Southern Renewable Energy Association
11610 Pleasant Ridge Rd.
Suite 103 #176
Little Rock, AR 72223

July 22, 2026

Kelly Baxter, NEPA Project Manager
Hunter Reed, IRP Project Manager
Tennessee Valley Authority
400 W. Summit Hill Drive, WT 11B
Knoxville, TN 37902

Re: Preliminary Final 2026 IRP Comments

Dear Kelly Baxter and Hunter Reed:

Please find enclosed the Southern Renewable Energy Association's Comments on Tennessee Valley Authority's Preliminary Final 2026 Integrated Resource Plan. Please contact me if you have any questions. Thank you for your consideration of these comments.

Respectfully submitted,

Simon Mahan
Executive Director
Southern Renewable Energy Association
11610 Pleasant Ridge Road, Suite 103 # 176
Little Rock, AR 72223
simon@southernwind.org
337-303-3723

Southern Renewable Energy Association

Comments on Tennessee Valley Authority's

Preliminary Final 2026 IRP

The Southern Renewable Energy Association (SREA) is a nonprofit trade association for large-scale renewable energy resource development throughout the southeast. Our advocacy focuses on utility-scale wind energy, solar power, battery storage, and transmission development in Alabama, Arkansas, Georgia, Kentucky, Louisiana, Mississippi, and Tennessee, including the Tennessee Valley Authority region. SREA has participated in TVA's Integrated Resource Planning (IRP) processes since 2015, and we appreciate the opportunity to provide feedback and input on this 2026 IRP effort.

TVA's IRP is not only an internal planning tool to help guide decision-making, but an important indicator to the region. A clear, reasonable, and well-vetted IRP is essential to attracting both new economic development opportunities, as well as new generation resources, to the region. If external development companies view the IRP as flawed, incomplete, or an otherwise inaccurate vision for the region, the region will be deprioritized for growth. This sort of deprioritization is already occurring. In 2023, there were approximately 149 projects in the TVA generator interconnection queue, representing nearly 30 GW of new generation opportunities. Today, there are just 97 projects, representing less than 23.5 GW, mostly proposed by TVA. Therefore, it is critically important that TVA represent a realistic view of its future, or put the growth of the region in jeopardy.

Table 1: TVA Generation Interconnection Queues, 2023 vs 2025

	2023		2025	
	Projects	MW	Projects	MW
Battery	21	2,097	14	2,347
Gas	16	10,986	22	15,087
Hydro	6	112	11	188
Nuclear	5	480	8	576
Solar	66	8,105	35	4,383
Solar+Battery	34	7,725	7	904
Wind	1	204	0	0
Total	149	29,709	97	23,485

Source: LBNL 2024, 2026[1]

I. Load Forecasts and Procurement of Resources

TVA evaluates three separate load forecasts in this IRP. Scenario 1 represents a mid-level load forecast, while Scenario 2 represents a high load forecast, and Scenario 3 represents a low load forecast. Between now and 2030, TVA's load forecast grows between 1-3 GW, and up to 6 GW by 2035. Without enough generation to cover the additional load, plus reserve margin, economic development within the TVA region may be limited. As recommended in SREA's prior comments on TVA's 2025 IRP, SREA continues to recommend that TVA create an annual procurement process for incremental resources (including renewable energy and storage resources) that targets annual capacity additions at the upper end of the range found to be cost effective, using the IRP as a guide. TVA should conduct competitive solicitations that evaluate all reasonable generation and storage solutions for meeting load growth.

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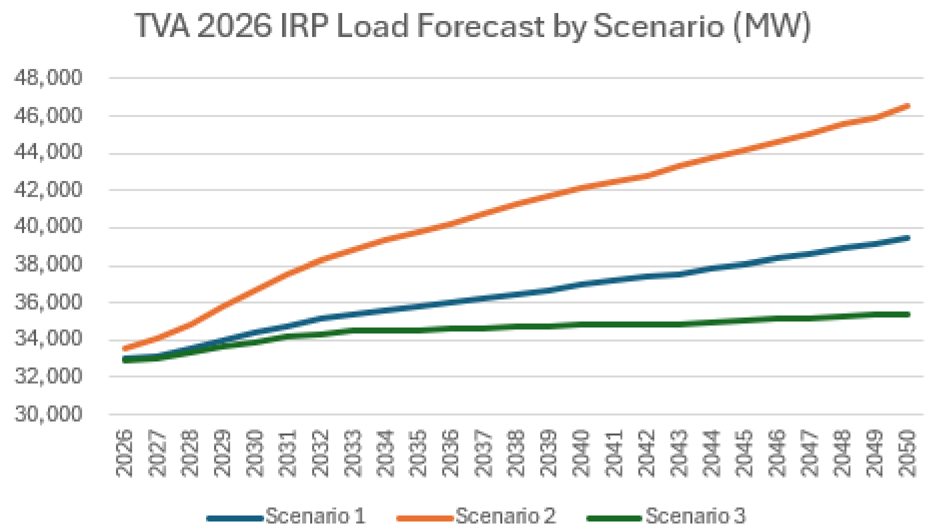
[1] Lawrence Berkely National Lab, 2024 edition and 2026 edition, *Queued Up*; https://emp.lbl.gov/publications/queued-2024-edition-characteristics, and https://emp.lbl.gov/sites/default/files/2026-05/LBNL_Ix_Queue_Data_File_thru2025.xlsx

Fig. 1: TVA 2026 IRP Load Forecast by Scenario (MW)



Source: TVA 2026 IRP

II. IRP Resource Cost and Timing Estimates

TVA provides reasonable assumptions regarding the use of the federal Investment Tax Credit (ITC) for nuclear, wind, solar, and battery energy storage systems. However, TVA assumes new generation is only available beginning in the year 2031, five years away. Based on the various load growth assumptions for the three separate scenarios, TVA faces significant capacity growth within the next five years that the IRP is unable to evaluate solutions for. This is a major deficiency in the IRP and unreasonably limits tax credit available resources as solutions, specifically renewable energy resources.

