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Re: 2015 Tennessee Valley Authority Integrated Resource Draft Plan Comments

The Southern Alliance for Clean Energy ("SACE") appreciates the opportunity to comment on the Tennessee Valley Authority ("TVA") Draft 2015 Integrated Resource Plan ("IRP"). SACE has been a leading voice for energy policy to protect the quality of life and treasured places in the Southeast since 1985. SACE staff was involved in TVA's 2011 IRP as members of the 2011 IRP Stakeholder Review Group. For the 2015 IRP process, SACE staff were members of the IRP Working Group, Energy Efficiency Information Exchange ("EE-IX"), Tennessee Valley Renewable Information Exchange ("TV-RIX"), and the recently created Regional Energy Resource Council ("RERC"), a formal advisory committee to TVA's Board of Directors.

TVA's commitment to public engagement throughout the IRP planning process has allowed for an exchange of information between stakeholders and utility staff that is unprecedented in the Southeast. SACE staff has gained valuable insight into TVA's planning exercises and decision-making criteria through engagement in both of TVA's IRP planning processes. Throughout the 2015 IRP process, SACE staff worked with other stakeholders and industry experts to provide TVA with current data related to performance and costs for both renewable energy and energy efficiency resources.

While the scope of the process has been unprecedented in the Southeast, there have been some significant gaps between the planning intent and recent decisions by TVA's management and Board of Directors. Recent TVA decisions reflect major investment decisions that appear to overreach on recent power plant decisions rather than following a least-cost, least-risk plan. Even as growth has slowed to only 1% per year, TVA's capital budget for 2015 is a record $3.5 billion. During the planning process, TVA proceeded to:

- Approve construction of gas plants at Allen and Paradise to serve not only reliability needs, but future growth needs;
- Purchase the Choctaw gas plant (which had been under contract); and

- Invest in costly environmental upgrades at the Shawnee coal plant, again without an immediate power need.

While TVA claimed that these decisions were consistent with the 2011 IRP, this capacity expansion policy was made concurrently with its failure to invest in energy efficiency and meet the commitments made in the 2011 TVA IRP. TVA's recent decisions to depart from the 2011 IRP planning guidance have not been adequately justified.

We commend TVA for demonstrating an organizational commitment to improvement in planning methods since the 2011 IRP. Many of the improvements effectively respond to concerns we raised in our comments on the 2011 IRP. TVA is commended for not only making these changes, but for the organizational discipline to track input and apply good ideas. In some cases, the recommendations we make for improvement can be appropriately addressed in future planning updates, but in other cases, time is of the essence and it is essential that TVA's IRP pathway drive the utility towards all cost-effective energy efficiency opportunities and seizing the opportunity to develop renewable energy rather than overinvesting in natural gas resources.

With respect to energy efficiency, TVA's Draft 2015 IRP does not meet the standard of taking all cost-effective steps to help families and businesses reduce their energy bills. In its 2011 IRP, TVA promised to become a regional leader in energy efficiency, helping customers cut energy bills by targeting energy savings as high as 1% of retail sales. Instead, TVA cut its energy efficiency budget and is stalled at one-third of its 2011 IRP goal. Even though the Draft 2015 IRP prompts TVA to resume program growth, the plan both falls significantly short of 2011 targets and fails to rely on best industry practices.

The two biggest departures from industry practices are growth caps and excessively high program cost assumptions. While it was reasonable for TVA to restrict the annual growth in energy efficiency programs at some level, utilities across the Southeast and the nation have recorded multiyear periods of annual growth rates that substantially exceed the restrictive caps used by TVA. TVA's recent sensitivity analyses show that these growth caps on low-cost energy efficiency resources drive up system costs.

TVA's Draft 2015 IRP also assumes that program growth will cause TVA's energy efficiency costs to skyrocket (contrary to other utilities' experience). This is accomplished both by significantly inflating the "Tier 2" and "Tier 3" energy efficiency resource block costs, and by applying a "planning factor" on top of these inflated costs. This undermines cost optimization in TVA's capacity expansion planning model, resulting in the model selecting resources whose costs exceed a best practice cost forecast. In addition to creating a cost bias against higher levels of energy efficiency, even those energy efficiency resources that are selected in the plan include these cost adders. For example, even though TVA is highly confident that it will be able to continue implementing existing "Tier 1" level programs at current costs, the costs added using the "planning factor" form a part of the resulting cost estimate. Thus, assuming energy efficiency costs will skyrocket results in choosing too little energy efficiency, and overstating costs for the energy efficiency that is chosen in the modeling process.

With respect to renewable energy, TVA's Draft 2015 IRP does not demonstrate a full awareness of, and progress towards, emerging opportunities that would lower power supply costs and risks. While the Draft IRP supports a reasonable growth rate for solar resources (potentially around 2,000 MW), we are dismayed by the skeptical posture that the planning staff has taken towards recent low-cost solar deals, dismissing the broad market for low-cost solar power as an anomaly. More disappointing is the response to data on the wind power market: TVA's Draft IRP relies on inflated cost assumptions and outdated technology assumptions, resulting in little to no wind development and suggesting that TVA may soon exit the wind market entirely at the very time when other Southeastern utilities are deepening their investment.

In fact, TVA's sensitivity analyses show that if TVA accepts the availability of cheap, plentiful and reliable wind energy (particularly Clean Line), then wind resources will drive down customer costs and rates, becoming one of TVA's leading energy resources as soon as the project can be completed.

In our attached technical comments, we lay out our concerns with the 2015 Draft IRP and suggest opportunities for TVA to improve the final 2015 IRP and TVA's ongoing planning process to include appropriate characterizations of the true value of energy efficiency and renewable resources. SACE, along with the Tennessee Clean Water Network ("TCWN"), Earthjustice, Environmental Integrity Project ("EIP"), and the Sierra Club, submitted joint comments on the 2015 Draft IRP Supplemental Environmental Impact Statement ("SEIS") separately. To the extent references to the SEIS were necessary to elucidate points in our IRP comments, we have made those references within our IRP comments.

On behalf of SACE, I thank TVA's staff and leadership for investing in a resource planning process that has truly faced outwards, and engaged the utility in critical questions facing the future of all electric utilities across the country.

Respectfully submitted,

Stephen A. Smith

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Re: Southern Alliance for Clean Energy Technical Comments on the 2015 Tennessee Valley Authority Integrated Resource Draft Plan

I. Resource Plan Development and Analysis

TVA's overall process for the development and analysis of its resource plan represents a national model, implementing many best practices. In consultation with stakeholders, TVA developed scenarios and strategies spanning a broad, yet reasonable range of potential futures and potential strategic policy choices for TVA to consider. While SACE does believe that TVA could have explored issues of future climate trends, particularly water availability and extreme weather conditions, as well as strategies to embrace distributed generation, overall TVA's breadth of scope is satisfying and positions TVA to understand how resource alternatives can best serve its customers' needs.

TVA's analysis also represents many best practices. Its range of metrics represents an appropriate consideration of the many strategic imperatives and values that TVA must balance in serving its customers and its broader environmental and economic missions. In particular, SACE appreciates the efforts of TVA staff to solicit and incorporate feedback from its stakeholders to address early concerns with some of the metrics and reporting formats. As TVA has acknowledged, one important topic not addressed in this IRP is the differential impacts on different populations within the Valley. It is common and appropriate for TVA to take special care for the economic and employment impacts of is plant retirement decisions, for example, as they have significant impacts on the host communities. While the IRP may not be the appropriate vehicle for addressing concerns about impacts of resource planning decisions on energy bills and employment opportunities for low and moderate income, minority, and rural communities, those impacts can be substantial – TVA should find an effective way to understand and engage these issues. Nonetheless, although there is no perfect reporting design that can satisfy every interest, TVA struck an appropriate balance and has selected an effective method for succinctly describing the complex impacts of its planning decisions.

Unfortunately, however, TVA staff were less consistent and embracing of stakeholder input and expert insights when it came to characterizing some of the resource alternatives evaluated in the Draft IRP. Issues that were fully explored in the TV-RIX process generally resulted in satisfactory conclusions – a good example is solar energy resource performance, as discussed below. However, TVA planning staff made some key decisions on renewable energy and most key decisions on energy efficiency without input from stakeholders. With respect to the "planning factor" used for energy efficiency (discussed below), these key decisions were made without input from EE-IX, the IRP Working Group or even TVA's external review consultant (Navigant). In some cases, TVA's resource characterizations differ by only a moderate amount and are not likely to have resulted in substantial impacts on TVA's Draft IRP. But in several significant cases, the gaps between TVA's assumptions and the best market information and planning practices appear to have been the key factor driving specific planning outcomes, and appear to be even more influential than assumptions made in the various scenarios.

II. Coal-Fired Generation

SACE commends TVA for its past commitments to retire a little over 7600 MWs of coal generating units, many of which were covered by an historic 2011 Consent Decree with the Environmental Protection Agency ("EPA").[1] Under each scenario laid out in the draft IRP, coal resources diminish over the planning period. Much of this decrease will be due to idling of coal units that are already committed to retire.

A. *TVA Should Include Full Cost of Coal Generation*

Coal generating units will continue to become more expensive to operate and maintain, in light of increasing stringency of public health regulations as well as dwindling low-cost coal reserves, which must be transported across long distances for delivery at a significant cost to TVA.[2] According to its 2014 10-K, coal accounted for TVA's highest fuel cost.[3] Costs will continue to increase the price of coal generation, as efforts to curb carbon dioxide ("CO_2") emissions from the power sector will invariably place either a market or regulatory price on carbon emissions.

[1] http://www2.epa.gov/sites/production/files/documents/tvacoal-fired-cd.pdf

[2] 47% of TVA's coal came from the Illinois Basin, 36 from the Powder River Basin in Wyoming, 14% from the Uinta Basin in Utah and Colorado and 3% from the Appalachian Basin. TVA 2014 10-K, page 22.

[3] *Id.* at 21. Available at http://www.snl.com/Cache/26167180.pdf?IID=4063363&FID=26167180&O=3&OSID=9

While SACE supports TVA's decision to study a range of potential carbon costs, as a federal entity, TVA should use the Social Cost of Carbon ("SCC") as a metric for evaluating climate impacts caused by CO_2 emissions.[4] The SCC is an estimate of the economic damages associated with a small increase in CO_2 emissions, conventionally one metric ton, in a given year.[5] This dollar figure also represents the value of damages avoided for a small emission reduction (i.e. the benefit of a CO_2 reduction).[6] See Figure 1 for the most recent SCC estimates for certain years.

Figure 1: EPA Social Cost of Carbon Costs[7]

Social Cost of CO_2, 2015–2050 [a] (in 2011 Dollars)

	Discount Rate and Statistic			
Year	5% Average	3% Average	2.5% Average	3% 95th percentile
2015	$12	$39	$61	$116
2020	$13	$46	$68	$137
2025	$15	$50	$74	$153
2030	$17	$55	$80	$170
2035	$20	$60	$85	$187
2040	$22	$65	$92	$204
2045	$26	$70	$98	$220
2050	$28	$76	$104	$235

[a] The SCC values are dollar-year and emissions-year specific.

B. TVA Should Evaluate the Impact of Global Warming on Thermal Generation Units

Rising water temperatures due to climate change raise special concerns for thermal generation units that utilize once-through cooling.[8] After this water is used, it is then returned back to the receiving water body at significantly higher temperatures, resulting in harmful thermal pollution. Due to the impacts of climate change on water temperature and water availability, it will become increasingly likely that TVA will have to curtail operations at certain coal units as water temperatures

[4] "The SCC is meant to be a comprehensive estimate of climate change damages and includes, among other things, changes in net agricultural productivity, human health, and property damages from increased flood risk." Environmental Protection Agency, Fact Sheet: Social Cost of Carbon, November 2013, available at http://www.epa.gov/climatechange/Downloads/EPAactivities/scc-fact-sheet.pdf

[5] "As noted by the IPCC Fourth Assessment Report, it is 'very likely that [the SCC] underestimates' the damages." *Id.*

[6] http://www.epa.gov/climatechange/EPAactivities/economics/scc.html

[7] Technical Support Document, "Technical Update of the Social Cost of Carbon for Regulatory Impact Analysis - Under Executive Order 12866," Interagency Working Group on Social Cost of Carbon, United States Government, November 2013 available at https://www.whitehouse.gov/sites/default/files/omb/assets/inforeg/technical-update-social-cost-of-carbon-for-regulator-impact-analysis.pdf

[8] Nuclear plants have similar impacts on water, as discussed in Section IV, below.

rise.[9] In fact, TVA's largest coal plant, the Cumberland Fossil Plant, had to curtail operations in 2012 due to increased temperatures in the Cumberland River.[10] Although this topic was raised during IRP Working Group sessions, TVA determined that it would be infeasible to include consideration of continuing climate change in its model and did not include appropriate risk assumptions related to the potential lack of water resources for cooling in its cost assumptions for continued operation of coal-fired power plants.

C. TVA Likely Underestimated Cost Assumptions for Pollution Controls on Shawnee Plant

Although TVA has committed to a significant amount of coal retirements, recently TVA has made decisions to upgrade coal plants with costly air pollution controls, like its Gallatin and Shawnee coal plants. Upgrades at Shawnee, in particular, are troubling given that TVA is not expected to experience significant demand growth in the 2015 IRP planning timeframe and local need for power produced by Shawnee is non-existent. Particularly troubling is TVA's decision to retrofit all operating units except Units 1 and 4 with Dry Sorbent Injection ("DSI") combined with its decision to retrofit only Units 1 and 4 with a FGD scrubber. There is evidence that the use of trona or sodium bicarbonate for high levels of sulfur dioxide ("SO_2") control in a high nitrogen oxide ("NO_2") gas stream with a pulse jet fabric filter ("PJFF") can create high levels of NO_2. High NO_2 levels can contribute to a visual plume that can affect visual opacity regulatory compliance.[11] If TVA has not already undergone analysis to predict the potential of NO_2 formation as a result of DSI installed at Shawnee, then it is likely underestimating the cost of the full suite of pollution controls needed to continue operation of Shawnee in the IRP planning period.

While TVA made the decision to install pollution controls on Shawnee prior to the planning period covered by the draft IRP, consideration of continuing operation and maintenance costs associated with keeping this plant online should be included and should reflect costs to comply with EPA's recently finalized Disposal of Coal Combustion Waste Residuals from Electric Utilities ("Coal Ash Rule").[12] Currently, Shawnee's coal ash facilities are unlined, causing surface and groundwater

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[9] For example, based on a 6.3 to 9°F temperature increase, climate change could increase the need for additional electric generating capacity by roughly 10-20% by 2050. This would require hundreds of billions of dollars in additional investment. "Global Climate Change Impacts in the United States" U.S. Global Change Research Program, 2009. Available at http://nnsa.energy.gov/sites/default/files/nnsa/inlinefiles/karl%20et%20al%202009.pdf

[10] TVA 2012 10K at 16 "Generation at Gallatin Fossil Plant ("Gallatin") and Cumberland Fossil Plant ("Cumberland") was curtailed during the summer of 2012 because of high river temperatures and the need to comply with thermal permit limits." Available at http://www.snl.com/Cache/15350412.pdf?IID=4063363&FID=15350412&O=3&OSID=9

[11] "Predicting Opacity Issues with DSI," Anthony A. Silva and Robert E. Snyder, Babcock and Wilcox Power Generation Group, March 2015, available at http://www.power-eng.com/articles/print/volume-119/issue-3/departments/clearing-the-air/predicting-opacity-issues-with-dsi.html

[12] See joint comments on the Draft SEIS submitted on behalf of SACE, TCWN, Earthjustice, EIP and Sierra Club.

contamination and are located in close proximity to the Ohio River. Compliance with the Coal Ash Rule will require movement to a lined facility, movement away from the Ohio River and may require additional action to remediate surface and groundwater.[13]

III. Solar Energy

TVA effectively engaged the solar energy development community and related experts and the resulting core modeling assumptions and analysis lead to what is overall a reasonable and effective consideration of solar energy resources in the Draft IRP. However, there are several potentially inaccurate or incomplete resource characterizations that constrain TVA's modeling process from identifying the full competitive benefits of solar generation. We also suggest several points that should be clarified in the Final 2015 IRP.

A. TVA's Draft IRP Properly Includes Solar PV Resources

SACE commends TVA's recognition and inclusion of utility- and commercial-scale solar photovoltaic ("PV") power as an energy resource option with real capacity value in their IRP process. In particular, TVA leveraged the expertise and data of Clean Power Research, arguably the most credible solar energy profile modeler in the country, among other analytic and modeling capabilities. With over 15 years of solar energy profiles for 26 locations throughout the Tennessee Valley, TVA had sufficient data to determine accurate capacity factors and net dependable capacity values ("NDC") for the selected solar PV technologies. The results of TVA's performance analysis are consistent with national trends, and demonstrate the high value potential that solar PV can and would play in helping TVA meet its peak demand and energy needs.[14]

SACE also commends TVA for recognizing that, at the very least, the rapidly increasing levels of distributed generation being developed across the country deserves analysis and consideration in this IRP. The Distributed Marketplace Scenario is a potential reality for the Tennessee Valley, and the more TVA can prepare for this shift in the energy market, the more the utility, grid, and customers will benefit. Solar PV and other distributed generation technologies are becoming increasingly competitive with conventional and centrally located resources. In 2014, over 2,200 megawatts ("MW") of distributed solar capacity were installed in the U.S., accounting for about two-thirds of the total solar

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[13] Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals From Electric, Utilities 40 CFR Parts 257 and 261, April 17, 2015. Available at http://www.gpo.gov/fdsys/pkg/FR-2015-04-17/pdf/2015-00257.pdf

[14] Lawrence Berkeley National Laboratory (LBNL), *Utility-Scale Solar 2013* (September 2014). Available at http://emp.lbl.gov/sites/all/files/lbnl-6912e.pdf and LBNL,*Solar Valuation in Utility Planning Studies* (January 2013). Available at http://emp.lbl.gov/sites/all/files/LBNL-Solar_Valuation_CESA.pdf

PV capacity installed that year.[15] The residential sector alone experienced a 50% increase in annual installed capacity compared to 2013. Customer demand for distributed generation is already apparent in TVA's service territory, as demonstrated by consistent interest in their Green Power Providers program and a small but growing interest in behind-the-meter generation. As prices continue to fall and consumers become increasingly interested in controlling their energy consumption and energy production, distributed generation resources will increase further across the Valley.

B. *TVA's Solar Price Forecast is Higher than Industry Data Suggests*

TVA selected initial price points and forecast escalation rates for various solar energy technologies results in price forecasts that are generally higher than what industry data suggests. In the final IRP, TVA should recognize that solar power costs and development prospects are likely to be even more favorable than what is suggested by the modeling results. For purposes of future annual system planning activities, TVA should re-engage the TV-RIX stakeholders for an update on current installed cost figures and escalation rate forecasts.

Based on information provided to the IRP Working Group, it appears that TVA's estimated initial installed costs for solar are similar to estimates provided by industry experts during TVA's TV-RIX process. TV-RIX stakeholders submitted recommended inputs on November 27, 2013. We recognize that TVA utilized the current cost inputs recommended by the stakeholders. However, due to delays in TVA's IRP schedule, even the "solar champions" (as TVA styled the advisory stakeholders) overstated the costs: current market data indicates that solar costs are already significantly lower compared to those submitted in 2013.

One important cost driver is a regional cost advantage. At the time of the TV-RIX stakeholder input, the Southeast utility-scale solar development market had reached the scale at which regional cost data were just becoming available. A quarterly market analysis by Greentech Media ("GTM") and the Solar Energy Industries Association ("SEIA") reported prices as low as $1,400/kW-dc for fixed-tilt utility-scale systems at the end of 2014, reflecting "strong competition of new markets with low labor pricing, such as those in the *Southeast U.S.*" (emphasis added). SACE has confirmed this cost advantage with regional industry players. Furthermore, the Tennessee Valley region is likely to have some of the lowest-cost development opportunities in the country due to an abundance of suitable sites in proximity to transmission.

