cleanenergy.org
Southern Alliance for Clean Energy

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1.866.522.SACE
www.cleanenergy.org

P.O. Box 1842
Knoxville, TN 37901
865.637.6055

46 Orchard Street
Asheville, NC 28801
828.254.6776

250 Arizona Avenue, NE
Atlanta, GA 30307
404.373.5832

P.O. Box 310
Indian Rocks Beach, FL 33785
954.295.5714

P.O. Box 13673
Charleston, SC 29422
843.225.2371

Matthew Higdon
NEPA Compliance
mshigdon@tva.gov
400 West Summit Hill Drive, WT 11D
Knoxville, TN 37902

Re: Comments regarding the TVA draft 2018 Environmental Assessment regarding the proposed rate structure change

Dear Mr. Higdon,

On behalf of the Southern Alliance of Clean Energy (SACE), we submit these comments in response to the Tennessee Valley Authority's (TVA) draft Environmental Assessment for its 2018 Rate Change (hereinafter referred to as "Draft 2018 Rate EA"). Not only is the Draft 2018 Rate EA inconsistent with statutory requirements laid out in the TVA Act, it also fails to meet National Environmental Policy Act (NEPA) procedural and substantive requirements. Most importantly, TVA offers scant documentation to support the purpose and need for its preferred alternative in the Draft 2018 Rate EA and has failed to undertake the required environmental and economic impact analysis. TVA's Draft 2018 Rate EA runs counter to TVA's mission to provide the lowest possible rates to its residential electric customers and continues TVA's practice of beneficial rate treatment for its large industrial customers.

SACE is a regional organization that promotes responsible energy choices to ensure clean, safe and healthy communities throughout the Southeast. SACE's members are concerned by the short public input timeline, the lack of transparency and TVA's failure to provide sufficient information to support its preferred alternative in the Draft 2018 Rate EA. TVA has failed to provide its ratepayers adequate time to engage around the rate structure proposals contained in the Draft 2018 Rate EA. In contrast, industrial customers and local power companies (LPCs) have enjoyed extensive opportunities to discuss potential rate structure changes with TVA in dozens of private meetings taking place for over a year. Despite holding private meetings with members of other customer classes, TVA has not held *any* public hearings around the Draft 2018 Rate EA. In fact, TVA denied a formal request from SACE and others to extend the comment period and host public hearings.

The Draft 2018 Rate EA misleads the public on the potential adverse impacts of the Grid Access Charge (GAC) for small commercial and residential customers and, particularly, low-income households. If implemented, the preferred alternative supported in the Draft 2018 Rate EA would result in disincentives for economic energy technologies and continue the trend of shifting electric generation costs away from industrial customers and onto residential customers. For the reasons laid out below, TVA should withdraw its Draft 2018 Rate EA and complete a full Environmental Impact Statement (EIS) in order to comply with the requirements of NEPA.

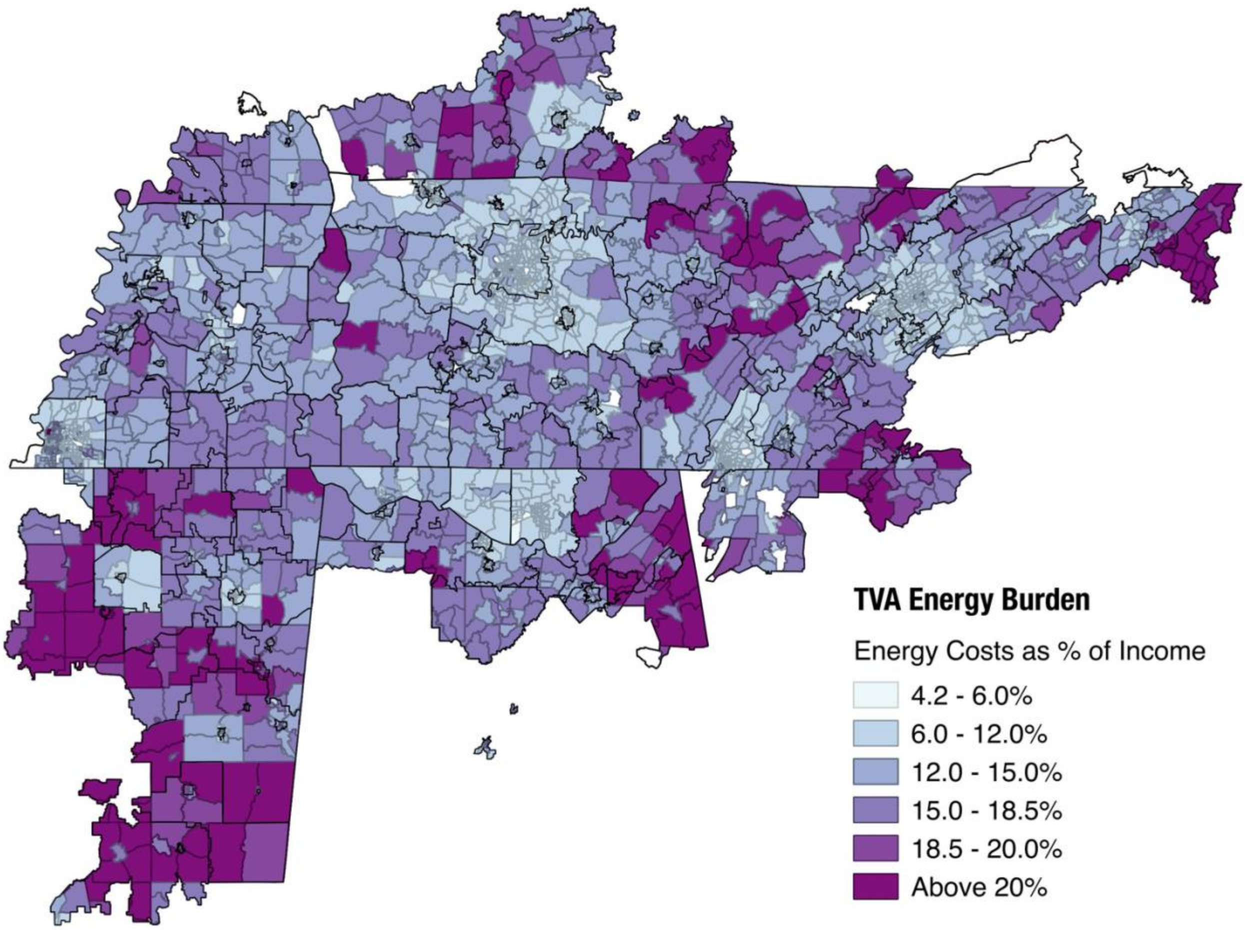
I. Introduction

TVA's proposed 2018 rate structure change includes a new GAC that is unnecessary and harmful. This policy is inconsistent with the TVA Act[1], as are other actions taken under TVA's 8-year "Strategic Pricing Plan." TVA is specifically mandated to provide electric power to "domestic and rural consumers to whom the power can economically be made available…."[2] The Act continues by specifying that the "sale to and use by industry" of electricity generated by TVA "shall by a *secondary* purpose" (emphasis added).[3] Rather than favoring industrial customers, as has been TVA's practice in recent history, Congress intended TVA to "permit domestic and rural use at the lowest possible rates and in such manner as to encourage increased domestic and rural use of electricity."[4]

Rather than focusing on providing the lowest possible costs to residential customers, TVA appears to be purposefully creating disincentives that reduce the economic benefits and customer choice regarding Distributed Energy Resources (DER). The proposed wholesale and retail rate structure changes related to the GAC are intended to suppress investment in solar power by TVA's larger commercial and industrial customers. TVA anticipates that implementation of the preferred alternative in the Draft 2018 Rate EA will result in a 60% decrease in solar investment. Only a few TVA customers - no more than 2% - are anticipated by TVA to invest in solar power.

[1] Tennessee Valley Act of 1933, 48 Stat. 58-59, 16 U.S.C. sec 831j.
[2] *Id.*
[3] *Id.*
[4] *Id.*

TVA's determination to favor industrial customers over residential customers is especially frustrating given that over 40% of the households in TVA's residential service territory fall within federal limits to be defined as low income. [5] These lower income customers are most likely to be significantly harmed by TVA's proposed GAC. On average, lower-income customers use 10% less energy than higher energy than higher income customers and have an average "energy burden" – defined as the percentage of annual household income spent on energy costs - of 12.6% of household income towards their energy bills. This means TVA's low-income residential customers have energy burdens that are four times the national average.



Source: Low-Income Energy Affordability Data (LEAD) census tract raw data.

[5] U.S. Department of Housing and Urban Development income guidelines define 'low income' as households earning at or below 80% of area median income (AMI). These limits are used as eligibility criteria for programs that address issues of housing affordability, including energy costs.

Because the retail rate structures that TVA's GAC will promote are intended to encourage load growth, benefitting customers with higher energy usage, TVA's lower-income residential customers will be disproportionately impacted. Depending on the retail rate structure and ultimate level of the GAC, these customers will see their energy burden increase by between 0.1% and 1.9% system wide. At the LPC level, the *average* impact on lower-income households could be as much as 2.8% of their annual household income. Minority households, the elderly, and renters will be the most disproportionality impacted customers under TVA's proposed rate structure in the Draft 2018 Rate EA.[6]

Specifically, SACE objects to the proposed GAC at any of the proposed levels. SACE also objects to raising standard service rates to enable a decrease in large general service rates, and instead recommends that TVA evaluate increasing large manufacturing service rates and reducing standard service rates as part of a rate change to realign cost recovery more equitably across classes.

TVA's heavy-handed proposal to suppress customer investment in solar power is also poorly aimed, targeting 40% of TVA's lowest-income customers resulting in potentially large increases to families' electric bill. Considering these substantive shortcomings, as well as the legal and procedural flaws, TVA should withdraw its Draft 2018 Rate EA and engage in a broad dialogue about its priorities and future as a utility. This dialogue should include engagement through, but not limited to, TVA's Distributed Energy Resources Integrated Resource Plan and TVA's 2019 Integrated Resource Plan (IRP).

II. TVA's Draft 2018 Rate EA Does Not Comply with NEPA Regulations

The rate structure changes proposed in TVA's 2018 Rate EA represent a major federal action significantly affecting the human environment. Based on NEPA's statutory directives, Council of Environmental Quality (CEQ) regulations and TVA's own NEPA guidelines, TVA must prepare an EIS following a full public comment process before deciding what action to take regarding its Draft 2018 Rate EA.

[6] U.S. Census Bureau's Public Use Microdata Samples (PUMS) of responses from the American Community Survey (ACS) indicate that these types of households residing in the statistical geographic areas in TVA's territory experience higher energy burdens than the average customer.

A. TVA's Proposal Represents a Major Federal Action and Requires an EIS

NEPA is "our basic national charter for protection of the environment."[7] Other environmental statutes focus on a particular section of the environment, like air, water, or land, specific natural resources, such as wilderness areas or endangered species, or discrete activities, such as mining or disposing of hazardous substances. In contrast, NEPA applies broadly "to promote efforts which will prevent or eliminate damage to the environment."[8]

To accomplish this expansive goal, NEPA requires that government agency decision-makers consider and weigh the environmental consequences of proposed actions "at the earliest possible time to insure that planning and decisions reflect environmental values, to avoid delays late in the process, and to head off potential conflicts."[9] "[B]y focusing the agency's attention on the environmental consequences of a proposed project, NEPA ensures that important effects will not be overlooked or underestimated only to be discovered after resources have been committed or the die otherwise cast."[10] Whereas the substantive environmental protection goals of NEPA provide some flexibility and responsible exercise of agency discretion, NEPA "also contains very important 'procedural' provisions—provisions which are designed to see that all federal agencies do in fact exercise substantive discretion given to them."[11] NEPA's procedural protections "are not highly flexible. Indeed, they establish a strict standard of compliance."[12]

The EIS is the centerpiece of the NEPA process and the principal tool for insuring that agencies fulfill both NEPA's substantive and procedural requirements. NEPA directs federal agencies, like TVA, to provide a coordinated public process and to prepare a detailed EIS for "every recommendation or report on proposals for legislation and other major Federal actions significantly affecting the human environment."[13] The requirement to prepare an EIS fulfills two of NEPA's essential mandates. First, it "ensures that the agency, in reaching its decision, will have available and will carefully consider detailed information

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[7] 40 C.F.R. § 1500.1(a).
[8] NEPA § 2, 42 U.S.C. § 4321.
[9] 40 C.F.R. 1501.2; s*ee* NEPA § 102, 42 U.S.C. § 4332; *see also* 40 C.F.R. § 1501.1(a).
[10] *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 349 (1989); *see also Jones v. District of Columbia Redev. Land Agency*, 499 F.2d 502, 512 (D.C. Cir. 1974), *cert. denied*, 423 U.S. 937 (1975) ("NEPA was intended to ensure that decisions about federal actions would be made only after responsible decision-makers had fully adverted to the environmental consequences of the actions, and had decided that the public benefits flowing from the actions outweighed their environmental costs.").
[11] *Calvert Cliffs Coord. Comm., Inc. v. Atomic Energy Comm'n*, 449 F.2d 1109, 1112 (D.C. Cir. 1971), *cert. denied*, 404 U.S. 942 (1972).
[12] *Id*.
[13] NEPA § 102(2)(C); 42 U.S.C. § 4332(2)(C).

concerning significant environmental impacts" before committing resources to a course of action.[14] Second, "[p]ublication of an EIS, both in draft and final form, also serves a larger informational role. It gives the public the assurance that the agency 'has indeed considered environmental concerns in its decision making process,' and, perhaps more significantly, it provides a springboard for public comment."[15] Where an agency is uncertain whether an EIS is required for a proposed action, it may first develop a concise public document known as an Environmental Assessment (EA) to help resolve the question and as an aid in preparing an EIS. But the decision whether to prepare an EIS "is not committed to the agency's discretion."[16]

In addition to the inadequate comment period and the lack of public hearing, the Draft 2018 Rate EA does not adequately support TVA's proposal to add a new wholesale fixed fee and is insufficient to meet the requirements under the NEPA. As explained in more detail below, TVA fails to adequately analyze socio-economic and environmental impacts of decreased reliance on energy efficiency and renewable DER, like solar. TVA should withdraw its current Draft 2018 Rate EA and conduct a full EIS that fully analyzes all of the environmental and economic impacts required by NEPA.

B. TVA Draft 2018 Rate EA Fails to Analyze Full Range of Environmental Impacts

A bedrock principle of NEPA law is that an agency must consider the entirety of a project, and may not regard a mere subset of an overall project. Accordingly, TVA must include analysis of all actions that are "connected" or "similar" to the proposed action and must consider impacts of all "cumulative" actions involved in completing the goal of the project. Under NEPA, actions must be considered together if, for example, one action "[a]utomatically trigger[s]" another, one action "[c]annot or will not proceed unless" another action is "taken previously or simultaneously" or the actions "[a]re interdependent parts of a large action."[17] Such actions must be considered together as part of a proper NEPA analysis. In other words, "[a]n agency may not

[14] *Robertson*, 490 U.S. at 349.
[15] *Id.*; *see also Citizens for a Better Henderson v. Hodel*, 768 F.2d 1051, 1056 (9th Cir. 1982) (the "form, content and preparation [of the EIS] foster both informed decision-making and informed public participation"); 40 C.F.R. § 1502.1 (purpose of EIS is to "provide full and fair discussion of significant environmental impacts and . . . [to] inform the decision makers and the public of the reasonable alternatives which would avoid or minimize adverse impacts . . .").
[16] *Foundation for N. Am. Wild Sheep v. Dept. of Agric.*, 681 F.2d 1172, 1177, n. 24 (9th Cir. 1982).
[17] 40 C.F.R. § 1508.25(a)(1); *see also* 40 C.F.R. § 1508.27(b)(7) ("Significance cannot be avoided by . . . breaking [an action] down into small component parts.").

segment a project into smaller projects . . . simply to expedite the NEPA process or avoid addressing environmental impacts."[18]

Likewise, under NEPA an agency is required to include "connected actions," "cumulative actions," and "similar actions" in a project EA.[19] "Connected actions" include those actions that are "interdependent parts of a larger action and depend on the larger action for their justification."[20] "Similar actions" are ones that "when viewed with other reasonably foreseeable or proposed agency actions, have similarities that provide a basis for evaluating their environmental consequences together, such as common timing or geography."[21]
In preparing an EA or EIS, an "agency need not foresee the unforeseeable, but . . . [r]easonable forecasting and speculation is . . . implicit in NEPA, and we must reject any attempt by agencies to shirk their responsibilities under NEPA by labeling any and all discussion of future environmental effects as 'crystal ball inquiry.'"[22]

While the statute does not demand forecasting that is "not meaningfully possible," an agency must fulfill its duties to "the fullest extent possible."[23] An agency impermissibly "segments" NEPA review when it divides connected, cumulative, or similar federal actions into separate projects and thereby fails to address the true scope and impact of the activities that should be under consideration.[24] The Supreme Court has held that, under NEPA, "proposals for . . . actions that will have cumulative or synergistic environmental impact upon a region . . . pending concurrently before an agency . . . must be considered together. Agencies must provide meaningful analyses of the cumulative impacts of projects that are connected, contemporaneous, closely related and interdependent of the project at issue in the NEPA analysis.[25] Only through comprehensive consideration of pending proposals can the agency evaluate different courses of action."[26]

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[18] *W. N.C. Alliance v. N.C. Dep't of Transp.*, 312 F. Supp. 2d 765, 774-75 (E.D.N.C. 2003).
[19] 40 C.F.R. § 1508.25(a).
[20] *Id.* § 1508.25(a)(1)(iii).
[21] *Id.* § 1508.25(a)(3)
[22] *Scientists' Inst. for Pub. Info., Inc. v. Atomic Energy Comm'n*, 481 F.2d 1079, 1092 (D.C. Cir. 1973).
[23] *Id.*
[24] *Delaware Riverkeeper Network, et al v. Federal Energy Regulatory Commission*, at 5, available at http://www.troutmansandersenergyreport.com/wp-content/uploads/2014/06/Tennessee-Gas-Opinion.pdf at 15.
[25] "Given the self-evident interrelatedness of the projects as well as their temporal overlap, the Commission was obliged to consider the other three other Tennessee Gas pipeline projects when it conducted its NEPA review of the Northeast Project." Delaware Riverkeeper Network, et al v. Federal Energy Regulatory Commission, at 5.
[26] *Kleppe v. Sierra Club*, 427 U.S. 390, 410 (1976).

i. TVA Fails to Properly Assess Socio-Economic Impacts

In the Draft 2018 Rate EA, TVA does not adequately address socio-economic impacts of any of its alternatives. To the extent TVA attempts to address socio-economic impacts, TVA continually contradicts itself when categorizing potential negative effects on minority or lower-income residential customers as alternately uncertain or conclusively negligible. For example, TVA first claims that "no particular minority or other socioeconomic group would bear a disproportionate share of negative effects." Later in the document, TVA admits, however, that "the potential impacts of (its preferred Alternative) Alternative C to [LPC] customers is difficult to assess precisely." Yet, TVA goes on to admit that "each alternative has the potential to slightly increase the monthly bill for a majority of residential customers." In fact, TVA claims residential customers who have a high usage would see a decrease in their average monthly bills, while low-usage households would see increases in average monthly bills. Taken together, these statements show that even while claiming that any impact would be insignificant, TVA has not done the appropriate analysis to determine actual impacts to residential customer bills.

The impacts are also uncertain because TVA has never produced a clear analysis of the impacts of recent rate structure changes implemented under its Strategic Pricing Plan. TVA enhances this uncertainty by failing to provide details such as the new Fuel Cost Adjustment method and the proposed "rebalancing" hydro allocation credits. TVA states that the "exact amounts of the rebalancing cannot be determined until after June 30, 2018." Ignoring already existing compounding factors, and then proposing additional changes that will further compound deleterious effects on ratepayers without analysis, because such analysis is "too difficult," does not alleviate TVA from its responsibilities under NEPA.

TVA's private conversations with LPCs and direct serve industrial customers include substantial evidence that TVA, in fact, believes that the changes it proposes will be extended and eventually have a substantial impact on DER, energy efficiency, and other aspects of customer generation. Yet TVA ignores the significant impact the proposed rate structure changes would have on TVA's generation mix over time and the resultant environmental impacts. Evidence suggests that if implemented, these rate structure changes would result in a 40% decrease in growth of DER in TVA's service territory. This means that TVA would be relying more heavily on electric generating units that negatively impact the environment and public health. Yet TVA has concluded hastily that its Draft 2018 Rate EA, under any alternative, would have minimal or negligible impacts on the environment. In order to meet NEPA requirements, TVA must undertake full EIS analysis of all potential impacts on the environment and public health caused by a decrease reliance on DER resources.

ii. <u>TVA Severely Underestimates or Ignores Environmental Impacts of Proposed Grid Access Charge</u>

It is unclear from TVA's supporting documents whether the ultimate goal of a 40% or 60% reduction in DER investment at commercial facilities is associated with the 1 cent per kWh GAC or the "roadmap" goal of 2.5 cents per kWh. Assuming that the larger reductions are associated with the overall "roadmap" goal, it is clear that the overall purpose of TVA is to substantially deter the development of clean energy resources not undertaken under utility control.

As discussed below, the actual impact of the GAC on DER investment will depend on retail rate design. TVA carefully raises this issue without resolving it in the Draft 2018 Rate EA - effectively deferring any actual impacts to future actions that it does not believe to be within the scope of this Draft 2018 Rate EA. In doing so, TVA is repeating a pattern of taking actions at the wholesale level that trigger harmful actions at the retail level, but hiding behind a fig leaf of "uncertainty."

It should be evident that deterring DERs would result in less solar generation, energy efficiency and other forms of clean, emission-free DER on TVA's system. Thus, it is highly likely that TVA's proposed actions and overall intent is to maintain fossil fuel generation at a higher level than would be the case if DERs were deployed by customers. This would have substantial air, water, and human health impacts, none of which are adequately analyzed or identified in the Draft 2018 Rate EA.

iii. <u>TVA Fails to Properly Analyze Impact of Proposed Grid Access Charge On Commercial and Industrial Customers</u>

TVA claims that the Draft 2018 Rate EA is intended to "improve the alignment of wholesale rates with their underlying costs to serve …" But as documented extensively in TVA's Strategic Pricing Plan communications over the past several years, TVA's proposed GAC serves two additional purposes: to discourage energy efficiency and DER and to perpetuate and expand a hidden subsidy to large industrial customers.

Notably, TVA may not even believe that these three purposes can be simultaneously achieved. In discussions with the Tennessee Valley Public Power Association's (TVPPA) Rates and Contracts Committee on July 6, 2017, TVA acknowledged that there is a conflict between rate alignment and reducing incentives to solar.

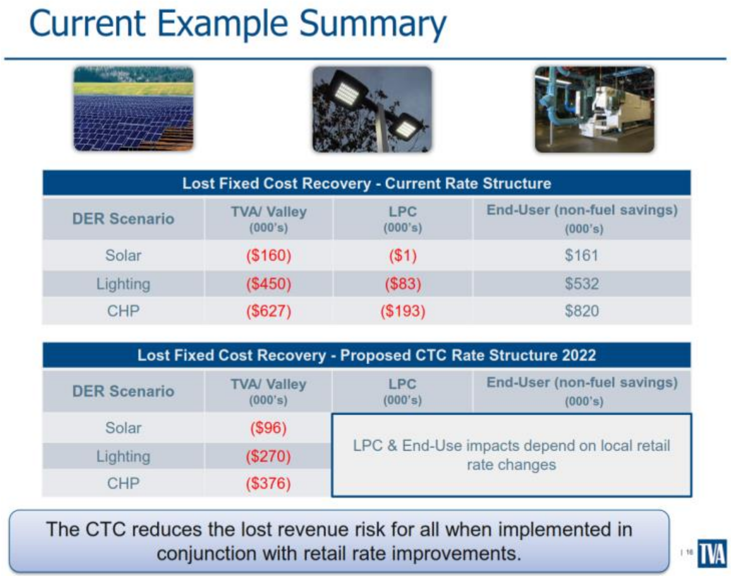
Rate Alignment and DER

- If LPCs better align their retail rates to wholesale with TOU pricing, as TVA proposes, this will increase their summer on-peak pricing, increasing incentives to solar, not mitigating
- TVA: That's true; under existing wholesale energy prices there is a conflict between incentives to DER and rate alignment. That's why TVA wants to reduce wholesale energy prices: LPCs can go to TOU pricing for GSA-2 & 3, better align their retail rates and not increase DER incentives
- At present, many LPCs could benefit financially from solar because they sell fewer kWhrs at a loss; TVA wants to remedy that "perverse incentive" by lowering wholesale energy prices
  - LPCs shouldn't benefit from solar due to retail/wholesale price mismatches
- TVA will lay out which is more important: fixing misalignment or DER incentives

Source: TVPPA, Report to the Membership (July, 2017).

Yet in many presentations to TVPPA committees and others, TVA has made it very clear that this 2018 Draft 2018 Rate EA is intended to address "cost shifting" that it anticipates might occur as customers invest in energy efficient technologies. In spite of this clear intent, TVA misleads the public by failing to include any meaningful estimates of the impact of customer investment in solar, energy efficiency, and other new technologies in its Draft 2018 Rate EA. For example, TVA skims over potential impacts on energy efficiency, and leaving a purposefully strong impression that the proposed GAC is a response to customer investments in DER generation like solar, rather than energy efficiency. TVA completely leaves out energy efficiency when it states, "[s]ome DER are based on fossil fuels, but the vast majority is solar or other clean renewable energy."

However, energy efficiency is clearly one of the threats to TVA's "fixed cost recovery" that the GAC is intended to address. In a presentation to the TVPPA Rates and Contracts Committee in March 2017, TVA gave three technology examples associated with the "cost shifting" that it seeks to discourage through the GAC, including installations at commercial facilities of solar, efficient lighting and combined heat and power generation (CHP), which is typically only installed at commercial or industrial facilities.



Current Example Summary

Lost Fixed Cost Recovery - Current Rate Structure			
DER Scenario	TVA/ Valley (000's)	LPC (000's)	End-User (non-fuel savings) (000's)
Solar	($160)	($1)	$161
Lighting	($450)	($83)	$532
CHP	($627)	($193)	$820

Lost Fixed Cost Recovery - Proposed CTC Rate Structure 2022			
DER Scenario	TVA/ Valley (000's)	LPC (000's)	End-User (non-fuel savings) (000's)
Solar	($96)	LPC & End-Use impacts depend on local retail rate changes	
Lighting	($270)		
CHP	($376)		

Source: TVA, Presentation to TVPPA Rates and Contracts Committee (March 21, 2017).

