas	44.8	55.9	63.8	61.0	59.7	59.7	77.4	80.2	76.7	76.8	72.9	71.2	68.9	63.0	63.3	56.6	52.2	49.4	49.0	45.4	47.8	45.5	44.2	44.9	45.3
Renewables	8.3	9.0	10.4	11.4	11.8	13.6	13.3	13.2	14.8	16.4	17.6	20.1	21.0	22.0	23.2	25.3	26.9	28.9	31.0	31.9	33.6	35.2	36.4	37.8	39.8
Storage	2.3	2.0	2.3	2.1	2.2	2.6	2.3	3.2	3.1	4.0	4.7	4.8	5.0	5.4	5.9	7.0	7.6	7.7	9.0	9.5	10.1	11.1	11.5	11.8	12.5
EEDR	0.0	0.0	0.1	0.1	0.5	0.8	1.1	1.5	1.8	2.2	2.5	2.8	3.2	3.5	3.8	4.1	4.3	4.6	4.8	4.8	4.8	4.8	4.9	4.9	4.9
Economic Purchases	0.0	0.0	0.0	0.0	0.0	0.0	0.3	0.1	0.2	0.2	0.1	0.2	0.1	0.1	0.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Subtotal	176.6	178.8	183.5	186.6	189.7	191.6	192.4	193.2	193.0	194.0	195.5	195.3	195.9	196.7	198.0	199.1	200.3	200.8	203.4	204.2	205.5	207.2	209.0	209.6	211.5

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Appendix I – Cost and Risk Metrics

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Appendix I – Cost and Risk Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the nine resource portfolios resulting from applying the three strategies in the three scenarios. This appendix discusses the cost and risk metrics used in the IRP analysis, the methodology employed to derive them, and some trend comparisons.

I.1 Cost and Risk Metric Definitions

To evaluate portfolio performance with respect to cost and risk, TVA and the IRP Working Group identified three cost metrics and two risk metrics, as described below. These metrics can be compared across portfolios and strategies to evaluate relative cost and risk profiles, as well as tradeoffs. Metrics cover the 2026-2050 study period.

Table I-1: Cost and Risk Metrics

Metric Category	Metric	Good	Definition
Low Cost	Present Value of Revenue Requirements (PVRR) ($B)	Lower	Total plan cost (capital and operating) expressed as the present value of revenue requirements
	System Average Cost ($/MWh)	Lower	Average system cost expressed as levelized average annual revenue requirements divided by average annual sales
	Total Resource Cost ($B)	Lower	Total plan cost (capital and operating) expressed as PVRR plus participant costs net of bill savings and tax credits
Risk Informed	Risk / Benefit Ratio	Lower	PVRR above expected value divided by PVRR below expected value based on stochastic analysis
	Risk Exposure ($B)	Lower	PVRR above expected value based on stochastic analysis

I.2 Cost and Risk Metric Scorecard Results

Table I-2 below shows a comparison of the five cost and risk metrics for each strategy and scenario.

Table I-2: Cost and Risk Metric Scorecard

Metric / Strategy	Strategy A	Strategy B	Strategy C
PVRR ($B)			
1 - Reference	$189	$200	$194
2 - High Growth	$257	$262	$261
3 - Carbon Legislation	$218	$218	$219
System Average Cost ($/MWh)			
1 - Reference	$78	$83	$80
2 - High Growth	$96	$98	$98

Metric / Strategy	Strategy A	Strategy B	Strategy C
3 - Carbon Legislation	$93	$94	$94
Total Resource Cost ($B)			
1 - Reference	$190	$201	$195
2 - High Growth	$258	$263	$263
3 - Carbon Legislation	$218	$219	$221
Risk / Benefit Ratio			
1 - Reference	2.19	2.10	2.18
2 - High Growth	2.17	2.17	2.11
3 - Carbon Legislation	1.98	1.98	1.94
Risk Exposure ($B)			
1 - Reference	$32.8	$26.5	$29.6
2 - High Growth	$31.1	$29.4	$28.6
3 - Carbon Legislation	$22.4	$22.4	$20.9

I.3 Present Value of Revenue Requirements

The Present Value of Revenue Requirements (PVRR) represents the total portfolio costs, both capital and operating, to TVA over the planning horizon, expressed in today's dollars. The formula for PVRR is:

$$NPV(Annual\ Revenue\ Requirements\ (2026\ -2050))$$

Strategy A results in the lowest cost portfolio within each of the scenarios, as it reflects baseline utility planning and has the fewest constraints or resource promotions. Strategy B (Innovation) is generally the highest cost due to the large capital requirements needed for the new technologies like nuclear. Strategy C (Distributed) tends to have median cost performance as it leans more heavily on mature technologies than Strategy B.

From a scenario perspective, Scenario 1 (Reference) tends to have the lowest cost. Scenario 2 (High Growth) is the most costly, as this scenario features increased capacity expansion to serve higher electricity demand growth and higher natural gas prices correlated to higher national economic growth. Even though Scenario 3 (Carbon Legislation) has slower electric demand growth than Scenario 1, the introduction of the carbon tax in the 2030s raises the expected natural gas price forecast and requires the construction of more expensive generation to offset the impacts of the carbon tax.

I.4 System Average Cost

System average cost expresses revenue requirements in terms of a levelized rate per unit of energy sales and is directionally indicative of overall trends in customer bills. The formula for system average cost, which derives a levelized annual average system cost rate in $/MWh, is:

$$\frac{NPV\ Revenue\ Requirements\ (2026\ -2050)}{NPV\ Sales\ (2026\ -2050)}$$

Within each scenario, the relative performance of each strategy is the same in system average cost as it is in PVRR. Strategy A is the lowest system average cost withing each scenario. Scenario 3, which assume carbon legislation, show an increase in system average cost in the 2030s as the impacts carbon taxes are realized.

The following charts provide additional details on the forecasted trajectory of system average cost over time.