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[15] Solar Energy Industries Association & Greentech Media. Annual Solar Market Insight: 2014 Q4. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q4

Another reason that TVA's cost forecast is too high is the continuing trend in cost reduction for solar development. The GTM/SEIA analysis showed that the national average installed cost for utility-scale solar dropped by over 12% and commercial solar PV dropped by over 11% in 2014 alone (compare Q1 to Q4 in Figures 2 and 3).[16]

[16] Solar Energy Industries Association & Greentech Media. Annual Solar Market Insight: 2014 Q4. Available at http://www.seia.org/research-resources/solar-market-insight-report-2014-q4

Figure 2. Quarterly 2014 Installed Cost Utility-Scale PV

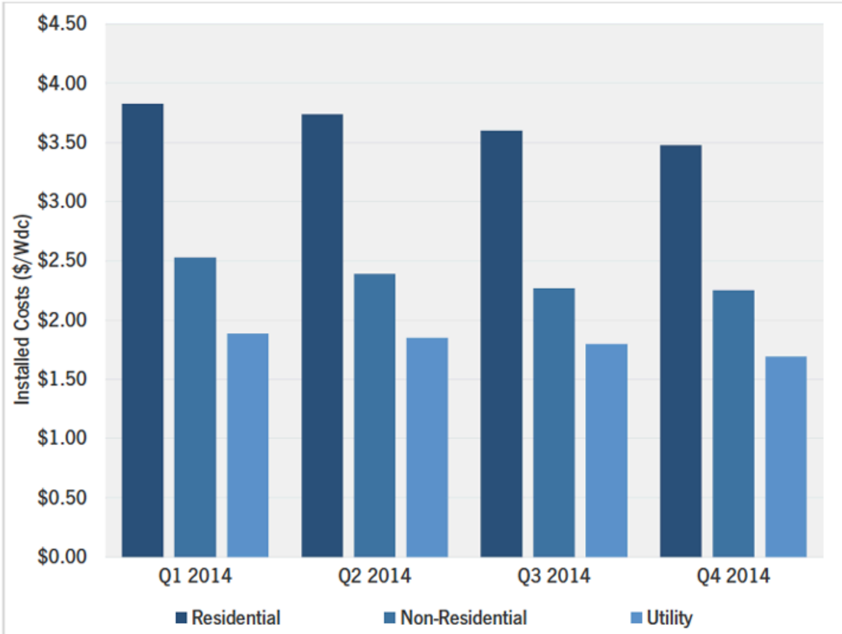
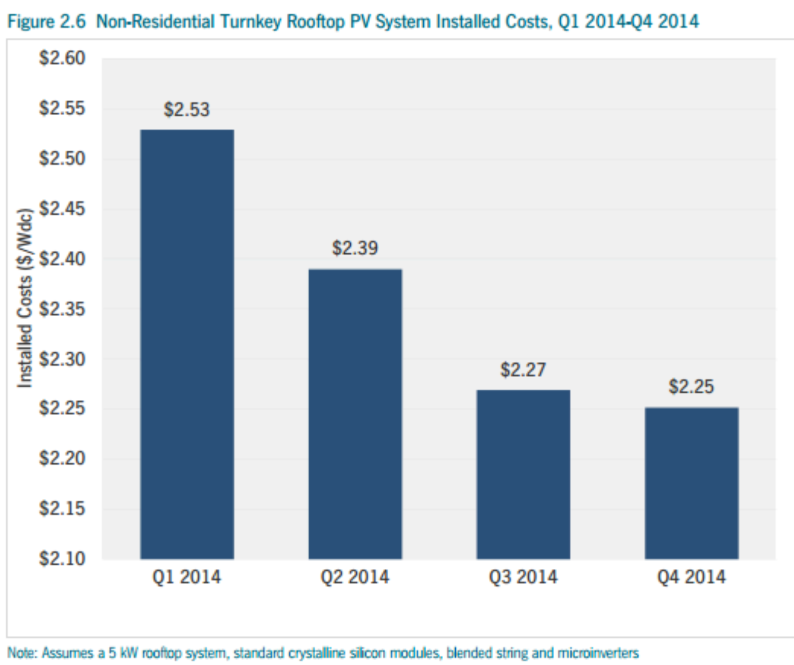


Figure 3. Quarterly 2014 Installed Cost of Commercial Solar PV



TVA appropriately adopted an escalation rate forecast for solar development costs that recognizes a continuing decline in costs, which differs from conventional resources that tend to increase in costs. Stakeholders in the TV-RIX process recommended a negative escalation rate, -7% for utility-scale systems and -9% for commercial systems, with the noted expectation that they would gradually become closer to zero after 2020. These estimates are within analyst projections, and clearly reasonable, if not conservative, based on the example previously mentioned of prices falling at least 11%-12% in 2014 alone (not even a full 12 months).[17]

TVA assumed escalation rates that were 4 percentage points (or 50%) higher than recommended by TV-RIX, -3% for utility-scale systems and -5% for commercial systems through 2020, then dropping to zero. Although TVA staff claimed that these recommendations were identical to those recommended in TV-RIX, with the discrepancy due to the difference between nominal and real escalation rates, the 4 percentage points higher value does not correspond to the 1.8% inflation rate that TVA assumed in the IRP.[18] Thus, it appears that TVA (perhaps inadvertently) adopted an escalation rate that is 2% higher (more costly) than recommended through the TV-RIX process.

Taken together, TVA's excessive estimate for 2014 solar costs and the discrepancy in the escalation rates, TVA's solar cost forecast for 2020 is likely about 20% higher than the forecast recommended by solar industry experts during TV-RIX. If TVA had adopted the lower cost forecast:

- The capacity forecasts in the Draft IRP would have tended to include more solar capacity overall, and tended to schedule it earlier in the planning period;
- As a result, CO_2 emissions would have been lower; and
- Costs of each plan, but particularly Strategies C and E that include more solar resources, would have been diminished.

The most important of these observations is the last: although Strategy E tended to have higher present value of revenue requirements ("PVRR") and system average cost values than Strategy A, those cost differences could have been at least partially reduced if TVA had adopted the TV-RIX solar cost recommendations. Even if TVA does not reconsider its analysis, the Final IRP should explain that the Strategy E costs may reflect a cost forecast for solar power that is too high.

C. *TVA is Not Fully Leveraging Distributed Generation*

TVA thoughtfully evaluated a Distributed Marketplace "scenario" to reflect the potential impact of customer-driven decisions to invest in self-generation activities. However, TVA decided not to evaluate distributed solar generation as a "resource option" in its strategies, except to the extent that large and small commercial solar PV are considered "distributed generation." TVA should explicitly include distributed solar generation in future planning studies, considering the unique benefits and

[17] National Renewable Energy Laboratory. September 2014. "Photovoltaic System Pricing Trends". Available at http://www.nrel.gov/docs/fy14osti/62558.pdf

[18] TVA 2015 Draft IRP. Page 130.

other reasons to invest in distributed solar generation. The Draft IRP does not recognize several unique benefits of distributed power:

- TVA applied the same land requirement ratio (7.5 acres per MW) to "small" commercial systems as what was applied to fixed utility-scale systems, even though smaller-scale projects are often located on rooftops or in parking lots.
- Distributed generation avoids line losses that occur on transmission and distribution systems.
- Customer-sited generation reduces utility financing requirements.

Some of these and other benefits have been identified in TVA's Distributed Generation – Integrated Value ("DG-IV"). Understandably, DG-IV remains "under development" as of early April 2015 and any final determinations coming out of that process will not be included in the Final IRP. However, TVA should clearly recognize in the Final IRP that distributed generation does in fact offer benefits above and beyond avoided cost or wholesale energy purchases.

In addition to the performance and financial benefits of distributed generation, there are other reasons for TVA to consider the opportunities of enabling more distributed generation for its system plan. Rooftop solar capacity is large: TVA notes a potential of 30,000 MW of rooftop solar capacity in its service territory.[19] Studies of utility future business plans suggest that utilities should embrace the "disruptive" distributed technology sector and enable it to their advantage, rather than considering it as only an external force that reduces load and may need to be addressed (as depicted in TVA's Distributed Marketplace scenario). A recent report by the Rocky Mountain Institute, *The Economics of Load Defection*,[20] highlights that there is an opportunity for utilities to advance an "integrated grid" as opposed to one where there is increasing levels of "grid defection." To the extent that other distributed technologies, especially storage, become more price competitive, TVA will need to substantially reconsider its resource planning scenarios.

While this IRP has focused mainly on the scale and schedule of several categories of resource investments, TVA could take its next IRP further to evaluate strategies to respond to the distributed energy paradigm shift such as using rate design to give customers appropriate price signals, leveraging smart inverters for easier solar DG integration, and incentivizing locational benefits to reduce grid congestion. Other states are beginning to think creatively and develop preemptive solutions rather than continuing to merely react with old utility practices. For example, New York's Reforming the Energy Vision ("REV") is exploring real changes that work *with* rather than *against* distributed generation.

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[19] TVA IRP Draft Supplemental Environmental Impact Statement ("SEIS"). Page 134.
[20] Rocky Mountain Institute. April 2015. "The Economics of Load Defection". Available at http://www.rmi.org/electricity_load_defection

The REV initiative aims to make regulatory changes that "promote more efficient use of energy, deeper penetration of renewable energy resources such as wind and solar, wider deployment of 'distributed' energy resources, such as micro grids, on-site power supplies, and storage."[21] While many of these topics are not ideally considered in-depth in a resource planning study, specialized studies on these topics can be used to develop appropriate assumptions for the characterization of distributed energy resources as a supply resource in future planning studies. As the largest public power utility in the country, TVA is in a unique position to provide leadership similar to New York's REV initiative.

D. *Additional Points and Assumptions that Require Clarification*

Several key methods and assumptions could impact when and how much solar resources are selected by the IRP models are discussed in this section.

i. Assumptions Related to Power Purchase Agreements

In the Draft SEIS, TVA states: "the great majority of future additions of solar generating capacity will be obtained through power purchase agreements ("PPAs") and purchases through Green Power Providers program."[22] SACE is encouraged by this approach (i.e., using PPAs) because it has the potential to reduce the levelized costs of solar for TVA, which, as a public entity, could otherwise not leverage tax benefits. Developers can also have access to an increasingly robust financing sector, further reducing project costs.

During the IRP Working Group process, SACE and other stakeholders made repeated requests for information regarding methods and outcomes from TVA's financial models of PPAs (as distinct from self-build resources). This is of particular consequence for resources that are eligible for production tax credits, but it is also the case that financial structures available to specialized solar developers often outperform conventional financial assumptions. Recently, TVA recognized the importance of getting financial structures right in the analysis by revising Strategy C to require 20-year PPAs for many resources rather than allowing that strategy to emphasize short-term power contracts. Similarly, TVA needs to ensure that its representation of solar (and wind) project PPAs reasonably represents the relationship between capital cost estimates and the resulting energy price offered to the utility. Accordingly, we renew our request for TVA to disclose this information to ensure that the effective PPA prices evaluated in the financial model do not diverge significantly from market prices, which are trending downward (see Figure 4).

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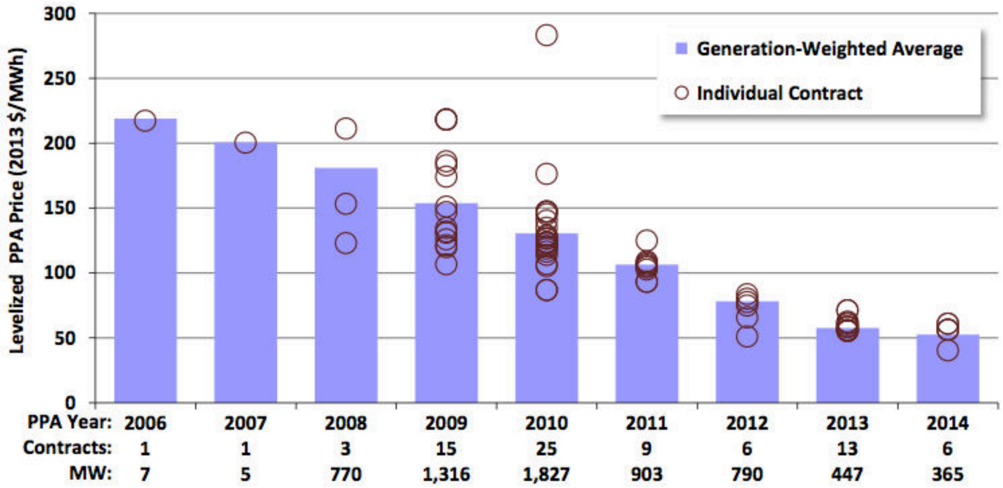
[21] New York State Department of Public Service. Reforming the Energy Vision. Available at http://www3.dps.ny.gov/W/PSCWeb.nsf/All/26BE8A93967E604785257CC40066B91A?OpenDocument

[22] Draft Supplemental Environmental Impact Statement at 150.

Figure 4: Utility PV PPA Prices ($/MWh) by Contract Execution Date[23]



The Southeastern regional market has experienced numerous recent solar contract prices of below $65/MWh, including TVA and NextEra's 80 MW project at $61/MWh. TVA uses a book life of 25 years for solar technologies, however TVA has traditionally used 20 years as their contract duration period. As was identified by TVA Board Member Marilyn Brown during the proposal and approval of the 80 MW NextEra project, Georgia Power and others are increasingly offering contract options for longer durations, such as 25, 30, or even 35 years. At the very least TVA should match the contract terms with the book life of the asset (i.e., 25 years), however the best practice would be to allow for even longer durations, and provide developers with options from which they can propose the most competitive rates.

ii. Limitations on Solar Capacity Build Out

TVA states that Strategies A, B, C, and D place a solar capacity expansion cap of 300 MW/year and at 4,000 MW of total capacity by the end of the planning period, with a higher expansion cap in the Maximize Renewables Strategy (E). Under high growth scenarios and sensitivities, these caps are reached. TVA should explicitly note that the model may thus be forced to select natural gas or other resources even if additional solar might be preferred due to cost and performance advantages.

[23] GTM Research. December 2014. *The One Chart that Shows Why 2014 was a Breakthrough Year for Utility-Scale Solar in North America*. Available at http://www.greentechmedia.com/articles/read/the-one-chart-that-shows-why-2014-was-a-pivotal-year-for-us-solar

iii. Solar Capacity Additions through 2020

TVA states that their capacity expansion plans all include a "continuation of the current Renewable Standard Offer ("RSO") and related Solar Solution Initiative ("SSI") programs until 2020, adding a total of about 325 MW of predominantly solar capacity and small amounts of wind and biomass-fueled generation."[24] However, the RSO and SSI programs are currently adding 120 MW of available capacity each year, as of 2015. Assuming TVA continued to make these programs available, there could be as much as 720 MW of solar capacity added from 2015 through 2020. TVA should clarify the start and end date of the "continuation" period and how TVA programs that add 120 MW a year could result in a 325 MW total.

iv. Apparent Misstatements

In the Draft SEI Summary section, the discussion of solar under Strategy D states, "Overall solar capacity additions are similar but slightly lower than those for Strategy A except for Scenario 5, which has a lower total capacity addition of 1,025 MW." [25] But in the Draft SEIS Chapter 6, discussion of solar under Strategy D states, "Overall solar capacity additions are slightly lower than those for Strategy A except for Scenario 5, which has a lower total capacity addition of 897 MW."[26] These two statements should be reconciled.

In the Solar summary of the Draft IRP, TVA states: "The utility tracking option is considered a single installation and includes a *dual axis tracker* that allows the solar panels to follow the sun" (*emphasis added*).[27] However, it is clear that TVA modeled a tracking solar technology that consists only of single-axis tracking systems and does not include dual-axis trackers.

IV. Nuclear Energy

A. New Nuclear Generation

TVA's analysis and consideration of nuclear as a capacity resource and subsequent conclusion in the Draft IRP that no new nuclear generation was selected beyond the scheduled Watts Bar Unit 2 affirms SACE's long-standing position that these technologies are too expensive and risky to build. New nuclear generation considered include Advanced Pressurized Water Reactor ("APWR") designs, such as the Toshiba Westinghouse AP1000 (previously proposed as Units 3 and 4 at TVA's Bellefonte

[24] Draft SEIS at 155.
[25] Draft SEIS at S-13.
[26] Draft SEIS at 162.
[27] Draft IRP at 48.

site in Alabama); a Pressurized Water Reactor ("PWR"), in this case, the abandoned Bellefonte Units 1 and 2; and small modular reactors ("SMRs").[28]

In Appendix A of the Draft IRP, Navigant identified that about half of the parameter values (15 of 31) were found to be consistent and that 12 values were 20% or more different.[29] The summary letter then stated: "Generally speaking, [Navigant's] recommended outage rates, plant and total overnight capital costs, and variable O&M values were materially higher than TVA values."[30] We are concerned about this observation given TVA's history of cost overruns, delays, suspensions and cancellations with its nuclear generation fleet, most notably with the recent attempts to complete construction of Watts Bar 2 – a project that began in the early 1970s and has experienced significant delays and cost increases. Although TVA expects Watts Bar 2 to receive an operating license from the U.S. Nuclear Regulatory Commission ("NRC") and perhaps be operational by the end of 2015, this schedule is substantially delayed from the schedule anticipated in the 2011 IRP.

Based on the high costs and risks of the technologies along with environmental concerns such as water consumption and spent nuclear fuel generation identified in the Draft IRP, results that show no new nuclear generation development in the planning period are appropriate and supported by reasonable evidence. As demonstrated in the sensitivity results shared with the IRP Working Group in April 2015, adding new nuclear reactors tends to be a poor match to TVA's future needs, increasing revenue requirements and average system costs, while generally offsetting only peaking capacity resources.

B. *Small Modular Reactors*

The draft IRP's indicated that SMRs are neither needed nor cost-effective. In light of this finding, TVA's continued investment of resources to permitting and research activities related to SMRs does not appear to be a sound investment of ratepayer dollars, providing customers with no long-term benefits.[31] TVA's efforts to pursue submittal of an early site permit ("ESP") application for potentially multiple SMR reactor designs at the Clinch River Site in Tennessee to the NRC are wholly unsupported by the Draft IRP analysis and subsequent sensitivity analyses.[32]

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[28] Draft IRP, p. 43.
[29] Draft IRP, Appendix A, p. 109.
[30] Draft IRP, Appendix A, p. 109.
[31] Draft IRP, p. 3.
[32] Ed Marcum, "TVA shifts focus on Oak Ridge nuclear reactor," Knoxville News Sentinel, December 4, 2014. Available at http://www.knoxnews.com/business/tva-shifts-focus-on-oak-ridge-nuclear-reactor_78705489.

C. Browns Ferry Extended Power Uprates

The extended power uprates ("EPU") capacity expansion projects for all three reactor units at Browns Ferry in Alabama were selected in every case, and are in fact the only new baseload resource in the Draft IRP. If completed, the EPU would provide approximately 400 MW of added capacity.[33] Due to TVA's history of schedule and cost problems with its nuclear fleet, as well as the industry's lack of precedent for successful completion of similar EPU projects, SACE recommends that TVA reconsider the cost and schedule characterization for the Browns Ferry EPU by increasing the assumed cost, construction schedule, or construction cost risk.