As illustrated in this presentation to TVPPA, TVA expects the benefits of energy efficient lighting to be greatly diminished as a result of adopting a GAC (referred to as a "CTC" in the slide above). TVA's presentation does not address why a customer who voluntarily chooses to install more efficient lighting in their home or business facility must continue to pay for non-fuel generation costs, as if that customer was continuing to use the older, less efficient lighting. Nowhere in TVA's presentation materials was there analysis of the extent to which or how customer investments in efficient lighting are "uneconomic."

In fact, TVA has previously found that energy efficiency investments are economic. In its 2015 IRP, TVA concluded that it should achieve energy efficiency savings between 900 and 1,300 MW by 2023.[27] TVA states its intention and "work with LPCs to refine delivery methods, program designs and program efficiencies, with the goal of lowering total cost and increasing deliveries of efficiency programs."[28] Now in this Draft 2018 Rate EA, TVA contradicts its own analysis, presuming that customer investment in efficient lighting technologies may have undesirable economic impacts.

TVA's new position on energy efficiency has not often been shared publicly. One exception are remarks made by Jay Stowe, TVA's Senior Vice President for Distributed Energy Resources, at the October 2017 Southeast Energy Efficiency Alliance conference, in which Mr. Stowe stated that it is TVA's intent to phase out all incentives for customer installation of energy

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[27] Tennessee Valley Authority 2015 Integrated Resource Plan at 4.
[28] *Id.*

efficient products. While made at a public meeting, it is SACE's understanding that TVA either failed or refused to allow distribution of Mr. Stowe's presentation materials or any other documents referencing or supporting Mr. Stowe's remarks.

In addition to misdirecting readers to focus mainly on solar DER generation to the exclusion of other DERs like energy efficiency, the Draft 2018 Rate EA creates a misleading impression of potential impacts. Nowhere does TVA estimate the degree to which its preferred alternative would mitigate the alleged cost shifting caused by DER adoption. The Draft 2018 Rate EA includes the statement that "2 percent of its customers are likely to install solar photovoltaic systems by 2030," but does not provide the analysis used to reach that figure.[29] This number is somewhat greater than the figure reported in the 2015 IRP.

In contrast to this "2 percent" figure, in discussions with the LPCs, TVA suggests that the potential impact is about 5% of total generation and retail revenue before fuel. In several presentations to TVPPA committees, TVA claimed that non-fuel revenue loss could be up to $500 million if the known corporate and federal renewable energy goals are met, which would represent over 5% of the TVA system's total retail revenue before fuel.[30] This suggests that TVA expects its large users to be the majority of DER adopters, however this is difficult to assess without more information about the analysis TVA used to get these figures.

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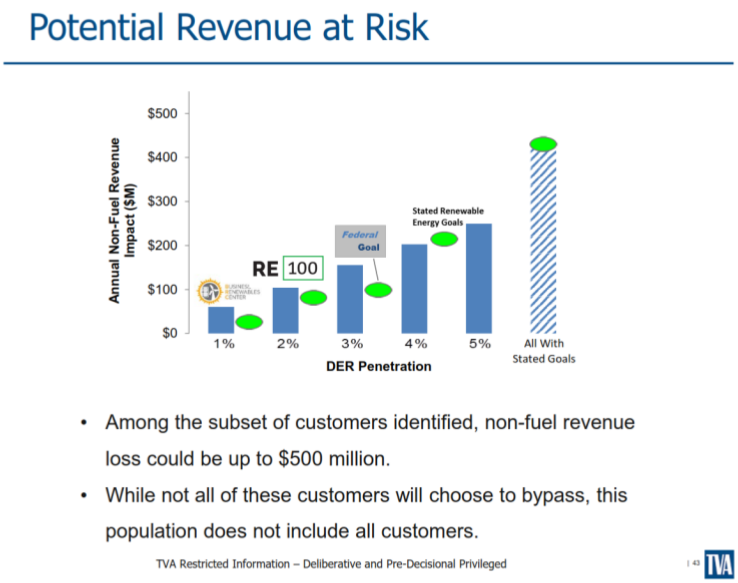
[29] TVA references this to a 2017 analysis, but does not include such a document in its "literature cited" or provide any support for this analysis in the draft assessment. This number is somewhat greater than the figure reported in the 2015 IRP.

[30] TVA's total retail revenue before fuel is about $9.7 billion. Source: TVA, presentation to TVPPA Rates & Contracts Committee (August 3, 2017), slide 63.



Source: TVA, Presentation to TVPPA Research, Analysis and Design Committee (March 7, 2017).

Taken at face value, the Draft 2018 Rate EA states that demand and DER adoption will not be significantly affected by its proposed actions. If that is the case, it should be relatively straightforward to estimate the amount of cost shifting that will occur under the no action alternative, and to what degree the other alternatives would reduce this cost shifting. The fact that TVA has not presented any such findings, but has clearly conducted such analysis, strongly suggests that TVA intends to move forward regardless of whether its policies have an impact on DER adoption.

In summary, TVA's Draft 2018 Rate EA indicates that the GAC and associated retail rate structure changes are a response to a 2% penetration rate of vaguely defined and inadequately quantified DER generation resources. However, other documents not included as part of this NEPA process indicate that TVA's actual concern is a potential 5% penetration rate of solar DER generation installed on-site at large commercial and federal government facilities. In addition, other proposed actions in the Draft 2018 Rate EA would perpetuate and expand a hidden subsidy to large industrial customers.

One other reason TVA may be pursuing the Grid Access Charge is, according to notes taken during a TVPPA webinar, that "Bill Johnson wants to take the For Sale sign off TVA." It is not clear from the notes just how TVA feels that this proposal would advance that goal.

iv. <u>The Draft 2018 Rate EA Misrepresents TVA's Analysis of the Impact of the Grid Access Charge on DER.</u>

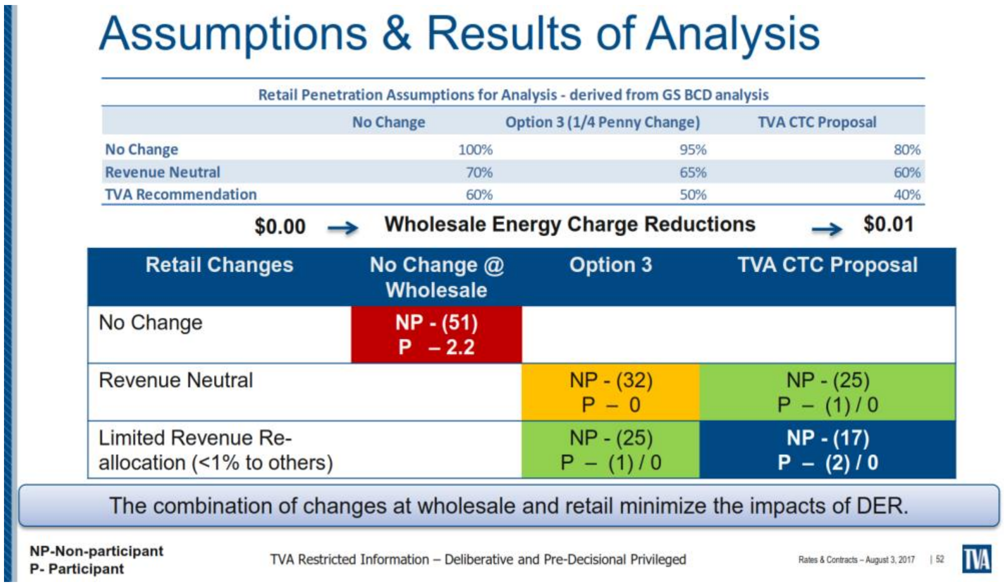
It is remarkable that TVA finds that nearly all of the environmental, socioeconomic, market and financial effects of its alternatives would be minimal and non-impactful, using terms such as "minor," "negligible," and "slowed marginally" in the Draft 2018 Rate EA. For example, TVA claims that, "under Alternative B, no change in the trend of DER adoption is expected, while under Alternatives C and D, it is expected that the penetration of DER may be slowed marginally." The only effect that TVA appears to find impactful would be the "cost shifting to nonparticipant consumers" due to DER investment. While neither the level of DER investments nor the amount of "cost shifting" is quantified in the Draft 2018 Rate EA (except as noted above), TVA nonetheless concludes that its preferred alternative (Alternative C) would address the concern of "cost shifting" without having any adverse effects.

In contrast, in various "confidential and proprietary" or "privileged" documents,[31] TVA presents a far more aggressive "case for change." Specifically, TVA expects the number of "economic installations" of on-site solar installations to decrease by about 40% as a result of the recommended rate restructuring.[32] Notably, TVA conducted an analysis that appears to show:

- Wholesale rates changed as recommended in the Draft 2018 Rate EA: Commercial (general service) DER penetration reduced by 20% (e.g., to 80% of the baseline level)
- Retail rates changed as recommended by TVA: Commercial DER penetration reduced by 40%
- Both Wholesale and Retail rates changed as recommended: Commercial DER penetration reduced by 60%

These findings were a core component of TVA's "case for change," that strongly contradicts the Draft 2018 Rate EA. educing commercial DER penetration by 60% is hardly "slowed marginally."

[31] Most documents with these designations were provided to SACE and others in response to FOIA requests. Others have been made public in the media.
[32] TVA, presentation to TVPPA Rates & Contracts Committee (July 6, 2017).



Source: TVA, Presentation to TVPPA Rates & Contracts Committee (August 3, 2017).

While a similar analysis of how retail and wholesale rate structure changes would affect residential DER, this example illustrates that it is retail rate structures that TVA views as the key to reducing future investment in DERs below projected levels.

C. TVA's Draft 2018 Rate EA Improperly Tiers Off Previous TVA NEPA Documents

TVA misleadingly claims its proposed rate and structure change "tiers" from its 2011 IRP Environmental Impact Statement and subsequent Supplemental Environmental Impact Statement (SEIS) for its 2015 IRP. In neither the 2011 IRP[33] nor 2015 IRP[34] documents, nor EIS or SEIS[35] documents, did *any* of the following issues arise:

- Fixed charges
- Declining block rates
- Cross-subsidization
- Customer classes
- Fuel Cost Adjustments

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[33] Tennessee Valley Authority (March 2011). Integrated Resource Plan TVA's Environmental & Energy Future. [http://152.87.4.98/environment/reports/irp/archive/pdf/Final_IRP_complete.pdf]
[34] Tennessee Valley Authority (March 2015). Integrated Resource Plan 2015 Final Report. [https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf]
[35] Tennessee Valley Authority (July 2015). Supplemental Environmental Impact Statement, 2015 Integrated Resource Plan. [https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/TVA%20Final%20Integrated%20Resource%20Plan%20EIS%20Volume%201.pdf]

In the 2015 IRP Final SEIS, TVA unequivocally stated, "[t]he IRP does not address rate design."[36] Consistent with that perspective, TVA actually referred related issues to its Distributed Generation Integrated Value initiative.[37] The DG-IV initiative is not referenced in the Draft 2018 Rate EA.

Furthermore, the Draft 2018 Rate EA does not indicate how it is linked to prior IRP documents. TVA does not specify which scenario(s), nor which strategy(ies), from the 2015 IRP are relied upon for its analysis in the Draft 2018 Rate EA. In its past two IRPs, TVA evaluated rate impact *solely* based on a volumetric value ($/MWh) and made *no* recommendation about structural rate changes. For example, the 2015 IRP states:

> In addition to computation of the total plan cost (PVRR) over the full 20-year study period, a 10-year system average cost metric was calculated. This metric provides an alternative view of the revenue requirements for the 2014-2023 timeframe expressed per MWh. *It is not intended as a forecast of wholesale or retail rates over the study period.* Rather, it was developed to gauge *the potential rate impact* associated with a given portfolio and provides *an indication of relative rate pressure* across the strategies being studied.[38]

Even in this Draft 2018 Rate EA, TVA states that "[i]n 2015, TVA, the Tennessee Valley Public Power Association and the Tennessee Valley Industrial Committee (TVIC) agreed on a direction to incrementally improve pricing signals and fixed cost recovery, as well as to encourage technology investment." If TVA began discussions with TVPPA and TVIC in 2015, there is no possible way that the 2011 EIS nor 2015 SEIS could have fully vetted a structural rate change discussion, given that those analyses occurred *before* TVA began its rate discussions with TVPPA and TVIC.

TVA relies heavily on the National Association of Regulatory Utility Commissioners (NARUC) manual for justifying the proposed changes. According to NARUC, however, "[t]he beginning of this Manual was in February 2016, when the drafting team first convened to talk about what the Manual should accomplish, what issues we needed to cover, how to start organizing the Manual, and assign responsibilities."[39] The final document was published in November 2016. Again, TVA cannot legitimately claim its 2011 IRP EIS and 2015 IRP SEIS

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[36] TVA 2015 SEIS p. 13.
[37] TVA 2015 SEIS p. 50.
[38] Tennessee Valley Authority (March 2015). Integrated Resource Plan 2015 Final Report. [https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/IRP/Documents/2015_irp.pdf]
[39] National Association of Regulatory Utility Commissions (November 2016). Distributed Energy Resources Rate Design and Compensation, A Manual. [https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0)

even touched upon the issues considered in this Draft 2018 Rate EA, when the supporting documentation was not yet in existence.

TVA improperly misappropriates the 2015 IRP as a pre-approval of any future decisions within the *entire* scope of the IRP. In the Draft 2018 Rate EA, TVA notes "that any potential changes to air emissions, including release of greenhouse gases, associated with Alternative C are easily bounded by analysis in its 2015 IRP." In the 2015 IRP, for example, projected carbon dioxide (CO_2) emissions range from 39.9 million metric tons to 59.7 million metric tons, but those values are not meant as an entirely acceptable range of possible air emissions for any future TVA action. As an integrated approach, IRP processes evaluate many inputs simultaneously to determine possible outcomes. What TVA is improperly suggesting and relying on in the Draft 2018 Rate EA is that *any* input from the 2015 IRP is *justification* for a future action.

Finally, TVA is currently undergoing a new IRP process specifically geared toward evaluating DER resources. A number of questions proposed in our comments, and a number of deficiencies in this Draft 2018 Rate EA, may be addressed in the TVA's 2019 IRP.

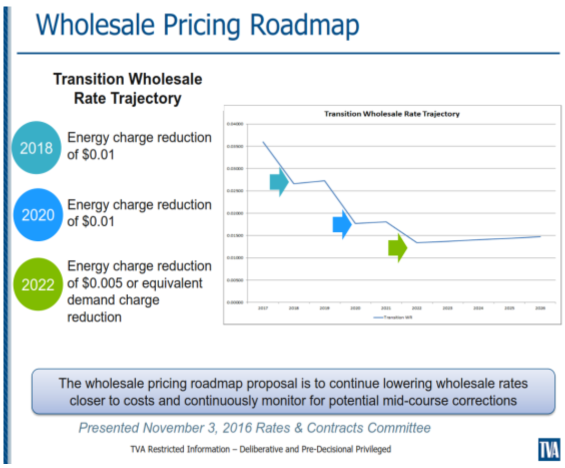
D. The Draft 2018 Rate EA Appears to Support Alternative Other than Preferred Alternative (Alternative C).

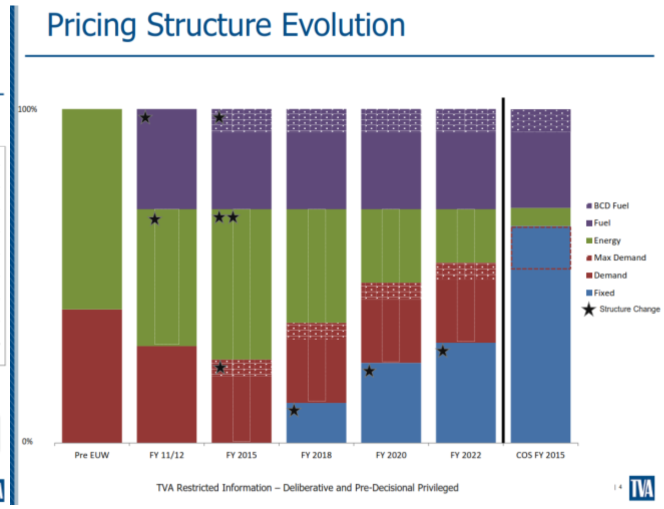
One key way that TVA obscures its intent to reduce customer investment in DERs is by focusing on Alternative C, a 1 cent per kWh shift from the energy charge to the GAC, and identifying it as its preferred alternative. However, as documented in a number of TVA presentations made in 2017, TVA expects its wholesale pricing structure to have a "trajectory" towards a shift of 2.5 cents per kWh, which is more similar to Alternative D. TVA is engaging in a disingenuous, and ultimately useless, NEPA process if it misrepresents or misidentifies its preferred alternative in the Draft 2018 Rate EA.

It appears most likely that TVA intends to use the Draft 2018 Rate EA as a basis for pursuing Alternative C in the short term, but Alternative D in the long term. In Table 1 of the Draft 2018 Rate EA, TVA summarizes the impacts of Alternative D using the exact same words as Alternative C - suggesting that a GAC that is 2.5 times that of Alternative C has exactly the same impact. It is easy to imagine members of the TVA Board being told that while this Draft 2018 Rate EA indicated Alternative C as its preferred alternative, the record also supports Alternative D and no further NEPA review is required.

Furthermore, in the pursuit of "alignment," TVA seems to suggest that the GAC may go even further than Alternative D. In the March 21, 2017 presentation slide titled "Pricing

Structure Evolution," TVA shows that its 2015 fixed costs would not be fully recovered through even a GAC of 2.5 c/kWh. With such confusing documentation and misleading information, the public is essentially robbed of the ability to be informed and engage effectively around the Draft 2018 Rate EA.





Sources: TVA, Presentation to TVPPA Research, Analysis and Design Committee (May 31, 2017); TVA, Presentation to TVPPA Rates & Contracts Committee (March 21, 2017).

E. TVA Failed to Consider All Reasonable Alternatives in its Draft 2018 Rate EA

Under NEPA regulations, an agency must consider all reasonable alternatives that fit that agencies purported purposed and need for any major federal agency action. In its Draft 2018 Rate EA, however, TVA failed to evaluate an alternative that would roll back rate preferences for industrial customers. Beginning in 2011, the structural rate changes in TVA's Strategy Pricing Plan have pushed TVA's LPCs to adopt retail rate structure changes. First, residential customers are paying higher overall electricity prices for residential customers than they were in 2011, even though TVA's overall electricity prices have gone down (See Appendix C and Attachment 3). Second, residential customers are paying vastly higher mandatory fees than they were in 2011 (See Appendix A).

Rolling back these changes would significantly benefit residential customers.[40]

- The average customer paid $109 more in 2016 for electricity as a result of the industrial rate shift. (See Appendix C and Attachment 3.)
- If the industrial rate shift were rolled back by restoring residential rates to the average rate trend since 2011, the energy burden for the average lower-income customers would

[40] Note that SACE anticipates this would also benefit small commercial customers, but due to the difficulty in separating out small commercial customers as a group in available data, we have not conducted supporting analysis.

be reduced by 0.5%. In some LPCs, the average lower-income customers would see their annual electricity bill reduced by 1.5% of household income.

- The average customer has had a 50% increase in monthly mandatory fees from 2010 to 2018, removing an increasing portion of residential electric bills from the ability of customers to control their bills.

As shown above, TVA's rate structure changes in 2010, 2013, 2015, and now proposed for 2018, have not fully examined these issues.

TVA should also have considered an alternative in which it encourages DER adoption by large customers. Analysis would be most appropriately completed during the resource planning process, with implementation through a rate structure change. TVA is justifying its rate change by an assumption that increased investment in DERs by its customers will increase system costs, but provides zero evidence to back up this claim. In a recent study, Lawrence Berkeley National Lab explored factors that drive retirement of power generation by region, and found that low load growth (particularly load contraction) and high reserve margins tend to have strong relationships with high retirements in a region.[41] If DERs do reduce load growth, as TVA infers in their Draft 2018 Rate EA, DER's would allow TVA to retire older, inefficient conventional power generation and thus reduce its cost to serve.

TVA should evaluate the costs of adding utility-scale and customer-sited DERs against the costs of retiring aging conventional power plants. Energy efficiency, which falls under the DER category, already undergoes extensive cost-benefit analysis in the TVA footprint and across the country, and holds up well against existing generation. So-called "value of solar" studies have been undertaken in many states or regions (including TVA), to comprehensively evaluate the benefits and costs associated with solar power. Across utilities, results have varied widely by methodology and input assumptions. TVA's *Distributed Generation - Integrated Value* only included some of the benefits of solar, and still resulted in a net benefit to the system for distributed solar.[42]

Including all of the benefits of distributed solar, such as the health benefits from reduced air pollutants and the economics benefits of local jobs, provide a more accurate understanding of how solar - and other DERs - potentially advance TVA's overall mission.

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[41] Andrew Mills, Ryan Wiser, Joachim Seel, *Power Plant Retirements: Trends and Possible Drivers*, LBNL November 2017, [https://emp.lbl.gov/sites/default/files/lbnl_retirements_data_synthesis_final.pdf]
[42] TVA, *Distributed Generation - Integrated Value (DG-IV), October 2015.*

Instead of considering customer interest in power sources to be an opportunity to provide improved customer service, TVA views claims corporate and military procurement of renewable energy resources as a risk to its business model. By restricting consumer programs and choice, TVA will create a self-fulfilling prophecy of customer abandonment.

TVA should have also considered an alternative in which it encourages residential DER adoption. Analysis would be most appropriately completed during the resource planning process, with implementation through a rate structure change. TVA has not made the case that residential DER adoption, including energy efficiency and rooftop solar, would result in a less cost-effective and reliable service. Such an analysis should be considered prior to adopting any policy changes, especially considering that such technologies could be substantially aided by a rate structure change. DER penetration is one of the three focuses that TVA has named for its 2019 IRP. The 2019 IRP development could be an effective process for considering whether a rate structure change to encourage DER adoption would result in lower overall system costs for TVA.

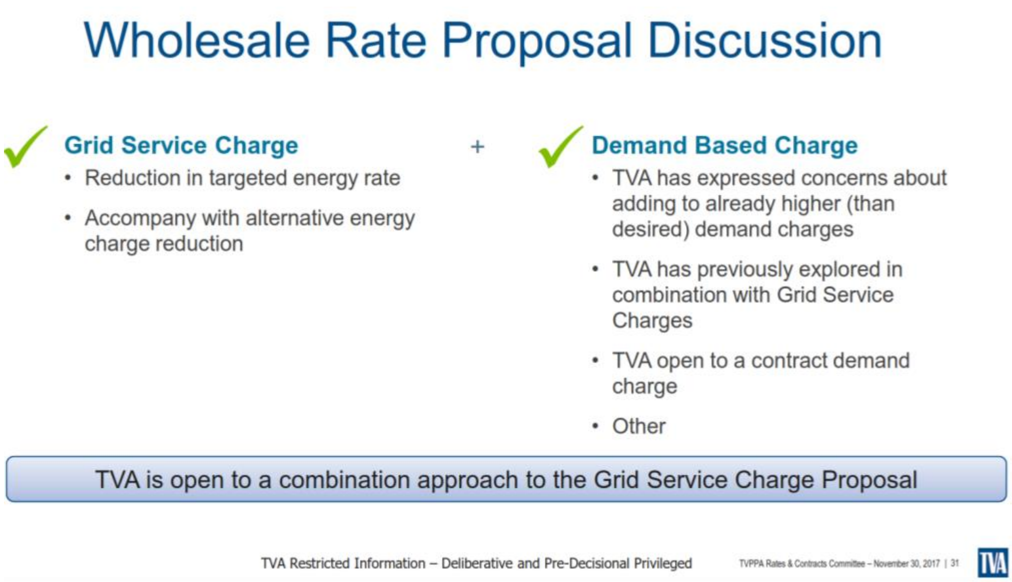
F. TVA Failed to Include Relevant Evaluations of Additional Alternatives to the Grid Access Charge

TVA provides three alternative GAC levels and a No Action alternative in the Draft 2018 Rate EA. As noted previously, there are a number of issues that TVA's rate change proposal does not address, including electric vehicle program development, other storage DERs, and fuel swapping. TVA's Draft 2018 Rate EA should also include discussion of the alternative approaches to the specific GAC TVA evaluated and presented to TVPPA during Strategic Pricing Plan discussions.

TVA evaluated at least five other wholesale rate alternatives that did not include a GAC, which is referred to in this table as a "competitive transition charge." At least one of these was heavily favored by a number of LPCs. While we were able to review presentation materials that discussed the pros and cons of these options, the materials were not fully descriptive of the designs that were evaluated and it was not entirely clear what the different opinions were regarding their adoption.

Source: TVA, TVPPA Research, Analysis, and Design Committee Meeting, "Strategic Pricing Plan", February 7, 2017

As late as November 2017, TVA wrote that it was "open to a combination approach" that would involve a demand based wholesale rate design. But this "combination approach" is not among the alternatives considered in the Draft 2018 Rate EA.



Source: TVA, TVPPA Research, Analysis, and Design Committee Meeting, November 17, 2017.

TVA also appears to have considered a number of retail rate structure design alternatives to the declining block rate discussed in the Draft 2018 Rate EA. TVA appears to have postponed the development of "default rates" until after the wholesale rate structure issue is resolved.

However, there is no language in the Draft 2018 Rate EA committing TVA to bringing forward the default rate structure or any other policy changes that may be made following its decision on the GAC.

Beyond programs and rate design alternatives that were not considered, TVA also did not consider generation-based changes such as retirements, reduction of reserve margins, or potentially transmission-based solutions that would reduce overall operating and fixed costs for the system as a whole. Larger, long-term structural changes that have not been evaluated include privatization, joining a regional transmission organization, allowing LPC's to procure alternative generation resources, or customer acquisitions.

G. TVA Inadequately Supports Underlying Needs of its 2018 Draft Rate EA

Despite claiming that increased penetration of DER on TVA's system is one of the primary reasons TVA needs to revisits its rate structure, TVA barely analyzes DER investment by residential customers. To the extent that TVA quantified DER penetration in its service territory, the impacts on TVA's system generation were forecast to be small. As noted above, TVA conducted quantitative analysis of DER investments by commercial customers and shared that information with TVPPA committees in "deliberative and pre-decisional privileged" materials. However, nowhere in the materials provided to SACE did we see any quantitative analysis of DER investment by residential customers.