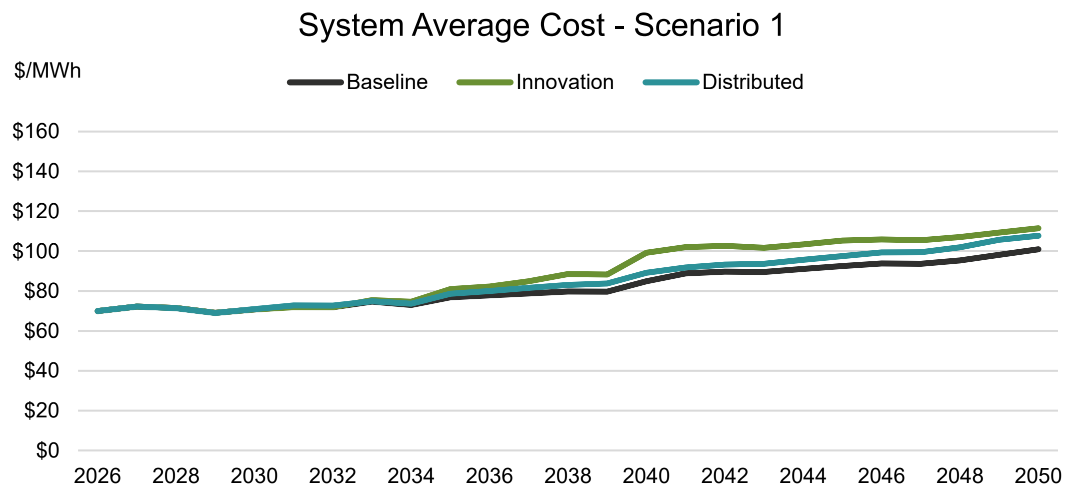

Figure I-1: Annual System Average Cost, Scenario 1 (Reference)

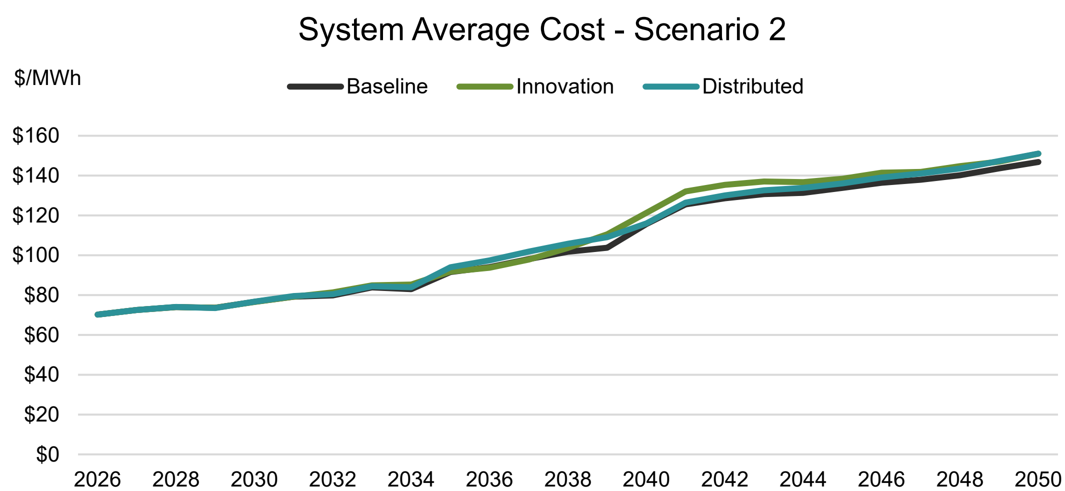

Figure I-2: Annual System Average Cost, Scenario 2 (High Growth)

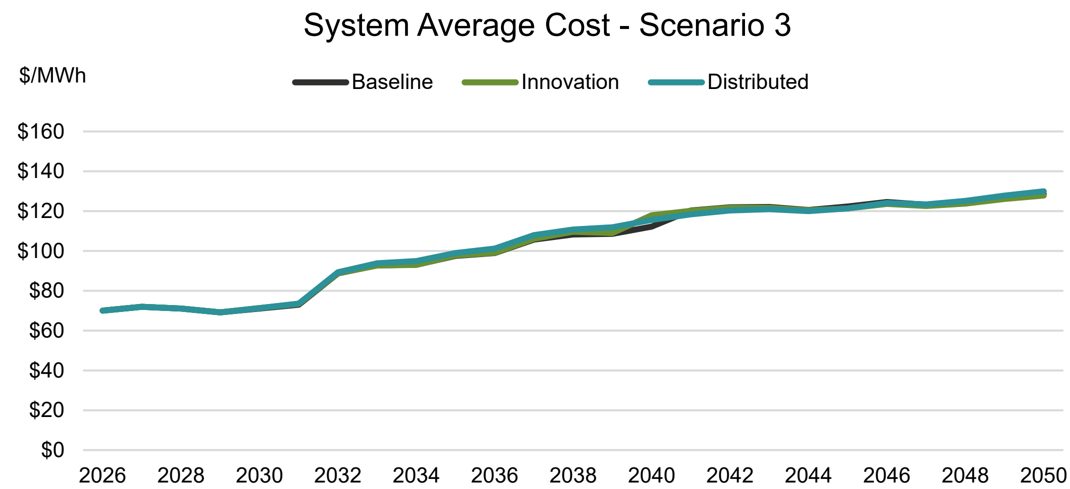

Figure I-3: Annual System Average Cost, Scenario 3 (Carbon Legislation)

I.5 Total Resource Cost

Total resource cost starts with PVRR and adds the costs paid by participants to install distributed generation or invest in energy efficient measures, net of bill savings and tax credits. The formula for total resource cost is:

$$PVRR + Participant\ Cost\ Net\ of\ Savings\ (bill\ savings,\ tax\ credits)$$

This metric provides a view of the total costs associated with a resource portfolio, whether paid by TVA or program participants.

Because total resource cost accounts for both the TVA system cost and the participant costs of behind-the-meter generation and energy efficiency, Strategy A is consistently the least cost within each scenario. Strategy C, which promotes distributed and demand side resources, has the largest participant costs.

I.6 Risk/Benefit Ratio

The two risk metrics express financial risk in different ways. Risk/benefit ratio looks at the potential for higher costs as a ratio of the potential for lower costs. The formula for risk/benefit ratio is:

$$\frac{95th\ (PVRR) - Expected\ (PVRR)}{Expected\ (PVRR)\ - 5th\ (PVRR)}$$

This metric is based on stochastic analysis. A ratio of one indicates an equal chance of having higher or lower costs than estimated, a ratio less than one indicates better odds of having lower costs than estimated, and a ratio more than one indicates better odds of having higher costs than estimated.

Stochastic analysis evaluates the risk of uncertainty around multiple key assumptions and identifies the risk exposure inherent in long-term resource planning. A primary use of stochastic analysis is to quantify financial risk. The first step is to identify the key drivers of portfolio costs associated with electricity demand, fuel and market power prices, generating unit performance, and operating and capital costs. Then, a distribution around the fundamental forecasts for each of the drivers is developed using scalars based on historical variability. The stochastic model uses a Monte Carlo simulation (a form of repeated random sampling) to test the variability of key assumptions and understand the likely range of cost results, allowing for a comparison of financial risk across plans.

The figure below illustrates the 5th percentile, 50th percentile, and 95th percentile in a lognormal distribution.