The schedule assumed in the Draft IRP for the Browns Ferry EPU is questionable. TVA is in the early stages of the EPU process and has yet to submit a License Amendment Request ("LAR") to the NRC.[34] In a recent presentation to the NRC, TVA outlined key steps in the process including: submittal of the LAR to the NRC in October 15, 2015; estimated approval by the NRC two years later; and the completed EPUs estimated for Unit 3 in March 2018, Unit 1 in October 2018 and Unit 2 in March 2019.[35] Other utilities have experienced problems with meeting EPU schedules. For example, the EPU for the Quad Cities nuclear plant in Illinois, a GE Mark I BWR design like Browns Ferry, was extremely problematic.[36] Furthermore, as a 3-reactor EPU project, there are additional complexities: there are few 3-reactor nuclear plants in the country and no examples of an EPU being conducted for any 3-reactor nuclear plant.[37]

EPU projects have a history of going over budget, as indicated in a 2013 study, "The major uprates that have been proposed, and in a number of cases cancelled or abandoned, generally have cost estimates in the range of $1800 to $3500 per kW. Actual costs have been much higher, in the range of $3400 to $5800/kW."[38]Numerous utilities across the country have cancelled or delayed uprate projects

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[33] Draft IRP, p. 77.

[34] Letter from TVA to NRC, re: Technical Specifications (TS) Changes TS-431 and TS-418- Extended Power Uprate (EPU) -Withdrawal of Requests and Update to EPU Plans and Schedules, September 18, 2014. Available at http://pbadupws.nrc.gov/docs/ML1426/ML14265A487.pdf

[35] TVA presentation to the U.S. Nuclear Regulatory Commission, "Browns Ferry Nuclear Plant, Extended Power Uprate License Amendment Request Startup Test Plan," April 7, 2015. Available at http://adamswebsearch2.nrc.gov/webSearch2/view?AccessionNumber=ML15096A056

[36] Dave Lochbaum, Union of Concerned Scientists, "Snap, Crackle, & Pop: The BWR Uprate Experiment," July 9, 2004. Available at http://www.ucsusa.org/sites/default/files/legacy/assets/documents/nuclear_power/20040709-ucs-snap-crackle-pop-bwr-epu.pdf

[37] Palo Verde 1, 2 and 3 in Nevada was a Stretch power uprate and Duke's Oconee 1, 2 and 3 in South Carolina is on hold and the NRC's review has been suspended for a Measurement uncertainty recapture power uprate all of which are less of a capacity increase (up to 7% and less than 2% respectively) than Browns Ferry's proposed EPUs. See U.S. Nuclear Regulatory Commission, "Nuclear Power Uprates" at http://www.nrc.gov/reactors/operating/licensing/power-uprates.html.

[38] Mark Cooper, Institute for Energy and the Environment Vermont Law School, "Renaissance in Reverse: Competition Pushes Aging Nuclear U.S. Nuclear Reactors to the Bring of Economic Abandonment, July 18, 2013, p. 19. Available at http://216.30.191.148/071713 VLS Cooper at risk reactor report FINAL1.pdf

due to higher cost estimates for completion and/or less favorable economic conditions.[39] The reactor design used at Browns Ferry illustrated this problem. In addition to the Quad Cities EPU, Monticello's EPU in Minnesota, which also has the same reactor design as Browns Ferry, also experienced significant cost overruns.[40]

A more recent and local example is Duke Energy's Crystal River 3 reactor (formerly Progress Energy's reactor) in Florida was permanently closed after shutting down in 2009 to conduct upgrades and improvements to the reactor in order to eventually implement an EPU.[41] In February 2013, after more than $1 billion was spent, Duke cancelled the project and closed the reactor. Duke customers are paying billions of dollars because of this botched project and replacement power costs.[42]

In addition to EPU project cost overruns, O&M costs are increasing industry-wide[43] and the increased wear and tear (e.g. corrosion, embrittlement, etc.) from running reactors at higher power may drive up operating costs.[44] TVA should review whether its O&M costs for nuclear plants with EPUs incorporate these findings.

V. Wind Energy

Although TVA engaged wind industry experts in identifying and characterizing wind resources available to TVA, TVA disregarded many of these recommendations. As a result, the Draft IRP departs from market and modeling data in several key respects.

The inclusion of several different forms of wind energy resources in the Draft IRP represents a significant accomplishment for TVA. Wind energy resources vary in cost and performance based on

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39 Steven Dolley, "Exelon cancels power uprates for LaSalle, Limerick nuclear plants," Platts, June 12, 2013. Available at http://www.platts.com/latest-news/electric-power/washington/exelon-cancels-power-uprates-for-lasalle-limerick-21152061; Nuclear Street News, "NPPD Decides Against Uprate for Cooper Nuclear Plant," August 12, 2013. Available at http://nuclearstreet.com/nuclear_power_industry_news/b/nuclear_power_news/archive/2013/08/12/nppd-decides-against-uprate-for-cooper-nuclear-plant-081302.aspx - .VSU-UJTF9Vi

40 Nuclear Street News, "Over Budget, Monticello Nuclear Plant Completes Uprate," July 16, 2013. Available at http://nuclearstreet.com/nuclear_power_industry_news/b/nuclear_power_news/archive/2013/07/16/over-budget_2c00_-monticello-nuclear-plant-completes-uprate-071601.aspx - .VSVR8pTF9Vh

41 Progress Energy presentation to the U.S. Nuclear Regulatory Commission, "Crystal River Unit 3 Extended Power Uprate," April 1, 2009. Available at http://pbadupws.nrc.gov/docs/ML0909/ML090910729.pdf

42 Ivan Penn, "Duke Energy Florida proposed $600 million savings for customers," Tampa Bay Times, April 6, 2015. Available at http://www.tampabay.com/news/business/energy/duke-energy-florida-proposes-600-million-in-savings-for-customers/2224369

43 Mark Cooper, Institute for Energy and the Environment Vermont Law School, "Renaissance in Reverse: Competition Pushes Aging Nuclear U.S. Nuclear Reactors to the Bring of Economic Abandonment, July 18, 2013, pp. 9-10. Available at http://216.30.191.148/071713 VLS Cooper at risk reactor report FINAL1.pdf

44 Department of Transportation, Federal Highway Administration, "Corrosion Costs and Preventive Strategies in the United States," Main Report, September 30, 2001, pp. 33-34, 56. Full report available at http://isddc.dot.gov/OLPFiles/FHWA/011536.pdf.

different technology as well as geography. TVA effectively split wind energy resources into three separate categories:

- High Voltage Direct Current ("HVDC") Wind Energy Resources. HVDC wind energy resources are characterized by having the highest available capacity factors as well as relatively low installed capital costs.
- Midcontinent Independent System Operator ("MISO") and Southwest Power Pool ("SPP") Wind Energy Resources. MISO and SPP wind energy resources are characterized by having mid-level capacity factors as well as mid-level installed capital costs compared to the other two wind energy resources. MISO and SPP wind energy resources are fairly reflective of TVA's current wind PPAs. TVA did not identify what, if any, cost or performance distinctions there might be between MISO and SPP wind resources in either the Draft IRP or in stakeholder discussions.
- In-Valley Wind Energy Resources. Wind energy resources within the TVA footprint are considered "In-Valley" wind energy resources. These In-Valley resources are generally characterized as having higher installation costs and lower capacity factors compared to other wind energy resources. The Buffalo Mountain Wind project is currently the only wind farm developed within the TVA territory and is an In-Valley resource.

While we commend TVA for using these three categories for the various wind energy resources, several outcomes in the Draft IRP raise significant concern over data and cost assumptions used by TVA in its modeling runs.

In the Reference Plan under the Current Outlook Scenario, the only wind resources that are included are HVDC transmission deliveries at the end of the planning period (after 2030). In fact, with the exception of the Decarbonized Future Scenario runs and the Maximize Renewables Strategy E, application of TVA's preferred cost and wind performance assumptions result in the same result – or even a "no wind" resource plan in nine cases. Thus, the current assumptions effectively indicate that after TVA's current PPAs (totaling 1,542 MW)[45] expire and the Buffalo Mountain wind project is decommissioned, TVA would not have any wind resources, and would not reinvest in any wind project until at least 2030.

If TVA continues to actively plan for a future without any wind resources in its portfolio, then TVA would be taking precisely the opposite view of the wind power market from peer utilities. This outcome suggests that data assumptions in the Draft IRP are misaligned with industry standard

[45] Tennessee Valley Authority (2013, October). Energy Purchases from Wind Farms. Available at http://www.tva.com/power/wind_purchases.htm

information. SACE is not alone in expressing this concern: TVA hired Navigant Consulting to evaluate its data assumptions for the Draft IRP. Navigant's report in the Draft IRP notes that: "For wind energy, 16 of the 29 parameter values compared (or 55%) were consistent, with about half of the remaining values showing differences greater than 20%."[46] Navigant's report underscores our concern that TVA's data assumptions for wind energy are inaccurate.

A. *TVA's Cost Assumptions for Wind Energy Should Benchmark Industry PPAs*

Lazard, the world's leading independent financial advisory and asset management firm, reports recent unsubsidized levelized cost of energy for a variety of energy generation technologies including wind energy. Based on Lazard's most recent analysis (Figure 5), the unsubsidized cost of wind energy in 2013 ranged from $37-$81/MWh based on recently reported PPA prices from around the country.[47] As an energy resource, wind power can displace higher cost generation resources and reduce overall system costs. As such, current wind energy PPAs could represent a cost saving compared to even TVA's existing generation fleet.

Some existing out-of-region wind energy purchases include Arkansas Electric Cooperative (201 MW)[48], Alabama Power (404 MW)[49], Georgia Power (250 MW)[50], Gulf Power (300 MW)[51], Southern Power (299 MW)[52] and SWEPCO (469 MW).[53] Virtually all of these purchases of out-of-region wind energy have been the result of voluntary evaluations by utilities, further underscoring wind energy's current cost competitiveness.

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[46] Navigant Consulting (2014). Navigant Summary Letter Report on Generating Resource Cost and Performance Estimates. Available at http://www.tva.com/environment/reports/irp/pdf/TVA-Draft-Integrated-Resource-Plan.pdf

[47] Lazard (September 2014). Lazard's Levelized Cost of Energy Analysis - Version 8.0. Available at http://www.lazard.com/PDF/Levelized Cost of Energy - Version 8.0.pdf

[48] Arkansas Electric Cooperative Corporation (2014). Wind Energy. Available at http://www.aecc.com/renewable-resources/wind-energy

[49] Alabama Power (2014). Chisholm View, Buffalo Dunes projects provide cost-effective power. Available at http://www.alabamapower.com/environment/news/chisholm-view-project-provides-low-cost-power.asp

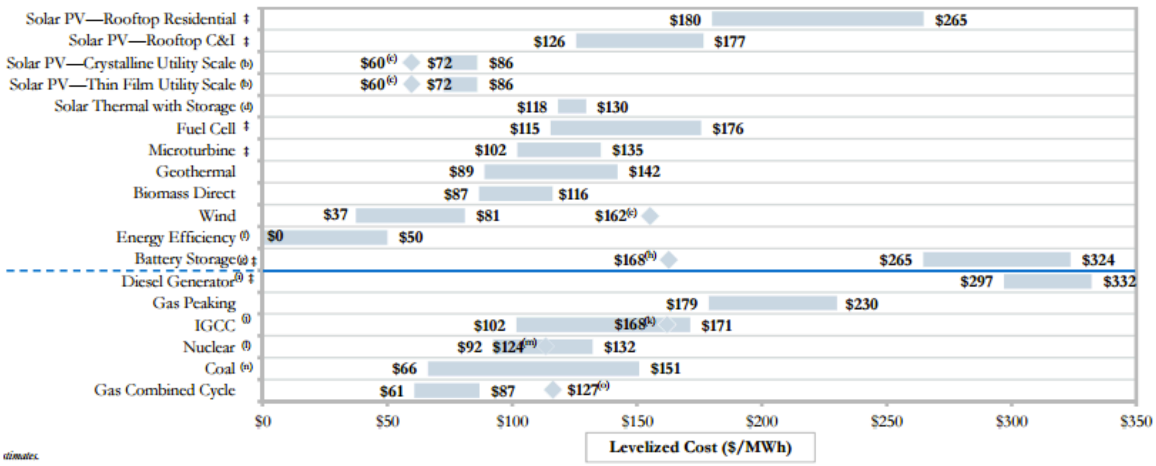
[50] Georgia Power (2013, April 22). Georgia Power to acquire 250 megawatts of wind energy from leading developer EDP Renewables. Available at http://online.wsj.com/article/PR-CO-20130422-910916.html

[51] Pensacola News Journal (February 15, 2015). Gulf Power to add wind power from Oklahoma. Available at http://www.pnj.com/story/news/2015/02/11/gulf-power-add-wind-power-oklahoma/23239883/

[52] Justin Doom (March 31, 2015). Southern Moving into Wind Power with Deal for 299-Megawatt Plant, Bloomberg Business. Available at http://www.bloomberg.com/news/articles/2015-03-31/southern-moving-into-wind-power-with-deal-for-299-megawatt-plant

[53] SWEPCO (2014). SWEPCO Wind Power Purchase Agreements Total 469 MW. Available at https://www.swepco.com/info/projects/WindPowerPurchase/

Figure 5. Unsubsidized Wind Energy Costs \$37-81/MWh Currently[54]



TVA was provided with extensive documentation from developers, national laboratories, and other sources of these favorable costs during the TV-RIX process, but it would appear that TVA considered other information more authoritative. More recently, the Department of Energy ("DOE") released *Wind Vision: A New Era for Wind Power in the United States*,[55] which further corroborates the recommendations made by wind industry experts during the TV-RIX process.

The *Wind Vision Report* relies on industry data to form a conclusion that the country could achieve 20% or more of its electricity needs from wind power by 2030. The report splits wind energy resource types into five different categories called "techno-resource groups" ("TRGs"). TRG 1 resources are characterized by having the lowest installation costs and highest capacity factors compared to TRG's 2-5. TRG 1 is indicative of HVDC wind energy resources, TRG 3 is indicative of MISO/SPP wind energy resources and TRG 5 is indicative of TVA In-Valley resources.

When TVA provided its cost estimates for wind resources to the IRP Working Group, SACE commented that the assumed values exceeded industry values by more than 20%. In its Final IRP, TVA should re-evaluate wind energy resources using DOE's 2014 "mid cost" overnight capital cost estimates as presented in Figure 6. The original and re-evaluated values should be benchmarked against recent industry PPA values to ensure that TVA's financial models are accurately representing the potential price for PPAs that TVA may find are in its customers' interests.

[54] Lazard (September 2014). Lazard's Levelized Cost of Energy Analysis - Version 8.0. Available at http://www.lazard.com/PDF/Levelized Cost of Energy - Version 8.0.pdf

[55] Department of Energy (March 2015). Wind Vision: A New Era for Wind Power in the United States. Available at http://energy.gov/eere/wind/wind-vision

Figure 6. Overnight capital cost by year (2013$/kW) [56]

TRG		2012	2014	2020	2030	2050
1	Low Cost	$1,537	$1,641	$1,388	$1,281	$1,268
1	Mid Cost	$1,537	$1,641	$1,571	$1,518	$1,512
1	High Cost	$1,537	$1,641	$1,641	$1,641	$1,641
2	Low Cost	$1,665	$1,641	$1,388	$1,281	$1,268
2	Mid Cost	$1,665	$1,641	$1,571	$1,518	$1,512
2	High Cost	$1,665	$1,641	$1,641	$1,641	$1,641
3	Low Cost	$1,784	$1,729	$1,487	$1,399	$1,389
3	Mid Cost	$1,784	$1,729	$1,674	$1,630	$1,625
3	High Cost	$1,784	$1,729	$1,729	$1,729	$1,729
4	Low Cost	$1,807	$1,758	$1,570	$1,540	$1,536
4	Mid Cost	$1,807	$1,758	$1,738	$1,724	$1,722
4	High Cost	$1,807	$1,758	$1,758	$1,758	$1,758
5	Low Cost	$1,807	$1,758	$1,570	$1,540	$1,536
5	Mid Cost	$1,807	$1,758	$1,738	$1,724	$1,722
5	High Cost	$1,807	$1,758	$1,758	$1,758	$1,758

B. TVA's Net Dependable Capacity Undervalues Wind

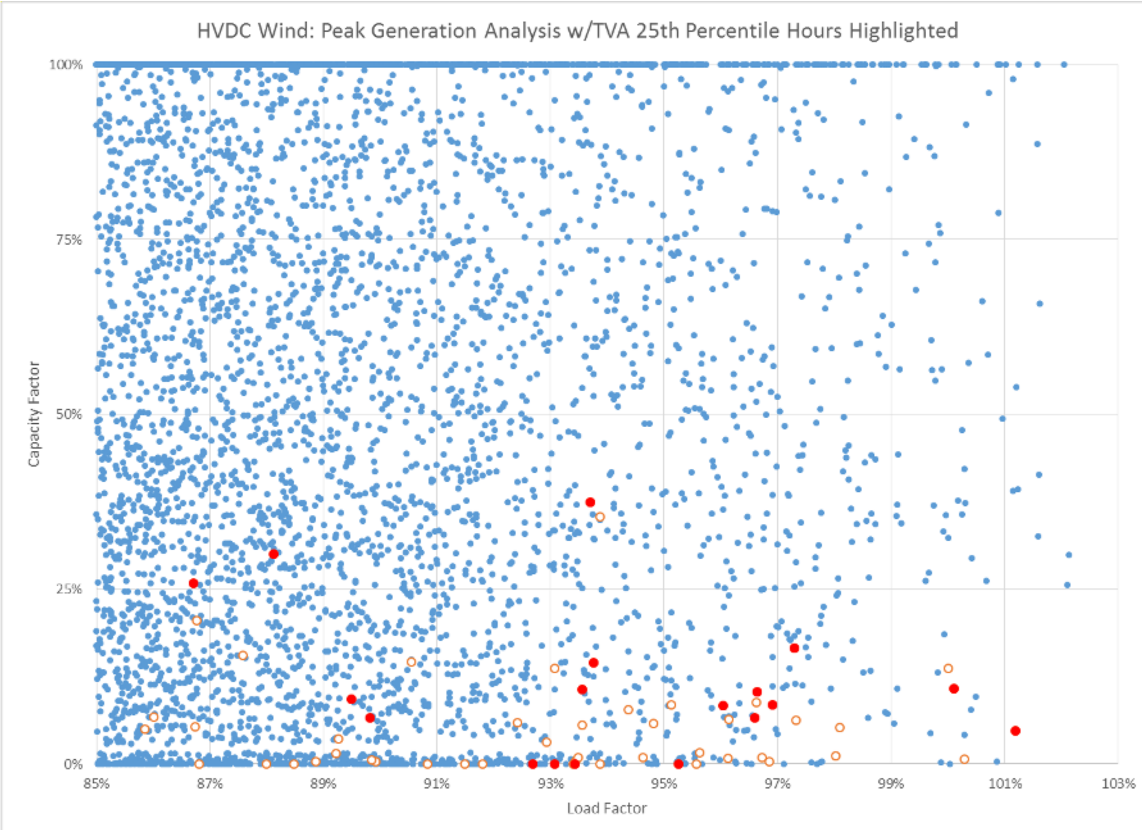
In addition to updating cost assumptions for wind energy resources, the TVA Draft IRP should reevaluate its NDC for HVDC wind energy resources. The Draft IRP assigns a 14% NDC for all energy generation resources, despite significant differences between the various wind energy resources. HVDC wind energy resources would have the highest capacity factors, as well as the ability to provide oversubscribed wind energy resources that also increase the NDC. SACE recommends that rather than 14%, TVA utilize a 53% NDC value.