TVA did analyze residential solar implementation in its 2015 IRP, but did so only in combination with commercial (non-industrial) scale distributed generation. As illustrated below, TVA found a range of 815 to 4,000 MW of potential distributed solar by 2040.

TVA IRP Scenarios*	Impact of TVA RS-CO DG by 2040		
	Reduction in TVA load	Cumulative Capacity Growth (MW dc)	Avg. Annual Capacity Growth (MW dc)
Stagnant Economy	~0.6%	~815	~31
Distributed Marketplace	~3.0%	~4,000	~154
Growth Economy	~2.0%	~3,050	~117
De-carbonized Future	~2.5%	~3,315	~127

* Projections for renewable DG under our current outlook do include some portion of renewable DG penetration as part of the load forecast, however they are based off historical implementation levels only (not future projections) and are limited in magnitude.

Figure C-5: Residential/Commercial DG Adoption Levels (by 2040)

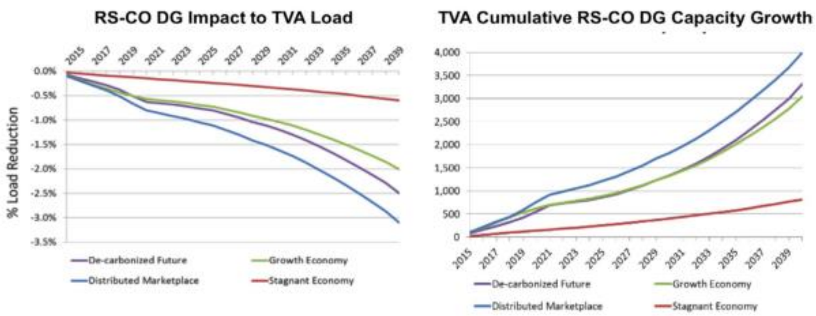


Figure C-6: Residential/Commercial DG Adoption Levels (Annual)

Source: TVA, *Integrated Resource Plan: 2015 Final Report* (July 2015).

Considering these findings, and the indications that TVA did not analyze residential DER in preparation for the Draft 2018 Rate EA, it is reasonable to assume that TVA does not have data that suggests residential solar DER would reduce TVA load by more than 1% over the next decade.

TVA claims that its proposed structural rate change is aimed to stabilize its finances, and address reduced customer consumption. However, TVA has made no apparent adjustments to its models, programs, or estimates regarding the implications of all DER technologies on its operations, particularly electric vehicles. According to a recent report from the Smart Electric Power Alliance (SEPA), "Utilities have generally taken a conservative approach to electric vehicle (EV) deployment, despite forecasts that EVs' annual energy consumption will rise from a few terawatt-hours (TWh) a year in 2017 to at least 118 TWh and potentially as high as 733 TWh by 2030. According to SEPA research, many utilities may be caught unprepared."[43] By developing new programs, specifically for electric vehicles, TVA would develop a new source of revenue, likely to be led by its Standard Service ratepayer class.

[43] Smart Electric Power Alliance (March 2018). Utilities and Electric Vehicles, Evolving to Unlock Grid Value. [https://sepapower.org/resource/utilities-electric-vehicles-evolving-unlock-grid-value/]

Another problem with TVA's overall "case for change" is that it fails to consider the dynamics of the solar plus battery storage. In 2015, RMI studied the impacts of load defection under net metering (NEM) policies. RMI found that monthly mandatory fees delay the adoption rate of customer-based solar-plus-storage in the near-term, but that mandatory fees actually create a steeper tipping point for adoption of these systems in the longer term. As mandatory fees increase and installation costs decline, the two will eventually meet, at which grid defections are likely to increase more quickly than under the low/no fixed charge scenario. The RMI report explains:

> "Though we didn't specifically model other scenarios, our quantitative findings with NEM are useful for qualitatively considering other possibilities, such as recent proposals to introduce more significant residential fixed charges to utility customers' bills. Similar to our "with" and "without" NEM scenarios, residential fixed charges would likely alter (i.e., delay) the economics for grid-connected solar and solar-plus-battery systems, but likely wouldn't alter the ultimate load defection outcome. Customers might instead wait until economics and other factors reach a tipping point threshold and more dramatically "jump" from grid dependence to off-grid solar-plus-battery systems that offer better economics for electric service. "[44]

INFLUENCE OF RATE STRUCTURE ON SOLAR-PLUS-BATTERY ECONOMICS

	FIXED	CURRENT	VOLUMETRIC
Structure of potential rate	Single fee for use ($/month)	three-part rate ($/kWh, $/kW, $/month)	Priced per consumption ($/kWh)
Timing of parity for grid-connected solar-plus-storage systems	Up to 15 years later (coincident with timeline for grid defection)	*The Economics of Load Defection* Reference Case	Up to 7 years earlier
Likely customer behavior	Defer DER investment until off-grid parity point, and then defect	Invest to reduce both demand charges and total energy purchases	Investment in successively larger systems to continually lower electric cost
System profile	A completely off-grid system oversized to meet full customer load	Balanced investment between distributed generation and load-shaping (through batteries) to reduce demand charges	Solar-focused system to reduce grid purchases; no investment in improvements to load shape

Therefore, its entirely likely that TVA has the "solution" backwards. If TVA creates a retail rate structure that does not encourage customers to invest "with" TVA, then the eventual result could be defection, with customers investing in oversized system to meet full customer loads.

More generally, TVA has, at times, been exceptionally wrong in its forecasts of load growth (as have many utilities). By asserting a confident vision of the future in the Draft 2018 Rate EA, TVA is asserting a view that is at odds with the load forecasting practices it espouses in its resource planning process. In its 2015 IRP, TVA explained that in order "to identify an energy

[44] RMI (*April 2015). The Economics of Load Defection, [*https://rmi.org/insights/reports/economics-load-defection/.]

resource plan that performs well under a variety of future conditions," TVA created five scenarios, each modeling a possible future, and "structured to present different challenges to the resource planning process."[45] The draft 2015 EA does not discuss how TVA considered the impact of potential sources of load growth and other "different challenges" to the implementation of its rate structure changes.

III. TVA Did Not Adequately Address Negative Impacts of Preferred Alternative in Draft 2018 Rate EA

A. TVA Fails to Sufficiently Analyze Impacts of LPC Implementation

It is most likely that a GAC would be implemented using mandatory fees hidden in customer bills rather than declining block rates. Over the past seven years, TVA has approved an average 50% increase in mandatory fees charged by its LPCs. However, many residential customers of TVA's LPCs do not see these mandatory fees on their monthly bills, and those customers may not even be notified when their LPC is considering an increase in the fee.

As discussed below, in 2011, TVA began to cut electricity prices for industrial customers. In addition to shifting the balance of power costs from industrial customers on to residential and small commercial customers, TVA quietly accepted (or even endorsed) another large change in rates. One by one, as summarized in Appendix A, about three-quarters of TVA's local power companies have approved increases in mandatory fees of at least 20%, and in 2018 this will result in a $300 million increase in mandatory fee revenue.

For example, Knoxville Utilities Board (KUB) is one of at least 16 local power companies that doubled, or even tripled, mandatory fees over the past 7 or 8 years. In 2010, KUB charged a "Basic Service" fee of just $6.09 per month. Today, that fee is $17.50. KUB has scheduled additional increases so that it will reach $20.50 by the beginning of 2020, which means that over a single decade, the amount customers pay before flipping the switch will have tripled.

KUB initiated this trend in 2011 in response to implementation of TVA's 2010 EA, as discussed below. In addition to shifting costs away from industrial customers and on to residential customers, the rate structure change included application of a "demand charge" for power used by residential and small commercial customers. TVA claimed that their 2011 rate

[45] TVA 2015 IRP, p.12-13.

structure change would likely have "no substantive, disproportionate negative impacts to minority or low-income populations." TVA's rate changes did pretty much the opposite. Instead of improving opportunities for customers to save money, KUB and many of TVA's other local power companies reacted by raising mandatory fees, which are paid by the customer regardless of how much power they use, or when they are used.[46]

Ironically, the very same wholesale rate changes that triggered an increase in the use of mandatory fees by LPCs for their residential and small commercial customers also initiated the transition to favorable rate structures for their industrial customers that give them greater opportunities to reduce their bills. TVA has not explained why giving greater control over bills is good for industrial customers, but bad for residential customers.

Mandatory fees are preferred by utilities because they guarantee income from small customers, but are opposed by SACE and organizations like the NAACP because they have a disproportionate impact on "low-income, elderly and minority ratepayers." In addition to having disproportionate impacts on these customers, mandatory fees also make it hard for customers to estimate the potential benefits of energy efficiency in reducing their monthly bills.

Many of the at least 94 local power companies that have adopted fee increases of 20% or greater do not itemize the mandatory fees on customer bills. For example, Memphis Light Gas and Water (MLGW) does not disclose its $11.60 per month mandatory fee on customer bills. And, like most other LPCs, MLGW does not make proposed increases its mandatory fee visible to the public.

In November 2017, MLGW prepared a proposal to increase the fee by $1 per month for residential customers as part of an overall 7.1% rate increase. In the draft council resolution prepared to endorse the overall rate, this rate increase was described as "a compound annual growth rate of 2.3% in the electric sales revenue over the three-year period 2018-2020 and a revenue neutral increase in fixed cost recovery and reduction in variable cost recovery for RS and RS-TOU rates." This is not language that even a rate expert can interpret with certainty, much less the general public.

MLGW's proposal to increase the fee by $1 per month was not mentioned in the draft resolution. Instead, it is buried near the back of a 379 page budget document provided to the Memphis City Council. That document also showed that the "reduction in variable cost

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[46] John Wilson (February 7, 2018). Why has TVA encouraged its local power companies to raise mandatory fees for its customers? Southern Alliance for Clean Energy available at http://blog.cleanenergy.org/2018/02/07/tva-mandatory-fees-up-since-2011/.

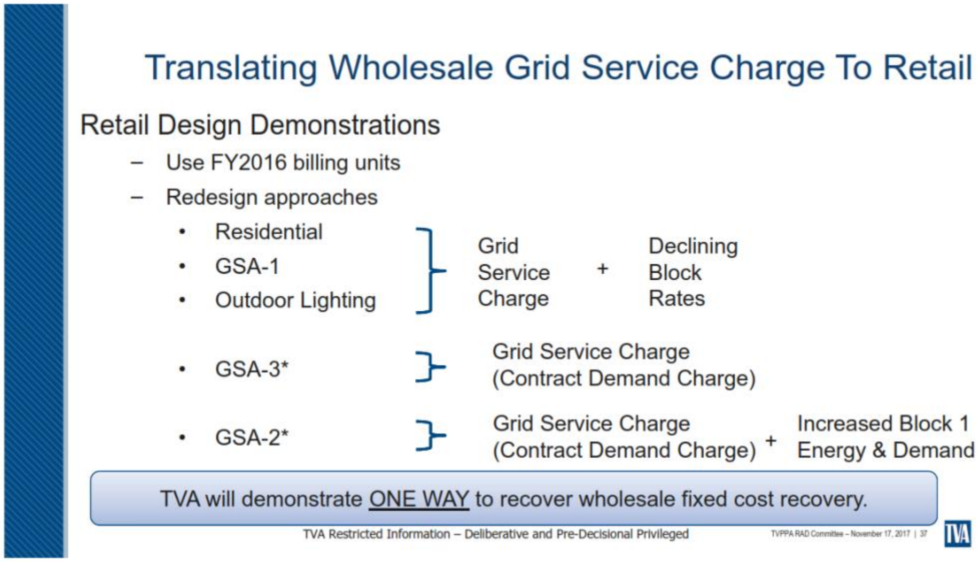
recovery" did not actually mean a decrease in rates: In addition to the increase in mandatory fees, electric rates were also proposed to increase by about 4%.

MLGW's proposed rate increase was communicated following practices used by most utilities across the TVA region. Increases in mandatory fees are described as "revenue neutral," even when overall electricity prices are trending upwards. This double-talk is characteristic of the "favor the big guy at the expense of the little guy" approach that is increasingly favored by TVA and many large, for-profit utilities.

Certainly there are exceptions. Athens Utility Board, KUB, and some other utilities do publicly share what they are doing, and why, with their customers. But MLGW and many others do not. For example, Middle Tennessee Electric Membership Cooperative (MTEMC) operated with a mandatory fee of $9.79 per month in 2011, but today, residential customers pay $19.75 per month. MTEMC's CEO Chris Jones recently boasted that his customers "not only enjoy rates 20 percent below the national average, they also have a voice in how their cooperative is run through their elected Board of Directors." While MTEMC touts "rates 20 percent below," its press releases, blogs, and newsletters are strangely silent on why its mandatory fee is above the national average.

Ultimately, the problem with the lack of transparency is being driven by TVA. TVA is the "retail rate regulator" for 150 of its local power companies, and also has "non-discriminatory oversight" over the other 4 companies. Yet the public does not know what TVA's regulatory oversight accomplishes. For a regulator, TVA is remarkably secretive. TVA provides no disclosure as to what standards it applies in reviewing proposed rates, the process for approving them, or what rates it has approved.

It is clear that TVA intends to bill LPCs for the GAC as a monthly wholesale charge, *fixed in advance* of the October deadline for rate changes by LPCs. As recently as November 2017, TVA indicated a preference for a combination of a grid service charge and declining block rates to translate the wholesale GAC (then called a Grid Service Charge) to retail rates.



Source: TVA, Presentation to TVPPA Research, Analysis and Design Committee (November 17, 2017).

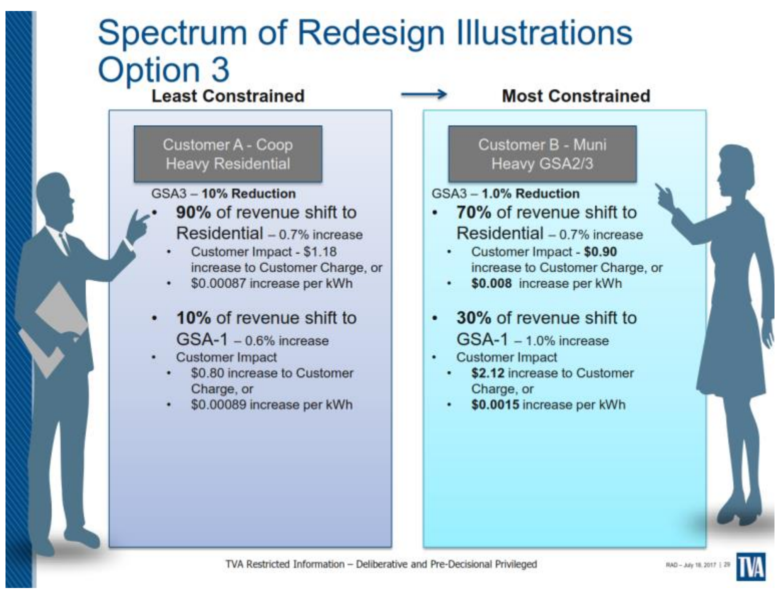
Yet even though TVA considered this option, it did not analyze its impacts or provide any rationale as to why its LPCs would choose to collect a monthly charge by adopting declining block rates, rather than continuing to increase mandatory fees. TVA's failure to consider this possibility in its Draft 2018 Rate EA is misleading at best. In our view, it is most likely that LPCs will raise mandatory fees to collect the monthly charges.

B. The Draft 2018 Rate EA Will Result in Significant Negative Impacts on Residential Customers, Particularly at 2.5 cents per kWh and Retail Fee Increases.

TVA's Strategic Pricing Plan "roadmap" demonstrates an intent to eventually implement a Grid Access Charge of at least 2.5 cents per kWh. Furthermore, while TVA proposes that its LPCs could adopt a declining block rate structure to recover the GAC, LPCs are more likely to request further increases in mandatory fees. Yet TVA's explanation of the impacts of its wholesale and retail rates analysis finds identical impacts regardless of whether the GAC is 1.0 or 2.5 cents per kWh, as presented in Tables 5 and 6 of the Draft 2018 Rate EA. TVA either conducted this analysis improperly, or explained it very poorly. One reason that TVA may have limited its analysis to consider only declining block rates is that an increase in customer's monthly mandatory fee would result in greater impacts. Our analysis of TVA's suggested declining block retail rate design resulted in findings that are generally consistent with those listed in the Draft 2018 Rate EA.

However, our findings differ with TVA in two key respects. First, load growth will be largest when TVA raises the GAC to the Strategic Pricing Plan "roadmap" goal of 2.5 c/kWh, and also if LPCs elect to utilize the monthly mandatory fee rate structure approach instead of declining block rates. Second, increases to mandatory fees will increase disproportionate negative impacts to lower-use residential customers, who tend to be minority or low-income populations. Thus, while TVA concludes that the socioeconomic and environmental impact of the proposed actions are minimal, our analysis comes to a different conclusion. TVA's proposed actions – especially the long-term "roadmap" that it intends to follow – would have substantial socioeconomic and environmental impacts not studied in the Draft 2018 Rate EA.

In addition to the impacts of the GAC, residential rates will also be affected by the proposal to redesign and reduce rates for large commercial (GSA3) customers. In presentations to TVPPA committees, TVA presented potential impacts of the proposed changes for commercial customers using two example LPCs, a "heavy residential" cooperative utility and a "heavy GSA2/3" municipal utility. In July 2017, TVA explained that in order to achieve a reduction in rates for commercial customers, residential rates are increased by 0.7%, either through a roughly $1 monthly mandatory fee increase, or a 0.1 cent per kWh energy rate increase.



Source: TVA, Presentation to TVPPA Research, Analysis and Design Committee (July 18, 2017).

It is unclear from TVA's presentation materials why the GSA3 reduction was 8.8% for the example coop, as compared to only 1.0% in reduction for GSA3 customers at the example municipal utility.

Yet in the Draft 2018 Rate EA, TVA suggests that the rate impact of this change would be only a 0.3% rate increase to residential customers. We were unable to locate any presentations to TVPPA that support this lower value, but nonetheless have relied upon this figure for purposes of preparing these comments. However, if TVA did intend to increase rates by 0.7%, resulting in a potential $1 monthly mandatory fee increase, then this only increases the potential socioeconomic impact of TVA's rate structure change proposal.

Another source of potential rate impacts is the possibility of a "risk premium" to be built into retail rate design. Although not discussed in TVA's Draft 2018 Rate EA, TVA gave extensive consideration to the potential that LPCs would need to request a rate increase (styled as a "risk premium") in order to better manage risks of under-recovery during lower demand years.

Managing Risk of a GAC

- If no changes are made at retail to reflect the GAC, risk is moved from TVA to LPCs
- LPCs can manage that risk by making changes at retail, by including a risk factor (rate increase) in existing retail rates, or do neither and carry the risk

Source: TVPPA, Rates and Contracts Committee notes (January 3, 2018).

Although this "risk premium" concept is not included in the Draft 2018 Rate EA, it is another source of potential rate risk for TVA's smaller customers.

Considering each of these factors, our analysis of residential rate impacts focused on three issues: retail rate design (declining block rate vs mandatory fees), demand impacts (rate impacts on residential demand), and commercial rate shifts. As discussed in greater detail in Appendix D, our analysis finds:

- Under Alternative C, with declining block rates, low use customers see a 0.4% decrease in demand, but above-average customers see a 0.4% increase in demand. On average, the demand impact would be lower than the 0.4% increase in overall demand presented in Table 5 of the Draft 2018 Rate EA.
- Under Alternative D, with declining block rates, customer demand is increased (or decreased) by more than double that in Alternative C. On average, this would be 0.3%, a value that is similar to that presented TVA's result shown in Table 6 of the Draft 2018 Rate EA. Notably, this would undo the last year of TVA's energy efficiency programs.
- Under Alternative C, with increased monthly mandatory fees, customer demand increases for all customers by 1.6%. Notably, this would undo about four years of TVA's energy efficiency program efforts with one single policy action.

- Under Alternative D, with increased monthly mandatory fees, customer demand increases for all customers by about 4.0%. Notably, this would undo all of TVA's historical and planned energy efficiency program efforts through 2025 with one single policy action.
- Because the weight of the evidence suggests that Alternative D with increased monthly mandatory fees is a very probably outcome within just a few years, TVA should analyze the potential socioeconomic and environmental impacts of such a policy change.

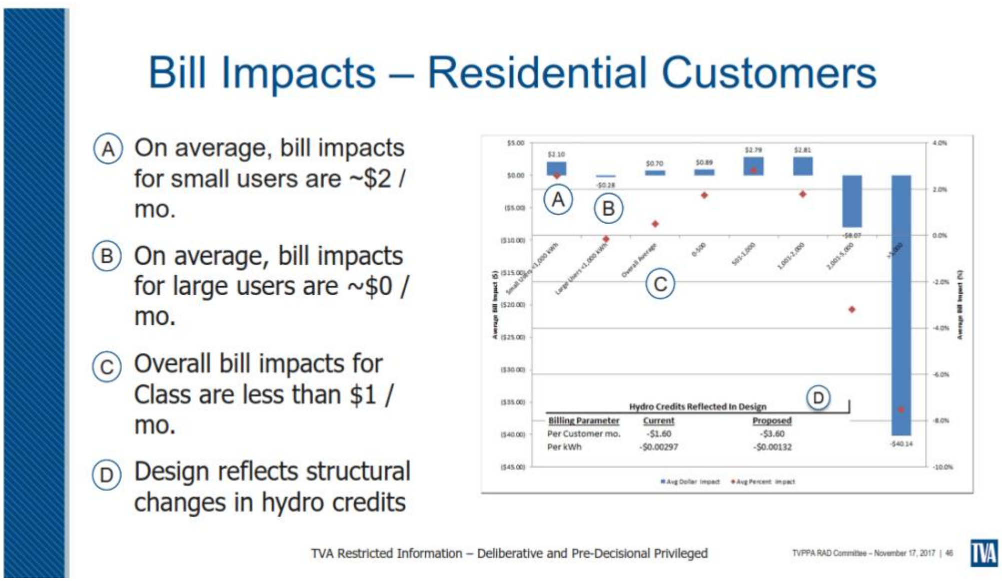
Highlights of SACE Bill Impacts Analysis

Case	**Change in Monthly Bill**		**Change in Residential Electricity Demand**	**Years of EE program savings reversed**	**Increase in Energy Burden for Lower-Income Households**
	Customers Using Less than 1,000 kWh	**Customers Using More than 1,000 kWh**			
Alternative C, declining block rates	+ $1	+$1	+0.1%	>1	+0.1%
Alternative C, monthly mandatory fees	+ $8	- $5	+1.6%	~4	+0.8%
Alternative D, declining block rates	+ $2	+$2	+0.3%	~1	+0.2%
Alternative D, monthly mandatory fees	+ $19	- $14	+4.0%	2011 through approximately 2025	+1.9%

C. Declining Block Rates are Problematic and are Poorly Aligned with System Costs

Even if TVA pursues its preferred approach, declining block rates, the Draft 2018 Rate EA lacks analysis of the concept of declining block rates. According to the Regulatory Assistance Project, "[t]he cost of producing energy does not decline as usage increases. Long-run marginal costs are increasing, not decreasing, as utilities rely on lower-emission, higher-cost new resources. Higher consumption levels also introduce several distinct environmental costs. Declining block rates – where consumers pay less per kWh at higher levels of energy usage – send exactly the wrong price signal."[47] In other words, declining block rates are contrary to TVA's stated intent to align retail rates with costs. This is unsurprising, since one of the main reasons TVA prefers declining block rates is that it would help "counter residential DER."[48]

As analyzed in these comments, declining block rates result in substantial variation in bill impacts to residential customers. TVA's largest residential customers would see huge savings at the expense of most other residential customers. As illustrated below, customers using 2,000-5,000 kWh would average over $8 per month in bill savings, and customers with over 5,000 kWh per month would save over $40 per month on average. It is hard to imagine a customer who routinely uses five times the typical household's energy being interested in saving $40 per month on the electric bill, but that's what TVA is proposing.



Source: TVA, Presentation to TVPPA Research, Analysis, and Design Committee, November 17, 2017.

D. Mandatory fees are Misaligned with Costs and Have Undesirable Impacts on Energy Demand.

As discussed above, while TVA featured its interest in promoting declining block rates for residential customers, it is more probably that the GAC will be implemented using mandatory fees, at least in part. Based on our analysis, if TVA's proposed GAC is converted into retail

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[47] Jim Lazar, Lisa Schwartz and Riley Allen (April 2011). "Pricing Do's and Don'ts: Designing Retail Rates As if Efficiency Counts," Regulatory Assistance Project. [http://www.raponline.org/wp-content/uploads/2016/05/rap-lazar-pricingdosanddonts-2011-04.pdf]

[48] Knoxville Utility Board, Notes

increase mandatory fees, the average customer would be billed an additional charge of $12.12 per month. This would represent a 71% increase over an average we estimate at $17.12/month currently to $29.24/month per residential customer. (See Appendix for estimated cost impacts).

Higher mandatory fees mean customers pay a higher fixed amount every month, even before customers flip on a light switch. Customers lose the freedom to control the magnitude of their bill through energy efficiency and solar power. Fixed charges are highly unpopular. "The fact that nearly nine in ten Tennessee voters prefer that their electricity bill be based on usage, rather than a fixed fee (or so called 'grid access fee') should not be a surprise," stated Elder Jimmie Garland, Vice President Middle TN for the TN State Conference NAACP. "Forcing these additional fees onto customers every month is a regressive move that is not in the best interest of consumers and will especially hurt families on low and fixed income."[49]

If this were to occur, TVA's policy change would go well beyond the customary application of mandatory fees to include the cost of generation, which TVA views as a "fixed cost." Of course, it is widely recognized that the cost of building power plants is not truly fixed in the long term, it is only fixed in the sense that TVA's management has made decisions on behalf of its customers to invest in power plants, and now has costs associated with those power plants that it is obligated to pay.