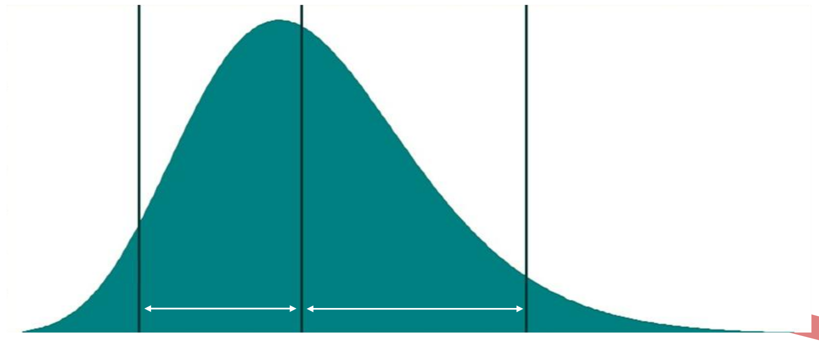

Figure I-4: Illustrative Lognormal Distribution showing P5, P50, P95

The figure below shows the resulting stochastic distributions of PVRR for the nine core portfolios that was used to calculate the risk/benefit ratio and risk exposure metrics.

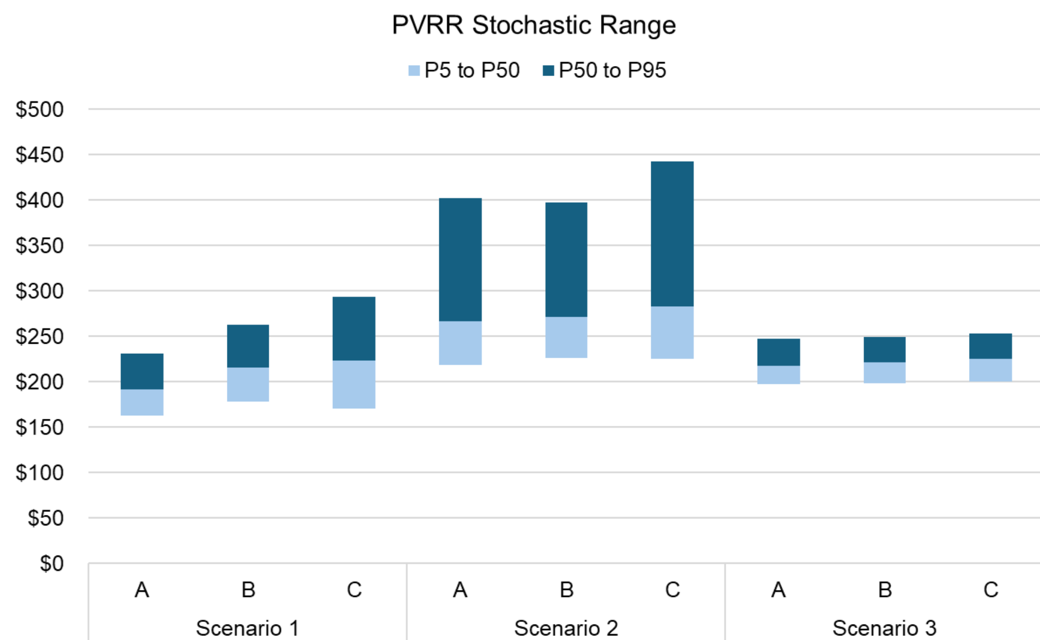

Figure I-5: Stochastic Distribution of Core Portfolio PVRR showing P5, P50, P95

I.7 Risk Exposure

Another way of describing risk is risk exposure, or the potential for higher costs. The risk exposure formula is:

$$95th\ (PVRR) - Expected\ (PVRR).$$

A wider distribution indicates higher risk that costs could increase above the expected value and ratepayers could be negatively impacted. This metric is also based on stochastic analysis, and it represents the risk of higher costs based on variations in key assumptions.

I.8 Conclusion

The cost and risk metrics each capture a different aspect of portfolio performance. They provide insights into cost and risk tradeoffs across portfolios, as well as across broader metric categories. See Chapter 3 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.

J

Appendix J – Environmental Metrics

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Appendix J – Environmental Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the nine resource portfolios resulting from applying the three strategies in the three scenarios. This appendix discusses environmental metrics used in the IRP analysis, the methodology employed to derive them, and some trend comparisons.

J.1 Environmental Metric Definitions

To evaluate portfolio performance with respect to environmental impacts, TVA and the IRP Working Group identified five metrics, as described below. These metrics can be compared across portfolios and strategies to evaluate relative environmental profiles and tradeoffs. Metrics cover the 2026-2050 study period, except for one metric that focuses on 2050, as noted.

Table J-1: Environmental Metrics

Metric Category	Metric	Good	Definition
Environmentally Responsible	Land Use Intensity (Acres/GWh)	Lower	Acreage needed for expansion units divided by energy generated and purchased in 2050
	Water Consumption Intensity (Gallons/MWh)	Lower	Average annual gallons of water consumed divided by average annual energy generated and purchased
	Waste Intensity (Tons/GWh)	Lower	Average annual quantity of coal ash and gypsum produced divided by average annual energy generated and purchased
	CO_2 Direct Emissions (Million Tons)	Lower	Average annual tons of CO_2 emitted
	CO_2 Intensity (lbs/MWh)	Lower	Average annual CO_2 emissions divided by average annual energy generated and purchased

J.2 Environmental Metric Scorecard Results

Table J-2 below shows a comparison of the five environmental metrics for each strategy and scenario.

Table J-2: Environmental Metrics Scorecard

Metric / Strategy	Strategy		
	A	B	C
Land Use Intensity (Acres/GWh)			
1 - Reference	0.06	0.06	0.20
2 - High Growth	0.19	0.19	0.32
3 - Carbon Legislation	0.18	0.19	0.32
Water Consumption Intensity (Gallons/MWh)			
1 - Reference	294	327	289
2 - High Growth	331	345	328

Metric / Strategy	Strategy		
	A	B	C
3 - Carbon Legislation	328	330	312
Waste Intensity (Tons/GWh)			
1 - Reference	8.5	8.8	8.7
2 - High Growth	9.1	9.0	9.1
3 - Carbon Legislation	6.2	6.5	6.4
CO_2 Direct Emissions (Million Tons)			
1 - Reference	52	47	49
2 - High Growth	49	46	46
3 - Carbon Legislation	35	35	33
CO_2 Intensity (lbs/MWh)			
1 - Reference	542	489	513
2 - High Growth	466	445	447
3 - Carbon Legislation	382	385	370

J.3 Land Use Intensity

Land use intensity represents the acres of land needed for expansion units expressed as a rate per unit of annual energy. The formula for land use intensity is:

$$\frac{Acres\ Needed\ for\ New\ Units\ (2026\ -2050)}{GWh\ Generated\ \&\ Purchased\ (2050)}$$

The variations in load levels across scenarios also naturally lead to variations in land usage. Expressing this as a rate allows for better comparison across scenarios as well as between strategies. In general, generating units that are less energy dense use more land. Strategies that promote resources like solar will use more land than alternative strategies. Only land used directly for expansion generating resources owned or controlled by TVA is included in this metric. Land used by distributed resources is not considered to be owned or controlled by TVA. Because land use is cumulative across the study period, this metric looks at total land use for all expansion units through 2050 divided by the energy generated or purchases in that final year.