TVA's methodology for determining NDC does not accurately reflect HVDC wind energy resource ability to serve power during particularly difficult load hours. Based on the NDC methodology provided in the Draft IRP, the NDC is the average of the capacity factor during a particular hour in each year between 1998-2013. As illustrated in Figure 7, most of those load hours occurred while TVA was operating at less than a 97% load factor and only one hour evaluated occurred while TVA was operating over a 100% load factor.[57]

[56] Department of Energy (March 2015). Wind Vision: A New Era for Wind Power in the United States. Available at http://www.energy.gov/sites/prod/files/wv_appendix_final.pdf Appendix H.

[57] In this calculation, the "load factor" is calculated as TVA's reported system load for the hour divided by the forecast system peak for the year. The forecast system peak for each year is the prior year's forecast as submitted to FERC on Form 714. For example, the forecast system peak for 2000 is the value submitted to FERC by TVA in 1999. This "load factor" calculation is intended to provide a simple approach to identifying those hours in which the peak demand is a challenge to TVA's available generation resources.

Figure 7. HVDC Wind: Peak Generation Analysis with TVA NDC Methodology[58]



TVA normally maintains a reserve margin of at least 15% or greater. Thus, for hours in which the system load factor may be less than 90%, TVA should have available reserves of at least 25%. As noted above, TVA's NDC methodology emphasizes hours with system load factors below 97%. This emphasis skews the analysis towards capacity factors that occur during less important load hours. SACE developed the System Peak Hours method, which calculates the average capacity factor for a variable energy resource (in this case, HVDC wind) across all hours in which the system load is greater than 90%. Using this method, SACE recommends that TVA adopt an HVDC NDC value of 53%.[59]

Skewing the analysis towards hours with lower system load factors would not affect the result if wind generation were not correlated with TVA's system load. As illustrated in Figure 7, however, even though the average wind generation does not change much as TVA's system load grows, the

[58] Each dot represents the hourly capacity factor during the 1998-2013 time period for load factors greater than 95% of system forecast peak. Red dots represent the 25th percentile hours utilized by TVA to calculate the NDC for HVDC wind resources. Red circles represent the hours below the 25th percentile that are implicitly included in the TVA methodology (the 5th least value of 20 hourly values is selected). SACE analysis. Wind data from 3tier, as provided by Clean Line Energy Partners .TVA hourly system load data provided by TVA. TVA annual forecast obtained from FERC.

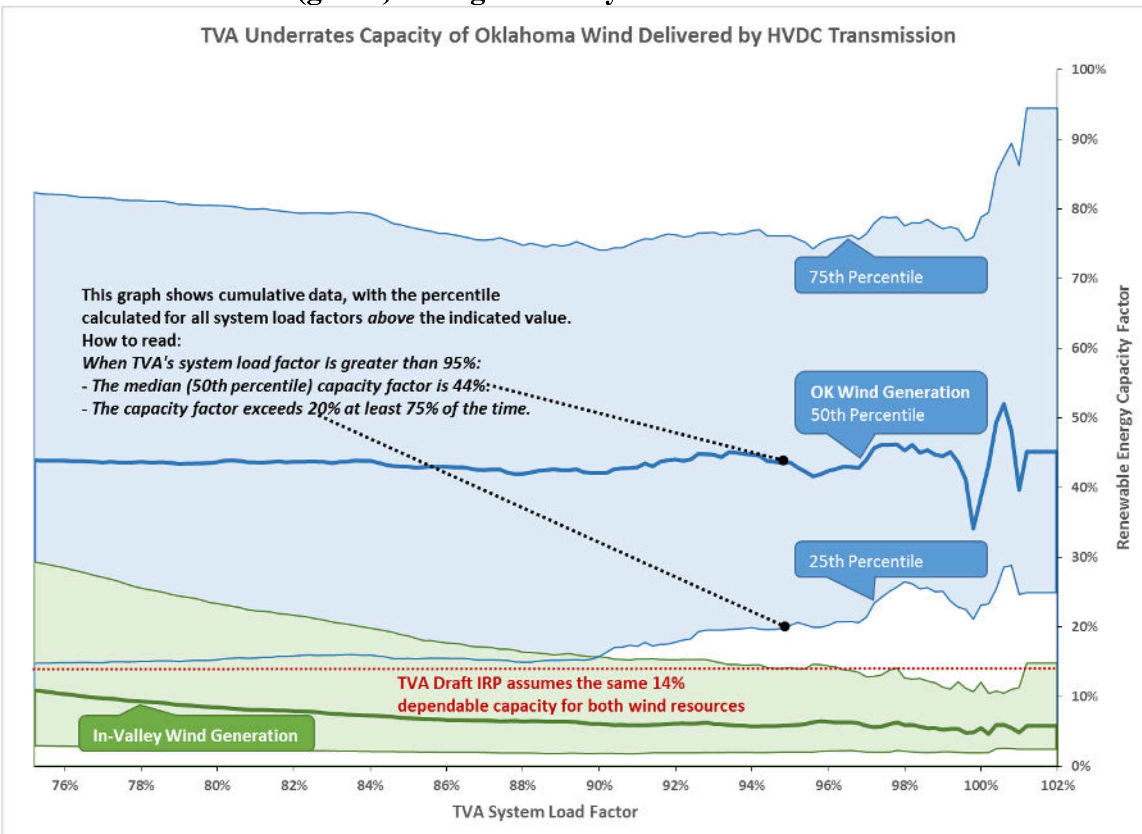
[59] Southern Alliance for Clean Energy, *Southeast Renewables and Reliability: Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast* (November 2014), p. A-15.

certainty at which wind generation remains close to or above average does grow as TVA's system load grows.

- The 50th percentile (median) capacity factor for wind sourced near the development regions targeted by HVDC wind projects is about 45% during peak hours under pretty much any definition.
- Focusing on hours with relatively poor performance (at the 25th percentile), for hours with greater than 75% load factors, the minimum capacity factor is aligned with TVA's 14% NDC assumption. However, for hours with greater than 90% load factors, the minimum capacity factor begins to rise, eventually reaching roughly 25%.

These findings for HVDC wind are in marked contrast to the same analysis performed on In-Valley Wind Resources. Also illustrated in Figure 8, In-Valley Wind Resources perform poorly during on-peak hours, and actually perform worse during the most critical hours in which the load factor nears or exceeds 100%. The contrast between the on-peak performances of the two wind resources is stark, and does not justify TVA's decision to assume identical NDC values.

Figure 8. Wind Generated for Delivery via HVDC Transmission (OK Wind, blue) and In-Valley Wind (green) at High TVA System Load Factors[60]



SACE analysis also shows that TVA's focus on the 25th percentile is an improper application of system reliability planning principles. TVA's method is exclusively focused on hours in which the below-average performance of wind resources results in an increase in risk as measured by loss of load probability. Hours in which the *above-average performan*ce of wind resources results in a *decrease in risk* are not considered in TVA's method. TVA thus gives no value to the special advantage that variable energy resources may offer: Unlike thermal generation, which can never significantly exceed its dependable capacity rating, variable energy resources often over perform and provide "free" system reliability services.

TVA's method also ignores the likelihood that the variability of wind and solar resources will to some extent cancel out. In many hours the below-average generation from wind, for example, will be compensated for by over-average solar generation (or vice versa). In a review of 15 years of data (over 131,000 hours), the total number of hours in which a combination of renewable energy resources increased TVA's loss of load probability was only 11. In contrast, the number of hours in which the

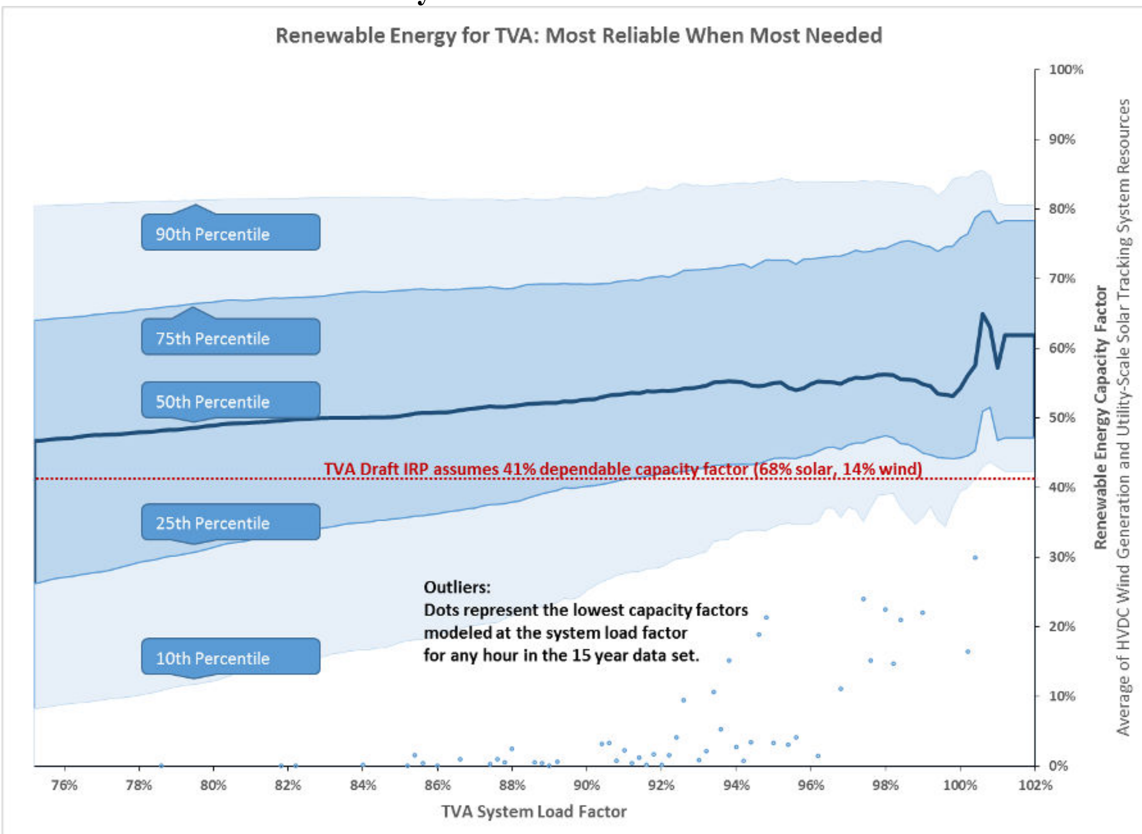
[60] SACE analysis. Wind data from 3tier, as provided by Clean Line Energy Partners, and AWSTruepower, and provided by Southern Wind Energy Association. TVA hourly system load data provided by TVA. TVA annual forecast obtained from FERC.

loss of load probably was decreased was 840, demonstrating that renewable energy reduces system risks far more often than the variability enhances risk.[61] Without access to TVA's loss of load probability values, it is impossible to verify the apparent conclusion that renewable energy does not reduce reliability, but rather with a proper NDC, will actually increase it. Effectively, by underrating the NDC for HVDC wind, TVA would actually be substantially enhancing system reliability beyond the level recommended in its reserve margin study.

The improved performance of wind and solar energy resources at high TVA system load factors is illustrated in Figure 9. Considering all hours above a system load factor of 75%, there is a fairly wide range of capacity factors represented in the data. The data also demonstrate that occasional outlier hours do occur in which neither wind nor solar generate power. However, for system load factors with generation above 96% of forecast system peak, no hours were observed with generation below 10% of nameplate capacity. At high system load factors, wind and solar together actually have relatively little variability, remaining within 20% of the median value during the vast majority of hours in the 15-year dataset.

[61] Southern Alliance for Clean Energy, *Southeast Renewables and Reliability: Increased Levels of Renewable Energy Will Be Compatible with Reliable Electric Service in the Southeast* (November 2014), p. B-9.

Figure 9. Wind and Solar Energy Combine to Provide High Capacity Factors at High TVA System Load Factors[62]



Our finding that the NDC for wind from high capacity factor regions can be significantly higher than TVA and other planning authorities have measured for other wind resources is not without precedent. In testimony related to the Grain Belt Express HVDC project, expert witness Robert M. Zavadil of Enernex estimated the effective load carrying capacity (a more robust measure of NDC) of the project to be 28%.[63]

C. HVDC Transmission Business Model Impacts on Capacity Factors and Capacity Value

Although recommended during the TV-RIX process by stakeholders, TVA did not recognize the impacts of the business model inherent to the economics of operating HVDC transmission lines. Because the private transmission line developer's price incentive is to maximize line utilization, the developer is encouraged to provide a financial incentive to developers and operators to "oversubscribe" the capacity of the transmission capacity.

[62] SACE analysis. Wind data from 3tier, as provided by Clean Line Energy Partners. Solar data from Clean Power Research. TVA hourly system load data provided by TVA. TVA annual forecast obtained from FERC.
[63] Robert M. Zavadil, *Direct Testimony on Behalf of Grain Belt Express Clean Line LLC*, Illinois Commerce Commission Docket No. 15-0277 (April 10, 2015).

In order to "oversubscribe," the transmission line owner contracts with wind development projects whose total maximum delivered capacity exceeds the capacity of the transmission lines. During the vast majority of hours in which production falls short of maximum generation, all power generated is delivered. However, contracts with developers provide for curtailment or delivery to alternative markets during those few hours in which the total generation exceeds the HVDC transmission capacity limit, thus providing a financial constraint on the extent to which the line is "oversubscribed." As a result of this economic incentive (which is not present for more typical direct interconnection projects), both the average capacity factor and the NDC for HVDC wind projects is anticipated to be enhanced due to the business model that HVDC wind operators will adopt.

The "oversubscription" business model is entirely distinct from other common industry practices involving firm delivery contracts. Firm delivery contracts are offered by wind developers who then engage in market transactions to assure scheduled delivery of energy resources according to a negotiated contract. Although such contracting practices are common, SACE <u>does not recommend</u> that TVA speculatively select any such specific contracting practices since they are highly dependent on financial and power market conditions and thus beyond the scope of an IRP.

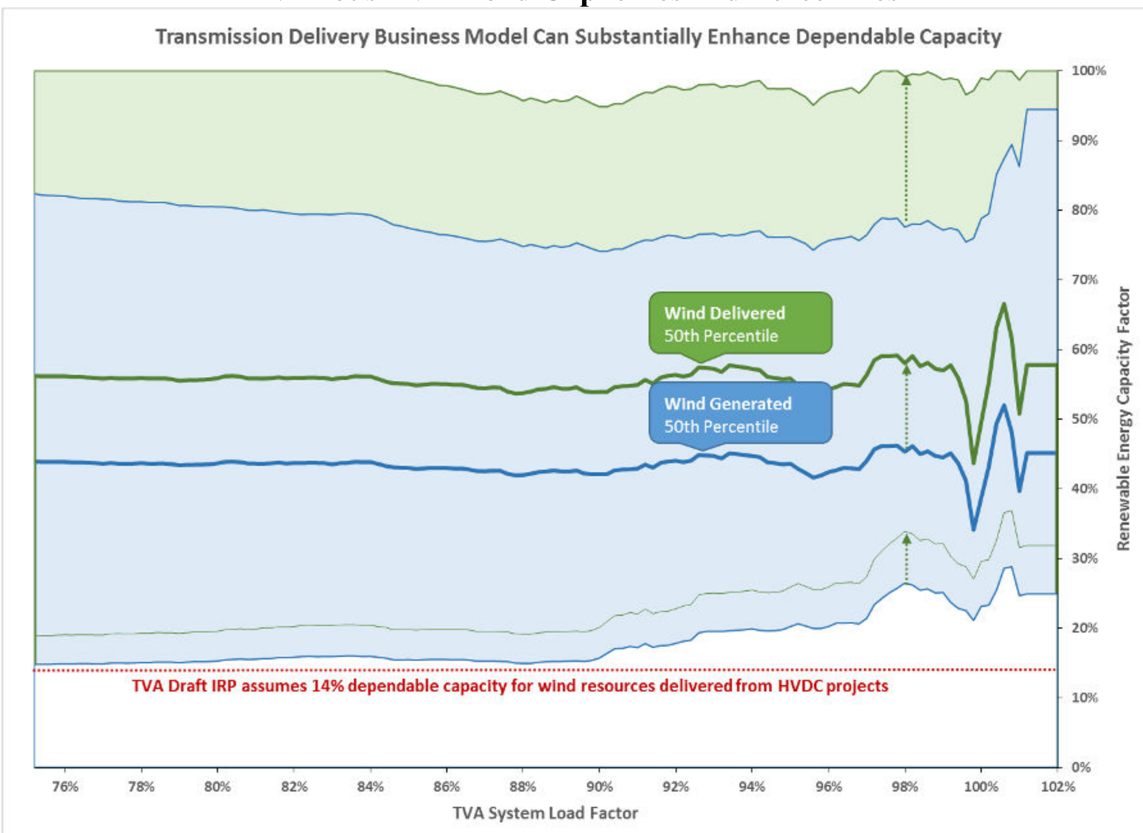
Nonetheless, the impact of oversubscription can and should be responsibly estimated by TVA in its modeling as it is a virtual certainty that HVDC transmission project contracts will recognize the line utilization incentive and "oversubscribe." During the TV-RIX process, SACE convened the "wind champions" and identified a likely oversubscription model reflecting the characteristics of different HVDC transmission line plans. The impact of this oversubscription factor is illustrated in Figure 10. At the 50th percentile, during peak hours, "oversubscription" is forecast to enhance the average capacity factor of delivered wind energy by about 10%. "Oversubscription" also enhances the utility's confidence that on-peak capacity factors will not be close to zero – in over 75% of hours with a load factor greater than 97%, the capacity factor with the oversubscription model is greater than 30%.

Our recommendation that TVA adopt a 53% NDC for HVDC-delivered wind resources includes the impact of the "oversubscription" value. If TVA were to adopt our reasoning, but reject the "oversubscription" value, then our recommendation would drop to 43%.[64] One consideration TVA may apply to manage any uncertainty would be to assume that the HVDC project would bear the risk of underperformance with respect to NDC; if a 2,000 MW contract demonstrates a 15% underperformance of NDC, that would mean TVA would need to acquire 300 MW of capacity

[64] The suggested values are for Summer NDC. For Winter NDC, our analysis indicates NDC values of 62% with oversubscription, and 52% without oversubscription.

resources – a significant, but manageable short-term acquisition contingency representing less than 1% of TVA's system resources.

Figure 10. Wind Delivered (green) and Wind Generated (blue) NDC for Oversubscribed HVDC at Various TVA Load Capacities and Percentiles[65]



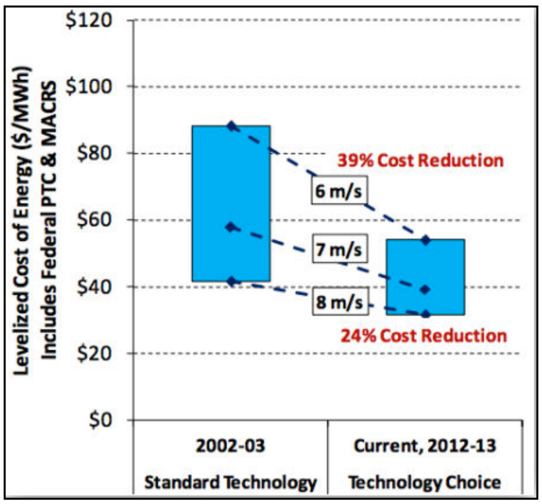
D. TVA Should Apply a Learning Curve for Wind Energy Resources

Wind energy resources have improved over the past five years. Even though TVA evaluated highly speculative technologies such as small modular reactors, TVA's resource characterization utilizes data from existing projects or modeled data developed prior to 2013. The application of these data without subsequently applying a technology learning curve essentially freezes wind turbine technology at pre-2012 levels for the duration of the planning period. During the TV-RIX process, the "wind champions" recommended use of a technology learning curve to the performance data, but TVA planning staff reported back that this was impractical. A less optimal approach of incorporating the technology learning curve in the cost forecast was also discussed, but was not ultimately applied in the wind resource characterization.