While mandatory fees are common, most states define customer costs using the "basic customer charge" method, including those costs that are directly attributable to a customer, such as metering and billing, excluding portions of the distribution system shared by multiple customers. For example, a report commissioned NARUC found this method was the most common approach at the time of the report:

> There are a number of methods for differentiating between the customer and demand components of embedded distribution plant. The most common method used is the basic customer method, which classifies all poles, wires, and transformers as demand related and meters, meter-reading, and billing as customer-related. This general approach is used in more than thirty states.[50] This approach continues to be accepted by many state regulators. For example, in Nevada Power Company's 2017 general rate case, the Public Utilities Commission of Nevada reduced basic service charges, and noted that "Rate design should balance the need for recovery of these fixed costs with the principles of sending proper price signals and creating stability in rates. … This reduction also sends a price signal that

[49] Alissa Jean Schafer (December 4, 2017). Poll: Majority of Tennessee Voters Support Solar and Oppose Fixed Charges On Bill or Restrictions to Customer Choice. [blog.cleanenergy.org/2017/12/04/poll-majority-of-tennessee-voters-support-solar-and-oppose-fixed-charges-on-bill-or-restrictions-to-customer-choice/]x

[50] F. Weston, et al., Charges for Distribution Service: Issues in Rate Design, p. 19, Regulatory Assistance Project (2000), available at http://pubs.naruc.org/pub/536F0210-2354-D714-51CF-037E9E00A724.

encourages residential ratepayers to conserve energy and promotes stability by allowing customers to exercise greater control over their total bills."[51]

The Nevada commission's language points to the likely effect of TVA's actions on retail rates: Residential ratepayers will be discouraged from conserving energy, and higher mandatory fees will promote instability by denying customer the opportunity to exercise greater control over their total bills. Elsewhere, some utilities use the "minimum system method" to set monthly mandatory fees, including additional costs to build the distribution system - but not the bulk power system components such as power plants. Recently Gulf Power proposed to expand its basic service charge to include generation plant costs, but withdrew the proposal in a settlement with SACE and other parties.

TVA is now aligning itself with this misguided view - that load-related costs should be shifted from high-usage to low-usage customers. The potential for TVA to drive mandatory fees that would collect the cost of power plants, including potentially unnecessary plants, on a per capita or per customer basis is well outside the norm for most utilities in this country. By shifting LPC retail rates towards a mandatory fee based system, TVA is causing, not resolving, a misalignment of costs and rates.

E. Mandatory Fees Disproportionately Harm Low-income, Minority and Other Low-usage Customer Groups

Increased fixed charges shift costs to low-income, elderly, and minority ratepayers. This has the effect of decreasing the incentive to reduce usage through methods of bill control such as energy efficiency or clean distributed generation like solar. On average, low-income households have *higher* energy burdens and *lower* energy usage. When income is low, even an average energy bill represents a significant economic burden.

The degree to which TVA misunderstands this point is reflected in a misleading statement from TVA CEO Bill Johnson, "[h]igh energy burden people will pay lower bills. Because we're going to reduce the energy cost the amount we put on the fixed cost. If you're a high energy user, if you live in an inefficient house, you're going to save money in this rate design." (Jan 23, 2018) His statement is misleading because it falsely conflates high energy

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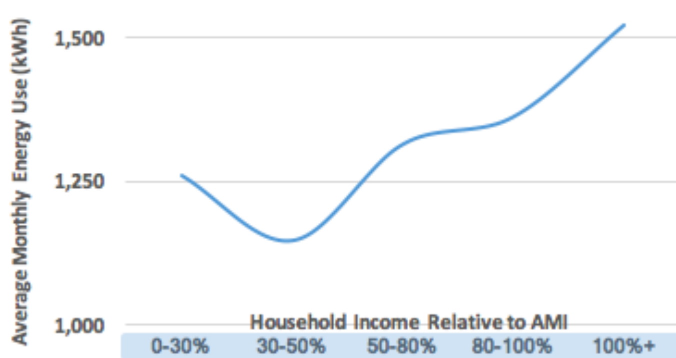
[51] Order Granting in Part and Denying in Part General Rate Application by the Nevada Power Company, p. 120, Public Utilities Commission of Nevada Docket Nos. 17-06003 and17-06004 (December 29, 2017).

burdens with high energy use, and he doesn't consider the potential that high energy burden households often sacrifice comfort to maintain a below-average bill.

TVA's policies could make things worse for these households, and often put its most vulnerable customers at risk. TVA's presumption - that lower-income households use high amounts of energy - are not supported by publicly available data.[52] As shown below, lower-income households[53] use less electricity than higher-income households. The lowest-use income levels in TVA's territory on average are households with 30-50% of the area median income (AMI). SACE also examined this household cost data to investigate whether this might be driven by unit type, primary heating type, or whether the household rented or owned. Considering these and other factors, SACE's findings for the TVA region are consistent with other expert analyses that find lower-income households have lower electricity costs.

TVA Residential Customers Electricity Use by Income Level



	0-30%	30-50%	50-80%	80-100%	100%+
Estimated Electricity Use (per kWh)	1,260	1,147	1,315	1,363	1,523
Average Electricity Bill	$131	$120	$136	$140	$155
Average Monthly Energy Bills	$196	$197	$216	$218	$240
Annual Energy Expenditures	$2,356	$2,361	$2,591	$2,619	$2,885
Energy Burden	24.4%	13.8%	8.6%	6.3%	3.1%

At the highest contrasting AMI levels (30-50% vs. 100%+), low income households use approximately 33% less energy. As presented in Appendix B, over 40% of households in TVA territory are considered low income (at or below 80% of AMI), and these lower income customers could be significantly harmed by TVA's proposed GAC. For example, the average household with an income in the 30-50% AMI range would buy about 90% of its electricity at

[52] Low-Income Energy Affordability Data (LEAD) tool raw dataset, developed by the Better Buildings Initiative's Clean Energy for Low Income Communities Accelerator (CELICA). The estimates of household energy costs from this dataset are based on cross-tabulations of U.S. Census housing data at the census tract level. Available at: https://openei.org/datasets/dataset/celica-data
[53] Households at or below 80% of AMI.

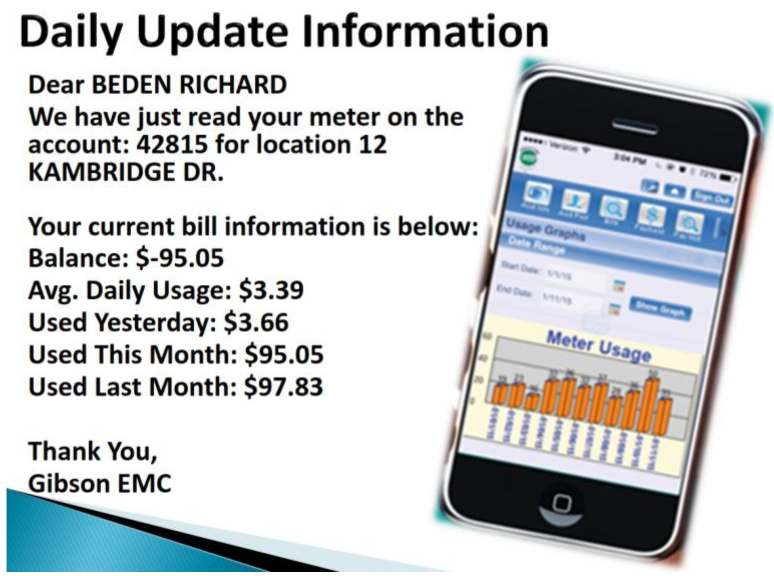
TVA's highest rate (under the declining block rate structure), while the average household with over 100% AMI would buy about a third of its electricity at TVA's lower rate. On average, TVA's lower-income customers use 10% less energy than higher energy than the average customer, and pay an average "energy burden" of 12.6% of household income towards their energy bills.

Because the retail rate structures that TVA's GAC will promote are intended to encourage load growth and will thus benefit customers with higher energy use, TVA's lower-income residential customers will be disproportionately impacted. Depending on the retail rate structure and ultimate level of the GAC, these customers will see their "energy burden" increase by between 0.1% and 1.9% system wide. At the LPC level (see Appendix B), the average impact on lower-income households could be as much as 2.8% of their household income.

In addition to obscuring the direct effect its actions would have on customer bills, TVA insidiously argues a duplicity that "Low-usage households' monthly bills would increase more than other households as a proportion of household income" while also claiming that "Alternatives C and D would…be more beneficial for low-income households, for whom variations in bills due to season or weather are more likely to cause a problem than for other households." Under no scenario is increasing electric bills "more beneficial for low-income households."

If TVA customers are requesting bill stability, there are alternatives beyond radical structural rate changes. For example, for customers that wish to better manage seasonal or monthly electric bills, other utilities offer *voluntary* average bill programs. Those programs provide customers a choice, while TVA's rate structure change inhibits customer choices. Some TVA LPCs have taken steps to develop customer-oriented opportunities that enable them to gain greater control over their bills, counter to the direction TVA is pushing them with this proposed rate structure change.

For example, Gibson EMC offers a residential pre-pay program with greater than 95% customer satisfaction, and achieving an ongoing energy efficiency benefit of 6-7%. The pre-pay program leverages the relationship between energy use and bill size to give greater control over bill amount to the customer (see illustration below). The GAC in the Draft 2018 Rate EA, if passed through by LPCs to their customers in the form of mandatory fees, would reduce the effectiveness of pre-pay programs such as the one offered by Gibson EMC.



Source: Gibson Electric Membership Corporation, Reinventing Your Utility / Thinking Differently, presentation to TVPPA 70th Annual Conference (May 2016).

Decreasing customer choice is a significant problem because TVA customers already have limited choices. They must take electric service from the Local Power Company in which they reside. However, thanks to the development of technology, codes and standards established by state and federal regulation, and programs offered by the TVA, customers have had the choice to reduce their use of electricity through investment in energy efficiency technologies, changes in practices, or installation of DERs.

Energy efficiency and renewable energy decrease air emissions by centralized, fossil-fueled power plants, including climate change-causing carbon dioxide. Increasing fixed charges on customers distorts the economics of energy efficiency measures and distributed generation like solar. Energy efficiency and distributed generation programs are in place to correct for existing market failures that block a customer's choice to reduce usage or self-generate electricity even if those options are much cheaper than supply from the utility. For example, in testimony, expert John Howat explains that "with each incremental increase in the fixed, non-bypassable charge on the monthly bill, the customer loses an increment of control over that bill, even in cases where the volumetric portion remains the larger portion of the total bill. Instead of sending a signal to the customer of control over energy usage, incremental increases in the customer charge chip away at the customer's incentive and ability to take control over the bill."[54]

[54] Direct Testimony And Exhibits Of John Howat On Behalf Of Coalition for Clean Affordable Energy (CCAE), January 29, 2016, New Mexico Public Regulation Commission Case No. 15-00261 UT. p. 11

Taken to the extreme, fixed charges eliminate all incentive to reduce energy consumption. For example, Reliant, a Texas utility, introduced a plan in 2014 that charges customers a predetermined monthly amount based on historical consumption, regardless of their current electricity use. According to Amanda Levin of NRDC:

> "Reliant designed this plan to give ultimate bill security to customers, but this new plan has quickly been dubbed the "all you can eat plan." There is no incentive for customers to invest in energy efficiency and no penalty for keeping the AC on at 60 F all summer — even if not at home. During peak summer hours, this plan provides an almost perfectly perverse price signal."[55]

An apt analogy: It is hard to imagine anyone could maintain a healthy weight if they had an all-you-can-eat buffet for every meal. And while TVA likes to compare mandatory fee billing to cell phone plans, the buffet analogy better captures the consumption that TVA is insidiously seeking to promote.

I.IV. TVA's Draft 2018 Rate EA Violates the TVA Act

A. The Draft 2018 Rate EA is Inconsistent and Counter to TVA's Statutory Requirement to Provide Lowest Possible Rates to Residential Customers

TVA's proposed rate structure change violates the TVA Act. The TVA Act was passed in 1933 as part of the New Deal. As explained above, President Franklin Roosevelt and Congress intended that TVA's electric power projects be "primarily for the benefit of the people … particularly the domestic and rural consumers." This interpretation is a widely shared view of the essential design and purpose of TVA; it is not just the view of SACE or a former TVA Board Chairman. For example, Volunteer Energy Coop (VEC) posted a response to TVA's proposed rate change to its Facebook page on March 13, 2018. VEC stated:

> "On May 18, 1933, Congress signed the TVA Act into law. Among the provisions of the act, Article 11 states that TVA is to sell the power generated for 'domestic and rural use at the lowest possible rates' and that 'the sale to and use by industry shall be a secondary purpose.' VEC believes the wholesale rate change proposed by TVA is in direct contradiction to the spirit of the TVA Act. TVA is currently one of the highest cost wholesale suppliers in the Southeastern United States. And the

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[55] Recovery of Utility Fixed Costs: Utility, Consumer, Environmental, and Economist Perspectives, a Future Electric Utility Regulation Report, published by LBL in June 2016: http://eta-publications.lbl.gov/sites/default/files/lbnl-1005742.pdf

> changes that TVA has proposed can only result in higher electric bills being paid by our residential members."[56]

TVA's proposed rate structure change contradicts TVA's mission as defined by the TVA Act because it will increase bills of a large number of residential customers in the process of attempting to discourage customer investment in DER resources.

Copies of contracts between TVA and some local power companies demonstrate that, until now, TVA has emphasized a preference for "domestic and rural customers" as a general policy.

> WHEREAS, the TVA Act authorizes TVA to sell the power generated by it and not used in its operations to States, counties, municipalities, corporations, partnerships, or individuals according to the policies therein set forth; and
>
> WHEREAS, the TVA Act provides that the sale of such power shall be primarily for the benefit of the people of the section as a whole and particularly the domestic and rural consumers, to whom it is desired to make power available at the lowest possible rates; and ,

Source: Power Contract Among Tennessee Valley Authority, City of Memphis, Tennessee and Memphis Light, Gas and Water Division (December 26, 1984).

B. TVA Fails to Identify Effect of its Strategic Pricing Plan on Cost-Shifting to Residential Customers and Implementation of Mandatory Fees at the LPC Level

Since 2010, the TVA Board of Directors have approved three rate structure changes as part of TVA management's "Strategic Pricing Plan." Beginning in 2010, TVA initiated a series of at least five actions that further adjusted rate structures in favor of industrial customers. The five actions we are aware of are below:

- The elimination of the end-use wholesale rate structure and introduction of time-of-use wholesale pricing (July 2010 EA).
- The Valley Commitment Program and optional Small Manufacturing rate (August 2013 Board Approval).
- The apparent 2014 reclassification of Bellefonte (and perhaps other) "regulatory asset" interest charges and "Administration & General" costs from "Other Costs" to "Generation Fixed Costs."
- The refinement of the wholesale pricing structure (July 2015 EA).
- This proposed GAC and other rate structure changes. (Draft 2018 Rate EA)

[56] Volunteer Energy Cooperative (March 14, 2018). Posted on Facebook. [https://www.facebook.com/volunteerenergycoop/posts/1073943222745862]

Each of these five policy shifts adjust rate structures to the detriment of residential and small rural customers. As discussed below, the first three actions were inaccurately presented to the public by TVA. The cumulative effect of these first three actions violate the TVA Act by unreasonably favoring TVA's industrial and direct serve customers with a nearly 20% cut in the price of electricity since 2011, while residential customers have experienced steady rate increases.

i. Prequel: The 2003 Rate Structure Policy Change

TVA's Strategic Pricing Plan, the umbrella term for the policy changes that began in 2010, is best understood in comparison to TVA's August 2003 Final Environmental Assessment (2003 EA) for a rate structure modification. In 2003, TVA was motivated by opportunities for "large users of energy to meet their needs from different and/or nontraditional energy suppliers to the disadvantage of … residential and rural customers." TVA explicitly acknowledged that the "TVA Act gives particular attention to the needs of domestic (residential) and rural energy consumers."

TVA's 2003 decision extended its pricing policy beyond cost of service to "better position its rates relative to regional market prices charged by other utilities for electricity." In the 2003 EA, TVA recited statistics demonstrating that its residential and commercial rates were well below prices charged by other utilities, but that its industrial rates were well above comparable prices. Furthermore, TVA stated that "the Valley has been losing manufacturing load."

The preferred alternative in the 2003 EA included a 5.2% rate reduction for large manufacturers, paid for by a 1.2% rate increase for residential and commercial customers.[57] In summary, TVA's 2003 EA adjusted rates in response to issues that it measured (loss of manufacturing jobs and noncompetitive electric rates for manufacturers), but considered and maintained the preference for residential and rural energy consumers.

ii. The 2010 Rate Structure Policy Change

TVA stated in its 2010 EA that, "distributor revenues by class are expected to remain close to the same (although there would likely be some impact on individual customers). Therefore, from

[57] The 2003 EA also discussed a contemporaneous general rate increase of 6.1 percent which it anticipated would result in net rate increases for all customers after the rate structure adjustment was taken into consideration.

this change there would be little or no effect on energy usage, either in total or with respect to specific types of use and no noticeable socioeconomic impacts." TVA also stated that, "Any changes in the recovery of TVA costs are expected to affect customers of each TVA distributor in a uniform fashion. For each distributor, households and businesses within a customer class would be impacted uniformly within that class."

At the time, readers of the 2010 EA would have felt reassured that the TVA Act's preference for residential and small rural customers was maintained. That was not the case. Although the 2010 EA clearly communicated that there would not be different treatment of customers by class, TVA's retail sales data clearly show that electricity prices for industrial customers declined beginning in 2011 while residential customer prices did not.

iii. <u>The 2013 Board Action Was Also a Rate Structure Policy Change</u>

TVA's 2013 Board Action (BA) approving the Valley Commitment Program was not publicized as a rate structure change. Neither the Board Presentation nor the Minutes of the August 22, 2013 TVA Board Meeting mention the word "rate" in connection with the Valley Commitment Program, and a "Rate Action Fact Sheet" shared at the meeting discussed other, unrelated rate actions.

Nevertheless, the Valley Commitment Program changed TVA's rate structure. According to TVA's 2016 Strategic Pricing Plan white paper (Attachment 1: Strategic Pricing Plan White Paper), "The second and third adjustments *targeted rate relief* to industrial customers, implemented through a 2013 Board action instating the Valley Commitment Program and optional Small Manufacturing (MSA) rate" (emphasis added). As enacted in a typical Valley Commitment Program Agreement, manufacturers were given a 0.2 c/kWh credit.

> TVA is offering a Valley Commitment (VC) credit of 0.2¢ per kWh to qualifying Customers who make a commitment to the Valley region and meet the eligibility requirements set out below during the period from October 1, 2013 to September 30, 2015 (Commitment Period). By signing below, Customer agrees that during the remaining Commitment Period, Customer will not give notice to terminate its firm power contract or otherwise take action to cause its firm power contract to terminate. Customer agrees that providing such notice or otherwise taking action to cause its firm power contract to terminate will require the repayment of all VC credits paid to Customer.

The only "commitment" the manufacturer made in this contract was to repay the credits if the manufacturer terminated its power contract prior to the end of the two-year commitment period. Yet according to the 2016 Strategic Pricing Plan white paper, "2013 TVA Board actions moved overall industrial effective rates into the top quartile." Providing the benefits of "top quartile" rates for industrial customers, while sacrificing residential customer rates and energy efficiency programs, doesn't meet the statutory requirements of the TVA Act.

iv. The 2014 Reclassification of Bellefonte Interest Costs

In 2014 (or perhaps 2013), it appears that TVA made significant changes to its allocation of costs in a manner that favored higher rates for residential customers, and lower rates for industrial customers. Based on a presentation Tennessee Valley Industrial Coalition in September 2014, it appears that TVA decided to reassign the allocating costs of incomplete power plants such as Bellefonte from "Other Costs" to Plant and Transmission. Concurrently, TVA reassigned Administration and General (A&G) Costs from "Other Costs" to "Generation Fixed Costs" (or Plant). While the reassignment of Bellefonte makes sense on its own, in combination with TVA's non-standard treatment of plant costs, both decisions likely had the effect of modifying the Cost of Service Study results to shift costs from industrial customers to residential customers.

TVA practices a non-standard method for classifying all plant costs as capacity costs. As discussed in a review by Douglas Jester of 5 Lakes (see Attachment 4), "a correct cost of service analysis would split "plant" carrying costs into an allocation to "capacity" costs and an allocation to energy costs," similar to the method practiced in TVA's integrated resource planning models and in its design of interruptible service rates. The impact of this on the allocation of costs between customer classes is explained by Jester as follows:

> "Unfortunately, TVA's current practice double-charges certain costs to residential customers … residential customers contribute a greater share of capacity than energy and therefore pay a disproportionate share of the cost of "baseload" power plants which provide energy at lower variable cost during the times when residential load is low. Consequently, TVA's current practice causes residential customers to pay for plant costs whose only justification is to reduce the costs of providing "baseload" power to non-residential customers. (Attachment 4) Thus, TVA's long-standing cost allocation practices already included a non-standard practice that increased costs for residential customers and reduced them for industrial customers."

The 2014 reclassification of A&G and Bellefonte costs from "other" to "plant" likely exploited this non-standard practice, resulting in rates that were more biased to the advantage of industrial customers. The result would have been an increase in the demand charge paid by local power companies, as well as some continued support for higher energy charges paid by local power companies, along with concurrent demand and energy rate cuts for industrial customers.

v. <u>The 2015 Rate Structure Policy Change</u>

The fiction of the "commitment" in Valley Commitment Program contracts was made evident in the 2015 EA, "The benefits of the Valley Commitment Program would be rolled into the TOU rate structure for [manufacturing customers]." The rate credit was renamed the General Manufacturing Credit (GMC), increased to nearly 1.1 c/kWh plus a demand credit of $1.38 to $1.63 per kW, and the "commitment" terms were removed.

HOW IT WORKS:

For each month* in which an eligible customer has a metered demand that exceeds 1,000 kW**, the General Manufacturing Credit is calculated as:

General Manufacturing Credit =

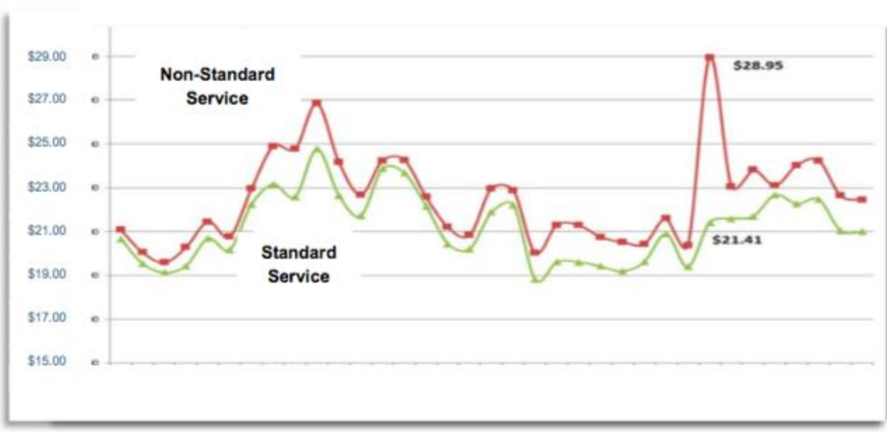
($1.38 × 1,000 kW) + ($1.63 × (firm billing kW – 1,000 kW)) + (1.076¢ × firm billing kWh)

Source: Attachment 2: TVA General Manufacturing Credit (GMC)

So even though manufacturing rates had already been moved into the "top quartile" by the 0.2 c/kWh Valley Commitment Program, TVA's 2015 EA increased that rate credit by nearly a full cent per kWh, including both the demand and energy components of the GMC.

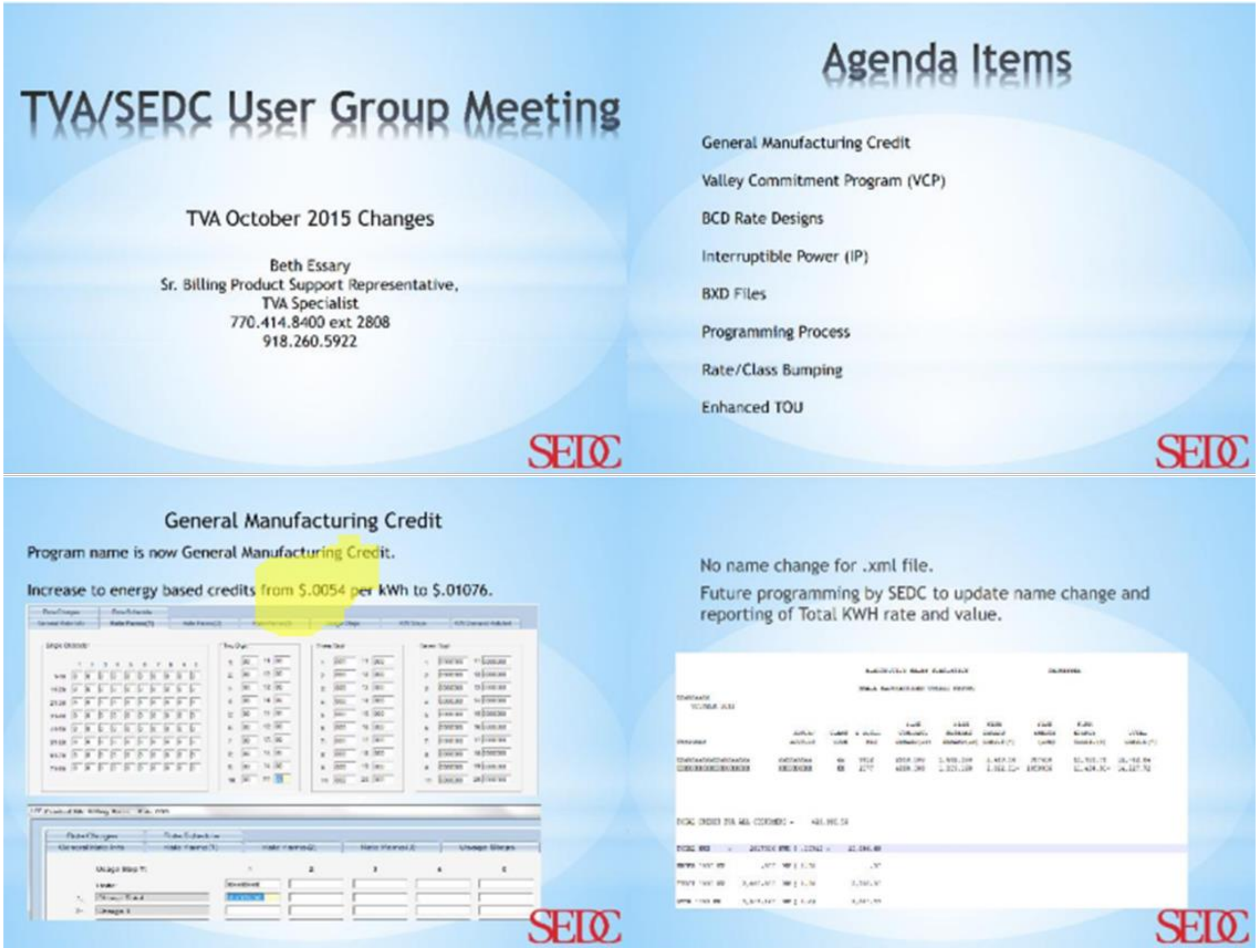
In addition to the General Manufacturing Credit, TVA also changed the structure of its fuel cost adjustment (FCA) in a manner that shifted costs from industrial to residential customers.