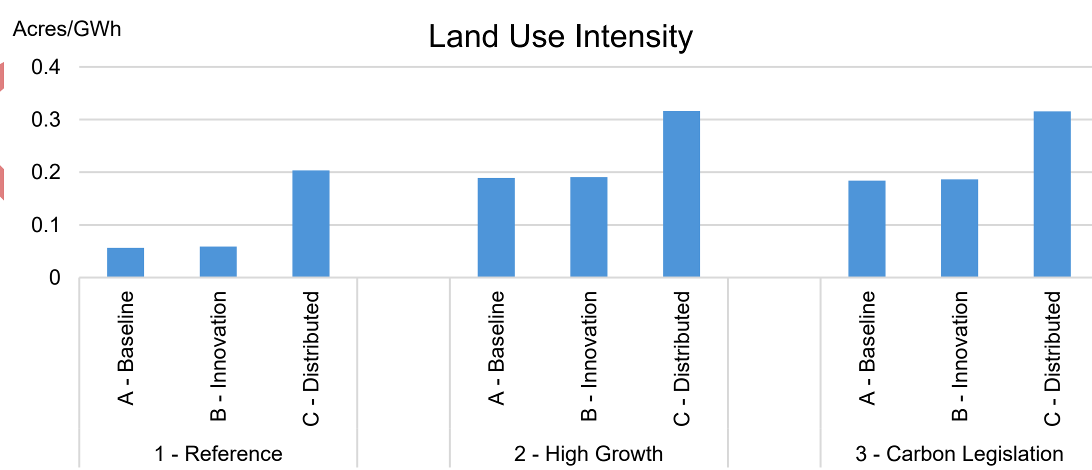

Figure J-1: Land Use Intensity

J.4 Water Consumption Intensity

Water consumption intensity represents the gallons of water consumed expressed as a rate per unit of annual energy. The formula for water consumption intensity is:

$$\frac{Gallons\ of\ Water\ Consumed\ (2026\ -2050)}{MWh\ Generated\ \&\ Purchased\ (2026\ -2050)}$$

The variations in load levels across scenarios naturally lead to variations in water consumption, so expressing this as a rate allows for better comparison across scenarios as well as between strategies. Water consumption includes only water lost to evaporation in the production of electricity and associated thermal cooling systems.

As the scenario that materializes primarily drives the differences in water consumption intensity, the charts below shows how water intensity varied for each scenario and strategy.

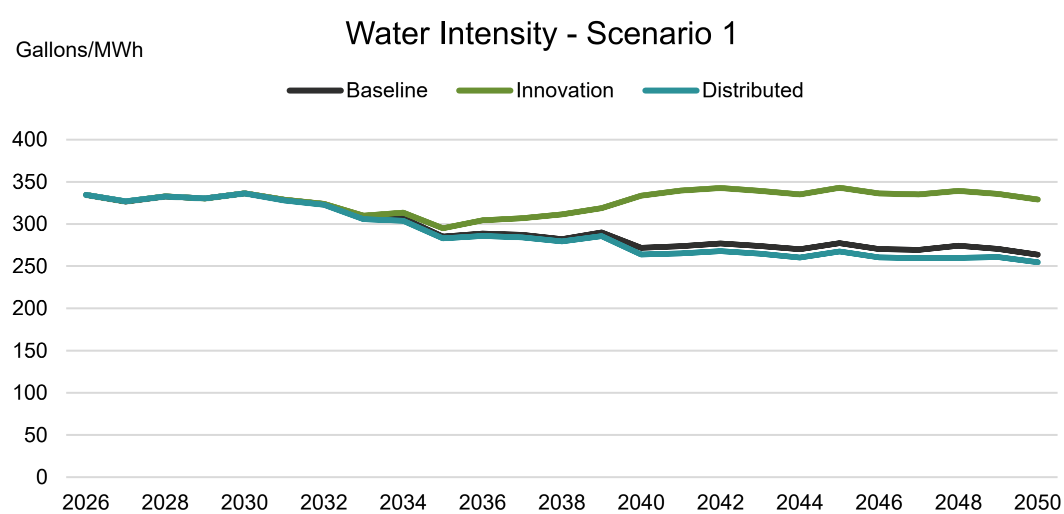

Figure J-2: Annual Water Consumption Intensity, Scenario 1 (Reference)

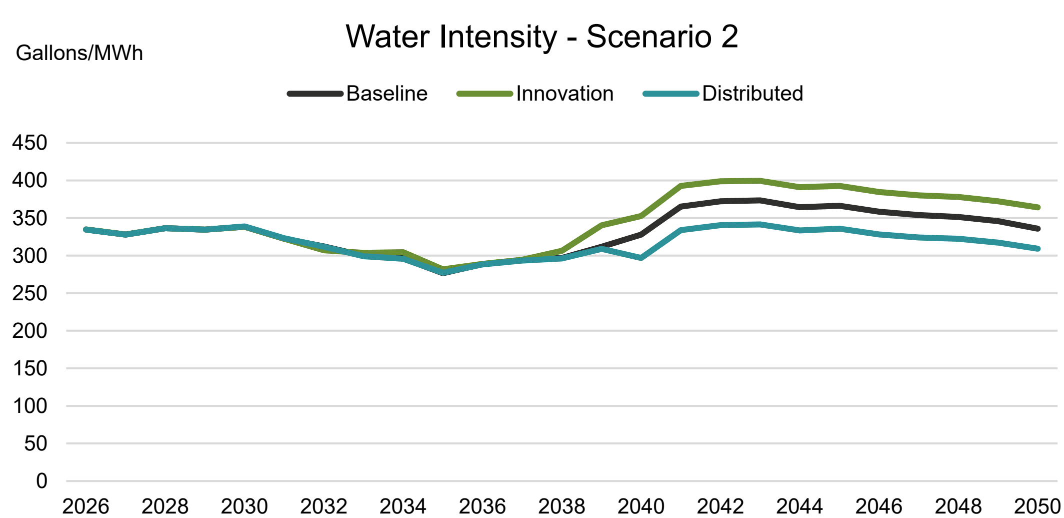

Figure J-3: Annual Water Consumption Intensity, Scenario 2 (High Growth)