[65] Source: SACE analysis. Wind data from 3tier, as provided by Clean Line Energy Partners, and AWSTruepower, and provided by Southern Wind Energy Association. TVA hourly system load data provided by TVA. TVA annual forecast obtained from FERC.

TVA's decision to exclude technology learning and market adaptation to new wind regimes is particularly challenging to the In-Valley wind resources, as the pre-2012 wind turbine market primarily served higher wind speed regions. More recently, deployments to lower wind speed sites have supported new turbine models optimized to serve this market, as illustrated in Figure 11. Applying turbine models designed for higher wind speed regions to wind patterns in lower wind speed regions results in suboptimal performance. Thus, assuming pre-2012 wind turbine technology is not the best assumption the Tennessee Valley region, which has proposed wind projects located in areas with lower wind speeds than the average pre-2012 wind project and thus requires different designs.

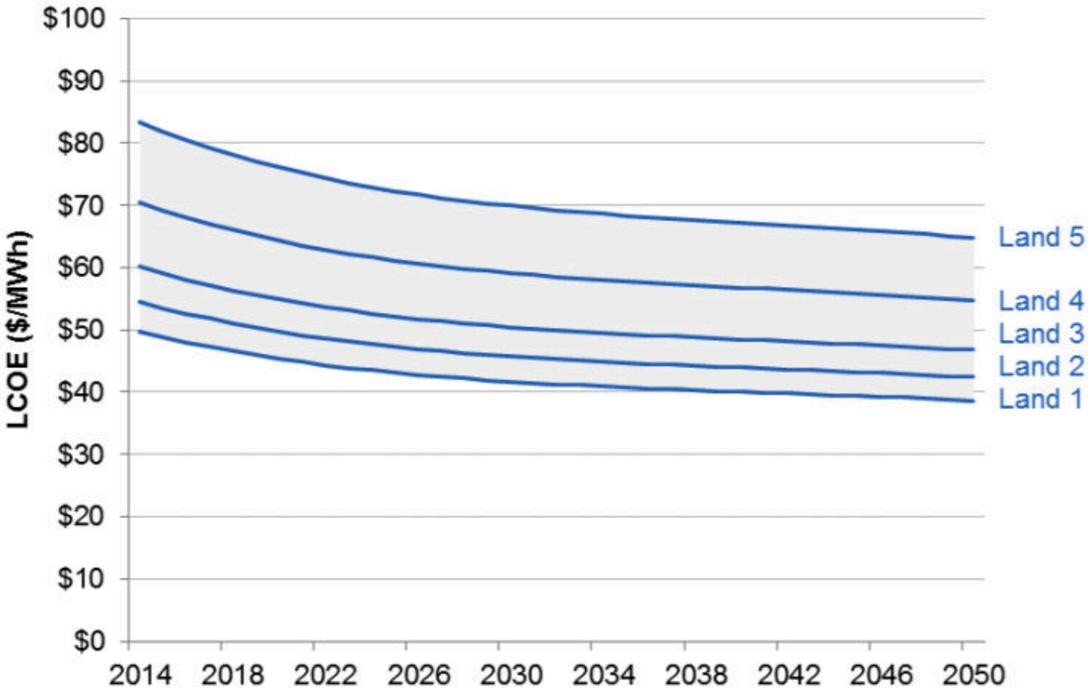
Figure 11. Wind Energy Costs Decline as Performance Improves[66]



Taller turbines with longer blades have greatly improved wind turbine Levelized Cost of Electricity ("LCOE") as well as capacity factor performance, particularly at sites with lower wind speeds. TVA should model these learning curve improvements over the course of the IRP timeframe. Based on the *Wind Vision Report* cost and performance reductions over time (Figure 12), TVA should model cost reductions in the range of 6-19% and performance improvements in the range of 1-18% between now and 2020 for the various wind energy resource options.

[66] Owen Roberts (September 11-12, 2013). Land-based Wind Potential Changes in the Southeastern United States. Available at http://www.nrel.gov/docs/fy14osti/60381.pdf

Figure 12. Future land-based wind plant mid-cost technology advancement projection.[67]



E. TVA Should Improve Capacity Factors for In-Valley and MISO/SPP Wind Energy

TVA underrated the annual capacity factor (total energy generation) for some wind resources in the Draft IRP. TVA capacity factor assumptions for wind energy resources were derived from its current PPA's, which date back to technology being deployed prior 2012, as well as the much older Buffalo Mountain wind farms. As illustrated in the NREL data below (Figures 13 and 14), market deployment of new technology designed to increase capacity factors particularly in lower wind speed regimes has dramatically altered the quantity of wind available in these two region.

Notably, TVA accepted wind modeling data supplied by 3tier for purposes of calculating the annual net capacity factor for wind delivered by HVDC transmission projects. This wind modeling data reflects more up-to-date technology assumptions than the data that TVA relied on to set the net annual capacity factors for In-Valley and MISO/SPP wind resources. For this reason, TVA's assumptions for these resources are reasonable.

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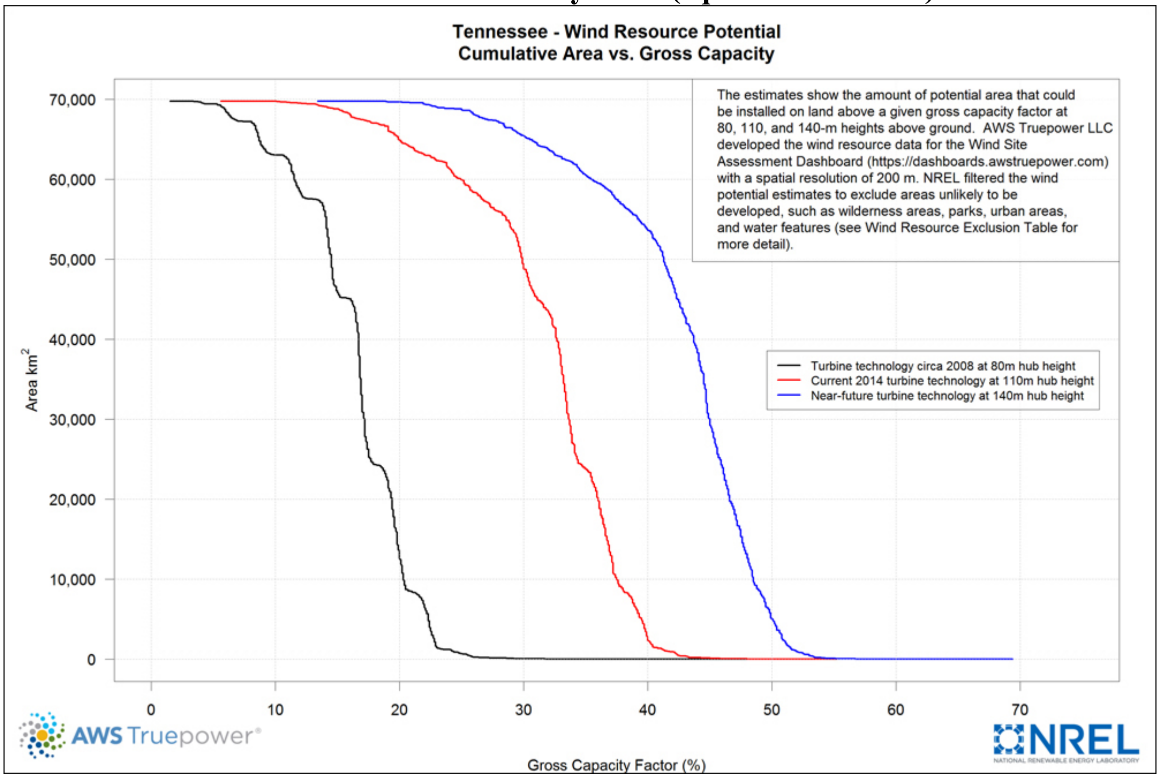
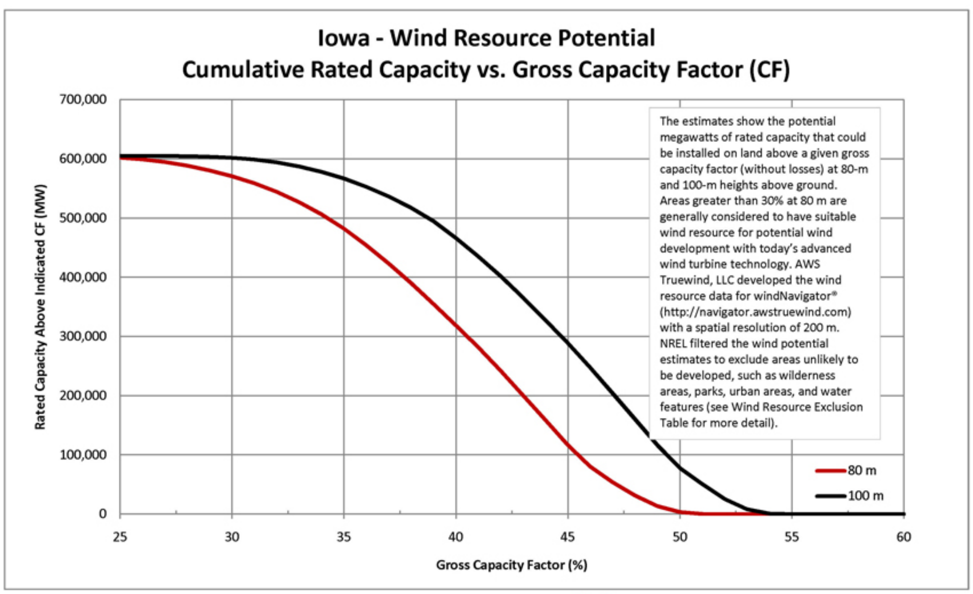
[67] Department of Energy (DOE) *Wind Vision: A New Era for Wind Power in the United States*, 2015.

Figure 13. In-Valley (Tennessee) Wind Energy Resources,
Wind Resource Potential by Area (square kilometers)[68]



(Multiply square kilometers by 2-3 MW to determine total capacity potential)

Figure 14. MISO (Iowa) Wind Energy Resources, Wind Resource Potential[69]



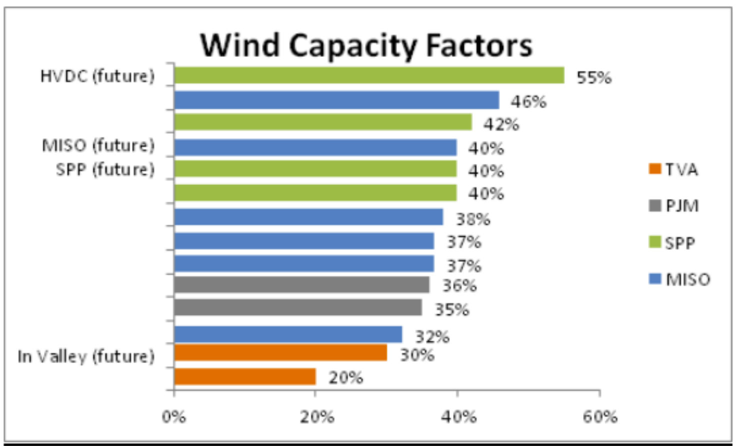
NREL
NATIONAL RENEWABLE ENERGY LABORATORY
AWS Truepower™
Where science delivers performance.

[68] National Renewable Energy Laboratory (2014). Wind Resource Potential for Tennessee. Available at http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=tn
[69] National Renewable Energy Laboratory (2011). Wind Resource Potential for Iowa. Available at http://apps2.eere.energy.gov/wind/windexchange/wind_resource_maps.asp?stateab=ia

As illustrated in Figure 14, TVA adopted a 30% net capacity factor assumption for In-Valley Wind. This is slightly below the DOE value for 2014 of 32% for "mid cost" TRG 5 wind resources (see Figure 15) and substantially below the DOE forecast of 37% net capacity factor by 2030 for the same wind resource. Utilizing the most appropriate and advanced wind turbine model available today, AWSTruepower modeling data submitted by the Southern Wind Energy Association demonstrated an average net capacity factor of 40.4% for five selected sites in the Tennessee Valley. SACE recommends utilizing an annual net capacity factor of 40% for In-Valley Resources.[70]

TVA also underrated the annual capacity factor for MISO/SPP wind. Rather than 40% (see Figure 15), TVA should adopt a value closer to the 44% value included in "mid cost" TRG 3 wind resources for 2014, increasing to 50% by 2030.

Figure 14. TVA Wind Capacity Factor Data



Source: TVA 2015[71]

[70] Using today's available technology, the quantity of resources at this capacity factor may be limited. However, as discussed above, over time market development will provide turbine designs that are suitable for a wider range of sites to perform at this level.
[71] Tennessee Valley Authority (March 2015). TVA Draft Integrated Resource Plan. Available at http://www.tva.com/environment/reports/irp/pdf/TVA-Draft-Integrated-Resource-Plan.pdf

Figure 15. Net Capacity Factor (%)[72]

	TRG	2012	2014	2020	2030	2050
1	Low Cost	47%	51%	58%	61%	62%
1	Mid Cost	47%	51%	54%	57%	60%
1	High Cost	47%	51%	51%	51%	51%
2	Low Cost	46%	47%	53%	56%	57%
2	Mid Cost	46%	47%	49%	52%	55%
2	High Cost	46%	47%	47%	47%	47%
3	Low Cost	44%	44%	51%	54%	56%
3	Mid Cost	44%	44%	47%	50%	53%
3	High Cost	44%	44%	44%	44%	44%
4	Low Cost	38%	38%	45%	50%	51%
4	Mid Cost	38%	38%	41%	44%	47%
4	High Cost	38%	38%	38%	38%	38%
5	Low Cost	32%	32%	38%	42%	43%
5	Mid Cost	32%	32%	35%	37%	40%
5	High Cost	32%	32%	32%	32%	32%

VI. Energy Efficiency

TVA's Draft 2015 IRP does not meet the standard of taking all cost-effective steps to helping families and businesses cut energy bills. Energy efficiency ("EE") has been demonstrated to be the least-cost and lowest-risk energy resource available to utilities.[73] In its 2011 IRP, TVA promised to become a regional leader in energy efficiency, helping customers cut energy bills by targeting energy savings as high as 1% of retail sales. Instead, TVA cut its energy efficiency budget and is stalled at less-than one-third of its 2011 IRP goal. Even though the Draft 2015 IRP prompts TVA to resume program growth, the plan both falls significantly short of 2011 targets and fails to rely on best industry practices.

SACE commends TVA's decision to model EE as a resource in its 2015 IRP, and we are hopeful that it will lead other utilities in the Southeast to include EE in their IRP modeling. TVA is now one of very few utilities in the country that uses a resource planning model to optimize the level of energy efficiency.

Unfortunately, TVA's characterization of energy efficiency departs from industry practices, using excessively restrictive growth caps and excessively high program cost assumptions. While it was reasonable for TVA to restrict the annual growth in energy efficiency programs at some level, its actual restrictions are much lower than demonstrated experience across the Southeast and the nation.

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[72] Department of Energy (DOE) *Wind Vision: A New Era for Wind Power in the United States*, 2015

[73] Molina. (2014). The Best Value for America's Energy Dollar: A National Review of the Cost of Utility Energy Efficiency Programs. ACEEE. Available at: http://www.cectoxic.org/AEEE_Best_Value_is_Energy_Efficiency.pdf.

TVA's recent sensitivity analyses show that these growth caps on low-cost EE resources drive up system costs.

TVA's Draft 2015 IRP also assumes that program growth will cause TVA's energy efficiency costs to skyrocket (contrary to other utilities' experience). In addition to artificially suppressing the amount of energy efficiency in the planning optimization process, the resulting plan costs include these cost adders that are not based on any actual cost forecast.

SACE recommends that TVA modify its EE analysis by: (1) lowering the costs assigned to blocks of EE in Tiers 2 and 3 to better reflect industry experience; (2) increasing the number of selectable blocks from 42 to 82 to allow a 2% incremental demand reduction in 2034; (3) changing the growth cap methodology to an inverse cap structure based on prior-year sales; and, (4) eliminating the Planning Factor Adjustment, which inappropriately inflates the cost of EE by as much as 30%.

A. Demand Response is Reasonably Considered as a Separate Resource

SACE notes that TVA has also separately modeled demand response ("DR") as a resource. TVA has appropriately treated DR as a dispatchable, peak-shaving resource similar to a gas-fired combustion turbine, but with shorter assumed contract lives. All 25 cases in the scenario-strategy analysis in the Draft IRP include an average of roughly 460 MW of DR, with a range of nearly 270 MW to 575 MW. SACE commends TVA for its reasonable treatment of DR in the Draft IRP.

B. TVA has Not Led the Region with Energy Efficiency Impacts

In its 2011 IRP, TVA promised to become a regional leader in energy efficiency, helping customers cut their energy bills by targeting system-wide energy savings as high as 1% of retail sales. In our comments on the draft 2011 IRP, SACE commended TVA for setting this admirable and achievable goal. Yet TVA cut its energy efficiency budget and is stalled at less than one-third of its 2011 IRP goal.

Due to these cuts, TVA lags significantly behind regional leaders. As shown in Figure 16, in 2013, TVA achieved less than half the savings of several regional peer utilities. This trend continued in 2014, when TVA achieved net energy savings of 0.24%,[74] as compared to Entergy Arkansas' 0.99% savings in the same year.[75]

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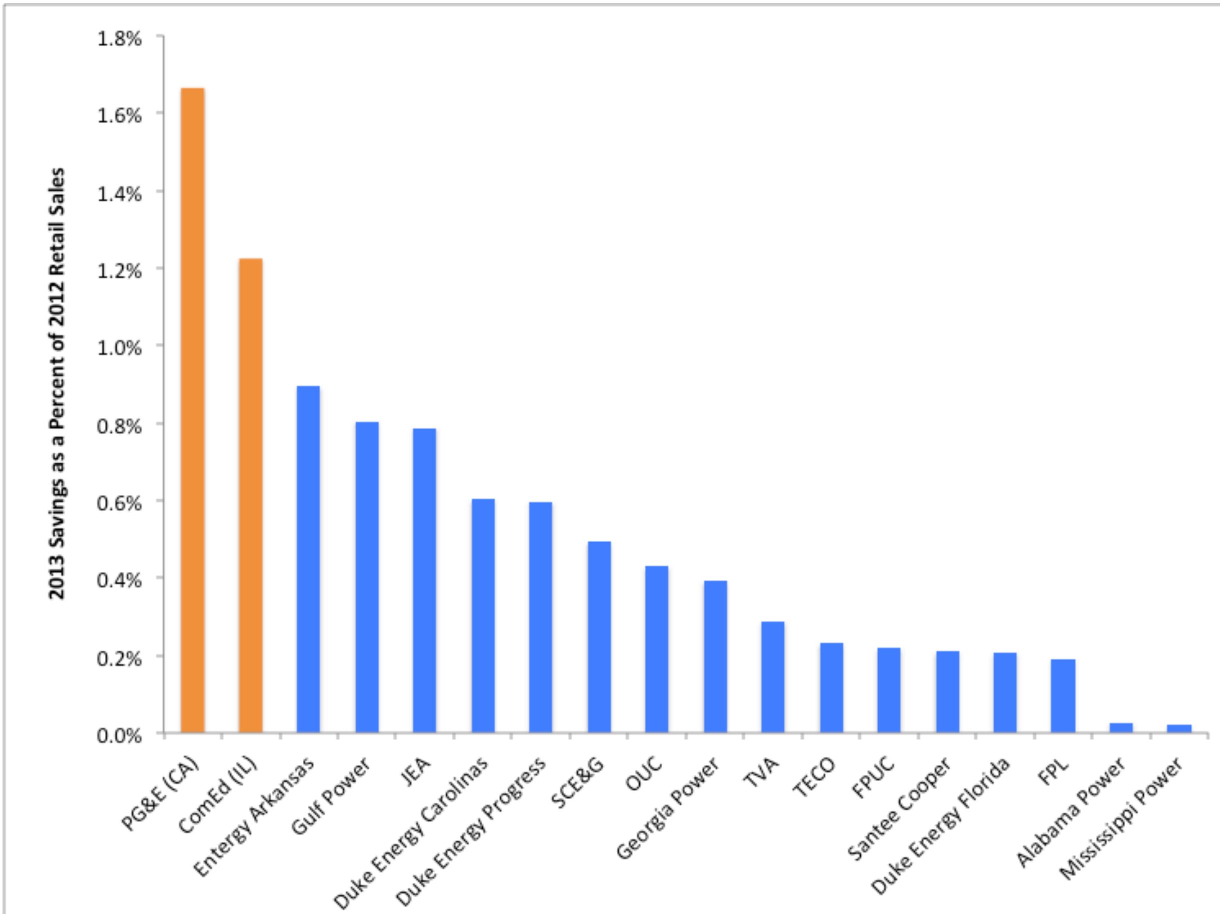
[74] TVA's net savings as a percentage of prior-year sales were calculated utilizing the gross savings reported in the EnergyRight Solutions 2014 Highlights Report (http://www.energyright.com/pdf/highlights_2014.pdf), for each energy efficiency program, the 2013 sales reported in TVA's FY2014 10-K, and a 0.75 net-to-gross ratio. SACE utilized a portfolio-level 0.75 net-to-gross ("NTG") ratio throughout its IRP comments. Taking a weighted average of the NTG ratios included in the IRP in Appendix D, page 129, utilizing gross savings reported in TVA's 2014 ERS Highlights report yields a NTG ratio of 0.73. SACE notes that savings data were not broken out between custom and standard incentives for

Figure 16. Savings Achieved by Southeastern Utilities[76]



In addition, the Draft IRP appears to roll back the energy efficiency resource target to a mere 0.6% annual savings (as a percent of generation), placing it significantly below regional leaders in Arkansas and Florida, well off the national pace, and TVA's 2011 IRP goals.