The only resources that are available for the model build in 2031, the first year for build-out, are hydro uprates, solar PPAs, wind energy, and battery storage. Therefore, any generation resources included in the various portfolios prior to 2031 appear to be manually selected, or "baked-in" resources outside of the capacity expansion modeling. Preselecting generation additions is antithetical to a modeling exercise designed to help guide decision-making.

Light Water SMR resources only become available beginning in 2033, with APWR (AP1000 equivalent) resources only available beginning in 2038. More advanced nuclear reactor resources become available to the model beginning in 2041. Given TVA's advanced experience with nuclear reactor technology, these timelines appear feasible.

Fig. 2: Subsidized Capital Expenditure Cost Assumptions

Nominal Overnight Cost with Investment Tax Credit applied ($/kW)																		
Year	Light Water SMR	Light Water SMR (Nth-of-a-Kind)	APWR	Gen IV SMR	Hydro Uprate	Coal	Coal w/ CCS	RICE (12x)	Aero (20x)	Frame CT (4x)	CC (3x1x1)	CC w/ CCS (2x1x1)	Solar PPA	Midwest Wind	SE High Hub	4-hr Lithium-Ion Battery	8-hr Adv Chem	Pumped Storage
2026$	12,084	6,120	9,964	6,826	1,818	3,482	4,905	2,305	2,513	1,161	2,148	3,635	1,188	1,102	1,544	1,511	2,720	2,234
2026																		
2027																		
2028																		
2029																		
2030																		
2031					1,957								1,279	1,186	1,661	1,626	2,927	
2032					2,000	3,831		2,536	2,764	1,277	2,363		1,812	1,713	2,401	1,662	2,992	
2033	13,448				2,043	3,912	5,510	2,590	2,822	1,304	2,413	4,084	1,793	1,732	2,429	1,697	3,055	
2034	11,841				2,080	3,983	5,567	2,637	2,874	1,328	2,457	4,115	1,766	1,752	2,456	1,728	3,111	
2035	10,685				2,116	4,052	5,620	2,682	2,923	1,351	2,499	4,142	1,736	1,771	2,484	1,758	3,164	2,599
2036	10,000				2,154	4,125	5,703	2,731	2,976	1,375	2,544	4,199	1,733	1,790	2,512	1,924	3,464	2,646
2037	10,666				2,197	4,208	5,800	2,786	3,036	1,403	2,596	4,266	1,732	1,810	2,541	2,148	3,867	2,699
2038	9,985		12,175		2,245	4,299	5,907	2,846	3,102	1,433	2,652	4,339	1,733	1,831	2,571	2,665	4,797	2,758
2039	9,608		12,429		2,294	4,393	6,016	2,908	3,169	1,464	2,709	4,414	1,734	1,854	2,603	2,723	4,901	2,818
2040	9,300		12,681		2,345	4,491	6,131	2,973	3,240	1,497	2,770	4,493	1,734	1,877	2,637	2,783	5,010	2,880
2041	7,948	7,948	12,940	8,864	2,398	4,592	6,250	3,040	3,313	1,531	2,833	4,575	1,735	1,901	2,672	2,846	5,124	2,946
2042	8,985	8,985	14,629	10,021	2,453	4,698	6,374	3,110	3,390	1,566	2,898	4,660	1,734	1,926	2,707	2,912	5,242	3,337
2043	10,062	10,062	16,381	11,221	2,512	4,810	6,504	3,184	3,471	1,604	2,967	4,750	1,734	1,951	2,743	2,981	5,367	3,747
2044	12,089	12,089	19,681	13,482	2,572	4,926	6,640	3,261	3,554	1,642	3,038	4,843	1,735	1,977	2,780	3,053	5,496	4,514
2045	12,343	12,343	20,096	13,766	2,634	5,044	6,777	3,339	3,639	1,682	3,111	4,937	1,732	2,003	2,818	3,126	5,628	4,622
2046	12,598	12,598	20,511	14,050	2,695	5,161	6,912	3,416	3,724	1,721	3,183	5,030	1,730	2,029	2,855	3,199	5,758	4,729
2047	12,854	12,854	20,927	14,335	2,755	5,276	7,043	3,493	3,807	1,759	3,254	5,119	1,722	2,054	2,892	3,270	5,887	4,835
2048	13,111	13,111	21,347	14,623	2,817	5,394	7,177	3,571	3,892	1,798	3,327	5,210	1,715	2,080	2,930	3,343	6,018	4,943
2049	13,378	13,378	21,781	14,920	2,881	5,517	7,316	3,652	3,980	1,839	3,403	5,304	1,706	2,107	2,968	3,419	6,155	5,055
2050	13,646	13,646	22,218	15,219	2,947	5,644	7,460	3,736	4,072	1,882	3,481	5,402	1,696	2,133	3,006	3,498	6,297	5,171