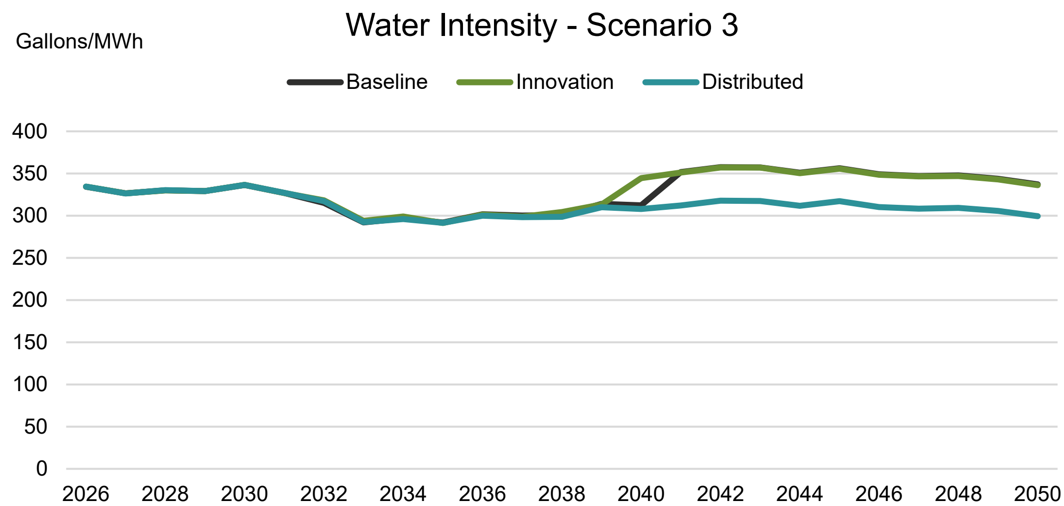

Figure J-4: Annual Water Consumption Intensity, Scenario 3 (Carbon Legislation)

J.5 Waste Intensity

Waste intensity represents the millions of tons of coal ash and gypsum produced expressed as a rate per unit of annual energy. The formula for waste intensity is:

$$\frac{Tons\ of\ Waste\ Produced\ (2026-2050)}{MWh\ Generated\ \&\ Purchased\ (2026-2050)}$$

The variations in load levels across scenarios naturally lead to variations in waste production, so expressing this as a rate allows for better comparison across scenarios as well as between strategies. Waste intensity falls to zero in all scenarios after the last coal units reach expected end of life.

As the scenario that materializes primarily drives the differences in waste intensity, the charts below shows how waste intensity varied for each scenario and strategy.

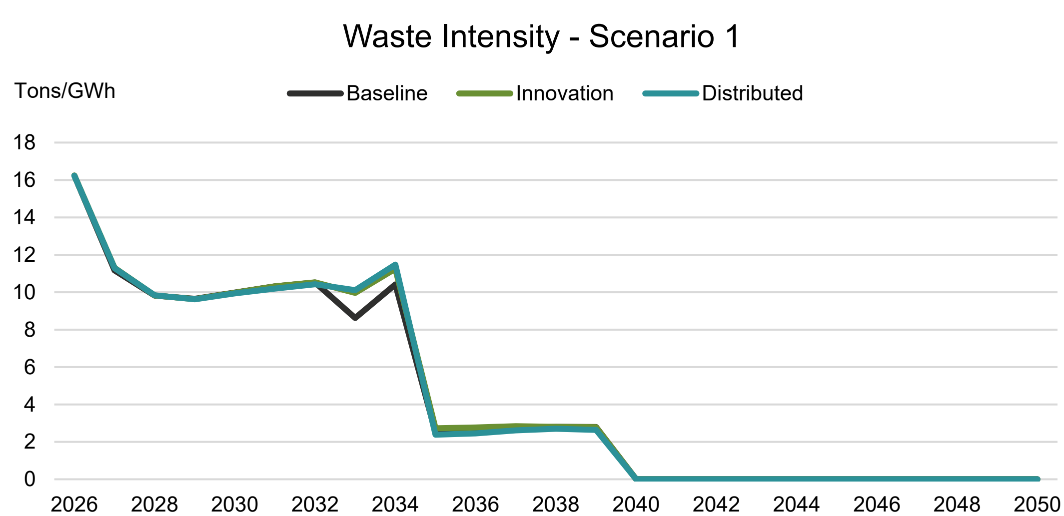

Figure J-5: Annual Waste Intensity, Scenario 1 (Reference)

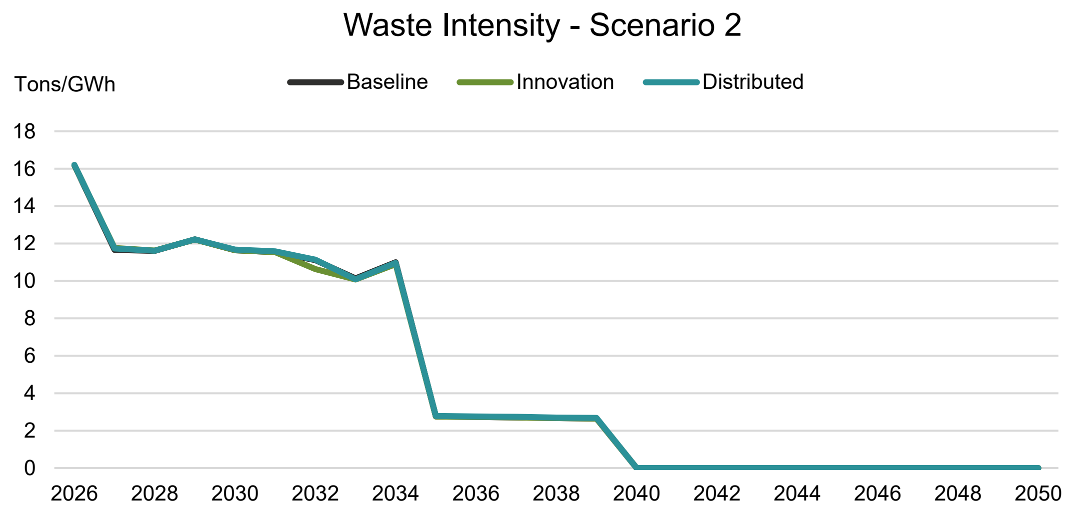

Figure J-6: Annual Waste Intensity, Scenario 2 (High Growth)