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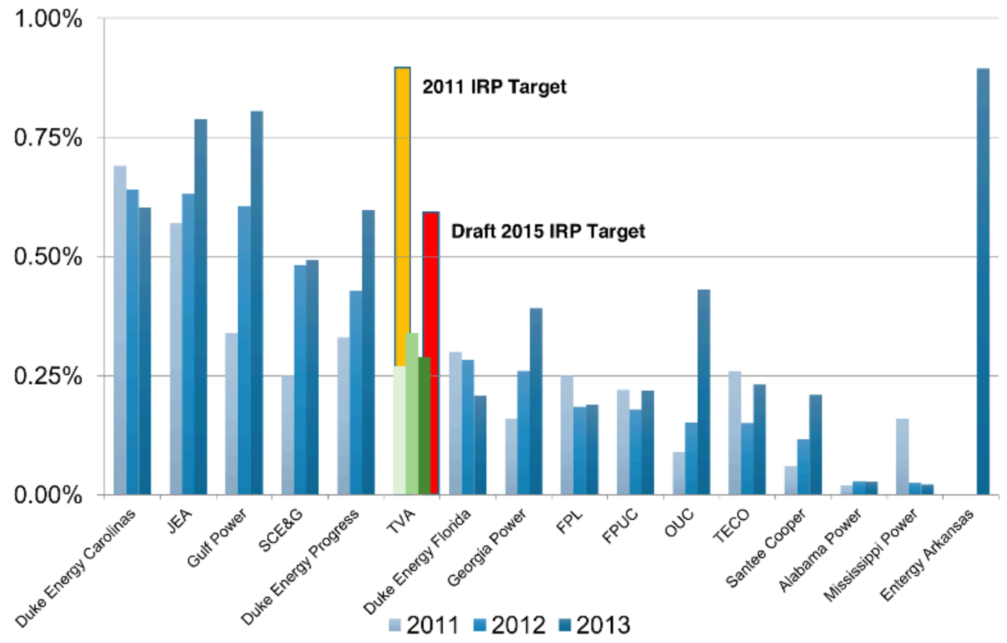
commercial and industrial customers. Given this limitation and the assumption that NTG ratios will change over time, SACE rounded up to 0.75 in order to err on the side of not overly discounting reported energy savings.

[75] Entergy Arkansas (2014). Energy Efficiency Program Portfolio Annual Report. Docket No. 07-085-TF.

[76] SACE analysis of utility program data.

Figure 17. TVA Energy Savings Performance and IRP Targets[77] Compared to Performance of Southeastern Utilities

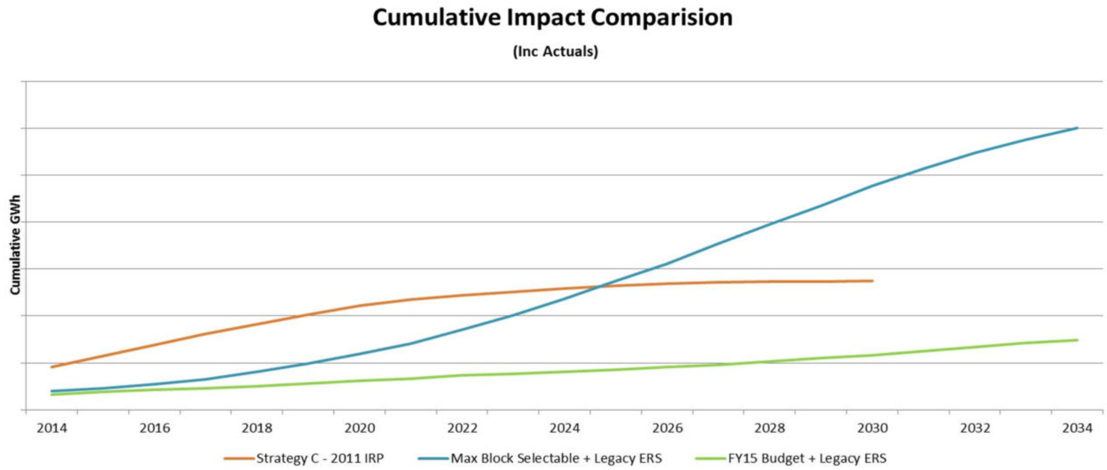


C. Excessive Restrictions on the Growth and Scale of Energy Efficiency

While TVA's characterization of energy efficiency reasonably includes limit to the annual impact of energy efficiency, the assumptions about that limit restrict the growth and scale of energy efficiency programs to much lower levels than utilities have demonstrated across the Southeast and the nation. As illustrated in Figure 18, TVA's maximum allowed energy efficiency resource is substantially lower than the maximum level of energy efficiency recommended in the 2011 IRP through 2024. In other words, TVA's characterization of energy efficiency resources excluded renewal of the current adopted TVA IRP. Characterizing energy efficiency with excessively restrictive growth caps has an impact: TVA's recent sensitivity analyses show that these growth caps on low-cost EE resources drive up system costs.

[77] TVA IRP targets are approximate representations of 2020 annual savings targets.

Figure 18. Maximum EE Impacts in the 2015 IRP
Compared to Business As Usual and Strategy C from the 2011 IRP



i. TVA Caps Energy Efficiency Too Restrictively

As with other resources, TVA set a cap on the maximum amount of energy efficiency that could be deployed in any one year. However, as illustrated in Figure 19, TVA limited the resource to 42 total blocks, only 420 MW, or roughly 2400 GWh (representing a 65% capacity factor).

Figure 19. Maximum Selectable 10 MW Energy Efficiency Blocks per Year

	Residential	Commercial	Industrial
Tier 1	9	4	4
Tier 2	7	4	2
Tier 3	8	4	2
Total	22	12	8

Selecting the maximum number of blocks in 2022 would result in net savings of just 1.00% as a percentage of prior-year sales and the capped value would decline in impact in subsequent years if sales gradually increase.[78] As discussed above, this only slightly exceeds the level of savings already achieved in a single year by Entergy Arkansas. In developing the EE targets for the Clean Power Plan, EPA found that 26 utilities have achieved savings of 1.5% to 3% between 2003 and 2012.[79] The total amount of EE selectable each year should not be substantially lower than what has been demonstrated as achievable by utilities across the country.

[78] Calculated from 2014 baseline gross savings as reported in TVA's 2014 ERS Highlights report, assuming a 0.75 NTG ratio and 1% annual sales growth.
[79] U.S. EPA. (2014). GHG Abatement Measures, Technical Support Document (TSD) for Carbon Pollution Guidelines for Existing Power Plants. Appendix 5-2.

SACE recommends that TVA increase the number of selectable blocks in each tier for each customer class from 42 to 74 to allow the model to evaluate at least a maximum of 740 MW in annual energy efficiency investment. The tiers should not be increased evenly – somewhat greater increases should be made for Tiers 2 and 3 than for Tier 1. This increase would allow for the possibility of up to 2% net savings at the end of the planning period.[80]

ii. <u>TVA's Unorthodox Growth Cap Methodology Is Unreasonably Restrictive</u>

The second way in which TVA unreasonably restricts the potential scale of energy efficiency in the model is to use unrealistically restrictive program growth caps. Industry experience does reflect that there are natural limitations on the ability of utilities to scale up programs, particularly when they are already deployed at substantial levels. However, by capping growth at a percentage of the prior-year demand reduction, TVA's cap structure is most restrictive at lower portfolio savings levels, which is precisely the opposite of industry experience.

TVA's unorthodox model restriction method sets growth caps based on a percentage of prior-year demand reduction attributed to its energy efficiency programs, with declining percentages permitted in later years. TVA capped demand reduction growth rates by 25% in planning years 1 through 5, by 20% in years 6 through 15, and by 15% in years 16 through 20, as shown in Figure 20.

Figure 20. TVA's Growth Cap Methodology

Planning Years	Growth Cap
1-5	25%
6-15	20%
16-20	15%

TVA's use of a cap as a percentage of prior-year demand reduction results in early-year limits on energy savings that are far lower than growth rates that other utilities in the Southeast have achieved. Figure 21, below, shows the maximum savings selectable by the model with the growth cap utilized by TVA. If TVA were to hit the growth caps each year, it would only achieve 1% savings in 2021. The growth cap becomes less important beginning in 2022, when the annual program cap becomes more restrictive than the growth cap.

[80] Calculated from 2014 baseline gross savings as reported in TVA's 2014 ERS Highlights report, assuming a 0.75 NTG ratio and 1% annual sales growth.

Figure 21. Maximum Selectable Energy Savings With TVA's Growth Cap

Year	**Growth Rate** % of Prior-Year kW Demand Reduction	**Gross Demand Reduction** % of Peak Demand	**Net Savings** % of Prior-Year Sales[81]
2013	25%	NA	0.22%
2014	11%	0.29%	0.24%
2015 (Y1)	25%	0.35%	0.30%
2016	25%	0.44%	0.38%
2017	25%	0.54%	0.47%
2018	25%	0.67%	0.58%
2019	25%	0.83%	0.72%
2020	20%	0.99%	0.85%
2021	20%	1.17%	1.01%
2022	20%	1.40%	1.20%
2023	20%	1.66%	1.43%
2024	20%	1.97%	1.69%
2025	20%	2.34%	2.01%
2026	20%	2.78%	2.39%
2027	20%	3.30%	2.84%
2028	20%	3.93%	3.38%
2029	20%	4.66%	4.01%
2030	15%	5.31%	4.57%
2031	15%	6.05%	5.20%
2032	15%	6.88%	5.92%
2033	15%	7.84%	6.74%
2034	15%	8.93%	7.67%

In fact, TVA has once exceeded the 25% growth cap utilized in the 2015 IRP. From 2012 to 2013, TVA increased its EE-related demand reduction by 25% and its net savings by 33%. This fact alone should sufficiently demonstrate that the growth cap is unreasonable, but other Southeastern utilities have also demonstrated that TVA's assumed annual growth caps can be exceeded – for several years in a row. The three utilities in Figure 22 illustrate different savings growth levels that have occurred with widely varying program structures. For example, Georgia Power's programs completely exclude industrial customers, one of the easiest sectors to ramp up quickly, yet its programs achieved 50% and 63% increases in net savings in 2012 and 2013, respectively.

[81] Shaded area represents levels of efficiency not allowed by the annual energy efficiency resource limit. Net energy savings calculated utilizing an estimated NTG ratio of 0.75, which falls within the range of NTG ratios for EE portfolios nationwide. Actual gross energy savings data was taken from TVA's ERS Highlights reports, and actual sales data were taken from TVA's Fiscal Year 2014 Form 10-K. Energy savings for 2015-2034 represent the maximum savings growth from the 2014 gross savings baseline utilizing TVA's growth cap methodology for the 2015 IRP, with a 0.75 NTG ratio applied. Total sales and peak demand were both assumed to grow by 1.0% annually. Savings do not reflect the maximum of 42 selectable 10-MW blocks for each year.

Figure 22. Energy Savings Growth Rates Achieved in the Southeast

	2010	2011	2012	2013
Gulf Power Savings	NA	0.35%	0.61%	0.80%
Gulf Power Growth Rate	NA	NA	74%	31%
Georgia Power Savings	NA	0.16%	0.26%	0.39%
Georgia Power Growth Rate	NA	NA	50%	63%
Kentucky Savings	0.07%	0.15%	0.25%	0.52%
Kentucky Growth Rate	NA	114%	67%	108%

The purpose of the growth cap should not be to limit the pursuit of cost-effective EE beyond what has been clearly demonstrated as an achievable growth rate. Instead, it should serve to place a limit in line with the outer boundary of what is reasonably achievable based on industry experience.

A more conventional approach to growth caps for modeling EE in resource planning would be to limit the growth of energy savings by a percentage of prior-year sales, rather than prior-year savings. In addition to demonstrated growth rates, the growth cap should take into account the levels of savings achieved by leading utilities nationwide. As shown in Figure 23, eleven states achieved savings greater than 1.0% of retail sales in 2013, and Illinois nearly crossed that threshold, with savings of 0.99% of sales. Data reported for 2014 so far indicates that leading states are continuing to grow their savings; Rhode Island, for example, achieved savings of 2.7% last year.

Figure 23. States that Achieved Savings Greater than 1.0% of Sales in 2013[82]

State	Savings as a % of Sales (2013)	State	Savings as a % of Sales (2013)
Rhode Island	2.09%	Oregon	1.43%
Massachusetts	2.05%	Washington	1.35%
Vermont	1.78%	New York	1.13%
Arizona	1.74%	Iowa	1.06%
Hawaii	1.67%	Minnesota	1.04%
Michigan	1.51%		

Not only is TVA's growth cap methodology too restrictive in the early years of the planning period; it is also arguably not restrictive enough in the latter years. As illustrated in Figure 21, if TVA were to hit the growth caps every year for the entire planning period, it would be achieving

[82] ACEEE. (2014). Comments of the American Council for an Energy-Efficient Economy ("ACEEE") On the Environmental Protection Agency's Proposed Clean Power Plan. http://aceee.org/files/pdf/regulatory-filing/clean-power-plan-comments.pdf

incremental annual savings of 7.67% of sales, which is roughly three-times the level achieved by Rhode Island in 2014.

As an alternative growth cap methodology, SACE recommends that TVA adopt an inverse cap structure, in which a reasonable target is set for the end of the planning period, and growth caps are set for each planning year based on a formula allowing for gradual incremental progress toward the ultimate target. SACE recommends that TVA adopt a maximum target for the planning period of 2.0% demand reduction as a percentage of prior-year peak demand, with a growth cap formula that allows for annual savings growth equal to 15% of the remaining difference between the 2.0% savings level and TVA's savings level in each given year. Figure 24, illustrates this recommendation as a formula.

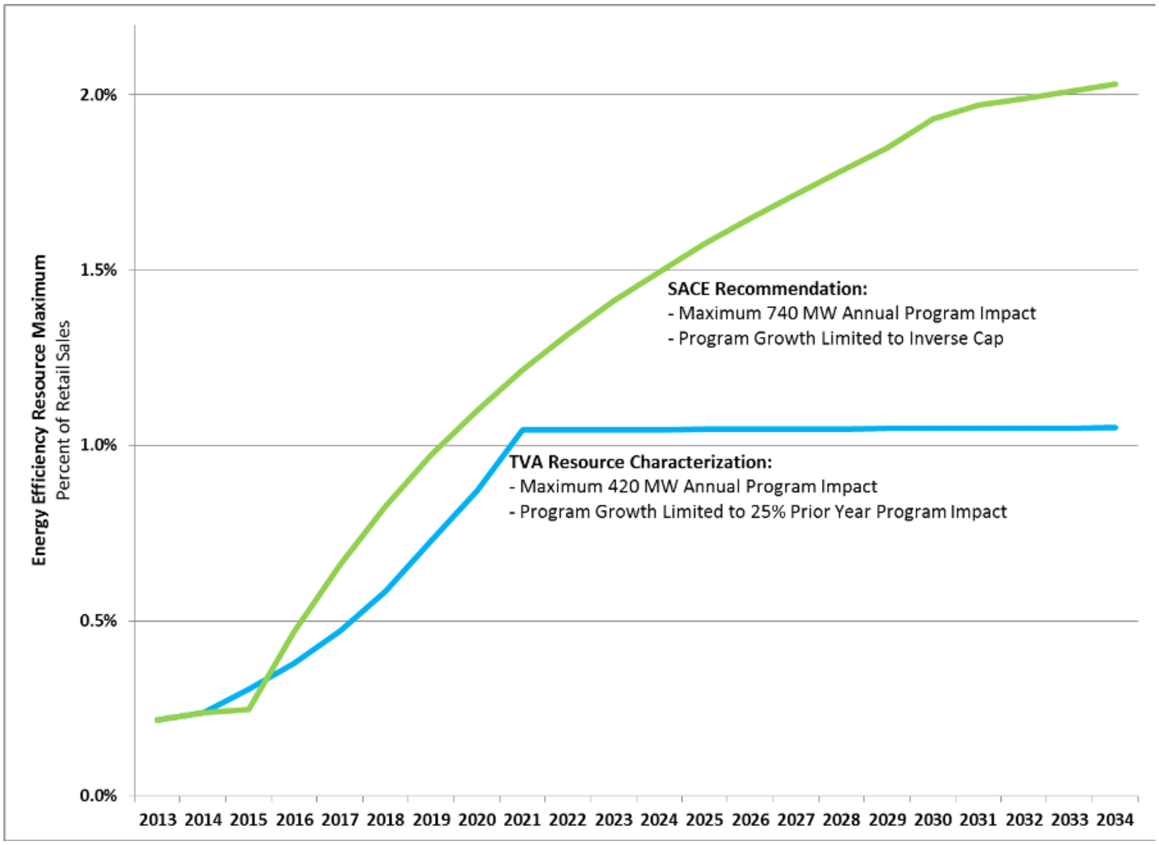
Figure 23. SACE's Recommended Inverse Growth Cap Methodology

$$M = PM + (2.0\% - PM) \times 15.0\%$$

*M = Maximum demand reduction each year as a percentage of prior-year peak-demand; and,
PM = Previous year's maximum demand reduction as a percentage of prior-year peak demand.*

This approach balances TVA's ability to ramp up savings at a fast pace in early years when achieving lower net savings, with the likely unrealistic expectation that very high growth rate will occur later years. When combined with our recommended maximum demand reduction potential of 720 MW per year from energy efficiency programs, the resulting energy savings achieved are estimated to ramp up more quickly than those of TVA to a cap of slightly more than 2% of prior year retail sales, as illustrated in Figure 24.