Figure 13: Back-cast of FCA fiscal year 2012-14 based on the new allocation



FCA cost allocation now split by customer type – Standard Service and Non-Standard Service

Also noteworthy, TVA increased the Valley Commitment Program from 0.2 c/kWh to 0.54 c/kWh between 2013 and 2015, according to one document (seen below). It is unclear what policy action authorized that intermediate rate cut, which further corroborates the general trend of TVA's policy decisions being relatively unaccountable to NEPA or other regulatory requirements.



Note: First four slides of a longer presentation. Title slide provides source.

The 2010, 2015, and 2018 EAs all each made only a cursory mention of the TVA Act's preference for residential and rural customers. None of these documents include any substantial discussion of rate structure changes, or any other changes, to specifically benefit residential and small rural customers.

In the 2015 EA TVA openly acknowledged that one of its purposes was to, "[i]mprove the competitiveness of industrial rates."[58] This was the first time this had been openly stated since 2003. In spite of this objective, TVA asserted, "[i]ndustrial power rates are just one factor

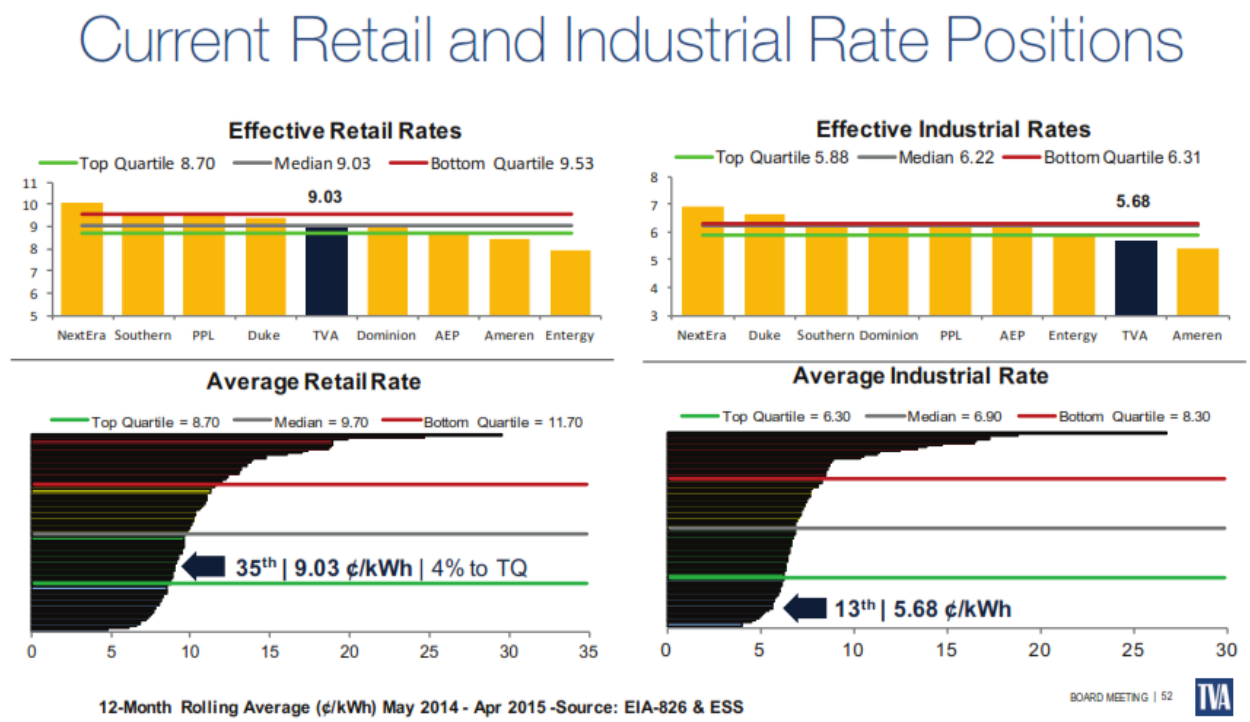
[58] Tennessee Valley Authority (July 2015). Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers. Final Environmental Assessment. [https://www.tva.gov/file_source/TVA/Site%20Content/Environment/Environmental%20Stewardship/Environmental%20Reviews/2015%20Rate%20Change/2015_rate_change_final_ea.pdf]

among many … Due to the minor nature of the proposed rate adjustments the likely result is only a minor influence. … regional effects would be minor." The 2015 EA estimated that the rate structure changes would be revenue neutral overall, but increase residential rates by about 0.4% while reducing rates for large commercial and industrial customers by between 1.7% and 3.6%.

However, as documented by Synapse Energy Economics, the changes in actual electric prices have been approximately three times larger than TVA estimated in the 2015 EA. From 2015 to 2016, average residential rates increased 1.1%, while average industrial rates fell by 6.4% and average direct serve rates dropped by 9.0%.[59] It is not entirely clear if the 2015 EA missed the mark so widely because it underestimated the impact of the rate structure change, or if the figures presented above related to either the fuel cost adjustment or the general manufacturing credit, but not both.

Furthermore, even though TVA established rate competitiveness as a purpose of the 2015 EA, nowhere in the EA did TVA provide any evidence that industrial power rates required an across-the-board reduction. As shown below, at its August 2015 meeting, the TVA Board was shown evidence that industrial power rates were highly competitive (in stark contrast to the situation in 2003, as discussed above).

[59] Synapse report, p. 3.



Source: TVA Board of Directors Meeting, Board Presentation (August 2015).

Thus, TVA granted a large rate cut in order to improve “competitiveness” for large industrial customers when its own data showed that those rates were already competitive, except for perhaps a small sub-group. In 2016, TVA reported in the Strategic Pricing Plan whitepaper (Attachment 1: Strategic Pricing Plan White Paper) that “TVA has more large industrial customers relative to peers,” who have “lower costs and lower rates”, but that small industrial customers were a “sub-group for whom TVA’s rates were less competitive.”

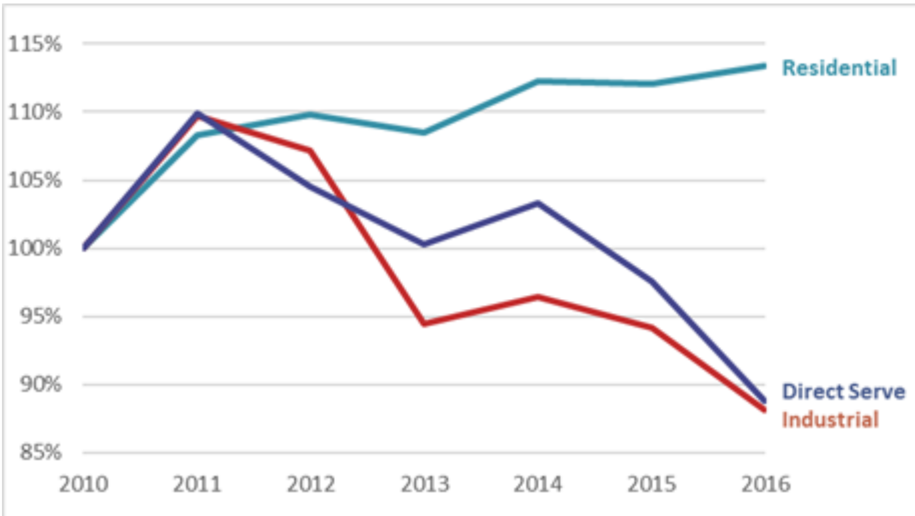
C. TVA’s Rate Decisions Have Resulted in Significant Decreases in Rates for Industrial Customers and Steady Rate Increases for Residential Customers

According to Synapse Energy Economics, “[s]ince 2011, the Tennessee Valley Authority’s industrial and direct serve customers have benefitted from a nearly 20% cut in the price of energy, while residential customers have experienced steady rate increases….the average price of electricity for residential customers has increased above 10 cents per kilowatt-hour for residential customers, but industrial customers directly served by TVA have seen prices drop to approximately 4 cents per kilowatt-hour.”[60]

[60] Synapse Energy Economics (January 31, 2018). Electricity Prices in the Tennessee Valley. [http://www.synapse-energy.com/sites/default/files/Whitepaper-TVA-Rates-17-091.pdf]

As shown below, from 2010 to 2011, the average revenue per kilowatt-hour increased for all classes of TVA's customers, including those served by local power companies as well as direct serve customers. However, from 2011 to 2016, rate trends diverge, as TVA's rate structure policy changes increasingly favored industrial customers over residential customers.

Average Revenue per Kilowatt-Hour at TVA and LPCs



Source: Attachment 3: Synapse Energy Economics, *Electricity Prices in the Tennessee Valley* (January 2018).

TVA's response to the Synapse report was to note that industrial rates are lower than residential rates because the cost to serve large customers is lower than the cost to serve small customers. This is not unique to TVA, and this point was recognized and addressed by the Synapse report. As the Synapse report notes, TVA is the only large Southeastern utility that is systematically changing rates to favor its industrial customers even more.

TVA has engaged in extensive conversations with its direct serve industrial customers about rate design through TVIC's Pricing Committee. In those conversations. TVA has indicated that its proposed rate designs would "encourage off-peak usage … The more you grow off-peak, the lower your effective rate." Furthermore, all proposed designs are "at least as good as current rates … and encourage all-hour load additions."[61]

This level of dialogue is not occurring with TVA's residential customers. Notably, retail rate structures such as mandatory fee increases on monthly bills would reduce, not increase, customer options for control over the amount on their bill. Although LPCs have been extensively

[61] TVA (October 18, 2017), TVIC Requested Analyses, presentation to Pricing Committee.

consulted, the actual bill paying consumers are only being afforded a 30-day comment opportunity.

Continuing its practice of giving preferential rate treatment to industrial customers, TVA's rate preferences for industrial customers come in addition to economic development programs already providing targeted benefits to the industrial customer class. TVA's statutory mission includes economic development, and like many other utilities (especially in the Southeast), TVA offers economic development programs. Although styled as an economic development program, the brief history of the Valley Commitment Program shows that it was never intended to promote economic development, but rather served as a pilot for a permanent rate structure change.

TVA's actual economic development programs are described on TVA's website, and include investment credits, coverage of security deposits, grants, and loans.[62] However, in practice, TVA often conflates the economic development programs with the industrial rate reductions. For example, a report by the Times Free Press (Chattanooga) identified "nearly $500 million of discounted rates offered since TVA adopted its Valley Investment Initiative in 2008."[63] It is not clear whether the $500 million refers to specific rate discounts to new or retained manufacturing facilities, or also to general industrial rate reductions. In response to the Times Free Press, TVA acknowledged that it has not conducted an environmental assessment or environmental impact statement regarding the excessive industrial incentives. TVA also declined its FOIA request on this issue, keeping the public very much in the dark.

At the same time, executives receive bonuses for exceeding economics development jobs targets. We are not arguing against regional job growth, but it goes against TVA's directive under the TVA Act when executives are personally incentivized to increase industrial customers, potentially to the detriment of small and residential customers, and not required to disclose the incentives.

To the extent that TVA addresses the role of rates in economic development activities, TVA should clearly distinguish between (a) appropriate cost-of-service ratemaking, (b) additional rate discounts or credits that are provided to most or all large customers, and (c)

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[62] TVA Valley Incentive Programs website: https://tvasites.com/Business-Benefits/Incentives.aspx, accessed March 29, 2018.

[63] Dave Flessner (February 11, 2015). "How the Tennessee Valley snagged $35 billion in business in just five years", Times Free Press. [http://www.timesfreepress.com/news/local/story/2015/feb/11/tvas-35-billiyieldfederal-utility-says-its-ra/287721/]

targeted services, investment credits, and other benefits linked to specific, verifiable economic development or job retention outcomes.

It is our impression that TVA frequently, and unreasonably, justifies its industry-favorable rates as "economic development" and cites job retention figures that are more properly associated with specific services and financial assistance given to new industrial facilities and other growth opportunities. TVA could clear up a lot of confusion by explaining these issues more clearly and with less apparent topic-shifting.

The NARUC manual, on which TVA relies heavily to justify its proposed rate change, explicitly states that the document is ill suited for evaluating outcomes. This version of the Manual is not the final word. As noted throughout, customer preferences and adoption rates, and the implementation of new technology on the grid side will continue to grow, and with that growth comes new evidence, more solutions, and, perhaps more questions. The lack of more widespread experience with certain types of DER, and the shortage of available data at this point in time means that we have barely scratched the surface of what this future could look like.[64] While TVA extensively cites the NARUC manual for discussions of TVA's preferred actions, it should be clear that NARUC is by no means confident that we understand how DERs will affect utilities.

D. TVA's Preferred Alternative is Not in Best Interests of LPCs

The Draft 2018 Rate EA has been met with frustration by TVA LPCs. Several LPCs have repeatedly requested that TVA reconsider certain alternatives, and discouraged TVA from adopting the preferred alternative. TVPPA's Rates and Contracts Committee appears to request that TVA consider two "Competitive Transition Charge" alternatives as well as Demand & Energy alternatives and the Current Structure alternatives in their February 21, 2017 meeting.

- TVA's fixed cost proposal is born of the declining sales future TVA and LPCs foresee as energy efficiency and distributed generation impact the electric industry. Many LPCs believe TVA's fixed cost proposal is just a sales volume risk transfer from TVA to LPCs and don't believe it is justified or at least reflects an appropriate sharing of the risks.

- A potential LPC strategy in reaction to changes in the electric industry is to compete for electric sales with distributed generation suppliers and to look for electrification opportunities. However, TVA has remained adamant the power contract prohibits any non-TVA generation or storage. TVA's position has become frustrating to many LPCs.

[64] National Association of Regulatory Utility Commissions (November 2016). Distributed Energy Resources Rate Design and Compensation, A Manual. [https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0)

Source: KUB, Summary of TVA Rate Issues (undated, circa November 2017).

TVA's LPCs are clearly uncomfortable with the direction TVA is pushing them. Etowah Utilities Board has raised electricity prices by over 15% since 2011. A public exchange at an Etowah Utilities Board meeting was reported as follows:

> "Those, typically, we pass through (to the ratepayers)," EUB General Manager John Goins said. "We're not certain what effect it'll have on our customers."

Those rate hikes occur routinely, and EUB Board member Gene Keller asked if that has been questioned by Goins.

> "We as the Southeast District Power Distributors Association have attended several meetings and expressed our feelings about the rate increases," Goins said. "About the way it's structured and that we aren't happy with TVA and what they're trying to do."

EUB Board member David James said it's led him to question the benefit of the presence of TVA.

> "I used to like the fact that we have TVA here, but it seems like every year they're going up, plus they're paying these higher-ups tremendous bonuses," James said.
>
> "It just sends the wrong message," Keller added. "It's a monopoly – it's a no-lose proposition."

Some LPCs have had trouble recognizing the frustration of customers. In April 2016, Huntsville Utilities proposed a $5 increase in the mandatory fee for residential customers. Through 2016, Huntsville's electricity prices had already increased by almost 6% as compared to 2011. After strong protests, the City Council rejected the proposed fee increase. Soon after this failed rate change, Huntsville Utilities CEO Jay Stowe was hired by TVA, and he is now directing TVA's overall strategy with regard to rates and weakening the economics for customers who wish to choose to install solar power and invest in energy efficiency.

Then-CEO Jay Stowe explained Huntsville Utilities' strategy as, "What we're trying to do is bring in more of our revenue on a fixed basis that will allow us to encourage people using less of their energy …" Effectively, Stowe told his customers that if they've used energy efficiency to reduce their power bill, the utility needs to raise it back up again.

V. Conclusion

For the reasons laid out above, TVA should withdraw its Draft 2018 Rate EA and complete a full EIS, that considers all appropriate impacts on the environment, public health and socio-economic status of TVA ratepayers and includes consideration of all reasonable alternatives.

Respectfully submitted by,

Angela Garrone
Energy Research Attorney

On behalf of the Southern Alliance for Clean Energy
P.O. Box 1842
Knoxville, TN 37901
865-637-6055

Appendix A

Mandatory Fees Charged by TVA's Local Power Companies, With Impact of Grid Access Charge at 1 ¢/kWh and 2 ¢/kWh

	Existing Mandatory Fee			TVA GAC (1 ¢/kWh)	Mandatory Fee w/GAC		Fee w/GAC at
Local Power Company	**2011**	**2018**	**% Increase**	**as Fee**	**2018**	**% Increase**	**2.5 ¢/kWh**
TVA - All Residential Customers	*$ 11.89*	*$ 17.66*	*48 %*	*$ 12.12*	*$ 29.78*	*150 %*	*$ 47.96*
4-County Electric Power Association	$ 19.43	$ 32.69	68 %	$ 12.25	$ 44.94	131 %	$ 63.33
Aberdeen Electric Department	N.A.	N.A.	N.A.	$ 11.67	N.A.	N.A.	N.A.
Albertville Municipal Utilities Board	N.A.	$ 11.42	N.A.	$ 12.89	$ 24.31	N.A.	$ 43.65
Alcoa Utilities, City of	$ 11.25	$ 15.25	36 %	$ 12.38	$ 27.63	146 %	$ 46.19
Alcorn County Electric Power Association	$ 18.10	$ 24.25	34 %	$ 12.48	$ 36.73	103 %	$ 55.45
Amory, City of	$ 9.86	$ 11.86	20 %	$ 11.46	$ 23.32	137 %	$ 40.51
Appalachian Electric Cooperative	$ 16.00	$ 20.90	31 %	$ 12.83	$ 33.73	111 %	$ 52.98
Arab Electric Cooperative	$ 16.17	$ 21.80	35 %	$ 12.98	$ 34.78	115 %	$ 54.26
Athens Electric Department, City of	$ 8.19	$ 8.19	0 %	$ 13.29	$ 21.48	162 %	$ 41.42
Athens Utility Board	$ 15.57	$ 15.68	1 %	$ 12.04	$ 27.72	78 %	$ 45.78
Benton County Electric System	$ 18.40	$ 22.73	24 %	$ 11.17	$ 33.90	84 %	$ 50.66
Benton Electric System	$ 10.00	$ 13.41	34 %	$ 11.46	$ 24.87	149 %	$ 42.07
Bessemer Utilities, City of	$ 12.66	$ 12.66	0 %	$ 10.77	$ 23.43	85 %	$ 39.60
Blue Ridge Mountain Electric Member Corp	$ 16.40	$ 20.90	27 %	$ 8.41	$ 29.31	79 %	$ 41.93
Bolivar Energy Authority	$ 21.44	$ 23.89	11 %	$ 12.63	$ 36.52	70 %	$ 55.47
Bowling Green Municipal Utilities	$ 11.50	$ 17.81	55 %	$ 8.99	$ 26.80	133 %	$ 40.29
BrightRidge	$ 9.51	$ 20.87	119 %	$ 12.06	$ 32.93	246 %	$ 51.01
Bristol Tennessee Essential Services	$ 12.77	$ 10.42	-18 %	$ 13.38	$ 23.80	86 %	$ 43.87
Brownsville Utility Department	$ 5.24	$ 9.83	88 %	$ 11.23	$ 21.06	302 %	$ 37.90
BVU Authority	$ 10.10	$ 18.00	78 %	$ 12.40	$ 30.40	201 %	$ 49.00
Caney Fork Electric Cooperative	$ 13.25	$ 20.03	51 %	$ 11.99	$ 32.02	142 %	$ 50.00
Carroll County Electric Department	$ 15.79	$ 22.40	42 %	$ 12.92	$ 35.32	124 %	$ 54.71
CDE Lightband	$ 15.11	$ 23.40	55 %	$ 11.11	$ 34.51	128 %	$ 51.18
Central Electric Power Association	$ 15.11	$ 15.11	0 %	$ 12.82	$ 27.93	85 %	$ 47.15
Cherokee Electric Cooperative	$ 20.75	$ 23.88	15 %	$ 11.69	$ 35.57	71 %	$ 53.11
Chickamauga Electric System	N.A.	$ 21.00	N.A.	$ 12.18	$ 33.18	N.A.	$ 51.45
Chickasaw Electric Cooperative	N.A.	$ 13.87	N.A.	$ 14.57	$ 28.44	N.A.	$ 50.29
Cleveland Utilities	$ 7.98	$ 18.43	131 %	$ 11.73	$ 30.16	278 %	$ 47.76
Clinton Utilities Board	$ 10.42	$ 22.42	115 %	$ 12.37	$ 34.79	234 %	$ 53.36
Columbia Power & Water Systems	$ 9.65	$ 17.08	77 %	$ 11.51	$ 28.59	196 %	$ 45.87
Columbus Light & Water	N.A.	N.A.	N.A.	$ 12.03	N.A.	N.A.	N.A.
Cookeville Electric Department	$ 10.00	$ 10.00	0 %	$ 10.14	$ 20.14	101 %	$ 35.35
Courtland, City of	N.A.	N.A.	N.A.	$ 11.86	N.A.	N.A.	N.A.
Covington Electric System	N.A.	$ 14.40	N.A.	$ 11.16	$ 25.56	N.A.	$ 42.30
Cullman Electric Cooperative	$ 23.83	$ 27.94	17 %	$ 12.53	$ 40.47	70 %	$ 59.25
Cullman Power Board	$ 6.59	$ 15.85	141 %	$ 11.01	$ 26.86	308 %	$ 43.37
Cumberland Electric Member Corp	$ 17.00	$ 33.00	94 %	$ 14.35	$ 47.35	179 %	$ 68.88
Dayton Electric Department, City of	$ 12.64	$ 12.75	1 %	$ 11.02	$ 23.77	88 %	$ 40.31
Decatur Utilities	$ 7.00	$ 11.45	64 %	$ 12.61	$ 24.06	244 %	$ 42.98
Dickson Electric Department	$ 8.70	$ 17.90	106 %	$ 13.08	$ 30.98	256 %	$ 50.60
Duck River Electric Member Corp	$ 11.65	$ 28.66	146 %	$ 13.59	$ 42.25	263 %	$ 62.64
Dyersburg Electric System	N.A.	N.A.	N.A.	$ 12.46	N.A.	N.A.	N.A.
East Mississippi Electric Power Association	$ 18.00	$ 28.00	56 %	$ 11.38	$ 39.38	119 %	$ 56.45
Electric Board of Guntersville	$ 11.00	$ 17.15	56 %	$ 12.60	$ 29.75	170 %	$ 48.66
Electric Power Board of Chattanooga	$ 7.36	$ 9.36	27 %	$ 12.09	$ 21.45	191 %	$ 39.58
Elizabethton Electric Department, City of	$ 11.02	$ 13.29	21 %	$ 11.64	$ 24.93	126 %	$ 42.39
Erwin Utilities	$ 11.29	$ 20.40	81 %	$ 10.75	$ 31.15	176 %	$ 47.27
Etowah Utilities	$ 9.17	$ 18.47	101 %	$ 11.55	$ 30.02	227 %	$ 47.33
Fayetteville Public Utilities	$ 18.00	$ 22.40	24 %	$ 12.60	$ 35.00	94 %	$ 53.90
Florence Utilities	$ 12.25	$ 19.53	59 %	$ 13.14	$ 32.67	167 %	$ 52.38
Forked Deer Electric Cooperative	N.A.	$ 30.90	N.A.	$ 14.08	$ 44.98	N.A.	$ 66.09
Fort Loudoun Electric Cooperative	$ 22.55	$ 22.55	0 %	$ 13.49	$ 36.04	60 %	$ 56.28
Fort Payne Improvement Authority	$ 11.02	$ 15.66	42 %	$ 11.93	$ 27.59	150 %	$ 45.47
Franklin Electric Cooperative	$ 17.00	$ 17.11	1 %	$ 10.09	$ 27.20	60 %	$ 42.33
Franklin Electric Power Board	N.A.	$ 22.45	N.A.	$ 10.78	$ 33.23	N.A.	$ 49.41
Fulton Electric System	N.A.	N.A.	N.A.	$ 10.88	N.A.	N.A.	N.A.