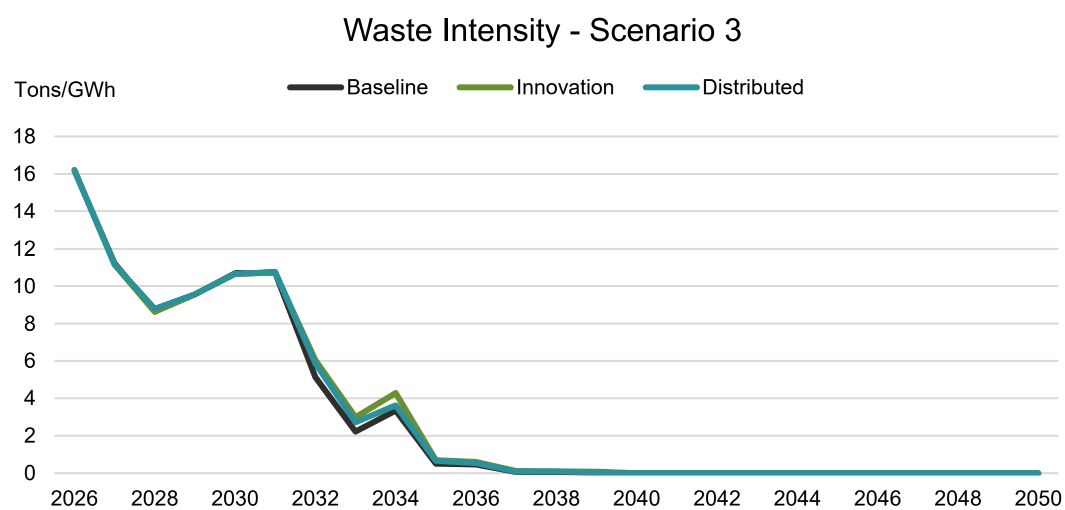

Figure J-7: Annual Waste Intensity, Scenario 3 (Carbon Legislation)

J.6 CO_2 Direct Emissions

CO_2 direct emissions represent the emissions directly attributable to generating units through combustion of fuels, expressed in millions of tons. This metric does not include life cycle or embedded emissions. While this metric is expressed as the average annual tons of CO_2 emitted over the planning period, annual amounts are generally expected to decline across the study period. The formula for CO_2 direct emissions is:

$$\frac{Millions\ of\ Tons\ of\ CO2\ (2026\ -2050)}{Number\ of\ years\ (2026\ -2050)}$$

Different resource types contribute to system emissions based on the CO_2 content of the fuel they burn. The table below denotes the typical CO_2 content for different fuel types and blends.

Table J-3: CO_2 Content of Various Fuels and Fuel Blends

Fuel	CO_2 Content (lbs/MMBtu)
Coal	205
Natural Gas	117
Natural Gas with 90% CCS	11.7

The charts below provide additional details on the forecasted trajectory of CO_2 emissions over time for each scenario and strategy.

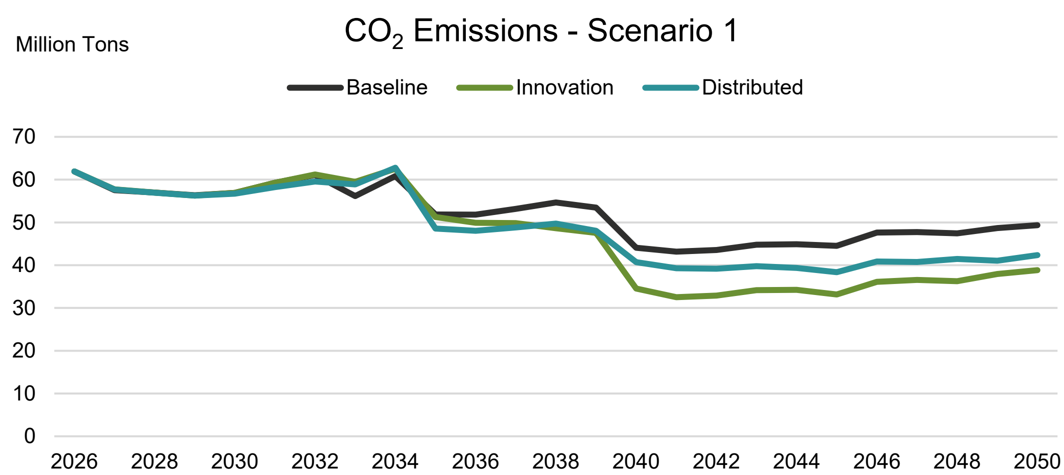

Figure J-8: CO_2 Direct Emissions (Million Tons), Scenario 1 (Reference)

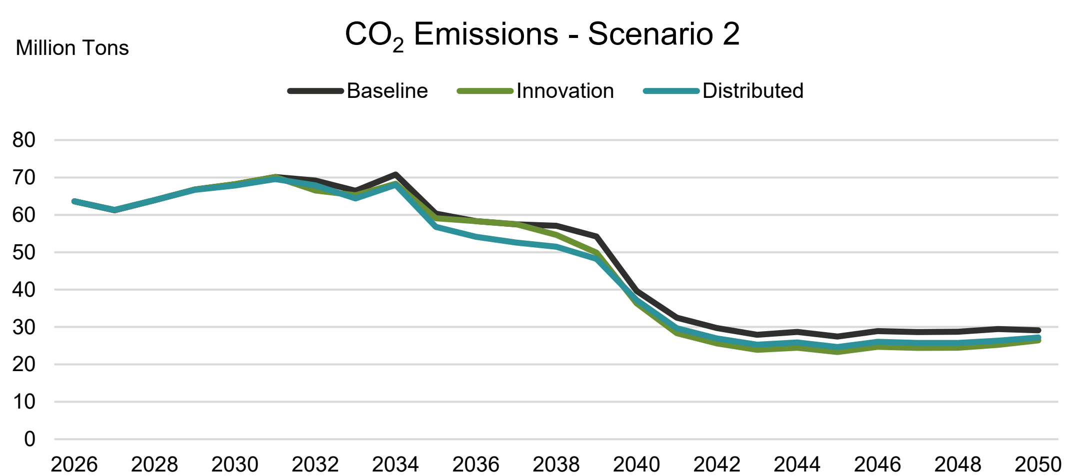

Figure J-9: CO_2 Direct Emissions (Million Tons), Scenario 2 (High Growth)