Figure 24. Maximum Selectable Energy Savings, Comparing TVA's Assumptions to SACE Recommendations[83]



Our recommended maximum annual portfolio size and growth cap method are suggested as constraints on TVA's energy efficiency resource in its capacity expansion model, and do not recommend what level of energy efficiency resources TVA should actually select. Adopting a growth cap similar to the one we recommend would allow the plan to consider program growth and scale consistent with industry experience.

D. *Excessive Costs for Energy Efficiency Resources*

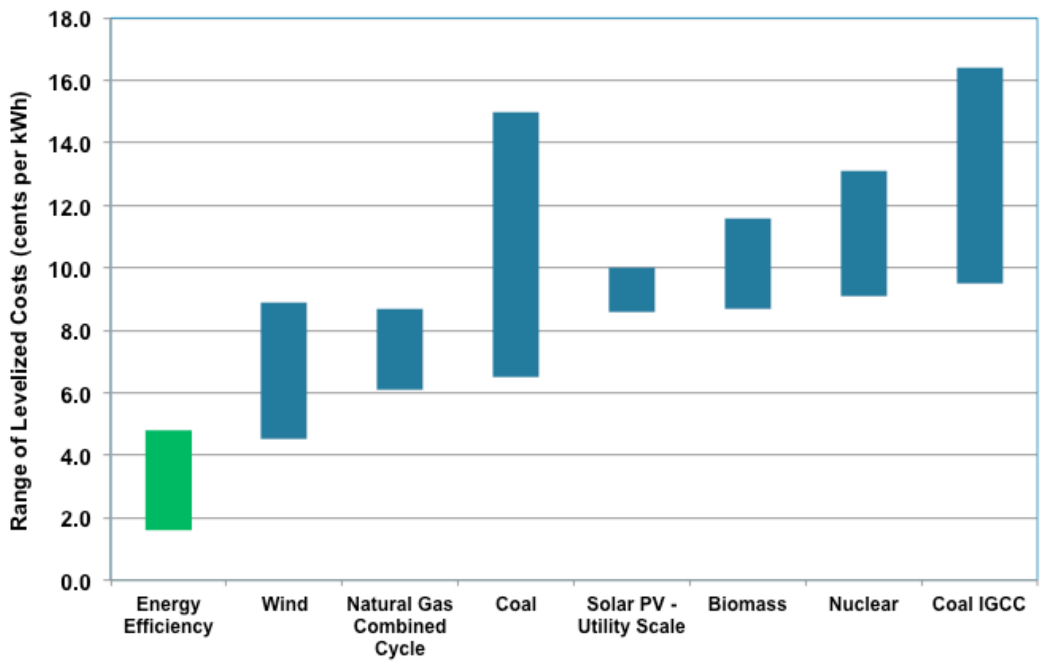
TVA's Draft 2015 IRP characterizes energy efficiency resources with a cost forecast that assumes program growth causes costs to skyrocket (contrary to other utilities' experience). TVA's method for forecasting the cost of energy efficiency includes three steps – which is different from all other resource cost forecasts, which include only two steps. Neither the specific characterization in the first two steps, nor the addition of a third step, is supported by evidence. Furthermore, the third "planning factor" step is without precedent as a utility planning practice.

[83] Program growth for 2015 was set equal to 2014 growth levels.

i. TVA's Cost Assumptions for EE Do Not Reflect Industry Experience

EE has been proven as the least-cost resource across the country. A 2014 study by ACEEE found that EE has the lowest levelized cost of any energy resource, with an average levelized cost for 2009-2012 of 2.8 cents per kWh and a range from 1.6 cents per kWh to 4.8 cents per kWh.[84] By comparison, a study performed by Lazard found that the levelized cost of a new natural gas combined-cycle ("NGCC") plant ranges from just over 6 cents per kWh to nearly 9 cents per kWh, as shown in Figure 25.[85]

Figure 25. Levelized Cost of Energy Efficiency Compared to Other Energy Resources



*Notes: Energy efficiency program portfolio data from Molina 2014; All other data from Lazard 2014.

TVA's own programs have experienced costs somewhat below the average cost of EE programs in the country. In its 2014 EnergyRight Solutions ("ERS") Highlights report, TVA reported that the average lifetime costs for its energy efficiency programs were just 1.8 cents per kWh, based on gross savings.[86] In the same report, TVA stated, "Having a competitive position within our power system and resource planning models makes [ERS] a least cost option." TVA reported the same cost in 2013,[87] and a slightly higher cost of 2 cents per kWh in 2012,[88] showing that the ERS programs have

[84] Molina. (2014).
[85] Lazard (2014). Lazard's Levelized Cost of Energy Analysis – Version 8.0. Available at http://www.lazard.com/PDF/Levelized%20Cost%20of%20Energy%20-%20Version%208.0.pdf
[86] TVA. ERS 2014 Highlights Report. Available at http://www.energyright.com/pdf/highlights_2014.pdf
[87] TVA. ERS 2013 Highlights Report. Available at http://www.energyright.com/pdf/highlights_2013.pdf
[88] TVA. ERS 2012 Highlights Report. Available at http://www.energyright.com/pdf/highlights_2012.pdf

been able to grow, however modestly, while shrinking or maintaining their already-low costs. Figure 26, below, shows calculated costs of net energy savings achieved by TVA, assuming a net-to-gross ("NTG") ratio of 0.75.

Figure 26. TVA's Average Lifetime Cost of EE

Year	**Cost of Gross Savings** Cents/kWh	**Cost of Net Savings** Cents/kWh[89]
2012	2.0	2.7
2013	1.8	2.4
2014	1.8	2.4

TVA staff has corroborated the opportunity to maintain or even reduce the per-kWh cost of energy efficiency. Subsequent to the 2014 staff and Board decision to cut the energy efficiency program budget, TVA staff commented to the IRP Working Group that the energy savings impact would not be as great as the percentage reduction in spending because the staff was continuing to become more efficient. In other words, as TVA has developed experience, it has found that it can achieve energy savings at a lower cost.

To allow its resource model to select incremental amounts of energy savings, TVA has parceled out EE into 10 MW blocks of load reduction. SACE agrees that this is a reasonable approach. TVA further parceled out EE into three tiers to reflect the assumption that incremental energy savings become more expensive after certain amounts of the most cost-effective measures have become exhausted. Again, SACE agrees that this is a reasonable approach as long as the costs used for all three tiers are supported by evidence using methods that are consistent with practices TVA uses for other resources.

TVA's costs for Tiers 2 and 3 are not reasonable or supported by evidence. As illustrated in Figure 27, the cost increases for Tiers 2 and 3 are very large. For example, Tier 2 incentives are nearly double the incentives in Tier 1, and Tier 3 incentives are double for residential and triple for commercial and industrial. As TVA staff pointed out during the February IRP workshop on energy efficiency resources, there are substantial opportunities to ramp up energy efficiency program impacts while simultaneously finding lower cost, more efficient program delivery mechanisms.[90]

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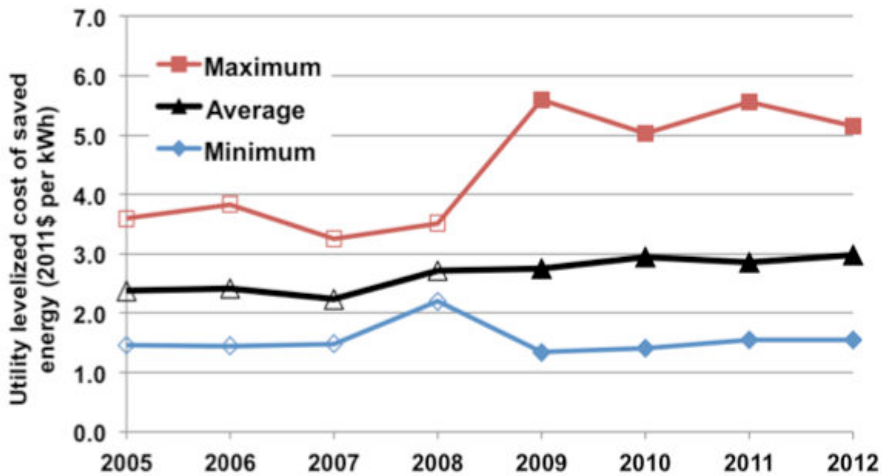
[89] Cost of net energy savings calculated by SACE utilizing a 0.75 NTG ratio and reported cost of gross savings from TVA's ERS Highlights reports.
[90] For example, HVAC incentives delivered through a TVA partnership with manufacturers and distributors could be more cost-effective as well as vastly more impactful than downstream customer incentives.

Figure 27. Average Unweighted Cost Increases for Tiers 2 and 3

Tier 2	Residential	Industrial	Commercial
ERS Incentives	50%	70%	70%
ERS Variable Costs	26%	70%	70%
ERS Fixed and Low Variable	15%	10%	10%
ERS Other	19%	70%	70%
Tier 3	**Residential**	**Industrial**	**Commercial**
ERS Incentives	100%	200%	200%
ERS Variable Costs	51%	200%	200%
ERS Fixed and Low Variable	25%	20%	20%
ERS Other	29%	200%	200%

TVA states that the energy efficiency tier costs "were developed through consultation with the managers of existing TVA programs and supporting consultants." However, TVA did not provide any specific information from studies or program experience, such as summaries of cost escalations or consultant reports, that would support this statement and demonstrate that the consultations were driven by data and industry experience. In fact, studies have shown that, as utility portfolio energy savings increase over time, costs do not increase as TVA's characterization assumes. For example, ACEEE's most recent rollup of national utility portfolio cost and energy savings data, as summarized in Figure 28, shows that energy efficiency costs have remained stable on average, with only a few programs showing substantial cost increases. Because utility portfolios have generally ramped up savings over time, average cost trends are a reasonable proxy for considering how costs change as savings are increased.

Figure 28. Cost of Saved Energy Over Time[91]

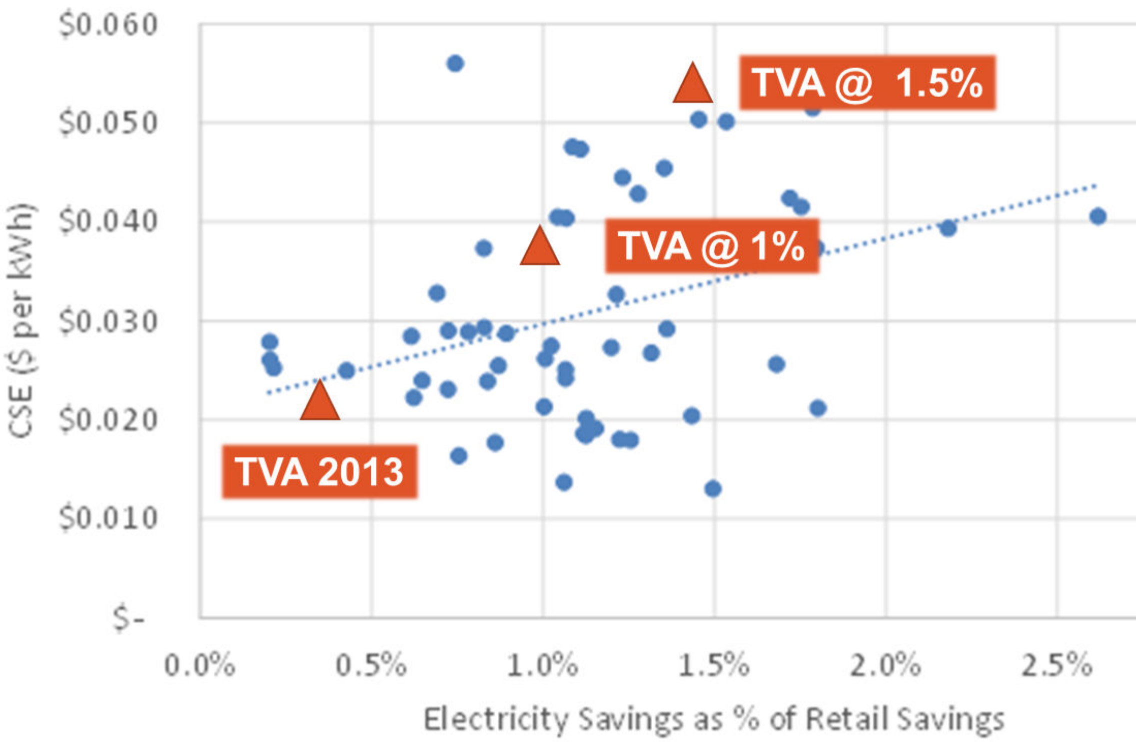


Another way to evaluate these same data is to directly compare the cost of saved energy of utilities with different levels of savings. As illustrated in Figure 22, above, there is a weak correlation between the cost of saved energy and portfolio scale (measured as savings as a percentage of sales). However, a closer review of the data suggests that costs do not escalate as energy savings increase. In fact, most of the data points at or above $0.04 per kWh represent states with relatively high fundamental costs (e.g., labor), such as Connecticut.

TVA's use of an increasing cost of saved energy is directly at odds with these findings. The ACEEE analysis in Figure 29 has been modified to illustrate the approximate cost TVA assumes for energy efficiency resources in its IRP analysis (orange triangles). Not only is the TVA cost increase much greater than the weak correlation found by ACEEE, but it is also at odds with the underlying data. When ACEEE's data are inspected on a state-by-state basis, it appears that for any specific state, the observed correlation disappears. Thus the apparent correlation between energy efficiency portfolio costs and portfolio scale may be due to higher cost states being disproportionately represented among the higher saving states. In fact, what studies have found is that cost of saved energy tends to decrease due to economies of scale and other factors.[92]

[91] Molina (2014).
[92] Takahashi, K. and D. Nichols. (2008). "The Sustainability and Costs of Increasing Efficiency Impacts: Evidence from Experience to Date." In *Proceedings of the 2008 ACEEE Summer Study on Energy Efficiency in Buildings.* Washington, DC: ACEEE.

Figure 29. Cost of Saved Energy for Utilities Achieving Different Levels of Savings[93]



SACE recommends that TVA lower the costs assigned to blocks of EE in Tiers 2 and 3 to better reflect the industry average of 2 to 3 cents per kWh. Based on the distribution of costs of existing programs across the country, SACE recommends a Tier 2 levelized cost of net savings no higher than 3 cents per kWh and a Tier 3 cost no higher than 5 cents per kWh.

ii. <u>TVA's Escalation Rate for Energy Efficiency Costs is Reasonable</u>

As with other resources, TVA also applies an escalation rate for energy efficiency costs. Although it does not appear that this value was reviewed by the IRP Working Group, a graph illustrating its effect was shared as part of a sensitivity analysis during its April 2015 meeting. The moderate escalation rate used by TVA for its forecast appears consistent with reasonable planning practices we have observed across the country.

iii. <u>TVA's "Planning Factor" Method is Unprecedented and Unreasonable</u>

TVA expressed concern during the planning process that energy efficiency has special "risks" that it needed to address in the modeling process. For all resources in the IRP, including EE, TVA analyzes risk by using stochastic modeling. However, for energy efficiency <u>only</u>, TVA utilizes additional risk adjustments in addition to its stochastic modeling. TVA considered two categories of EE uncertainty – design uncertainty and delivery uncertainty.

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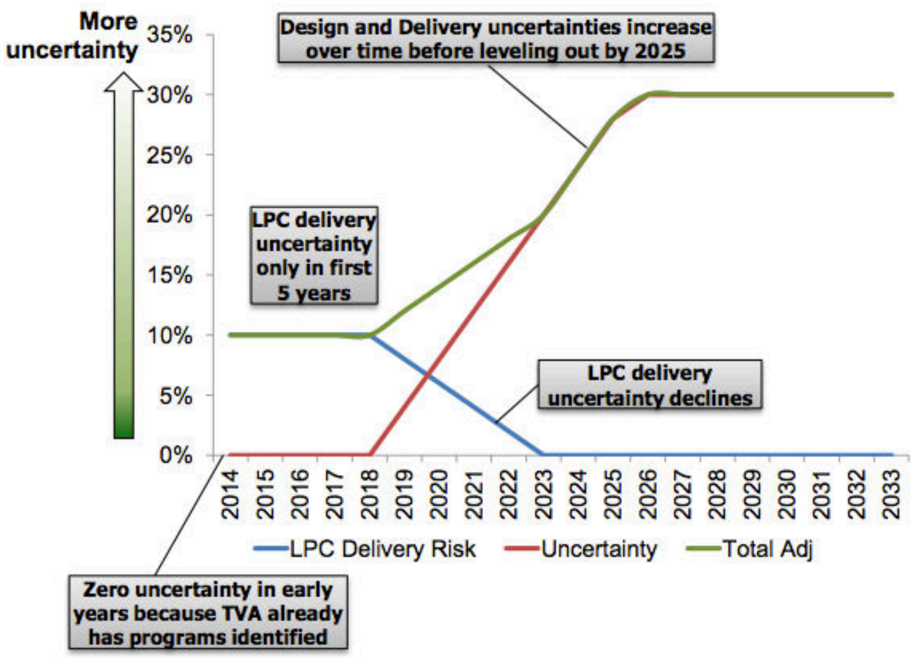
[93] Molina. (2014). The last word on the x-axis label should be "sales," instead of "savings."

a. TVA's Planning Factor is Based on One-Sided Reasoning

To adjust for these uncertainties, TVA developed a two-part Planning Factor Adjustment ("PFA"), with one component focused on design uncertainty and another to reflect delivery uncertainty, as illustrated in Figure 30. The LPC delivery planning factor adjustment starts off as a 10% cost adder in the beginning of the planning period and begins ratcheting down in 2018 until reaching 0% in 2023 and thereafter. The program design planning factor adjustment starts off at 0% in 2015 and begins ratcheting up in 2018 until reaching 30% in 2026 and thereafter.

Figure 30. TVA's Planning Factor Adjustment[94]



TVA states that delivery uncertainty reflects three factors: TVA does not "own the relationship with most end-use customers in the valley;" varied realization rates in other jurisdictions for energy and demand savings; and, the unknown impacts of future codes and standards. With respect to the impacts of future codes and standards, this should not be reflected as an uncertainty: if the codes and standards are not reflected in TVA's load forecasts in this study, then if such codes and standards are so effective that they constrain TVA's future energy efficiency portfolio, the resulting load decrease would be a significant decrease below TVA's forecast.

[94] Copied from TVA's 2015 draft IRP, Appendix D, page 138.

With regard to customer relationships, SACE notes that TVA directly markets to customers through mass media, and TVA also offers customer website portals and phone lines to enable customers to sign up for ERS programs. SACE also notes that TVA directly serves its large industrial customers. Instead of modeling customer relationships as a risk, SACE recommends that TVA leverage its existing relationships with end-use customers to mitigate any bottlenecks in the LPCs' role in ERS programs.

TVA states in the Draft IRP that design uncertainty exists because the blocks of EE utilized in the model are "proxies" for programs that have not been developed and may include technology that does not exist yet. TVA also expresses concern that the blocks include a mix of EE measures with (1) different lifespans and (2) different load-reduction profiles over time. Both of these observations reflect reality, but TVA does not provide any evidence that these uncertainties are only adverse, likely to drive up portfolio costs.

A balanced portfolio of EE programs is able to blend measures cost-effectively in a way that smoothly sustains energy savings and load reduction over time, much in the way that a diversified investment portfolio with debt instruments of different maturities is able to maintain a relatively consistent return on investment within the bounds of broad market trends. While there may be risk that EE measures fail before their estimated useful life, there is also an upside potential that they may last longer or perform better than expected.

With respect to realization rates, the cost and savings impact data cited above (e.g., from ACEEE) refflects actual realization rates, and utilities in states with statutory energy efficiency resource standards have consistently met their targets. Even in cases when utilities have achieved savings that were lower than forecasted, they frequently also experienced lower costs than expected, which is another reason it is not appropriate to inflate the cost of EE due to concerns about realization rates.