Local Power Company	Existing Mandatory Fee 2011	Existing Mandatory Fee 2018	Existing Mandatory Fee % Increase	TVA GAC (1 ¢/kWh) as Fee	Mandatory Fee w/GAC 2018	Mandatory Fee w/GAC % Increase	Fee w/GAC at 2.5 ¢/kWh
TVA - All Residential Customers	*$ 11.89*	*$ 17.66*	*48 %*	*$ 12.12*	*$ 29.78*	*150 %*	*$ 47.96*
Gallatin Department of Electricity	$ 7.92	$ 13.55	71 %	$ 10.91	$ 24.46	209 %	$ 40.82
Gibson Electric Members Corp	$ 17.97	$ 23.50	31 %	$ 13.60	$ 37.10	106 %	$ 57.51
Glasgow Electric Power Board	$ 10.00	$ 27.56	176 %	$ 9.93	$ 37.49	275 %	$ 52.39
Greeneville Light & Power System	$ 11.00	$ 18.24	66 %	$ 12.68	$ 30.92	181 %	$ 49.93
Harriman Utiliy Board	$ 9.43	$ 17.58	86 %	$ 12.05	$ 29.63	214 %	$ 47.71
Hartselle Utilities	N.A.	$ 16.65	N.A.	$ 12.62	$ 29.27	N.A.	$ 48.20
Hickman Electric System	N.A.	N.A.	N.A.	$ 9.77	N.A.	N.A.	N.A.
Holly Springs Utility Department	N.A.	$ 12.15	N.A.	$ 12.70	$ 24.85	N.A.	$ 43.90
Holston Electric Cooperative	$ 12.00	$ 18.00	50 %	$ 12.30	$ 30.30	153 %	$ 48.76
Hopkinsville Electric System	N.A.	$ 21.40	N.A.	$ 10.84	$ 32.24	N.A.	$ 48.49
Humboldt Utilities	$ 8.00	$ 11.00	38 %	$ 10.98	$ 21.98	175 %	$ 38.44
Huntsville Utilities	$ 5.88	$ 9.17	56 %	$ 12.65	$ 21.82	271 %	$ 40.80
Jackson Energy Authority	$ 15.00	$ 19.73	32 %	$ 10.93	$ 30.66	104 %	$ 47.06
Jellico Electric & Water System	$ 7.37	$ 10.37	41 %	$ 11.41	$ 21.78	195 %	$ 38.89
Joe Wheeler Electric Member Corp	$ 17.70	$ 31.40	77 %	$ 14.16	$ 45.56	157 %	$ 66.81
Knoxville Utilities Board	$ 8.00	$ 17.50	119 %	$ 11.47	$ 28.97	262 %	$ 46.18
LaFollette Utilities Board	$ 11.43	$ 20.13	76 %	$ 11.04	$ 31.17	173 %	$ 47.72
Lawrenceburg Electric System	$ 15.00	$ 19.00	27 %	$ 12.45	$ 31.45	110 %	$ 50.11
Lenoir City Utilities Board	$ 13.55	$ 16.52	22 %	$ 13.17	$ 29.69	119 %	$ 49.44
Lewisburg Electric System	$ 7.90	$ 16.20	105 %	$ 11.60	$ 27.80	252 %	$ 45.19
Lexington Electric System	$ 7.37	$ 15.50	110 %	$ 11.11	$ 26.61	261 %	$ 43.27
Loudon Utilities Board	$ 8.67	$ 12.67	46 %	$ 12.65	$ 25.32	192 %	$ 44.28
Louisville Utilities	N.A.	N.A.	N.A.	$ 10.94	N.A.	N.A.	N.A.
Macon Electric Department, City of	$ 15.95	$ 19.45	22 %	$ 10.98	$ 30.43	91 %	$ 46.91
Marshall-De Kalb Electric Cooperative	$ 9.39	$ 19.70	110 %	$ 13.00	$ 32.70	248 %	$ 52.20
Maryville Electric Department, City of	$ 6.62	$ 10.62	60 %	$ 11.29	$ 21.91	231 %	$ 38.85
Mayfield Electric & Water System	$ 13.55	$ 19.31	43 %	$ 9.33	$ 28.64	111 %	$ 42.64
McMinnville Electric System	$ 11.52	$ 17.21	49 %	$ 10.49	$ 27.70	140 %	$ 43.43
Memphis Light, Gas and Water	$ 9.49	$ 11.60	22 %	$ 11.90	$ 23.50	148 %	$ 41.35
Meriwether Lewis Electric Cooperative	$ 29.82	$ 33.40	12 %	$ 12.07	$ 45.47	52 %	$ 63.57
Middle Tennessee Electric Member Corp	$ 9.79	$ 19.75	102 %	$ 13.16	$ 32.91	236 %	$ 52.65
Milan Department of Public Utilities	$ 12.12	$ 15.19	25 %	$ 12.88	$ 28.07	132 %	$ 47.40
Monroe County Electric Power Association	$ 10.49	$ 16.00	53 %	$ 13.63	$ 29.63	182 %	$ 50.09
Morristown Utility Systems	$ 15.00	$ 24.87	66 %	$ 11.25	$ 36.12	141 %	$ 52.99
Mount Pleasant Power System	$ 13.91	$ 20.45	47 %	$ 12.26	$ 32.71	135 %	$ 51.10
Mountain Electric Cooperative	$ 13.75	$ 15.75	15 %	$ 9.49	$ 25.24	84 %	$ 39.47
Murfreesboro Electric Department	$ 8.65	$ 11.76	36 %	$ 10.89	$ 22.65	162 %	$ 38.97
Murphy Electric Power Board	$ 16.29	$ 16.55	2 %	$ 10.36	$ 26.91	65 %	$ 42.45
Murray Electric System	N.A.	$ 20.48	N.A.	$ 9.44	$ 29.92	N.A.	$ 44.08
Muscle Shoals Electric Board	$ 9.00	$ 16.11	79 %	$ 12.72	$ 28.83	220 %	$ 47.92
Nashville Electric Service	$ 10.01	$ 15.30	53 %	$ 11.28	$ 26.58	166 %	$ 43.51
Natchez Trace Electric Power Association	$ 13.15	$ 19.40	48 %	$ 12.05	$ 31.45	139 %	$ 49.53
New Albany Light, Gas & Water	N.A.	N.A.	N.A.	$ 12.21	N.A.	N.A.	N.A.
Newbern Electric, Water & Gas	N.A.	N.A.	N.A.	$ 11.53	N.A.	N.A.	N.A.
Newport Utilities	$ 9.40	$ 16.99	81 %	$ 11.24	$ 28.23	200 %	$ 45.09
North Alabama Electric Cooperative	$ 12.00	$ 19.42	62 %	$ 13.10	$ 32.52	171 %	$ 52.18
North East Mississippi Electric Power Association	$ 18.51	$ 19.05	3 %	$ 10.65	$ 29.70	60 %	$ 45.68
North Georgia Electric Member Corp	$ 12.00	$ 23.00	92 %	$ 14.08	$ 37.08	209 %	$ 58.20
Northcentral Mississippi Electric Power Associatio	$ 10.03	$ 17.00	69 %	$ 13.88	$ 30.88	208 %	$ 51.70
Oak Ridge Electric Department	$ 9.70	$ 11.83	22 %	$ 9.45	$ 21.28	119 %	$ 35.46
Okolona Electric Department, City of	$ 13.82	$ 17.83	29 %	$ 12.39	$ 30.22	119 %	$ 48.80
Oxford Electric Department, City of	N.A.	$ 13.46	N.A.	$ 8.84	$ 22.30	N.A.	$ 35.57
Paris Board of Public Utilities	$ 11.00	$ 13.00	18 %	$ 12.51	$ 25.51	132 %	$ 44.26
Pennyrile Rural Electric Cooperative	$ 14.51	$ 23.40	61 %	$ 12.53	$ 35.93	148 %	$ 54.72
Philadelphia Utilities	$ 12.70	$ 14.81	17 %	$ 12.18	$ 26.99	113 %	$ 45.25

Local Power Company	Existing Mandatory Fee 2011	Existing Mandatory Fee 2018	Existing Mandatory Fee % Increase	TVA GAC (1 ¢/kWh) as Fee	Mandatory Fee w/GAC 2018	Mandatory Fee w/GAC % Increase	Fee w/GAC at 2.5 ¢/kWh
TVA - All Residential Customers	*$ 11.89*	*$ 17.66*	*48 %*	*$ 12.12*	*$ 29.78*	*150 %*	*$ 47.96*
Pickwick Electric Cooperative	$ 19.46	$ 25.40	31 %	$ 12.41	$ 37.81	94 %	$ 56.42
Plateau Electric Cooperative	N.A.	$ 20.29	N.A.	$ 9.51	$ 29.80	N.A.	$ 44.07
Pontotoc Electric Power Association	$ 13.40	$ 17.20	28 %	$ 12.70	$ 29.90	123 %	$ 48.96
Powell Valley Electric Cooperative	$ 12.00	$ 12.00	0 %	$ 10.91	$ 22.91	91 %	$ 39.27
Prentiss County Electric Power Association	$ 11.00	$ 13.50	23 %	$ 12.32	$ 25.82	135 %	$ 44.29
Pulaski Electric System	$ 19.10	$ 22.42	17 %	$ 12.09	$ 34.51	81 %	$ 52.65
Ripley Power & Light	$ 11.49	$ 13.04	13 %	$ 11.54	$ 24.58	114 %	$ 41.88
Rockwood Electric Utility	$ 12.29	$ 16.29	33 %	$ 12.56	$ 28.85	135 %	$ 47.69
Russellville Electric Board	N.A.	$ 18.22	N.A.	$ 10.87	$ 29.09	N.A.	$ 45.39
Russellville Electric Plant Board	$ 11.00	$ 15.15	38 %	$ 9.42	$ 24.57	123 %	$ 38.69
Sand Mountain Electric Cooperative	$ 25.00	$ 25.00	0 %	$ 12.20	$ 37.20	49 %	$ 55.50
Scottsboro Electric Power Board	$ 13.15	$ 22.00	67 %	$ 12.44	$ 34.44	162 %	$ 53.10
Sequachee Valley Electric Cooperative	$ 18.19	$ 24.94	37 %	$ 12.05	$ 36.99	103 %	$ 55.06
Sevier County Electric System	$ 12.50	$ 16.50	32 %	$ 11.41	$ 27.91	123 %	$ 45.03
Sheffield Utilities	$ 6.63	$ 23.09	248 %	$ 12.74	$ 35.83	440 %	$ 54.93
Shelbyville Power System	$ 10.38	$ 18.11	74 %	$ 11.01	$ 29.12	181 %	$ 45.63
Smithville Electric System	N.A.	N.A.	N.A.	$ 8.92	N.A.	N.A.	N.A.
Southwest Tennessee Electric Member Corp	$ 15.00	$ 22.00	47 %	$ 13.77	$ 35.77	138 %	$ 56.42
Sparta Electric & Public Works	$ 9.50	$ 13.61	43 %	$ 9.71	$ 23.32	146 %	$ 37.89
Springfield Electric	$ 7.44	$ 11.37	53 %	$ 11.83	$ 23.20	212 %	$ 40.94
Starkville Electric Department	$ 11.20	$ 13.97	25 %	$ 8.50	$ 22.47	101 %	$ 35.21
Sweetwater Utilities Board	$ 8.70	$ 21.17	143 %	$ 13.07	$ 34.24	294 %	$ 53.84
Tallahatchie Valley Electric Power Association	$ 14.11	$ 27.11	92 %	$ 13.18	$ 40.29	186 %	$ 60.05
Tarrant Electric Department	$ 9.71	$ 18.50	91 %	$ 11.65	$ 30.15	210 %	$ 47.62
Tennessee Valley Electric Cooperative	$ 14.50	$ 21.50	48 %	$ 11.29	$ 32.79	126 %	$ 49.71
Tippah Electric Power Association	$ 16.50	$ 17.68	7 %	$ 11.93	$ 29.61	79 %	$ 47.50
Tishomingo County Electric Power Association	$ 12.00	$ 16.64	39 %	$ 11.25	$ 27.89	132 %	$ 44.76
Tombigbee Electric Power Association	$ 12.11	$ 16.40	35 %	$ 12.96	$ 29.36	142 %	$ 48.80
Trenton Light & Water Department	$ 12.25	$ 14.16	16 %	$ 10.63	$ 24.79	102 %	$ 40.73
Tri-County Electric Member Corp	$ 18.00	$ 18.00	0 %	$ 12.37	$ 30.37	69 %	$ 48.92
Tri-State Electric Member Corp	$ 17.50	$ 19.50	11 %	$ 9.33	$ 28.83	65 %	$ 42.84
Tullahoma Utilities Authority	$ 8.00	$ 21.00	163 %	$ 11.66	$ 32.66	308 %	$ 50.15
Tupelo Water & Light Department, City of	N.A.	N.A.	N.A.	$ 11.55	N.A.	N.A.	N.A.
Tuscumbia Electricity Department	$ 10.12	$ 12.70	25 %	$ 11.43	$ 24.13	138 %	$ 41.28
Union City Electric System	$ 13.31	$ 13.31	0 %	$ 11.00	$ 24.31	83 %	$ 40.80
Upper Cumberland Electric Member Corp	$ 11.25	$ 27.36	143 %	$ 12.00	$ 39.36	250 %	$ 57.36
Volunteer Electric Cooperative	$ 11.71	$ 11.71	0 %	$ 12.08	$ 23.79	103 %	$ 41.91
Warren Rural Electric Cooperative Corp	$ 11.80	$ 18.80	59 %	$ 12.96	$ 31.76	169 %	$ 51.20
Water Valley Electric Department, City of	$ 19.14	$ 22.73	19 %	$ 11.74	$ 34.47	80 %	$ 52.08
Weakley County Municipal Electric System	$ 8.88	$ 12.27	38 %	$ 13.87	$ 26.14	194 %	$ 46.94
West Kentucky Rural Electric Cooperative	$ 18.29	$ 23.40	28 %	$ 12.36	$ 35.76	96 %	$ 54.30
West Point Electric System, City of	N.A.	N.A.	N.A.	$ 9.76	N.A.	N.A.	N.A.
Winchester Utilities	N.A.	$ 18.00	N.A.	$ 11.84	$ 29.84	N.A.	$ 47.59

Source: Existing mandatory fees collected from websites or by phone survey from TVA's local power companies. Missing data reflects refusal or failure to respond.

Appendix B

Impact of TVA's Grid Access Charge and Industrial Rate Shift on Lower Income Residential Customers

Local Power Company	Average Monthly Energy Bills	Average Monthly Electric Bills	Average Monthly Electricity Use (kWh)	Current Average Residential Energy Rate ($/kwh)	Current Mandatory Fee	Proposed GAC per Customer	% of Households with Income Below 80% of AMI	Low Income Households (<80 AMI) Bill Characteristics								
											Energy Burden (% of Household Income Spent on Energy)					
								Monthly Energy Bills Bill	Monthly Electric Bills	Estimated kwh Monthly	Current Average	Declining Block Rates at 1 c/kWh GAC	Declining Block Rates at 2.5 c/kWh GAC	Mandatory Fee at 1 c/kWh GAC	Mandatory Fee at 2.5 c/kWh GAC	Roll Back Industrial Rate Shift
TVA Average	$ 220	$ 142	1,381	$ 0.092	$ 14.73	$ 12.12	41.8 %	$ 202	$ 129	1,245	12.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.5 %
4 County Electric Power Association	$ 224	$ 151	1,324	$ 0.093	$ 28.40	$ 12.25	45.4 %	$ 203	$ 134	1,134	15.9%	+ 0.1 %	+ 0.3 %	+ 1.0 %	+ 2.4 %	- 0.7 %
Aberdeen Electric Department	$ 221	$ 147	1,367	$ 0.097	$ 14.85	$ 11.67	53.2 %	$ 209	$ 136	1,245	18.2%	+ 0.1 %	+ 0.3 %	+ 1.0 %	+ 2.5 %	- 1.1 %
Albertville Municipal Utilities Board	$ 219	$ 148	1,575	$ 0.089	$ 8.55	$ 12.89	48.2 %	$ 190	$ 130	1,366	13.4%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.3 %	- 0.4 %
Alcoa Utilities, City of	$ 208	$ 136	1,346	$ 0.093	$ 11.25	$ 12.38	45.8 %	$ 182	$ 123	1,206	10.1%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.5 %
Alcorn County Electric Power Association	$ 247	$ 155	1,447	$ 0.093	$ 19.80	$ 12.48	44.7 %	$ 221	$ 136	1,250	15.5%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.9 %
Amory, City of	$ 206	$ 139	1,381	$ 0.093	$ 9.86	$ 11.46	45.8 %	$ 190	$ 127	1,251	15.0%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.6 %
Appalachian Electric Cooperative	$ 206	$ 152	1,384	$ 0.096	$ 19.40	$ 12.83	38.4 %	$ 188	$ 136	1,215	13.1%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.7 %
Arab Electric Cooperative	$ 246	$ 155	1,473	$ 0.092	$ 18.80	$ 12.98	39.6 %	$ 222	$ 134	1,248	15.2%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.5 %
Athens Electric Department, City of	$ 236	$ 163	1,711	$ 0.091	$ 8.19	$ 13.29	50.6 %	$ 219	$ 150	1,568	10.4%	+ 0.0 %	+ 0.1 %	+ 0.6 %	+ 1.6 %	- 0.3 %
Athens Utility Board	$ 228	$ 151	1,561	$ 0.086	$ 15.68	$ 12.04	47.3 %	$ 221	$ 136	1,388	16.1%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.3 %
Benton County Electric System (TN)	$ 236	$ 149	1,301	$ 0.098	$ 20.91	$ 11.17	45.5 %	$ 220	$ 139	1,203	16.8%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.8 %
Benton Electric System (KY)	$ 245	$ 153	1,346	$ 0.104	$ 13.00	$ 11.46	48.2 %	$ 232	$ 145	1,263	13.5%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.8 %
Bessemer Utilities, City of	$ 243	$ 159	1,557	$ 0.094	$ 12.66	$ 10.77	54.1 %	$ 231	$ 147	1,425	15.4%	+ 0.1 %	+ 0.1 %	+ 0.7 %	+ 1.8 %	- 0.4 %
Blue Ridge Mountain Electric Member Corp	$ 271	$ 130	1,057	$ 0.105	$ 19.40	$ 8.41	39.8 %	$ 257	$ 117	931	17.2%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.4 %	- 0.4 %
Bolivar Energy Authority	$ 247	$ 147	1,245	$ 0.099	$ 23.89	$ 12.63	42.8 %	$ 239	$ 135	1,121	17.1%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.9 %
Bowling Green Municipal Utilities	$ 176	$ 113	1,134	$ 0.087	$ 14.58	$ 8.99	54.1 %	$ 154	$ 101	989	10.2%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.5 %	+ 0.2 %
BrightRidge	$ 192	$ 127	1,245	$ 0.090	$ 14.51	$ 12.06	40.0 %	$ 177	$ 113	1,090	12.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.6 %
Bristol Tennessee Essential Services	$ 215	$ 144	1,553	$ 0.084	$ 12.88	$ 13.38	41.4 %	$ 213	$ 134	1,432	13.8%	+ 0.1 %	+ 0.1 %	+ 0.9 %	+ 2.1 %	- 0.5 %
Brownsville Utility Department	$ 180	$ 119	1,261	$ 0.089	$ 7.24	$ 11.23	51.9 %	$ 171	$ 110	1,160	13.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.4 %
BVU Authority	$ 169	$ 126	1,160	$ 0.100	$ 10.10	$ 12.40	59.7 %	$ 157	$ 118	1,079	11.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.7 %
Caney Fork Electric Cooperative	$ 222	$ 130	1,256	$ 0.093	$ 13.36	$ 11.99	42.5 %	$ 205	$ 119	1,135	14.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.6 %
Carroll County Electric Department	$ 206	$ 123	1,209	$ 0.085	$ 20.40	$ 12.92	44.5 %	$ 187	$ 113	1,091	13.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.3 %	- 0.8 %
CDE Lightband	$ 186	$ 140	1,298	$ 0.095	$ 16.16	$ 11.11	37.5 %	$ 169	$ 130	1,195	11.2%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.3 %
Central Electric Power Association	$ 277	$ 162	1,531	$ 0.096	$ 15.11	$ 12.82	39.5 %	$ 266	$ 147	1,374	19.6%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.4 %	- 0.4 %
Cherokee Electric Cooperative	$ 319	$ 179	1,407	$ 0.110	$ 23.58	$ 11.69	45.2 %	$ 315	$ 164	1,276	21.2%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.9 %
Chickamauga Electric System	$ 243	$ 165	1,686	$ 0.088	$ 17.31	$ 12.18	46.4 %	$ 225	$ 149	1,498	12.8%	+ 0.0 %	+ 0.1 %	+ 0.7 %	+ 1.7 %	- 0.6 %
Chickasaw Electric Cooperative	$ 251	$ 153	1,624	$ 0.087	$ 12.45	$ 14.57	35.7 %	$ 230	$ 131	1,375	13.8%	+ 0.1 %	+ 0.1 %	+ 0.9 %	+ 2.2 %	- 0.4 %
Cleveland Utilities	$ 193	$ 140	1,425	$ 0.092	$ 8.09	$ 11.73	46.5 %	$ 177	$ 125	1,266	13.2%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 1.0 %
Clinton Utilities Board	$ 210	$ 129	1,207	$ 0.096	$ 13.42	$ 12.37	48.1 %	$ 208	$ 119	1,104	12.0%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.6 %
Columbia Power & Water Systems	$ 217	$ 142	1,428	$ 0.091	$ 12.76	$ 11.51	48.2 %	$ 193	$ 130	1,290	12.2%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.6 %
Columbus Light & Water	$ 204	$ 147	1,570	$ 0.084	$ 14.85	$ 12.03	59.3 %	$ 188	$ 133	1,405	15.4%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.4 %	- 0.6 %
Cookeville Electric Department	$ 158	$ 109	1,089	$ 0.091	$ 10.00	$ 10.14	53.8 %	$ 128	$ 96	945	11.5%	+ 0.2 %	+ 0.4 %	+ 0.9 %	+ 2.3 %	- 0.3 %
Courtland, City of	$ 265	$ 172	1,844	$ 0.086	$ 12.67	$ 11.86	46.5 %	$ 247	$ 153	1,623	17.7%	+ 0.0 %	+ 0.1 %	+ 0.9 %	+ 2.1 %	- 0.3 %
Covington Electric System	$ 214	$ 130	1,354	$ 0.088	$ 10.11	$ 11.16	67.0 %	$ 206	$ 119	1,232	12.5%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.4 %
Cullman Electric Cooperative	$ 257	$ 182	1,692	$ 0.092	$ 26.94	$ 12.53	41.4 %	$ 225	$ 162	1,476	15.5%	+ 0.0 %	+ 0.1 %	+ 0.9 %	+ 2.2 %	- 0.6 %
Cullman Power Board	$ 220	$ 159	1,568	$ 0.094	$ 12.30	$ 11.01	43.5 %	$ 171	$ 132	1,280	13.9%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 1.2 %
Cumberland Electric Member Corp	$ 250	$ 170	1,569	$ 0.090	$ 29.00	$ 14.35	34.8 %	$ 224	$ 155	1,403	11.0%	+ 0.0 %	+ 0.1 %	+ 0.7 %	+ 1.8 %	- 0.7 %
Dayton Electric Department, City of	$ 216	$ 139	1,327	$ 0.095	$ 12.75	$ 11.02	47.8 %	$ 189	$ 128	1,209	13.6%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.5 %
Decatur Utilities	$ 180	$ 138	1,495	$ 0.086	$ 10.00	$ 12.61	43.8 %	$ 150	$ 118	1,267	10.3%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 0.8 %
Dickson Electric Department	$ 265	$ 159	1,629	$ 0.087	$ 17.90	$ 13.08	49.7 %	$ 254	$ 149	1,510	13.0%	+ 0.0 %	+ 0.1 %	+ 0.7 %	+ 1.7 %	- 0.3 %
Duck River Electric Member Corp	$ 255	$ 157	1,498	$ 0.090	$ 22.00	$ 13.59	37.2 %	$ 229	$ 145	1,364	14.0%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.4 %
Dyersburg Electric System	$ 184	$ 125	1,324	$ 0.085	$ 13.15	$ 12.46	43.9 %	$ 158	$ 106	1,103	11.1%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.6 %
East Mississippi Electric Power Association	$ 251	$ 171	1,451	$ 0.101	$ 25.00	$ 11.38	37.8 %	$ 245	$ 154	1,282	18.4%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	+ 1.4 %
Electric Board of Guntersville	$ 241	$ 147	1,485	$ 0.090	$ 12.60	$ 12.60	45.6 %	$ 220	$ 127	1,274	15.9%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.6 %
Electric Power Board of Chattanooga	$ 192	$ 134	1,284	$ 0.098	$ 7.36	$ 12.09	40.7 %	$ 169	$ 124	1,190	10.4%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.8 %
Elizabethton Electric Department, City of	$ 232	$ 129	1,223	$ 0.094	$ 13.29	$ 11.64	50.3 %	$ 228	$ 119	1,118	15.6%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.6 %
Erwin Utilities	$ 232	$ 116	1,154	$ 0.087	$ 15.29	$ 10.75	49.7 %	$ 229	$ 110	1,084	15.5%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.8 %	- 0.6 %