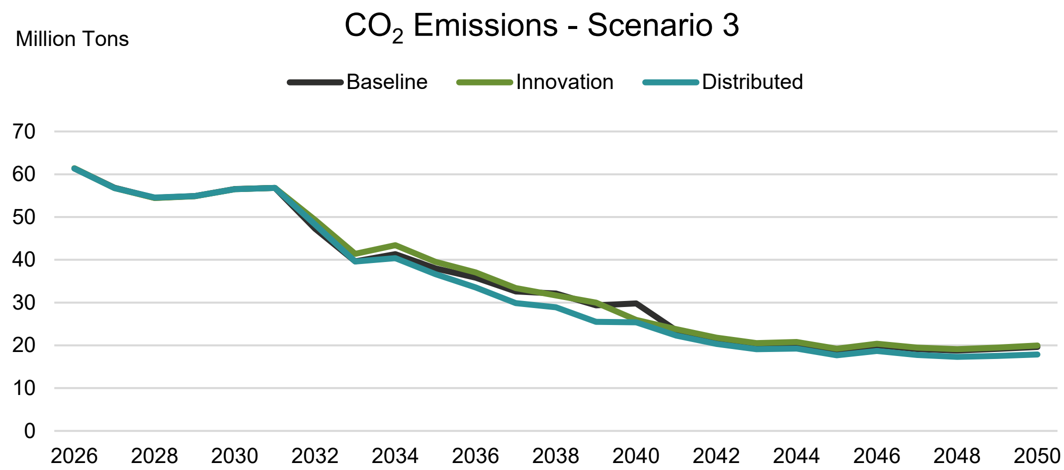

Figure J-10: CO_2 Direct Emissions (Million Tons), Scenario 3 (Carbon Legislation)

J.7 CO_2 Intensity

The variations in load levels across scenarios naturally lead to variations in direct CO_2 emissions. CO_2 intensity represents direct emissions expressed as a rate per unit of annual energy. This allows for better comparisons across all portfolios. The formula for CO_2 intensity is:

$$\frac{Pounds\ of\ CO2\ (2026\ -2050)}{MWh\ Generated\ \&\ Purchased\ (2026\ -2050)}$$

The figures below show the CO_2 intensities for each scenario and strategy.

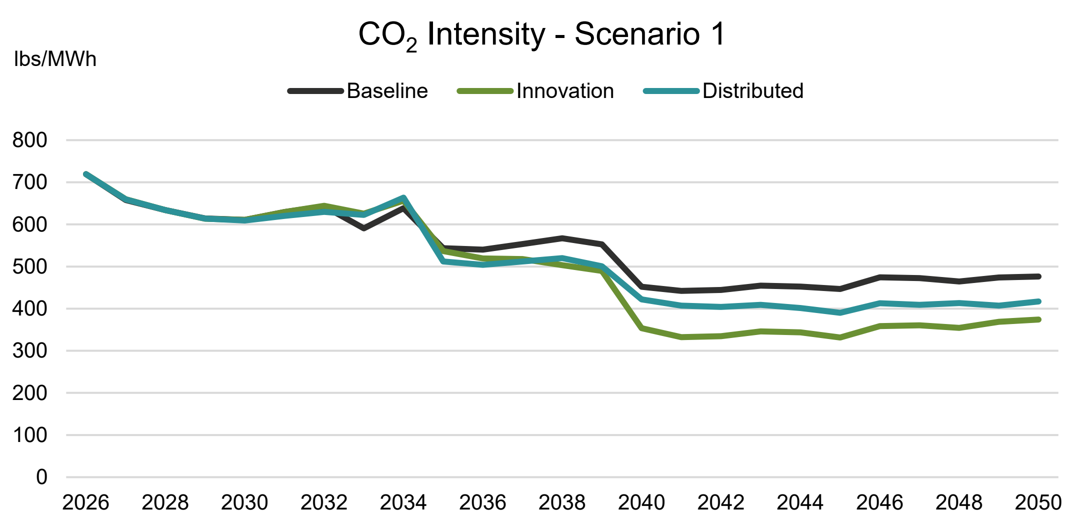

Figure J-11: CO_2 Intensity Trajectory, Scenario 1 (Reference)

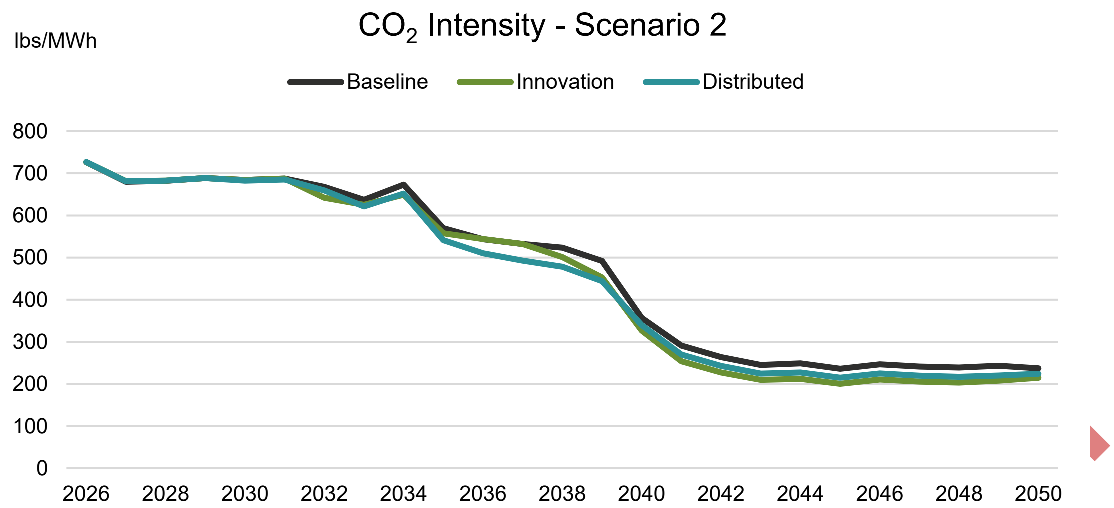

Figure J-12: CO_2 Intensity Trajectory, Scenario 2 (High Growth)

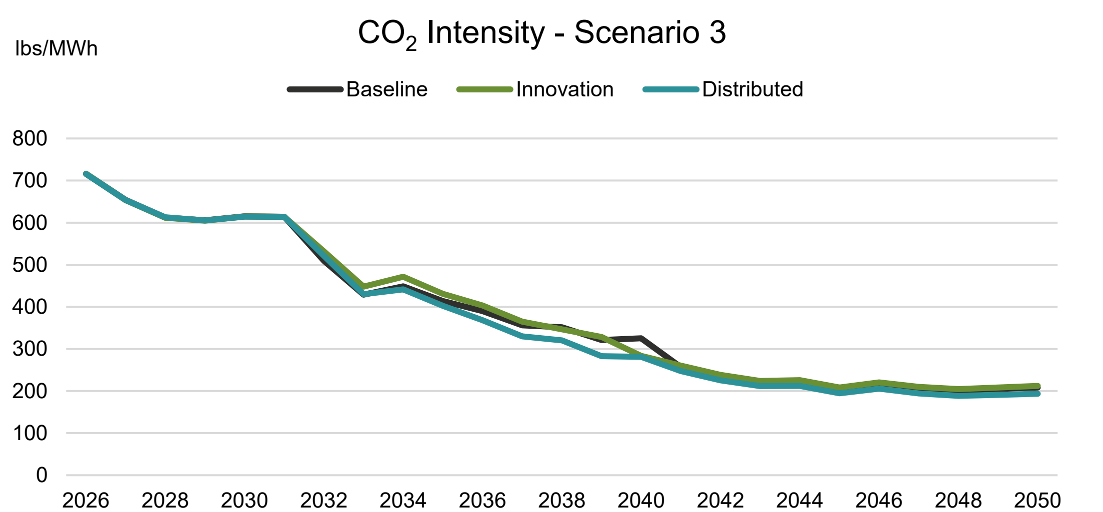

Figure J-13: CO_2 Intensity Trajectory, Scenario 3 (Carbon Legislation)

J.8 Conclusion

Each of these metrics describes a different aspect of environmental performance. They provide insights into environmental tradeoffs across portfolios, as well as across broader metric categories. See Chapter 3 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.