Source: TVA 2026 IRP

III. Incremental Capacity Model Outputs

TVA provided year-by-year tables for Scenarios 1, 2, and 3, as compared against Strategies A, B, and C, creating a matrix of nine potential Portfolios (1A, 1B, etc.). These Portfolios reflect higher levels of nuclear and natural gas additions, and fewer additions of renewable energy resources, than the 2025 IRP materials.[2] Evaluating capacity additions between now and 2030 compared to 2035 highlights the significant quantity of assumed or non-modeled generation resources included in the IRP. Almost 6 GW of new generation capacity is assumed in the IRP by

[2] https://www.tva.com/environment/draft-2025-integrated-resource-plan

2030, and most of the model-selected additions in the reference case by 2035 are gas CT, CC, and battery resources. No new coal, nuclear, reciprocating engine (gas), nor wind resources are added to the generation mix by 2035 in the base case.

Fig. 3: Generation Addition Comparisons, Various Portfolios (MW)

	MWs (2030) Across All Portfolios	High MWs (2031) (Portfolio)	Portfolio 1A MW (2035) Reference Case
Nuclear	0 MW	0 MW	0 MW
Coal	0 MW	0 MW	0 MW
Gas CC	2,146 MW	2,146 MW (all)	3,576 MW
Gas CT	0 MW or 820 MW	884 MW (1A, 1B)	2,652 MW
Gas Aero	1,048 MW or 1,378 MW	1,378 MW (1A, 1B)	1,378 MW
RICE	0 MW	0 MW	0 MW
Solar - Large	1,056 MW	2,060 MW (2A, 2B)	1,071 MW
Battery	222 MW	937 MW (2C)	959 MW
Wind	0 MW	0 MW	0 MW
Total	5,602 MW	7,365 MW	9,636 MW

Source: TVA 2026 IRP

a. Renewable Energy Assessment

Across all nine portfolios, between now and 2030, TVA plans to expand summer net dependable capacity of utility-scale solar to approximately 1,056 MW. This baseline of additions is likely a manual addition unaffected by the IRP modeling. Strategies A and B in each Scenario result in the same amount of utility-scale solar build-out between now and 2035 (e.g., 1A and 1B are the same, 2A and 2B are the same, 3A and 3B are the same), with only Strategy C (Distributed Strategy) representing a higher quantity of solar deployment in each Scenario. Almost no wind energy resources are added at all.

Between now and 2030, the TVA IRP includes just 222 MW of 4-hour battery storage across all nine portfolios. By 2035, the IRP adds about 1 GW of battery storage in Portfolio 1A, the reference case.

b. Gas Assessment

Natural gas additions in the 2026 IRP materials suggest strong reliance on combined-cycle (CC) and combustion turbine (CT) resources. To a lesser degree, aeroderivative (aero) and reciprocating internal combustion engine (RICE) generation are included. Under no circumstances is natural gas with carbon capture sequestration selected by the model, likely due to significantly higher cost. By 2040, all IRP portfolios result in between 7 GW and 14 GW of new gas resources.

For natural gas generation resource additions, both Portfolios 1A and 1B result in the same amount of total natural gas capacity additions by 2030 of 3,524 MW, predominately focused on combined-cycle technology. Portfolios 1C, 2A, 2B, 2C, 3A, 3B, and 3C result in the same amount of total capacity additions in 2030 of 4,013 MW; the difference between Portfolios 1A/B and the remainder for the year 2030 is the addition of 820 MW of combustion turbine generation. These results highlight that TVA's five-year plan for capacity additions is not driven by the IRP model, but instead some separate internal guidance.

By 2034, many of the portfolios stop adding new Gas CC units until the late 2040s, instead preferring Gas CTs during that time. It appears that no new Gas Aero facilities are added beyond 2030, indicating that any aeroderivative in this IRP are all manually selected resources, not selected by the IRP modeling software. RICE facilities only show up in Strategy C (1C, 2C, 3C; Distributed Strategy), starting in the mid-2030s, with a maximum contribution of 1.3 GW by 2050 in Portfolio 2C. These outputs suggest that RICE units are not a reasonable alternative to CC and CT generation, and rely on external modeling limitations for selection.

c. Nuclear Assessment

Nuclear generation resources are the most expensive generation resources included in the IRP modelling exercise, even more expensive than new coal generation units, new coal with carbon capture sequestration, and new natural gas with carbon capture sequestration. Adding 1,000 MW of any nuclear technology evaluated will cost between roughly $8 billion and $12 billion, even assuming the federal subsidies already available for new nuclear units. TVA's statutory debt limit ceiling is $30 billion, with only $7.9 billion remaining, suggesting any nuclear addition would require significant federal funds like direct grant subsidies or substantial innovative partnerships.[3] Nuclear resources also have some of the latest start-dates, typically in the late 2030s or early 2040s.