In summary, TVA's planning factor adjustment is based almost entirely on a set of uncertainties in which its evaluation is one-sided. Only the negative outcome is discussed, and the positive aspect to the uncertainty is entirely omitted from TVA's evaluation.

b. The Planning Factor Adjustment is Equivalent to Assuming Program Failure

In the second decade of TVA's analysis, the planning factor combines with the high cost forecast to result in the total modeled cost of energy efficiency to be roughly equivalent to the cost of replacement power and generation. This finding was obtained by constructing a simple model using publicly disclosed data and standard industry assumptions about natural gas generation costs, as summarized in Table 9. In the "EE Success" column, the historical cost of TVA's energy efficiency programs is contrasted with a rough estimate of TVA's High-Cost (Tier 3) programs: TVA characterizes Tier 3 programs at roughly 3 times the historical cost of TVA's energy efficiency portfolio.

With the addition of the "planning factor" adjustment, TVA's model then assumes that Tier 3 programs cost roughly four times that of today's energy efficiency programs. As discussed above, there is no evidence that utilities experience a fourfold increase in energy efficiency costs as programs scale up to as much as 1.5% annual savings. There is ample data from existing programs that suggests that costs are roughly flat or even declining at this scale. Yet TVA assumes that costs skyrocket in this fashion – even before applying the escalation factor described above.

This value may be compared with scenarios in which 1/3 or even all of the Tier 3 energy efficiency programs "fail." As illustrated in Figure 31, in each of these simple scenarios, the cost of obtaining power on short notice and then eventually building a replacement supply resource is approximately the same as the model assumes for program "success." Because TVA has not made all cost and program forecast data available, the analysis in Figure 31 is based on costs estimated from data publicly disclosed by TVA in chart form, as well as SACE assumptions, following the scenario designs as illustrated in Figure 32.

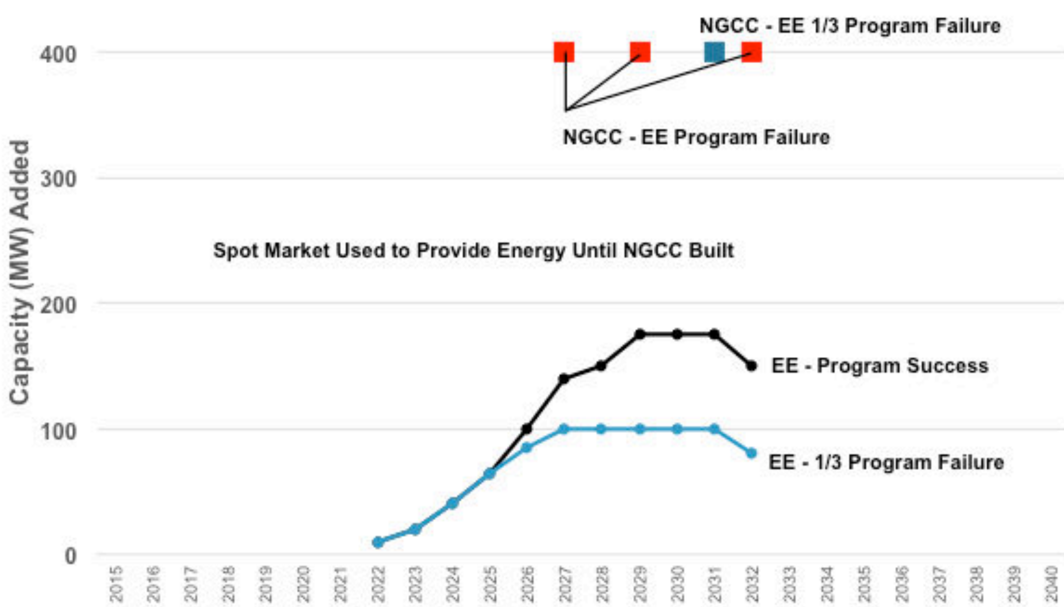
- EE Success: Under this scenario, customers participate in the programs. However, rather than using a cost based on historical costs, TVA uses higher cost estimates, a contingency, and a planning factor adjustment to reach a cost of roughly \$3 billion for the 10-year efficiency portfolio illustrated in Figure 32.
- 1/3 Program Failure: Under this scenario, customer participation is lower than expected, achieving only 2/3 of the projected savings, as illustrated in Figure 32. In the short term, the shortfall is made up by spot market power purchases, with a 400 MW NGCC unit being required after several years. The cost of this scenario is also roughly \$3 billion.
- 100% Program Failure: Under this scenario, Tier 3 programs have no participation, so TVA makes up the shortfall with spot market power purchases and 3 400 MW NGCC units. The cost of this scenario is also roughly \$3 billion.

By escalating the Tier 2 and especially Tier 3 costs by such large amounts, the energy efficiency resources become not cost effective – even though TVA has identified in its potential studies ample (if understated) opportunities.

Figure 31. Estimated Present Value Revenue Requirements of Tier 3 Cost Including the PFA is Equivalent to 100% Program Failure ($ Million)

<table>
<tr><th></th><th>EE Success</th><th>1/3 Program Failure</th><th>100% Program Failure</th></tr>
<tr><td>Historical Cost</td><td>$754</td><td>$1,496</td><td rowspan="4">$2,939</td></tr>
<tr><td>High-Cost</td><td>$1,988</td><td>$2,335</td></tr>
<tr><td>High-Cost w/ contingency</td><td>$2,386</td><td>$2,605</td></tr>
<tr><td>High-Cost w/ contingency & PFA</td><td>$3,084</td><td>$3,074</td></tr>
</table>

Figure 32. Scenarios Used to Evaluate Cost and Planning Factor Adjustments



Given these unreasonably high cost assumptions, it is not surprising that TVA's Strategy E fails to demonstrate significant cost savings and suggests substantial rate impacts. Over two-thirds of the cost in Tier 3, and a substantial portion of the Tier 2 costs, are attributable to TVA's internal planning assumptions without any foundation in external data. Only if TVA re-calculates the PVRR and system average cost without including the inflated costs and "planning factor" adjustment can a fair comparison of Strategy E to other strategies be made.

Regardless of what values TVA might assign to the "planning factor" adjustment, TVA did not provide any support in the IRP or in IRP Working Group discussions for any industry experience with this method. In fact, TVA's external reviewer, Navigant, acknowledged during the IRP Working

Group energy efficiency workgroup that it had concluded its review of TVA's energy efficiency modeling practices prior to TVA's introduction of this method. TVA has not shared any evidence of expert support for this method and it should be omitted from the Final IRP.

c. TVA Should Characterize Energy Efficiency Resource Risks Properly

TVA's primary method for accounting for resource cost and delivery risks is stochastic risk modeling. For example, TVA staff commented during an IRP Working Group meeting that codes and standards impacts might be accounted for in load forecasts as "low draws" during the stochastic modeling process. SACE agrees that stochastic modeling should be used to model utility portfolio risks, and that TVA should enhance its characterization of uncertainties in this area.

Enhancing TVA's characterization of energy efficiency risks should consider TVA's concerns noted above, but should also reflect advantages that mitigate risk:

- TVA has a highly contiguous territory, including an entire state, creating greater opportunity for upstream incentive program designs and governmental cooperation, as well as reducing "leakage" and "wasted" marketing costs that occur in markets with multiple utilities;
- TVA's energy efficiency programs are forecast to be most effective in the winter, providing valuable peak mitigation during challenging winter peak events;
- TVA lacks a concern about shareholder disincentives to investment in EE;
- TVA has the opportunity to use its low-cost debt to finance EE when it is not needed for capital projects; and
- TVA has an opportunity to leverage additional debt financing through partnerships with LPCs, local governments and Seven States Power Corporation.

By including consideration of these risk (or rate) mitigation features, as well as the upside potential for the risks cited by TVA in support of the "planning factor" adjustment, TVA could arrive at a more reasonable characterization of portfolio performance and cost risk.

SACE suggests that to the extent TVA is convinced there is a substantial risk of "program failure," TVA could modify its stochastic analysis to characterize this as a risk rather than including it as a cost. The approach should vary accounting for lower risk in Tier 1 and greater risk in the higher tiers, as illustrated in Figures 33a-c. The suggestion given below allows for the following characteristics:

- The most likely cost in each stochastic range remains close to TVA's historical cost plus a 20% contingency factor, similar to TVA's planning approach for other resources. The lowest possible cost for each tier is only slightly below TVA's historically experienced cost.
- The most likely cost of "program failure" is estimated at \$4,300/kW, which is an estimate of both capital and fuel costs for a NGCC unit plus short-term spot market costs.
- The incidence of "program failure" increases from one tier to the next, resulting in a different distribution curve. The broader distribution of "program failure" costs in the higher tiers is intended to represent cost uncertainty for TVA's replacement power options.

The resulting total average costs almost double from Tier 1 to Tier 3, indicating a significant cost risk but one that is substantially less than TVA's fourfold increase in costs. We suggest the stochastic cost distribution in Figures 33a-c because they would more accurately reflect TVA's description of program failure risks in the second decade of its planning period. However, if TVA adopots this approach, TVA should further reconsider its assessment of EE portfolio risks, potential scale, and special opportunities and reasonably incorporate its findings in a revised EE portfolio characterization.

Figure 33a. Tier 1 Stochastic Risk Solution

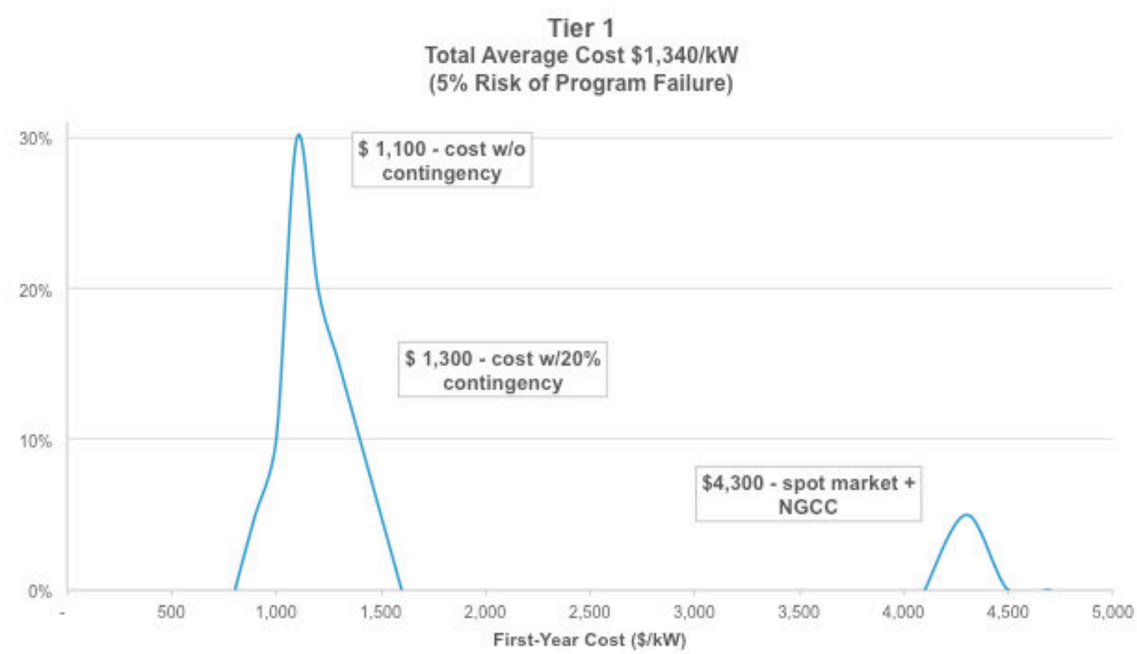


Figure 33b. Tier 2 Stochastic Risk Solution

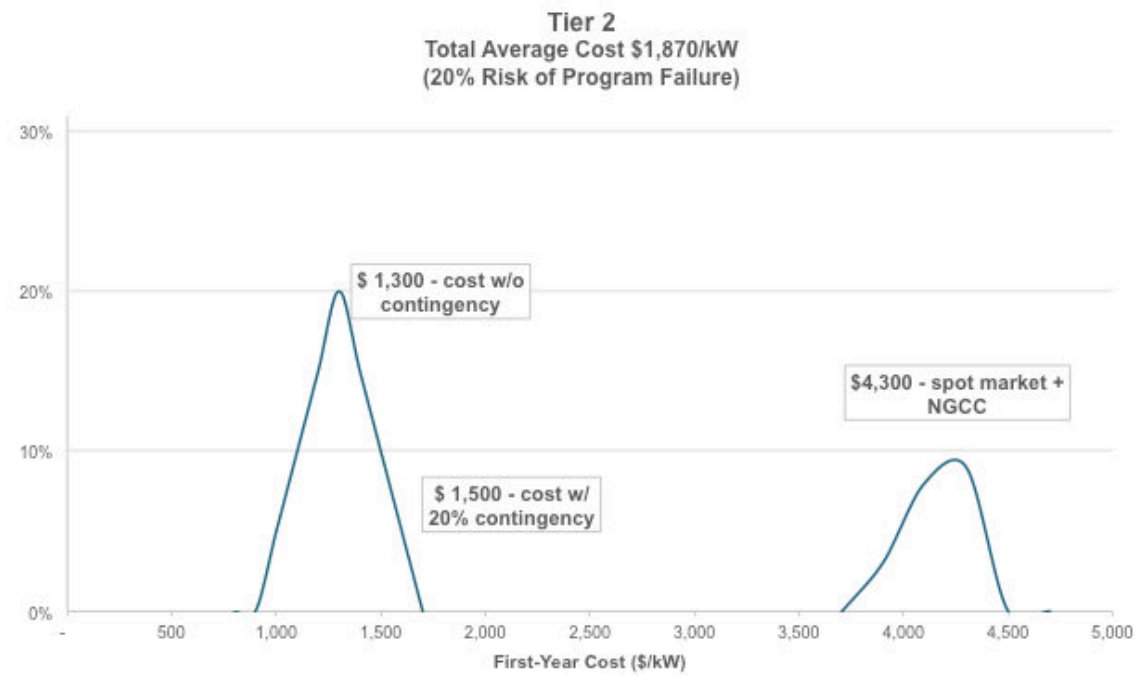
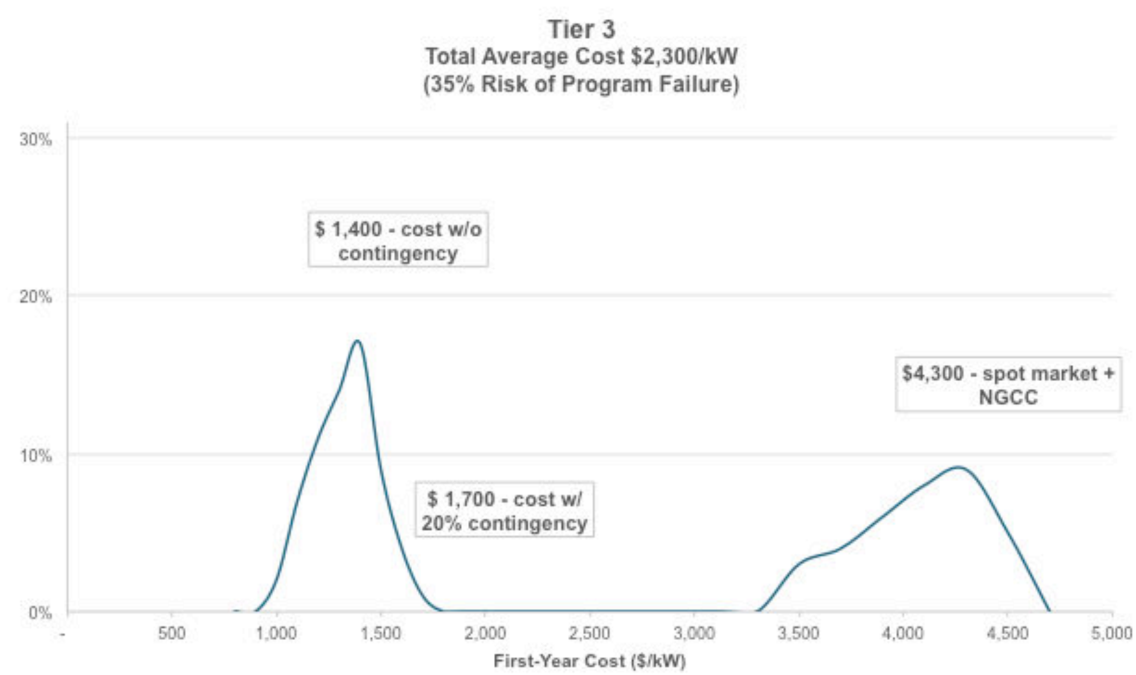


Figure 33c. Tier 3 Stochastic Risk Solution



One additional shortcoming of the TVA "planning factor" adjustment is that it assumes that there would be no environmental impact even with "program failure." To correct this oversight, TVA should revise its characterization of energy efficiency risks to add CO_2 emissions consistent with risk of “program failure.” For example, if Tier 3 is characterized as suggested in Figure 33c, then during the 35% of the draws with “program failure,” CO_2 emissions could be estimated as equivalent to a CCGT, with associated carbon costs.

VII. Conclusion

We reiterate our appreciation of TVA’s commitment to public engagement throughout the IRP planning process, which has allowed for an unprecedented exchange of information between stakeholders and utility staff here in the Southeast. However, there have been some significant gaps between the planning intent and decisions on major investments by TVA’s management and Board of Directors that appear to overreach on recent power plant decisions rather than following a least-cost, least-risk plan. While TVA claimed that these decisions were consistent with the 2011 IRP, this capacity expansion policy was made concurrently with its failure to invest in energy efficiency and meet the commitments made in the 2011 TVA IRP. TVA’s recent decisions to depart from the 2011 IRP planning guidance have not been adequately justified.

TVA’s Draft 2015 IRP does not meet the standard of taking all cost-effective steps to help families and businesses reduce their energy bills. In its 2011 IRP, TVA promised to become a regional leader in energy efficiency, but this has not occurred. Instead, TVA cut its energy efficiency budget and is stalled at one-third of its 2011 IRP goal. Even though the Draft 2015 IRP prompts TVA to resume program growth, the plan both falls significantly short of 2011 targets and fails to rely on best industry practices, especially in terms of growth caps and excessively high program cost assumptions.

While it was reasonable for TVA to restrict the annual growth in energy efficiency programs at some level, utilities across the Southeast and the nation have recorded multiyear periods of annual growth rates that substantially exceed the restrictive caps used by TVA. TVA’s recent sensitivity analyses show that these growth caps on low-cost energy efficiency resources drive up system costs. TVA’s Draft 2015 IRP assumes that program growth will cause TVA’s energy efficiency costs to skyrocket, which is contrary to other utilities’ experience. Assuming energy efficiency costs will skyrocket results in choosing too little energy efficiency and overstating costs for the energy efficiency that is chosen in the modeling process.

TVA’s Draft 2015 IRP does not demonstrate awareness of, and progress towards, emerging renewable energy opportunities that would lower its costs and risks. While the Draft IRP supports a reasonable growth rate for solar resources (roughly 2,000 MW), the planning staff has taken a skeptical posture towards recent low-cost solar deals, dismissing the broad market for low-cost solar power as an anomaly. We are even more disappointed with the response to data on the wind power market: TVA's Draft IRP relies on inflated cost assumptions and outdated technology assumptions, resulting in little to no wind development and suggesting that TVA may soon exit the wind market entirely at the very time when other Southeastern utilities are deepening their investment. This is particularly problematic given that TVA's sensitivity analyses show that if TVA accepts the availability of cheap, plentiful and reliable wind energy (particularly Clean Line), then wind resources will drive down customer costs and rates, becoming one of TVA's leading energy resources as soon as the project can be completed.