Local Power Company	Average Monthly Energy Bills	Average Monthly Electric Bills	Average Monthly Electricity Use (kWh)	Current Average Residential Energy Rate ($/kwh)	Current Mandatory Fee	Proposed GAC per Customer	% of Households with Income Below 80% of AMI	Low Income Households (<80 AMI) Bill Characteristics								
											Energy Burden (% of Household Income Spent on Energy)					
								Monthly Energy Bills Bill	Monthly Electric Bills	Estimated kwh Monthly	Current Average	Declining Block Rates at 1 c/kWh GAC	Declining Block Rates at 2.5 c/kWh GAC	Mandatory Fee at 1 c/kWh GAC	Mandatory Fee at 2.5 c/kWh GAC	Roll Back Industrial Rate Shift
TVA Average	$ 220	$ 142	1,381	$ 0.092	$ 14.73	$ 12.12	41.8 %	$ 202	$ 129	1,245	12.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.5 %
Etowah Utilities	$ 247	$ 154	1,304	$ 0.108	$ 13.26	$ 11.55	43.3 %	$ 252	$ 139	1,164	17.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 1.5 %
Fayetteville Public Utilities	$ 264	$ 158	1,496	$ 0.092	$ 21.10	$ 12.60	44.1 %	$ 236	$ 147	1,371	14.5%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.6 %
Florence Utilities	$ 201	$ 139	1,409	$ 0.090	$ 12.36	$ 13.14	52.4 %	$ 171	$ 124	1,240	12.5%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.4 %	- 0.4 %
Forked Deer Electric Cooperative	$ 211	$ 139	1,174	$ 0.095	$ 27.40	$ 14.08	42.4 %	$ 196	$ 123	1,002	13.5%	+ 0.1 %	+ 0.3 %	+ 1.0 %	+ 2.4 %	- 0.6 %
Fort Loudoun Electric Cooperative	$ 243	$ 156	1,472	$ 0.090	$ 22.55	$ 13.49	40.2 %	$ 220	$ 143	1,329	13.7%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.5 %
Fort Payne Improvement Authority	$ 239	$ 150	1,515	$ 0.089	$ 15.29	$ 11.93	42.8 %	$ 223	$ 134	1,328	16.6%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.7 %
Franklin Electric Cooperative (AL)	$ 243	$ 155	1,339	$ 0.103	$ 17.11	$ 10.09	40.3 %	$ 212	$ 137	1,165	13.5%	+ 0.1 %	+ 0.2 %	+ 0.6 %	+ 1.6 %	- 0.3 %
Franklin Electric Power Board	$ 239	$ 134	1,306	$ 0.089	$ 18.20	$ 10.78	44.5 %	$ 209	$ 115	1,096	13.7%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.8 %	- 0.9 %
Fulton Electric System	$ 239	$ 145	1,327	$ 0.099	$ 13.15	$ 10.88	47.9 %	$ 217	$ 132	1,194	16.5%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.8 %
Gallatin Department of Electricity	$ 220	$ 153	1,645	$ 0.085	$ 13.55	$ 10.91	51.5 %	$ 191	$ 137	1,463	9.5%	+ 0.0 %	+ 0.1 %	+ 0.5 %	+ 1.4 %	- 0.8 %
Gibson Electric Members Corp	$ 228	$ 145	1,348	$ 0.093	$ 20.00	$ 13.60	42.7 %	$ 207	$ 128	1,171	13.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.2 %
Glasgow Electric Power Board	$ 198	$ 120	1,129	$ 0.095	$ 12.37	$ 9.93	57.0 %	$ 166	$ 103	958	12.8%	+ 0.1 %	+ 0.4 %	+ 0.7 %	+ 1.8 %	- 1.2 %
Greeneville Light & Power System	$ 230	$ 140	1,448	$ 0.089	$ 11.11	$ 12.68	43.2 %	$ 227	$ 130	1,332	15.9%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.6 %
Harriman Utiliy Board	$ 235	$ 142	1,287	$ 0.099	$ 14.58	$ 12.05	51.8 %	$ 206	$ 132	1,181	14.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 1.2 %
Hartselle Utilities	$ 194	$ 144	1,491	$ 0.087	$ 13.78	$ 12.62	39.3 %	$ 165	$ 124	1,261	11.0%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.6 %
Hickman Electric System	$ 224	$ 132	1,115	$ 0.100	$ 20.90	$ 9.77	59.7 %	$ 205	$ 122	1,009	18.7%	+ 0.2 %	+ 0.4 %	+ 0.9 %	+ 2.2 %	- 0.8 %
Holly Springs Utility Department	$ 310	$ 162	1,499	$ 0.100	$ 11.02	$ 12.70	43.5 %	$ 276	$ 145	1,336	19.5%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.4 %
Holston Electric Cooperative	$ 192	$ 131	1,322	$ 0.090	$ 12.00	$ 12.30	42.2 %	$ 179	$ 119	1,187	12.6%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.1 %	- 0.5 %
Hopkinsville Electric System	$ 190	$ 121	1,182	$ 0.086	$ 19.06	$ 10.84	52.0 %	$ 173	$ 113	1,087	12.9%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.6 %
Humboldt Utilities	$ 204	$ 140	1,444	$ 0.090	$ 10.00	$ 10.98	47.6 %	$ 186	$ 129	1,317	11.9%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.6 %
Huntsville Utilities	$ 192	$ 143	1,501	$ 0.089	$ 8.88	$ 12.65	42.5 %	$ 171	$ 125	1,304	8.4%	+ 0.1 %	+ 0.1 %	+ 0.6 %	+ 1.5 %	- 0.4 %
Jackson Energy Authority	$ 213	$ 137	1,356	$ 0.090	$ 15.00	$ 10.93	54.5 %	$ 182	$ 127	1,249	13.8%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.6 %
Jellico Electric & Water System	$ 241	$ 126	1,241	$ 0.093	$ 10.37	$ 11.41	59.3 %	$ 225	$ 115	1,124	18.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.3 %	- 0.4 %
Joe Wheeler Electric Member Corp	$ 248	$ 170	1,582	$ 0.091	$ 26.00	$ 14.16	38.6 %	$ 231	$ 154	1,401	14.7%	+ 0.1 %	+ 0.1 %	+ 0.9 %	+ 2.2 %	- 0.8 %
Knoxville Utilities Board	$ 193	$ 128	1,294	$ 0.088	$ 14.00	$ 11.47	47.1 %	$ 172	$ 118	1,179	10.4%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.6 %
LaFollette Utilities Board	$ 225	$ 138	1,238	$ 0.100	$ 14.43	$ 11.04	47.1 %	$ 204	$ 122	1,077	15.5%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.5 %
Lawrenceburg Electric System	$ 223	$ 143	1,434	$ 0.089	$ 15.00	$ 12.45	42.0 %	$ 190	$ 130	1,291	13.0%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 0.2 %
Lenoir City Utilities Board	$ 216	$ 134	1,376	$ 0.087	$ 14.52	$ 13.17	25.9 %	$ 184	$ 120	1,224	10.2%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.3 %
Lewisburg Electric System	$ 215	$ 143	1,536	$ 0.086	$ 11.10	$ 11.60	50.8 %	$ 197	$ 135	1,445	12.7%	+ 0.1 %	+ 0.1 %	+ 0.7 %	+ 1.8 %	- 0.3 %
Lexington Electric System	$ 202	$ 136	1,320	$ 0.093	$ 12.50	$ 11.11	43.3 %	$ 192	$ 124	1,197	13.3%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 1.9 %	- 0.7 %
Loudon Utilities Board	$ 240	$ 160	1,604	$ 0.094	$ 8.67	$ 12.65	39.4 %	$ 210	$ 135	1,344	12.5%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.4 %
Louisville Utilities	$ 221	$ 139	1,444	$ 0.086	$ 14.85	$ 10.94	47.9 %	$ 209	$ 124	1,275	19.0%	+ 0.1 %	+ 0.3 %	+ 1.0 %	+ 2.5 %	- 0.5 %
Macon Electric Department, City of	$ 204	$ 144	1,384	$ 0.090	$ 18.91	$ 10.98	57.9 %	$ 189	$ 131	1,240	17.8%	+ 0.1 %	+ 0.3 %	+ 1.0 %	+ 2.5 %	- 0.9 %
Marshall De Kalb Electric Cooperative	$ 252	$ 153	1,491	$ 0.094	$ 13.70	$ 13.00	47.1 %	$ 235	$ 138	1,326	17.4%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.4 %	- 0.6 %
Maryville Electric Department, City of	$ 203	$ 137	1,467	$ 0.088	$ 8.62	$ 11.29	42.2 %	$ 174	$ 124	1,310	9.9%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.6 %	+ 0.0 %
Mayfield Electric & Water System	$ 234	$ 139	1,262	$ 0.095	$ 18.81	$ 9.33	54.1 %	$ 218	$ 130	1,171	15.9%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.7 %	- 0.3 %
McMinnville Electric System	$ 188	$ 120	1,256	$ 0.087	$ 11.63	$ 10.49	49.2 %	$ 168	$ 110	1,130	12.3%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 1.9 %	- 0.5 %
Memphis Light, Gas and Water	$ 181	$ 123	1,271	$ 0.089	$ 9.60	$ 11.90	42.2 %	$ 171	$ 115	1,181	11.5%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.1 %
Meriwether Lewis Electric Cooperative	$ 228	$ 146	1,359	$ 0.085	$ 29.93	$ 12.07	43.4 %	$ 213	$ 135	1,233	14.5%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.4 %
Middle Tennessee Electric Member Corp	$ 236	$ 152	1,557	$ 0.087	$ 15.75	$ 13.16	29.1 %	$ 189	$ 132	1,326	8.9%	+ 0.1 %	+ 0.1 %	+ 0.6 %	+ 1.5 %	- 0.3 %
Milan Department of Public Utilities	$ 207	$ 135	1,369	$ 0.089	$ 12.23	$ 12.88	50.1 %	$ 189	$ 119	1,189	12.6%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 0.3 %
Monroe County Electric Power Association	$ 248	$ 163	1,582	$ 0.095	$ 13.71	$ 13.63	36.1 %	$ 241	$ 147	1,414	16.4%	+ 0.1 %	+ 0.1 %	+ 0.9 %	+ 2.3 %	- 0.8 %
Morristown Utility Systems	$ 180	$ 139	1,384	$ 0.090	$ 15.00	$ 11.25	53.2 %	$ 161	$ 130	1,278	12.5%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.5 %
Mount Pleasant Power System	$ 247	$ 161	1,438	$ 0.100	$ 17.45	$ 12.26	43.7 %	$ 215	$ 146	1,280	14.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.7 %
Mountain Electric Cooperative	$ 415	$ 122	1,215	$ 0.087	$ 15.75	$ 9.49	49.0 %	$ 420	$ 111	1,088	28.7%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.6 %	- 0.2 %
Murfreesboro Electric Department	$ 164	$ 122	1,197	$ 0.092	$ 11.76	$ 10.89	49.2 %	$ 129	$ 105	1,016	7.1%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.5 %	- 0.2 %
Murphy Electric Power Board	$ 288	$ 132	1,144	$ 0.101	$ 16.55	$ 10.36	23.3 %	$ 281	$ 126	1,080	20.2%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.9 %	- 0.5 %

Local Power Company	Average Monthly Energy Bills	Average Monthly Electric Bills	Average Monthly Electricity Use (kWh)	Current Average Residential Energy Rate ($/kwh)	Current Mandatory Fee	Proposed GAC per Customer	% of Households with Income Below 80% of AMI	Low Income Households (<80 AMI) Bill Characteristics								
											Energy Burden (% of Household Income Spent on Energy)					
								Monthly Energy Bills Bill	Monthly Electric Bills	Estimated kwh Monthly	Current Average	Declining Block Rates at 1 c/kWh GAC	Declining Block Rates at 2.5 c/kWh GAC	Mandatory Fee at 1 c/kWh GAC	Mandatory Fee at 2.5 c/kWh GAC	Roll Back Industrial Rate Shift
TVA Average	$ 220	$ 142	1,381	$ 0.092	$ 14.73	$ 12.12	41.8 %	$ 202	$ 129	1,245	12.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.5 %
Murray Electric System	$ 195	$ 129	1,174	$ 0.094	$ 18.14	$ 9.44	53.3 %	$ 160	$ 110	970	13.5%	+ 0.2 %	+ 0.4 %	+ 0.8 %	+ 2.0 %	- 1.1 %
Muscle Shoals Electric Board	$ 233	$ 153	1,585	$ 0.089	$ 11.11	$ 12.72	39.0 %	$ 196	$ 134	1,379	11.7%	+ 0.1 %	+ 0.1 %	+ 0.8 %	+ 1.9 %	- 0.3 %
Nashville Electric Service	$ 192	$ 131	1,192	$ 0.100	$ 11.83	$ 11.28	44.4 %	$ 165	$ 123	1,112	8.7%	+ 0.1 %	+ 0.2 %	+ 0.6 %	+ 1.5 %	- 0.5 %
Natchez Trace Electric Power Association	$ 252	$ 155	1,493	$ 0.095	$ 13.56	$ 12.05	46.4 %	$ 236	$ 139	1,327	18.8%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.4 %	- 0.7 %
New Albany Light, Gas & Water	$ 234	$ 152	1,589	$ 0.086	$ 14.85	$ 12.21	43.1 %	$ 222	$ 138	1,431	15.2%	+ 0.1 %	+ 0.1 %	+ 0.8 %	+ 2.1 %	- 0.5 %
Newbern Electric, Water & Gas	$ 207	$ 145	1,619	$ 0.081	$ 13.15	$ 11.53	36.8 %	$ 190	$ 127	1,407	11.4%	+ 0.1 %	+ 0.1 %	+ 0.7 %	+ 1.7 %	- 0.2 %
Newport Utilities	$ 218	$ 134	1,283	$ 0.091	$ 16.99	$ 11.24	49.9 %	$ 200	$ 122	1,146	16.0%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.8 %
North Alabama Electric Cooperative	$ 260	$ 154	1,490	$ 0.096	$ 12.00	$ 13.10	45.6 %	$ 255	$ 141	1,348	17.7%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.9 %
North East Mississippi Electric Power Association	$ 227	$ 147	1,276	$ 0.100	$ 19.05	$ 10.65	45.4 %	$ 206	$ 130	1,101	12.8%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.7 %	- 0.5 %
North Georgia Electric Member Corp	$ 258	$ 167	1,628	$ 0.090	$ 19.75	$ 14.08	40.6 %	$ 252	$ 154	1,486	15.8%	+ 0.0 %	+ 0.1 %	+ 0.9 %	+ 2.2 %	- 1.0 %
Northcentral Mississippi Electric Power Association	$ 245	$ 153	1,537	$ 0.093	$ 10.14	$ 13.88	26.9 %	$ 230	$ 139	1,387	13.1%	+ 0.1 %	+ 0.1 %	+ 0.8 %	+ 2.0 %	- 0.3 %
Oak Ridge Electric Department	$ 212	$ 132	1,233	$ 0.099	$ 9.83	$ 9.45	42.2 %	$ 193	$ 119	1,101	12.2%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.5 %	- 0.4 %
Okolona Electric Department, City of	$ 252	$ 153	1,435	$ 0.096	$ 15.83	$ 12.39	47.2 %	$ 243	$ 140	1,296	18.5%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.3 %	- 0.5 %
Oxford Electric Department, City of	$ 182	$ 130	1,288	$ 0.092	$ 12.33	$ 8.84	61.9 %	$ 166	$ 118	1,153	12.3%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.6 %	- 0.3 %
Paris Board of Public Utilities	$ 220	$ 133	1,364	$ 0.088	$ 13.00	$ 12.51	42.3 %	$ 207	$ 124	1,264	14.1%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 0.5 %
Pennyrile Rural Electric Cooperative	$ 250	$ 146	1,330	$ 0.096	$ 18.40	$ 12.53	40.1 %	$ 229	$ 131	1,180	15.5%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.1 %	- 0.5 %
Philadelphia Utilities	$ 242	$ 150	1,524	$ 0.089	$ 14.81	$ 12.18	44.9 %	$ 227	$ 134	1,342	19.3%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.6 %	- 0.5 %
Pickwick Electric Cooperative	$ 243	$ 151	1,434	$ 0.090	$ 21.90	$ 12.41	48.1 %	$ 229	$ 141	1,321	16.1%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.7 %
Plateau Electric Cooperative	$ 234	$ 130	1,152	$ 0.097	$ 17.61	$ 9.51	50.1 %	$ 210	$ 116	1,013	15.3%	+ 0.1 %	+ 0.4 %	+ 0.7 %	+ 1.7 %	- 0.4 %
Pontotoc Electric Power Association	$ 243	$ 163	1,494	$ 0.099	$ 15.20	$ 12.70	42.1 %	$ 233	$ 147	1,333	15.1%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.7 %
Powell Valley Electric Cooperative	$ 224	$ 135	1,329	$ 0.093	$ 12.00	$ 10.91	46.9 %	$ 221	$ 120	1,166	16.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.4 %
Prentiss County Electric Power Association	$ 244	$ 147	1,617	$ 0.084	$ 11.50	$ 12.32	45.8 %	$ 224	$ 132	1,433	16.1%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.4 %
Pulaski Electric System	$ 246	$ 167	1,482	$ 0.099	$ 20.15	$ 12.09	39.0 %	$ 213	$ 153	1,341	14.7%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.8 %
Ripley Power & Light	$ 175	$ 118	1,142	$ 0.093	$ 11.49	$ 11.54	66.7 %	$ 162	$ 107	1,021	13.7%	+ 0.2 %	+ 0.4 %	+ 1.0 %	+ 2.4 %	- 0.7 %
Rockwood Electric Utility	$ 231	$ 143	1,321	$ 0.096	$ 16.29	$ 12.56	52.1 %	$ 207	$ 130	1,184	14.1%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.1 %	- 0.4 %
Russellville Electric Board (AL)	$ 234	$ 154	1,379	$ 0.101	$ 15.35	$ 10.87	48.5 %	$ 201	$ 142	1,262	14.5%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 1.5 %
Russellville Electric Plant Board (KY)	$ 260	$ 139	1,440	$ 0.089	$ 11.11	$ 9.42	44.0 %	$ 236	$ 120	1,232	17.1%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.7 %	- 0.5 %
Sand Mountain Electric Cooperative	$ 275	$ 156	1,487	$ 0.088	$ 25.00	$ 12.20	40.8 %	$ 277	$ 142	1,333	19.8%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.5 %
Scottsboro Electric Power Board	$ 233	$ 145	1,349	$ 0.092	$ 21.00	$ 12.44	42.8 %	$ 202	$ 129	1,176	13.5%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 1.2 %
Sequachee Valley Electric Cooperative	$ 243	$ 156	1,472	$ 0.091	$ 21.94	$ 12.05	47.0 %	$ 226	$ 147	1,375	14.7%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.6 %
Sevier County Electric System	$ 193	$ 139	1,390	$ 0.091	$ 12.50	$ 11.41	39.1 %	$ 172	$ 124	1,227	11.1%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.2 %
Sheffield Utilities	$ 233	$ 144	1,408	$ 0.090	$ 17.09	$ 12.74	51.8 %	$ 205	$ 131	1,267	14.5%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.8 %
Shelbyville Power System	$ 210	$ 148	1,480	$ 0.093	$ 10.61	$ 11.01	44.8 %	$ 188	$ 134	1,336	12.7%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.3 %
Smithville Electric System	$ 211	$ 116	1,169	$ 0.088	$ 13.15	$ 8.92	41.8 %	$ 185	$ 100	983	13.1%	+ 0.1 %	+ 0.3 %	+ 0.6 %	+ 1.6 %	- 0.4 %
Southwest Tennessee Electric Member Corp	$ 231	$ 151	1,365	$ 0.095	$ 22.00	$ 13.77	36.2 %	$ 213	$ 137	1,213	13.3%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.1 %	- 0.5 %
Sparta Electric & Public Works	$ 220	$ 116	1,182	$ 0.088	$ 11.61	$ 9.71	48.9 %	$ 196	$ 106	1,070	15.3%	+ 0.1 %	+ 0.4 %	+ 0.8 %	+ 1.9 %	- 0.7 %
Springfield Electric	$ 230	$ 157	1,698	$ 0.088	$ 8.37	$ 11.83	57.2 %	$ 222	$ 146	1,577	12.5%	+ 0.0 %	+ 0.1 %	+ 0.7 %	+ 1.7 %	- 0.5 %
Starkville Electric Department	$ 167	$ 122	1,163	$ 0.094	$ 12.97	$ 8.50	54.1 %	$ 145	$ 109	1,031	11.5%	+ 0.2 %	+ 0.4 %	+ 0.7 %	+ 1.7 %	- 0.2 %
Sweetwater Utilities Board	$ 239	$ 154	1,600	$ 0.086	$ 16.67	$ 13.07	43.6 %	$ 220	$ 142	1,450	15.7%	+ 0.1 %	+ 0.1 %	+ 0.9 %	+ 2.3 %	- 0.5 %
Tallahatchie Valley Electric Power Association	$ 293	$ 164	1,555	$ 0.091	$ 22.11	$ 13.18	40.3 %	$ 263	$ 150	1,398	20.1%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.5 %	- 0.7 %
Tarrant Electric Department	$ 227	$ 154	1,361	$ 0.104	$ 13.10	$ 11.65	67.3 %	$ 221	$ 152	1,337	15.1%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 1.5 %
Tennessee Valley Electric Cooperative	$ 232	$ 136	1,264	$ 0.093	$ 18.00	$ 11.29	48.4 %	$ 214	$ 126	1,158	15.1%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.5 %
Tippah Electric Power Association	$ 251	$ 143	1,327	$ 0.096	$ 16.50	$ 11.93	43.2 %	$ 238	$ 127	1,159	17.5%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.7 %
Tishomingo County Electric Power Association	$ 247	$ 141	1,344	$ 0.093	$ 16.54	$ 11.25	41.1 %	$ 228	$ 124	1,158	15.9%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.7 %
Tombigbee Electric Power Association	$ 224	$ 144	1,408	$ 0.094	$ 12.11	$ 12.96	44.1 %	$ 214	$ 129	1,249	13.4%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.4 %
Trenton Light & Water Department	$ 218	$ 135	1,261	$ 0.097	$ 12.36	$ 10.63	53.2 %	$ 193	$ 119	1,099	13.2%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.8 %	- 1.0 %
Tri County Electric Member Corp	$ 261	$ 143	1,382	$ 0.090	$ 18.00	$ 12.37	42.0 %	$ 237	$ 130	1,243	17.2%	+ 0.1 %	+ 0.2 %	+ 0.9 %	+ 2.2 %	- 0.4 %

Local Power Company	Average Monthly Energy Bills	Average Monthly Electric Bills	Average Monthly Electricity Use (kWh)	Current Average Residential Energy Rate ($/kwh)	Current Mandatory Fee	Proposed GAC per Customer	% of Households with Income Below 80% of AMI	Low Income Households (<80 AMI) Bill Characteristics								
								Monthly Energy Bills Bill	Monthly Electric Bills	Estimated kwh Monthly	Energy Burden (% of Household Income Spent on Energy): Current Average	Declining Block Rates at 1 c/kWh GAC	Declining Block Rates at 2.5 c/kWh GAC	Mandatory Fee at 1 c/kWh GAC	Mandatory Fee at 2.5 c/kWh GAC	Roll Back Industrial Rate Shift
TVA Average	$ 220	$ 142	1,381	$ 0.092	$ 14.73	$ 12.12	41.8 %	$ 202	$ 129	1,245	12.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.5 %
Tri State Electric Member Corp	$ 302	$ 137	1,157	$ 0.101	$ 19.50	$ 9.33	29.4 %	$ 301	$ 129	1,085	21.2%	+ 0.1 %	+ 0.3 %	+ 0.7 %	+ 1.7 %	- 0.3 %
Tullahoma Utilities Authority	$ 227	$ 142	1,508	$ 0.086	$ 12.00	$ 11.66	50.0 %	$ 188	$ 130	1,365	12.9%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.4 %
Tupelo Water & Light Department, City of	$ 184	$ 124	1,389	$ 0.079	$ 14.85	$ 11.55	50.0 %	$ 162	$ 107	1,176	10.2%	+ 0.1 %	+ 0.2 %	+ 0.7 %	+ 1.8 %	- 0.3 %
Tuscumbia Electricity Department	$ 221	$ 144	1,419	$ 0.095	$ 10.12	$ 11.43	44.3 %	$ 185	$ 129	1,251	12.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 1.9 %	- 0.6 %
Union City Electric System	$ 202	$ 119	1,273	$ 0.083	$ 13.31	$ 11.00	47.9 %	$ 161	$ 98	1,023	12.6%	+ 0.2 %	+ 0.4 %	+ 0.9 %	+ 2.1 %	- 0.4 %
Upper Cumberland Electric Member Corp	$ 222	$ 138	1,298	$ 0.093	$ 17.36	$ 12.00	42.8 %	$ 208	$ 124	1,151	15.0%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.2 %	- 0.4 %
Volunteer Electric Cooperative	$ 236	$ 144	1,380	$ 0.096	$ 11.71	$ 12.08	38.9 %	$ 231	$ 131	1,242	15.7%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.5 %
Warren Rural Electric Cooperative Corp	$ 242	$ 147	1,418	$ 0.092	$ 16.30	$ 12.96	37.6 %	$ 216	$ 131	1,238	13.6%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.0 %	- 0.3 %
Water Valley Electric Department, City of	$ 266	$ 144	1,449	$ 0.085	$ 20.91	$ 11.74	49.7 %	$ 214	$ 130	1,287	20.3%	+ 0.1 %	+ 0.3 %	+ 1.1 %	+ 2.8 %	- 0.5 %
Weakley County Municipal Electric System	$ 211	$ 138	1,445	$ 0.089	$ 8.99	$ 13.87	44.9 %	$ 186	$ 124	1,284	13.2%	+ 0.1 %	+ 0.2 %	+ 1.0 %	+ 2.4 %	- 0.6 %
West Kentucky Rural Electric Cooperative	$ 253	$ 150	1,290	$ 0.098	$ 23.40	$ 12.36	46.4 %	$ 227	$ 137	1,157	14.4%	+ 0.1 %	+ 0.3 %	+ 0.8 %	+ 2.0 %	- 0.3 %
West Point Electric System, City of	$ 209	$ 143	1,354	$ 0.095	$ 14.85	$ 9.76	54.2 %	$ 189	$ 131	1,228	17.9%	+ 0.1 %	+ 0.3 %	+ 0.9 %	+ 2.3 %	- 0.6 %
Winchester Utilities	$ 245	$ 139	1,392	$ 0.089	$ 14.62	$ 11.84	46.5 %	$ 207	$ 126	1,250	14.9%	+ 0.1 %	+ 0.2 %	+ 0.8 %	+ 2.1 %	- 0.7 %

Sources: Better Buildings Initiative, Clean Energy for Low Income Communities Accelerator (CELICA), Low-Income Energy Affordability Data (LEAD). Estimated of household energy costs based on cross-tabulations of U.S. Census housing data at the census tract level. Available at: https://openei.org/datasets/dataset/celica-data.
SACE survey of local power companies (see Appendix A). US Energy Information Administration data.