Figs. 5, 6: TVA Overnight Capital Cost Assumptions

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

Source: TVA 2026 IRP

[3] https://tva-azr-eastus-cdn-ep-tvawcm-prd.azureedge.net/cdn-tvawcma/docs/default-source/about-tva/guidelines-reports/annual-performance-report-2027.pdf

Figs. 5, 6: TVA Overnight Capital Cost Assumptions (continued)

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	

Source: TVA 2026 IRP

Given the high cost of new nuclear reactors, it is surprising that all Portfolios have some level of new nuclear additions, strongly suggesting that the nuclear additions are due to manual additions, or extreme modeling limitations that effectively force nuclear resources into the portfolios. For example, Portfolio 1B adds several SMRs from 2033-2040, and an APWR 1,110 MW reactor in 2040. During that time as new nuclear resources are added, the IRP adds almost no new natural gas generation resources. This is an unusual result given how much lower cost the natural gas generation resources are provided in the IRP model.

For nuclear technology, the nine portfolios all include a 25 MW Gen IV SMR resource installed in 2033, with no more Gen IV SMRs added in any portfolio through 2050. The model only allowed Gen IV SMR technology to begin in 2041, making the addition in 2033 clearly a manual addition, not one selected by the model. However, no public announcements around a 25 MW Gen IV SMR in TVA territory exist, making this manually added generation resource in the IRP an enigma.

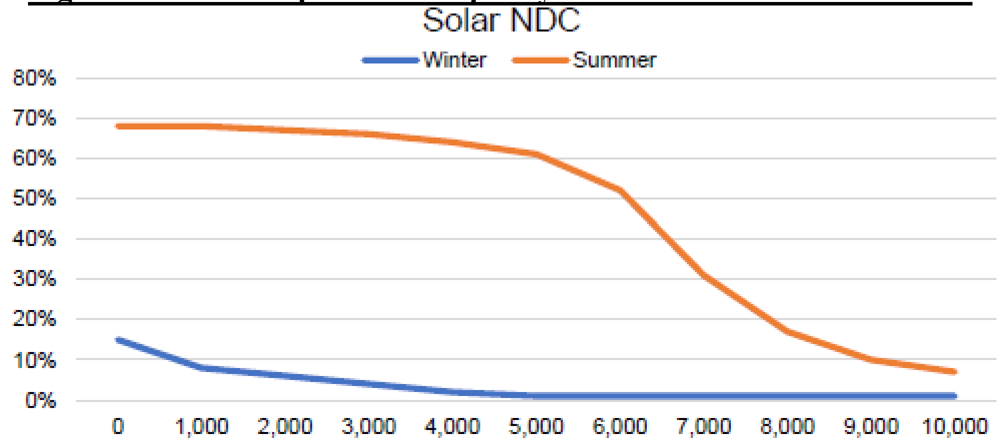
Most of the publicly available information around new nuclear development within the TVA region includes information around the Clinch River SMR facility, receiving $400 million from the U.S. Department of Energy to support the site. TVA also has a partnership with Type One to develop a stellarator fusion power plant called Infinity 2, a project approximately 300 MWs in size, slated for deployment in the mid-2030s. However, the in-service dates of Clinch River and Infinity 2 appear to be unstable according to the IRP. Five portfolios add a 285 MW SMR (likely Clinch River or Infinity 2) by 2033, two portfolios delay the SMR addition until 2035 (Portfolios 2A, 2C), and two portfolios include no SMR addition at all between now and 2050 (Portfolios 1A, 1C), which presumably means Clinch River and Infinity 2 projects would be cancelled in the reference case.

For large nuclear reactor types, the IRP includes six portfolios adding 1,110 MW of new APWR in the 2039-2041 timeframe. Three portfolios include no new APWR resources (Portfolios 1A, 1C, 3C), including the reference the case. The additions of APWR facilities in the various portfolios is unusual given that no new coal-fired generation, nor aero gas units are added by the model; both technologies are significantly lower cost than the nuclear units provided to the IRP model and would be expected to be selected before nuclear. To be clear, SREA is not advocating for the addition of new coal-fired power plants; however, the absence of coal additions, while at a lower cost than the nuclear reactors in this modeling exercise, strongly suggests that all the nuclear additions were somehow forced into the results. Forcing in any type of generation resource displaces other resources that may be able to provide the same reliability benefits at a lower cost and undermine the reliability of the final IRP results.

IV. <u>Capacity Accreditation</u>

The TVA IRP includes information regarding solar and wind energy net dependable capacity (NDC), using an effective load carrying capacity assessment. At approximately 6 GW, solar resources reach an inflection point for accreditation, achieving 50% during summertime and declining rapidly afterwards. TVA has just 2.3 GW of solar currently operating on its system, per its latest EIA Form 860M data. Yet, relying on a fixed accreditation value for all scenarios inaccurately assesses true value. ELCC calculations rely on base load projections, and if load projections are significantly higher in one scenario compared to another, the ELCC valuation for a resource would stay higher with more installed nameplate capacity to reflect the value to the growing low. Assigning lower capacity value to solar resources devalues those resources in the modeling exercises unnecessarily.