K

Appendix K – Operational Metrics

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Appendix K – Operational Metrics

TVA's least-cost planning program starts with low cost, complemented by evaluations of operational, environmental, and risk factors. Reflecting these planning principles and with input from the IRP Working Group, TVA developed metrics to assess the performance of the nine resource portfolios resulting from applying the three strategies in the three scenarios. This appendix discusses the operational metrics used in the IRP analysis and the methodology employed to derive them.

K.1 Operational Metric Definitions

To evaluate portfolio operational performance, TVA and the IRP Working Group identified three metrics, as described below. They capture various aspects of operational performance including diversity, reliability, and flexibility and can be compared across portfolios and strategies to evaluate relative operational profiles and tradeoffs. Metrics cover the 2025-2050 study period.

Table K-1: Operational Metrics

Metric Category	Metric	Good	Definition
Diverse, Reliable, and Flexible	Operating Cost Stability (%)	Lower	Stochastic volatility of operating cost ($/MWh) expressed as a percentage
Diverse, Reliable, and Flexible	P95 Average Unserved Energy Ratio	Lower	Stochastic 95th percentile average annual amount of energy shortfall (MWh) over study period divided by average annual sales (MWh)
Diverse, Reliable, and Flexible	Expected Average Energy Curtailment Ratio	Lower	Stochastic expected average annual curtailed energy (MWh) over study period divided by average annual sales (MWh)

K.2 Operational Metric Scorecard

The table below shows a comparison of the three operational metrics for each strategy and scenario.

Table K-2: Operational Metrics Scorecard

Metric / Strategy	Strategy		
	A	B	C
Operating Cost Stability (%)			
1 - Reference	8.82%	7.64%	7.74%
2 - High Growth	7.71%	7.36%	6.92%
3 - Carbon Legislation	7.94%	8.01%	7.70%
P95 Average Unserved Energy Ratio			
1 - Reference	$2.2x10^{-5}$	$4.9x10^{-5}$	$7.6x10^{-5}$
2 - High Growth	$6.2x10^{-5}$	$5.5x10^{-5}$	$6.8x10^{-5}$
3 - Carbon Legislation	$3.6x10^{-8}$	$1.1x10^{-5}$	$2.0x10^{-5}$
Expected Average Energy Curtailment Ratio			
1 - Reference	$1.0x10^{-9}$	$8.7x10^{-9}$	0
2 - High Growth	$3.7x10^{-4}$	$4.6x10^{-4}$	$5.2x10^{-4}$

Metric / Strategy	Strategy		
	A	B	C
3 - Carbon Legislation	$2.1x10^{-4}$	$1.8x10^{-4}$	$4.7x10^{-4}$

K.3 Operating Cost Stability

A diverse portfolio is not only more reliable; it also has less variability in expected operating costs. The ability to switch between resource or fuel types and take advantage of changing fuel costs and comparative economics over time is a key benefit to having a diverse portfolio of generating assets. This results in higher operating cost stability over time.

Operating cost stability measures the expected volatility in operating costs. Operating cost includes total production cost, program cost, energy settlements, ancillary services cost, fixed costs, capacity settlements, and contract costs. It is based on stochastic analysis, which takes a probabilistic view of variations in key assumptions to understand the range of potential operating costs for a given portfolio. As a volatility calculation, it measures the standard deviation of the annual change, or rate of return, in operating costs. This calculation uses the expected or average of the 120 stochastic cases run for each portfolio.

$$\sigma(Rate\ of\ Return\ of\ Annual\ Operating\ Costs\ (2026-2050, Expected\ Case)$$

K.4 P95 Average Unserved Energy Ratio

Unserved Energy is a reliability metric that measures the total volume of electricity (MWh) that cannot be supplied. Unlike other reliability metrics (like Loss of Load Expectation), Unserved Energy measures the severity of energy shortages rather than just the frequency.

Unserved Energy is a low probability, high impact risk. Because both the deterministic capacity expansion and stochastic median case for each portfolio have no unserved energy, it is necessary to look at the tail risk, in this case the 95th percentile (P95), to see measurable differentiation in system reliability among generation portfolios. As an example, a key tail risk would be the risk of much higher than expected electric demand as a result of extreme temperatures. Looking at the tail risk allows for a better assessment of the true reliability of a power system, ensuring that planning accounts for extreme scenarios, not just typical days.

The formula for calculating P95 Average Unserved Energy Ratio is:

$$\frac{Average\ Annual\ P95\ Unserved\ Energy\ MWh\ (2026-2050)}{Average\ MWh\ Generated\ \&\ Purchased\ (2026-2050)}$$

K.5 Expected Average Energy Curtailment Ratio

A portfolio that is flexible has sufficient capacity available to ramp up and down as energy demand and renewable output changes from hour to hour. In periods where load net of renewable generation drops below the amount of non-dispatchable energy being generated, a portion of that generation will need to be sold, stored, or curtailed. Energy curtailment represents a lost opportunity cost to TVA customers, and minimizing this is good for both the system and ratepayers.

The energy curtailment ratio measures expected curtailed energy as a rate per unit of annual energy. The formula for calculating energy curtailment ratio is:

$$\frac{Average\ Expected\ Total\ Curtailed\ MWh\ (2026-2050)}{Average\ MW\mathrm{h}\ Generated\ \&\ Purchased\ (2026-2050)}$$

This measure is calculated from the expected case, or average, of the 120 stochastic cases run for each portfolio. It is measured across all future years of the study period, though generally it is a growing concern through time.

K.6 Conclusion

These operational metrics each capture a different aspect of portfolio performance. They provide insights into operational tradeoffs across portfolios, as well as across broader metric categories. See Chapter 3 for a discussion of key tradeoffs across portfolios and strategies based on the metric results.