<u>Fig. 7: Solar Net Dependable Capacity Values in the TVA IRP Model</u>

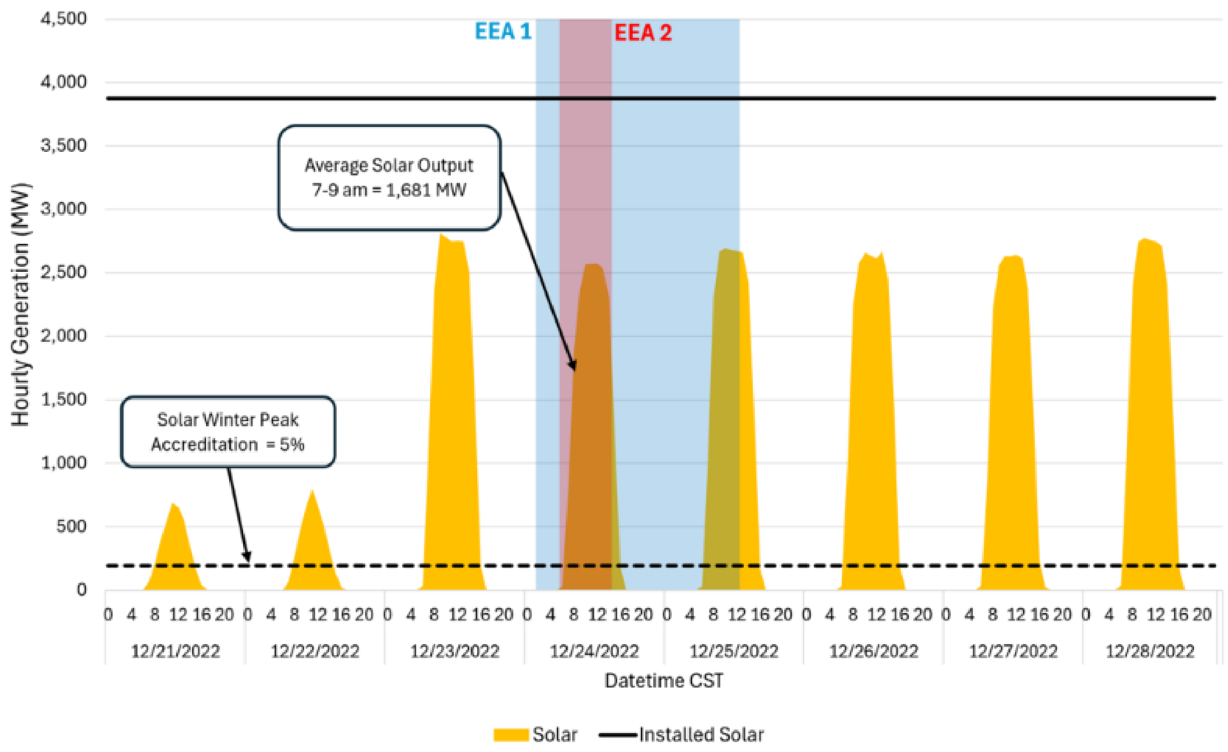


Source: TVA 2026 IRP

Winter capacity accreditation for solar resources deserves additional evaluation. While it is true that solar resources on average produce less energy during the average wintertime peaks (approximately 6-7AM) than summertime or afternoons, recent experiential data suggest solar produces well during more extreme weather events that result in absolute peak demand. TVA suffered power outages due to Winter Storm Elliott in 2022 from 9:43AM-11:43AM CT on December 23, and from 4:51AM-10:31AM CT on December 24, well beyond the typical average peak. Those times tend to align better with a higher delivery rate for solar than an average peak hour. If TVA had more solar power on its system during Elliott, the power outages could have been less severe and shorter in duration. Meanwhile, power flows from MISO into the TVA region helped ensure the power outages were limited, underscoring the value of regional and interregional transmission, and diversified generation.

In a post-storm analysis of solar resources in the Southern Company territory during Winter Storm Elliott, solar resources performed exceptionally well during the most difficult time for the grid. Higher solar penetration levels help explain, in part, Southern Company's ability to weather the storm without the major disruptions experienced by TVA.

<u>Fig. 8: Solar generation for Southern Company Balancing Authority, Winter Storm Elliott</u>

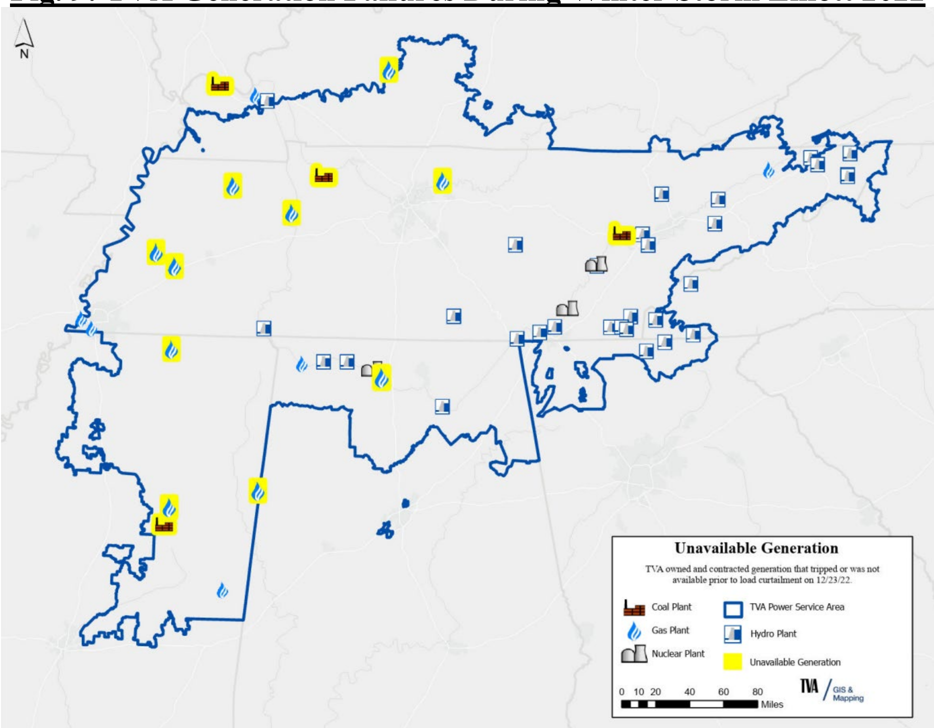


Source: Telos 2025[4]

[4] https://drive.google.com/file/d/1N8W60AN1jbnFPmFXCaKOV_N-TCFeKNmo/view

Similarly, the power outages suffered in the TVA region during Winter Storm Elliott were predominately due to downrates and failures to the natural gas and coal-fired generation fleet, not renewable energy resources. However, this IRP provides very high accreditation values to natural gas generation units,[5] regardless of season, the opposite of the experience during Winter Storm Elliott. PJM conducts an annual ELCC evaluation of various generation resources in its footprint and has found that the class average for gas CT and gas CC units are available approximately 60-74% of nameplate capacity, far below TVA's assumptions.[6] By under-estimating renewable capacity accreditation, and over-estimating natural gas accreditation, TVA's IRP results in significantly higher additions of natural gas resources while devaluing a diversified generation portfolio including renewable resources.

Fig. 9: TVA Generation Failures During Winter Storm Elliott 2022



Source: TVA 2023[7]

[5] See TVA 2026 IRP Table E-8: Gas Expansion Options and Key Assumptions
[6] https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/2026-27-bra-elcc-class-ratings.pdf
[7] https://apps.legislature.ky.gov/CommitteeDocuments/305/24160/Feb%202%202023%20TVA%20PowerPoint.pptx

V. Transmission Planning Must Be Prioritized

As noted in the IRP, "Additions of new energy resources of all types typically require additional investments in the transmission system."[8] Similarly, additions of new large loads such as data centers can also drive transmission additions. Retirement of generation units also affects the transmission system. Accessing generation resources from outside the TVA region, also called interregional transfer capacity, is a vital lifeline during extreme system events like winter storms or emergency generator outages. None of these issues are adequately addressed in the IRP as they pertain to transmission.

Shown below is a heat map created by TVA regarding its current transmission system. The map generally shows places that are good for adding new generation (green areas), and areas that are worse (red areas). While green areas are generally considered to be easy locations, further analysis may indicate those locations are more limited than this initial heat map represents. The map also shows where current generators are evaluating for connection to the grid via the queue process. As shown, most of the generators are in areas where the grid system is already at capacity and cannot handle additional generation.

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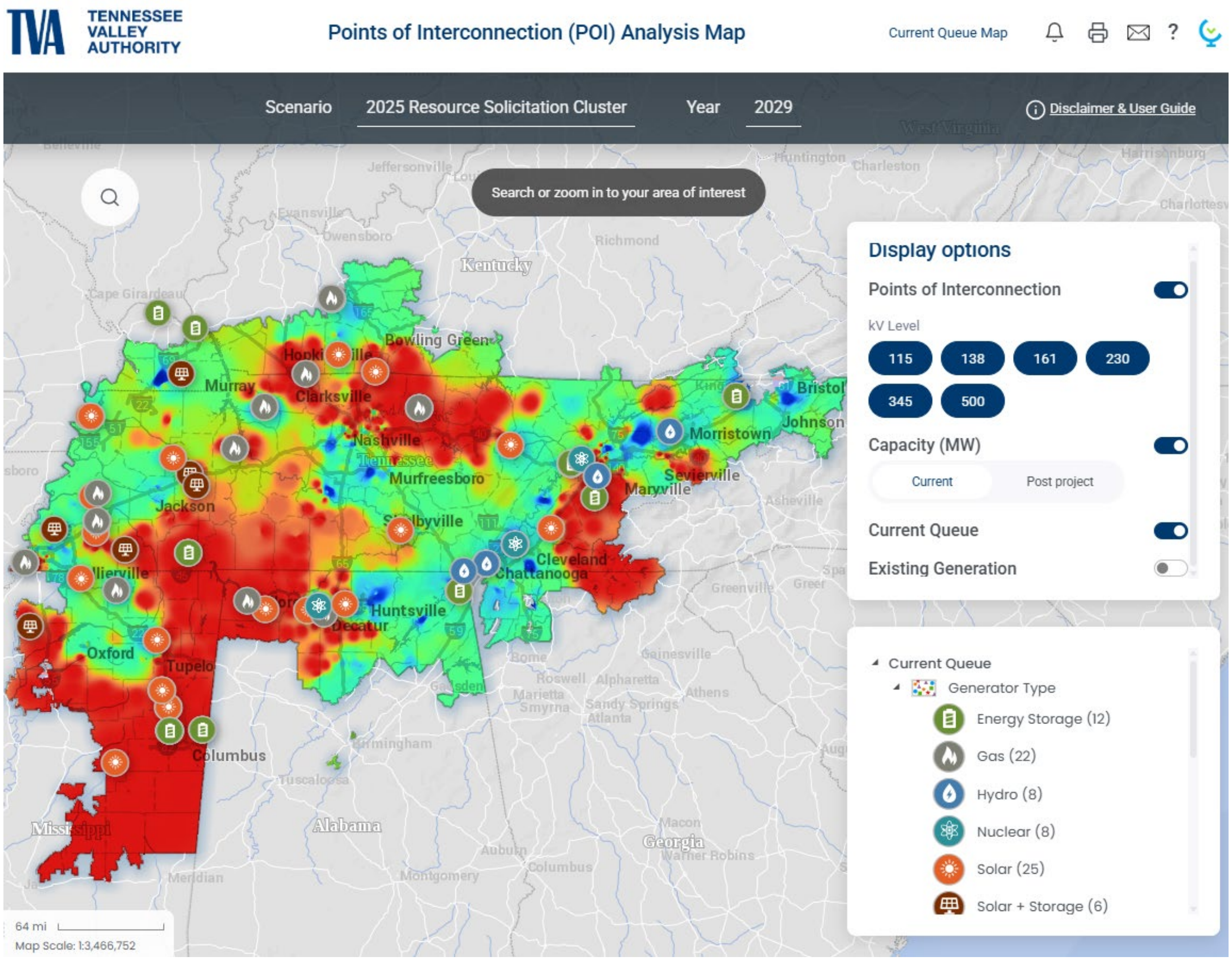
[8] TVA IRP pg. 4-4

<u>Fig. 10: TVA Transmission Points of Interconnection Analysis Map</u>



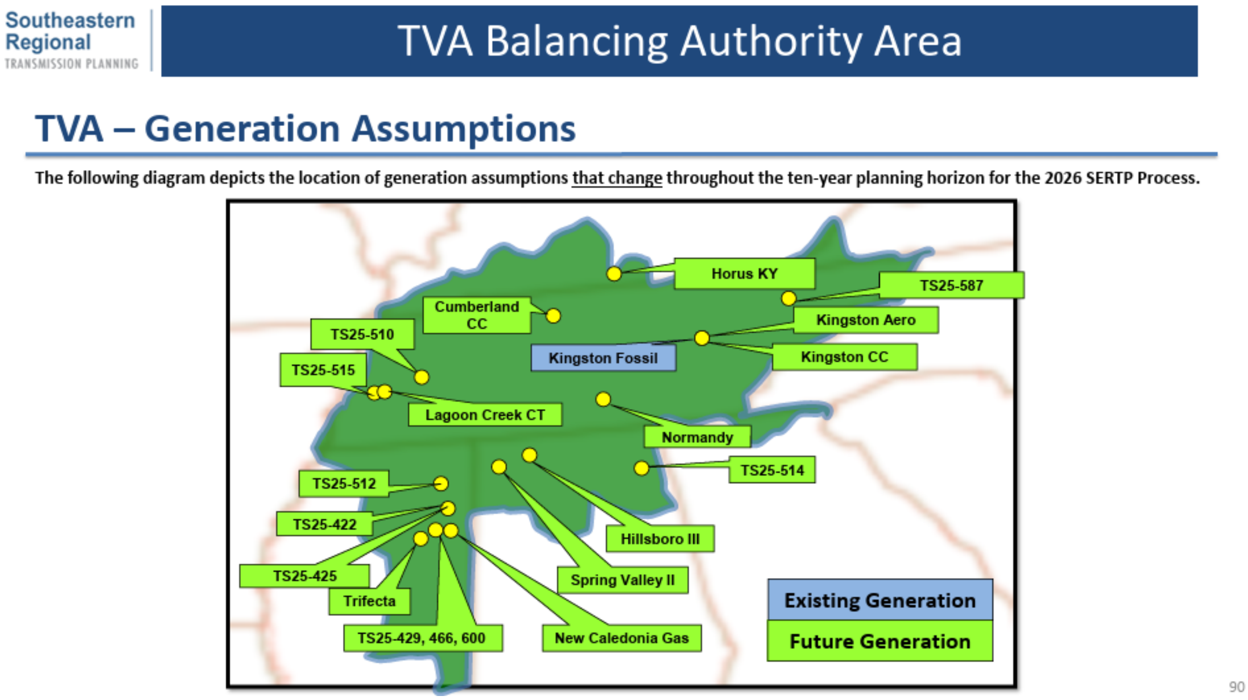
TVA participates in the Southeastern Regional Transmission Planning (SERTP) process. As part of the process, TVA provides data assumptions around generation additions and retirements. For example, TVA data in the SERTP process adds 3,769 MW of new gas resources, 1,654.3 MW of new solar, and 825 MW of new battery energy storage systems, all by 2029, adding significantly more resources than planned in this IRP. No nuclear additions are included in the SERTP data for the next decade, while the 50 MW Hermes project is currently in the queue for 2029. Furthermore, the IRP adds no new Gas Aero resources, and relies more heavily on gas CT units, than the SERTP data provided. While the IRP is meant to help guide TVA's decision-making process, it already appears that TVA has a separate process for its near-term resource additions.

Fig. 11: New Resource Additions by 2029 by Type (MW)

	SERTP	TVA 2026 IRP
Nuclear	0 MW	0 MW
Coal	0 MW	0 MW
Gas CC	2,576 MW	2,146 MW
Gas CT	345 MW	1,539 MW
Gas Aero	848 MW	0 MW
Renewables	1,514.3 MW	936 MW
Storage	825 MW	70 MW
Total	6,108 MW	4,691 MW

Sources: SERTP[9], TVA 2026 IRP Reference Case[10]

Fig. 12: TVA SERTP Generation Assumptions



Without accurate generation assumptions in the transmission planning models, transmission planning becomes an academic exercise with little value to decision-making. For example, TVA's SERTP assumptions of adding the Kingston CC unit steers transmission planning

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[9] www.southeasternrtp.com/docs/general/2026/2026_SERTP_2nd_Qtr_Presentation.pdf
[10] https://www.tva.com/environment/2026-integrated-resource-plan

to that area, whereas the IRP is strongly encouraging the addition of more CT units that are absent in the SERTP planning. Similarly, it appears that the IRP capacity additions greatly exceed the load growth anticipated by 2030; meanwhile, it is unclear what load forecasts are used in the SERTP planning model for transmission from TVA.

Transmission planning is advancing to evaluate multiple benefits of transmission including avoided or deferred facilities, reduced power outages, production cost savings, reduced line losses, transmission improvements during outages, mitigation of extreme weather, and reduced peak energy demands. These benefit metrics are industry standard, and TVA should begin a more robust transmission planning process to incorporate these multiple values.[11]

VI. Conclusions

Between the 2025 IRP draft and this new version, significant changes and modeling modifications have occurred. Due to the rapidly shifting energy industry landscape, SREA encourages TVA to consider more frequent IRP evaluations. More frequent IRPs will better enable TVA and the Board of Directors with new market intelligence to help guide the mission and purpose of the organization.

However, this latest IRP contains significant deviations from modeling best practices that undermine its final recommendations. First, new nuclear additions in the modeling appear to be heavily reliant on manual additions or narrowly crafted model assumptions that result in significantly more nuclear additions than the model would naturally add. By effectively forcing nuclear resources into the model, the model outputs result in decidedly less lower cost generation resources, like natural gas, renewable energy, and batteries.

Next, of the model runs that do add more natural gas resources, very few add aeroderivative

[11] https://gridstrategiesllc.com/wp-content/uploads/01920-Benefit-Metrics-Report.pdf

(Aero) and reciprocating units (RICE), and the model relies on adding more combustion turbine (CT) technology than TVA has publicly announced. This creates a disconnect between what the IRP says, and what TVA decides to implement, suggesting some entirely other process separate from the IRP for decision-making. If the IRP model fails to consider other factors that TVA and the Board of Directors find valuable, the model should be updated to help reflect those inputs. Part of the limiting factors in the modeling may be due to the capacity values[12] assigned to various generation technologies. TVA assigns a very low-capacity value to renewable resources, despite operational experience, while assigning very high-capacity value to natural gas resources.

Finally, the lack of transmission planning in the IRP is concerning. Transmission is necessary not only generation additions, but also new large load additions, such as data centers. Without strong transmission plans, economic development opportunities and reliability of the grid can be strained. Significant reforms are underway across the nation with regards to transmission planning, and TVA should better incorporate transmission in the IRP to help future-proof the grid.

VII. Summary of Recommendations

SREA thanks TVA for the opportunity to provide comments on its 2025 IRP. SREA is providing solution-oriented recommendations, with the strategic goal of helping TVA provide affordable, reliable, resilient, sustainable, and increasingly cleaner power to the Tennessee Valley region. The following is a summary of our recommendations for TVA to consider as it finalizes its 2025 IRP:

a) **Load Forecasts and Competitive Procurement of Resources:** TVA should conduct competitive solicitations that evaluate all reasonable generation and storage solutions for meeting load growth, and create an annual procurement process for incremental resources

[12] Capacity value generally refers to the effective load carrying capacity (ELCC) analysis, net dependable capacity (NDC), effective forced outage rate, resource adequacy, or other similar metrics depending on venue.

(including renewable energy and storage resources) that targets annual capacity additions at the upper end of the range found to be cost effective, using the IRP as a guide.

b) **Timing Assumptions:** TVA should prioritize adding renewable energy resources sooner rather than later, due to expanding load growth, retirement of existing generation resources, and expiring federal tax credits. Cost-effective resources may be available before 2031, and TVA should not exclude these resources from consideration.

c) **Resource Modeling:** TVA should follow best practice for optimized capacity expansion modeling and should not manually force any resource additions into the model.

d) Capacity Accreditation: TVA should reevaluate its capacity accreditation methodology to avoid underestimating renewable capacity accreditation or over-estimating natural gas accreditation.

e) **Transmission Planning:** TVA should prioritize and incorporate transmission planning in the IRP process to help future-proof the grid, including by engaging in a transmission planning process that evaluates multiple benefit metrics.

SREA strongly encourages TVA and the Board of Directors to evaluate this IRP with a critical eye. If resource planning is conducted in a fashion that predetermines the result, the process becomes unnecessary and its value is diminished. As implementation of the IRP begins, we strongly encourage incorporating competitive solicitations that evaluate all generation solutions to help ground-truth and challenge assumptions made in the IRP.