Appendix C

Estimate of TVA Industrial Rate Preference on Electricity Prices and Residential Customer Bills

Residential Data	2011-2016 Actual Price Difference	2016 Impact per Customer	2011				2016			
			Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)	Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)
TVA - All Residential Customers	104.6%	$ 109.28	61,021,335	$6,138,351	3,830,697	$0.1006	58,830,644	$6,184,608	3,969,896	$0.1053
4-County Electric Power Association	105.3%	$ 134.58	616,303	$67,868	37,311	$0.1101	576,627	$66,878	38,653	$0.1160
Aberdeen Electric Department	107.6%	$ 145.98	38,549	$3,978	2,712	$0.1032	35,243	$3,913	2,607	$0.1110
Albertville Municipal Utilities Board	102.6%	$ 76.94	133,656	$12,565	8,247	$0.0940	119,033	$11,478	7,915	$0.0964
Alcoa Utilities, City of	104.6%	$ 115.61	387,645	$38,633	23,756	$0.0997	388,712	$40,536	25,159	$0.1043
Alcorn County Electric Power Association	108.5%	$ 177.15	238,680	$24,779	14,523	$0.1038	219,979	$24,778	14,655	$0.1126
Amory, City of	104.0%	$ 96.90	44,032	$4,435	2,992	$0.1007	40,852	$4,281	2,935	$0.1048
Appalachian Electric Cooperative	106.5%	$ 152.88	643,674	$67,529	38,673	$0.1049	611,469	$68,343	39,469	$0.1118
Arab Electric Cooperative	104.7%	$ 122.02	211,307	$21,877	12,333	$0.1035	194,292	$21,063	12,498	$0.1084
Athens Electric Department, City of	102.6%	$ 86.37	634,161	$60,226	35,096	$0.0950	632,975	$61,674	38,051	$0.0974
Athens Utility Board	101.9%	$ 67.69	167,719	$16,485	10,861	$0.0983	157,671	$15,793	10,940	$0.1002
Benton County Electric System (TN)	107.2%	$ 149.56	120,941	$13,793	8,544	$0.1140	110,610	$13,519	8,467	$0.1222
Benton Electric System (KY)	107.4%	$ 152.49	26,394	$2,891	1,873	$0.1095	24,632	$2,899	1,826	$0.1177
Bessemer Utilities, City of	102.7%	$ 73.06	132,061	$13,747	9,556	$0.1041	117,733	$12,585	9,325	$0.1069
Blue Ridge Mountain Electric Member Corp	104.3%	$ 92.89	415,052	$50,514	37,955	$0.1217	425,543	$54,003	39,821	$0.1269
Bolivar Energy Authority	109.4%	$ 196.85	142,894	$15,677	8,866	$0.1097	128,386	$15,405	8,758	$0.1200
Bowling Green Municipal Utilities	95.4%	$ (21.52)	250,851	$27,194	23,128	$0.1084	279,797	$28,931	24,637	$0.1034
BrightRidge	106.0%	$ 129.18	1,042,999	$104,027	64,933	$0.0997	990,223	$104,670	67,673	$0.1057
Bristol Tennessee Essential Services	104.4%	$ 104.43	490,770	$45,023	28,448	$0.0917	450,792	$43,165	28,697	$0.0958
Brownsville Utility Department	103.1%	$ 75.04	62,574	$5,824	4,189	$0.0931	56,666	$5,440	4,228	$0.0960
BVU Authority	105.9%	$ 134.21	217,087	$23,035	13,765	$0.1061	196,569	$22,086	13,612	$0.1124
Caney Fork Electric Cooperative	105.7%	$ 125.91	410,281	$41,714	26,701	$0.1017	391,985	$42,115	27,046	$0.1074
Carroll County Electric Department	107.7%	$ 150.55	202,047	$19,373	12,520	$0.0959	181,291	$18,718	12,183	$0.1032
CDE Lightband	103.5%	$ 96.33	826,427	$87,677	53,697	$0.1061	851,713	$93,539	59,932	$0.1098
Central Electric Power Association	102.2%	$ 82.06	481,224	$51,191	29,224	$0.1064	453,141	$49,245	29,552	$0.1087
Cherokee Electric Cooperative	106.9%	$ 167.28	258,423	$31,851	17,539	$0.1233	240,786	$31,721	17,311	$0.1317
Chickamauga Electric System	106.3%	$ 126.80	13,314	$1,308	854	$0.0982	11,668	$1,218	825	$0.1044
Chickasaw Electric Cooperative	102.9%	$ 96.82	301,780	$28,067	15,425	$0.0930	291,336	$27,880	16,134	$0.0957
Cleveland Utilities	109.9%	$ 175.59	397,513	$37,611	24,989	$0.0946	385,125	$40,038	26,454	$0.1040
Clinton Utilities Board	105.5%	$ 130.30	404,641	$42,076	25,140	$0.1040	377,269	$41,403	25,322	$0.1097
Columbia Power & Water Systems	106.2%	$ 129.18	325,397	$32,072	20,992	$0.0986	324,624	$33,979	22,462	$0.1047
Columbus Light & Water	104.3%	$ 97.16	145,808	$13,846	9,472	$0.0950	132,490	$13,125	9,313	$0.0991
Cookeville Electric Department	102.4%	$ 64.67	179,900	$17,747	13,431	$0.0986	172,562	$17,437	13,956	$0.1010
Courtland, City of	102.2%	$ 64.05	9,215	$887	624	$0.0963	7,869	$774	598	$0.0984
Covington Electric System	104.2%	$ 91.05	54,607	$5,180	3,711	$0.0949	50,231	$4,967	3,722	$0.0989
Cullman Electric Cooperative	104.6%	$ 123.07	556,374	$60,750	34,592	$0.1092	529,015	$60,438	35,211	$0.1142
Cullman Power Board	111.0%	$ 178.63	95,661	$9,198	6,481	$0.0962	89,327	$9,536	6,682	$0.1068
Cumberland Electric Member Corp	107.4%	$ 189.36	1,470,748	$151,796	77,583	$0.1032	1,463,857	$162,338	82,330	$0.1109
Dayton Electric Department, City of	102.8%	$ 81.22	113,129	$11,839	8,382	$0.1047	116,213	$12,508	8,562	$0.1076
Decatur Utilities	109.2%	$ 155.41	375,478	$32,454	22,429	$0.0864	334,286	$31,563	22,514	$0.0944
Dickson Electric Department	102.2%	$ 78.12	459,820	$45,548	27,830	$0.0991	429,104	$43,453	27,749	$0.1013
Duck River Electric Member Corp	102.8%	$ 97.12	1,068,206	$110,709	60,353	$0.1036	1,025,608	$109,290	62,267	$0.1066
Dyersburg Electric System	106.2%	$ 124.16	150,499	$14,242	9,507	$0.0946	136,940	$13,756	9,416	$0.1005
East Mississippi Electric Power Association	88.5%	$ (161.14)	141,300	$19,849	9,894	$0.1405	129,582	$16,106	9,770	$0.1243
Electric Board of Guntersville	104.4%	$ 107.62	74,893	$7,367	4,717	$0.0984	70,624	$7,250	4,668	$0.1027
Electric Power Board of Chattanooga	108.4%	$ 166.22	2,362,934	$233,131	148,111	$0.0987	2,293,135	$245,207	153,156	$0.1069

Residential Data	2011-2016 Actual Price Difference	2016 Impact per Customer	2011				2016			
			Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)	Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)
TVA - All Residential Customers	104.6%	$ 109.28	61,021,335	$6,138,351	3,830,697	$0.1006	58,830,644	$6,184,608	3,969,896	$0.1053
Elizabethton Electric Department, City of	105.8%	$ 121.74	340,491	$34,216	22,632	$0.1005	319,939	$34,021	22,944	$0.1063
Erwin Utilities	107.0%	$ 121.38	104,995	$10,206	7,702	$0.0972	95,685	$9,956	7,596	$0.1040
Etowah Utilities	115.6%	$ 270.46	64,261	$6,768	4,363	$0.1053	60,597	$7,380	4,367	$0.1218
Fayetteville Public Utilities	105.0%	$ 124.38	250,491	$26,019	15,545	$0.1039	240,843	$26,268	15,833	$0.1091
Florence Utilities	102.7%	$ 85.34	686,044	$66,853	39,802	$0.0974	634,793	$63,527	40,356	$0.1001
Forked Deer Electric Cooperative	105.5%	$ 154.13	149,989	$16,526	8,357	$0.1102	138,527	$16,107	8,318	$0.1163
Fort Loudoun Electric Cooperative	103.7%	$ 112.10	469,220	$48,635	27,207	$0.1037	452,130	$48,606	27,544	$0.1075
Fort Payne Improvement Authority	106.8%	$ 135.33	100,735	$9,706	6,206	$0.0964	94,140	$9,684	6,457	$0.1029
Franklin Electric Cooperative (AL)	102.0%	$ 69.61	83,910	$9,900	6,566	$0.1180	78,964	$9,501	6,493	$0.1203
Franklin Electric Power Board (KY)	112.0%	$ 184.20	51,615	$4,921	3,774	$0.0953	49,585	$5,293	3,807	$0.1067
Fulton Electric System	106.5%	$ 121.43	17,223	$1,845	1,350	$0.1071	14,896	$1,700	1,236	$0.1141
Gallatin Department of Electricity	112.3%	$ 189.42	203,982	$17,609	13,147	$0.0863	217,854	$21,128	15,106	$0.0970
Gibson Electric Members Corp (merged w/HFC RECC)	101.5%	$ 74.62	552,208	$59,472	31,540	$0.1077	499,049	$54,546	31,387	$0.1093
Glasgow Electric Power Board	115.1%	$ 214.69	70,135	$7,136	5,330	$0.1017	64,170	$7,513	5,456	$0.1171
Greeneville Light & Power System	105.1%	$ 114.64	501,749	$47,891	30,675	$0.0954	462,833	$46,445	30,850	$0.1003
Harriman Utiliy Board	111.9%	$ 212.07	141,851	$14,620	9,510	$0.1031	127,917	$14,748	9,160	$0.1153
Hartselle Utilities	106.0%	$ 123.42	70,229	$6,641	4,316	$0.0946	63,094	$6,324	4,286	$0.1002
Hickman Electric System	106.6%	$ 128.89	11,118	$1,297	877	$0.1167	10,213	$1,270	875	$0.1244
Holly Springs Utility Department	102.0%	$ 79.02	140,243	$15,122	8,593	$0.1078	130,873	$14,400	8,776	$0.1100
Holston Electric Cooperative	103.8%	$ 96.64	383,666	$37,712	24,888	$0.0983	363,983	$37,152	24,853	$0.1021
Hopkinsville Electric System	106.8%	$ 117.93	142,680	$14,053	10,312	$0.0985	125,410	$13,194	10,146	$0.1052
Humboldt Utilities	106.1%	$ 111.18	51,191	$4,886	3,500	$0.0954	45,171	$4,575	3,484	$0.1013
Huntsville Utilities	105.8%	$ 123.43	2,594,019	$237,225	147,608	$0.0915	2,470,379	$238,955	158,161	$0.0967
Jackson Energy Authority	105.4%	$ 114.11	409,990	$41,462	27,841	$0.1011	399,763	$42,628	29,451	$0.1066
Jellico Electric & Water System	103.2%	$ 80.52	53,210	$5,330	3,773	$0.1002	49,116	$5,077	3,705	$0.1034
Joe Wheeler Electric Member Corp	106.9%	$ 173.61	620,172	$66,058	34,527	$0.1065	580,488	$66,087	34,739	$0.1138
Knoxville Utilities Board	107.0%	$ 131.93	2,562,594	$243,598	172,210	$0.0951	2,477,148	$251,970	176,259	$0.1017
LaFollette Utilities Board	104.1%	$ 101.49	265,446	$29,380	19,026	$0.1107	248,732	$28,671	19,029	$0.1153
Lawrenceburg Electric System	100.1%	$ 46.74	264,763	$26,571	16,822	$0.1004	266,706	$26,793	17,015	$0.1005
Lenoir City Utilities Board	101.9%	$ 76.57	864,475	$83,270	48,399	$0.0963	864,484	$84,817	51,409	$0.0981
Lewisburg Electric System	103.2%	$ 83.44	66,506	$6,368	4,395	$0.0958	65,704	$6,493	4,583	$0.0988
Lexington Electric System	107.1%	$ 131.76	253,932	$25,445	17,975	$0.1002	236,012	$25,319	17,824	$0.1073
Loudon Utilities Board	102.6%	$ 85.92	158,352	$15,641	9,541	$0.0988	158,494	$16,066	10,014	$0.1014
Louisville Utilities	102.9%	$ 71.29	36,073	$3,544	2,656	$0.0982	31,984	$3,233	2,538	$0.1011
Macon Electric Department, City of	106.4%	$ 124.28	13,019	$1,359	936	$0.1044	11,815	$1,312	918	$0.1110
Marshall-De Kalb Electric Cooperative	104.3%	$ 112.65	247,245	$25,051	14,590	$0.1013	230,084	$24,305	14,753	$0.1056
Maryville Electric Department, City of	97.7%	$ 8.50	251,878	$23,813	16,733	$0.0945	262,428	$24,252	18,087	$0.0924
Mayfield Electric & Water System	103.1%	$ 75.23	56,363	$6,363	4,600	$0.1129	50,212	$5,845	4,508	$0.1164
McMinnville Electric System	105.6%	$ 102.10	83,538	$7,965	6,136	$0.0953	80,768	$8,129	6,358	$0.1006
Memphis Light, Gas and Water	99.1%	$ 28.07	5,524,497	$529,496	360,359	$0.0958	5,322,901	$505,812	366,265	$0.0950
Meriwether Lewis Electric Cooperative	103.9%	$ 103.88	434,680	$46,614	28,641	$0.1072	408,793	$45,552	28,616	$0.1114
Middle Tennessee Electric Member Corp	102.6%	$ 91.04	3,036,974	$293,852	162,693	$0.0968	3,198,133	$317,409	185,051	$0.0992
Milan Department of Public Utilities	101.7%	$ 69.06	113,992	$11,275	6,678	$0.0989	104,150	$10,473	6,765	$0.1006
Monroe County Electric Power Association	106.5%	$ 160.03	165,111	$16,628	8,789	$0.1007	163,327	$17,520	9,647	$0.1073
Morristown Utility Systems	104.8%	$ 105.14	170,281	$17,239	11,740	$0.1012	161,883	$17,173	11,933	$0.1061

Residential Data	2011-2016 Actual Price Difference	2016 Impact per Customer	2011				2016			
			Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)	Retail Sales (MWh)	Retail Revenue (000s)	Retail Customers	Effective Rate ($/KWh)
TVA - All Residential Customers	104.6%	$ 109.28	61,021,335	$6,138,351	3,830,697	$0.1006	58,830,644	$6,184,608	3,969,896	$0.1053
Mount Pleasant Power System	106.3%	$ 147.93	51,992	$5,627	3,140	$0.1082	47,765	$5,497	3,217	$0.1151
Mountain Electric Cooperative	101.6%	$ 50.50	319,025	$32,865	27,889	$0.1030	303,812	$31,787	27,477	$0.1046
Murfreesboro Electric Department	101.3%	$ 60.13	690,234	$68,919	45,840	$0.0998	745,033	$75,383	52,018	$0.1012
Murphy Electric Power Board	103.9%	$ 97.20	44,427	$5,030	3,349	$0.1132	43,302	$5,095	3,427	$0.1177
Murray Electric System	113.3%	$ 181.51	75,288	$7,763	6,255	$0.1031	67,886	$7,934	6,254	$0.1169
Muscle Shoals Electric Board	102.6%	$ 83.53	103,584	$9,972	5,962	$0.0963	99,908	$9,868	6,297	$0.0988
Nashville Electric Service	107.3%	$ 146.98	4,919,345	$510,382	320,735	$0.1037	4,780,501	$532,095	342,609	$0.1113
Natchez Trace Electric Power Association	105.3%	$ 120.76	193,296	$19,939	12,455	$0.1032	177,112	$19,242	12,395	$0.1086
New Albany Light, Gas & Water	104.0%	$ 99.02	124,060	$12,170	7,854	$0.0981	115,624	$11,792	7,828	$0.1020
Newbern Electric, Water & Gas	102.6%	$ 69.62	21,925	$1,992	1,420	$0.0909	20,531	$1,914	1,468	$0.0932
Newport Utilities	107.4%	$ 140.65	259,237	$25,771	17,676	$0.0994	250,371	$26,740	18,236	$0.1068
North Alabama Electric Cooperative	107.8%	$ 165.17	217,746	$22,263	13,505	$0.1022	197,071	$21,724	13,037	$0.1102
North East Mississippi Electric Power Asssociation	105.9%	$ 139.48	297,626	$32,952	18,684	$0.1107	319,486	$37,457	22,226	$0.1172
North Georgia Electric Member Corp	109.8%	$ 204.72	1,518,792	$145,156	83,830	$0.0956	1,432,073	$150,226	84,444	$0.1049
Northcentral Mississippi Electric Power	102.4%	$ 90.83	444,223	$43,817	23,362	$0.0986	437,165	$44,146	24,916	$0.1010
Oak Ridge Electric Department	103.3%	$ 77.34	174,969	$18,657	13,905	$0.1066	163,635	$18,030	13,995	$0.1102
Okolona Electric Department, City of	103.7%	$ 101.04	67,307	$7,112	4,163	$0.1057	60,354	$6,616	4,174	$0.1096
Oxford Electric Department, City of	102.9%	$ 69.72	82,934	$8,460	6,266	$0.1020	87,782	$9,212	7,380	$0.1049
Paris Board of Public Utilities	104.4%	$ 100.14	246,649	$23,538	15,337	$0.0954	224,140	$22,322	15,439	$0.0996
Pennyrile Rural Electric Cooperative	104.1%	$ 112.71	592,626	$63,360	37,588	$0.1069	575,365	$64,057	38,225	$0.1113
Philadelphia Utilities	102.7%	$ 77.64	44,255	$4,418	2,893	$0.0998	39,333	$4,031	2,796	$0.1025
Pickwick Electric Cooperative	106.2%	$ 141.79	261,137	$27,288	16,370	$0.1045	244,048	$27,094	16,389	$0.1110
Plateau Electric Cooperative	104.1%	$ 91.98	162,344	$18,166	13,136	$0.1119	161,889	$18,860	13,752	$0.1165
Pontotoc Electric Power Association	106.1%	$ 147.70	245,321	$25,971	14,831	$0.1059	235,098	$26,411	15,144	$0.1123
Powell Valley Electric Cooperative	103.0%	$ 77.19	353,121	$35,792	25,393	$0.1014	335,275	$35,008	25,915	$0.1044
Prentiss County Electric Power Association	102.9%	$ 78.28	172,395	$15,761	10,772	$0.0914	160,551	$15,106	10,848	$0.0941
Pulaski Electric System	107.5%	$ 163.33	183,496	$20,100	11,598	$0.1095	170,780	$20,101	11,822	$0.1177
Ripley Power & Light	106.9%	$ 131.93	85,897	$8,528	5,353	$0.0993	72,396	$7,683	5,319	$0.1061
Rockwood Electric Utility	102.1%	$ 80.04	184,879	$19,844	11,711	$0.1073	171,388	$18,789	11,509	$0.1096
Russellville Electric Board (AL)	116.5%	$ 254.51	56,685	$5,740	3,925	$0.1013	51,770	$6,105	3,981	$0.1179
Russellville Electric Plant Board (KY)	105.5%	$ 93.10	39,382	$3,863	3,189	$0.0981	36,453	$3,773	3,222	$0.1035
Sand Mountain Electric Cooperative	103.8%	$ 101.95	382,689	$40,326	24,986	$0.1054	364,699	$39,894	25,179	$0.1094
Scottsboro Electric Power Board	114.0%	$ 243.03	107,573	$10,642	6,770	$0.0989	98,041	$11,054	6,721	$0.1127
Sequachee Valley Electric Cooperative	106.4%	$ 138.25	454,302	$47,297	29,283	$0.1041	424,203	$46,985	29,579	$0.1108
Sevier County Electric System	101.6%	$ 64.33	512,577	$51,227	33,193	$0.0999	510,021	$51,797	35,576	$0.1016
Sheffield Utilities	107.3%	$ 152.71	253,659	$25,131	15,266	$0.0991	231,477	$24,612	15,303	$0.1063
Shelbyville Power System	102.7%	$ 75.13	115,090	$11,542	8,170	$0.1003	115,368	$11,877	8,509	$0.1029
Smithville Electric System	107.4%	$ 99.84	23,806	$2,398	2,026	$0.1007	19,840	$2,146	2,052	$0.1082
Southwest Tennessee Electric Member Corp	104.2%	$ 123.61	763,099	$81,587	42,240	$0.1069	686,593	$76,495	42,028	$0.1114
Sparta Electric & Public Works	106.2%	$ 103.10	26,388	$2,522	2,176	$0.0956	25,822	$2,621	2,172	$0.1015
Springfield Electric	104.8%	$ 98.22	103,516	$9,541	6,877	$0.0922	96,027	$9,275	6,906	$0.0966
Starkville Electric Department	101.0%	$ 45.62	126,442	$13,496	10,572	$0.1067	127,611	$13,762	11,667	$0.1078
Sweetwater Utilities Board	104.4%	$ 110.25	116,765	$11,169	6,966	$0.0957	112,771	$11,258	7,081	$0.0998
Tallahatchie Valley Electric Power Assoc	105.2%	$ 129.79	347,382	$36,094	21,524	$0.1039	330,309	$36,107	21,362	$0.1093
Tarrant Electric Department	115.1%	$ 249.93	32,744	$3,346	2,232	$0.1022	29,318	$3,448	2,153	$0.1176

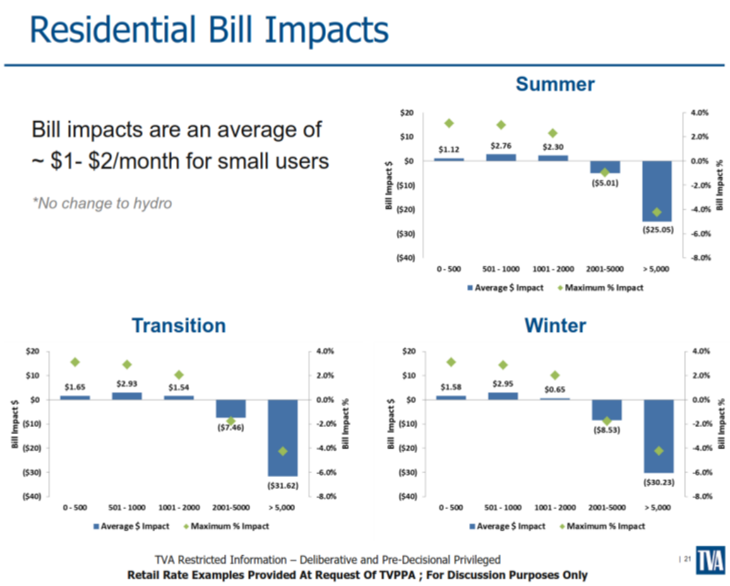
Residential Data	2011-2016 Actual Price Difference	2016 Impact per Customer	2011 Retail Sales (MWh)	2011 Retail Revenue (000s)	2011 Retail Customers	2011 Effective Rate ($/KWh)	2016 Retail Sales (MWh)	2016 Retail Revenue (000s)	2016 Retail Customers	2016 Effective Rate ($/KWh)
TVA - All Residential Customers	104.6%	$ 109.28	61,021,335	$6,138,351	3,830,697	$0.1006	58,830,644	$6,184,608	3,969,896	$0.1053
Tennessee Valley Electric Cooperative	104.2%	$ 102.00	230,963	$24,561	15,780	$0.1063	216,736	$24,012	15,937	$0.1108
Tippah Electric Power Association	106.4%	$ 137.79	159,878	$16,589	10,318	$0.1038	148,182	$16,364	10,378	$0.1104
Tishomingo County Electric Power Association	106.2%	$ 124.09	157,485	$16,040	10,981	$0.1019	145,942	$15,790	10,898	$0.1082
Tombigbee Electric Power Association	102.7%	$ 88.96	585,838	$59,286	34,003	$0.1012	558,174	$57,994	35,173	$0.1039
Trenton Light & Water Department	112.9%	$ 189.78	27,298	$2,690	1,961	$0.0985	23,818	$2,649	1,946	$0.1112
Tri-County Electric Member Corp (TN)	104.4%	$ 109.76	651,652	$66,883	40,686	$0.1026	616,648	$66,065	41,832	$0.1071
Tri-State Electric Member Corp	101.3%	$ 59.26	181,579	$21,835	14,982	$0.1203	183,060	$22,304	15,573	$0.1218
Tullahoma Utilities Authority	104.0%	$ 90.98	129,822	$12,138	8,478	$0.0935	124,540	$12,106	8,750	$0.0972
Tupelo Water & Light Department, City of	102.1%	$ 63.01	160,411	$14,577	10,843	$0.0909	146,564	$13,603	10,580	$0.0928
Tuscumbia Electricity Department	104.8%	$ 108.20	57,915	$5,826	3,833	$0.1006	54,825	$5,781	3,920	$0.1054
Union City Electric System	103.4%	$ 76.51	74,882	$6,971	5,189	$0.0931	68,507	$6,595	5,235	$0.0963
Upper Cumberland Electric Member Corp	102.7%	$ 84.78	629,495	$66,268	40,331	$0.1053	606,086	$65,496	41,567	$0.1081
Volunteer Electric Cooperative	103.7%	$ 100.45	1,458,118	$150,799	93,366	$0.1034	1,409,614	$151,201	95,601	$0.1073
Warren Rural Electric Cooperative Corp	101.8%	$ 76.94	843,368	$87,076	49,909	$0.1032	827,767	$87,042	52,378	$0.1052
Water Valley Electric Department, City of	102.8%	$ 80.98	23,416	$2,355	1,571	$0.1006	21,878	$2,263	1,554	$0.1034
Weakley County Municipal Electric System	105.1%	$ 120.29	282,914	$26,652	16,255	$0.0942	251,215	$24,884	15,775	$0.0991
West Kentucky Rural Electric Cooperative	102.0%	$ 81.77	478,354	$55,579	30,445	$0.1162	441,243	$52,278	30,361	$0.1185
West Point Electric System, City of	103.9%	$ 85.32	40,757	$4,416	3,236	$0.1083	36,295	$4,085	3,110	$0.1125
Winchester Utilities	105.8%	$ 121.70	67,065	$6,584	4,584	$0.0982	66,847	$6,940	4,649	$0.1038

Source for LPC Data: Energy Information Administration Form 861

Appendix D

SACE conducted an expanded analysis of TVA's residential rate impact data focused on three issues: retail rate design (declining block rate vs mandatory fees), demand impacts (rate impacts on residential demand), and commercial rate shifts.

One issue that SACE did not analyze is the seasonal variation in individual customer bills. While TVA did conduct evaluation for presentation to TVPPA committees that considered seasonal billing patterns, these data were aggregated. When evaluating rate structures that have monthly electricity use breakpoints (e.g., 1000 kWh), the best way to understand individual bills is to know whether customers are below 1000 kWh some months, and above it in others. Similarly, TVA also studied (but did not recommend as an alternative) load differentiated monthly billing fees such as $2 for monthly use below 1000 kWh and $5 for use above 1000 kWh. (It was not clear whether this would be an annual average, determined monthly, or determined based on how recently use exceeded 1000 kWh.) In any event, while TVA did analyze the effects of seasonal rate variations, as illustrated below, it was mainly from the perspective of overall impacts to LPC revenues by customer size, and not from the perspective of customers with varying bills from month to month.



Source: TVA, Presentation to TVPPA Research, Analysis, and Design Committee, May 31, 2017.

Since TVA did not study the seasonal patterns of individual customer use, it is not possible to know the seasonal or overall annual impact of the proposed rates on specific customers using different levels of energy, and whether there would be any meaningful "stabilizing" effect of TVA's wholesale rate change (as TVA claimed, as discussed in our comments).

In studying the retail rate design associated with implementing the GAC, one technical issue SACE encountered is that the declining block rate described in the Draft 2018 Rate EA would result in a rate cut for residential customers . While a rate cut would certainly be viewed as desirable to residential customers, the Draft 2018 Rate EA indicates that the proposed GAC is intended to be revenue neutral and does not indicate how the potential rate cut would be achieved. TVA considered revenue neutral rate structures in dialogue with TVPPA committees, and also considered revenue increasing rate structures to capture a "risk premium," a concept not discussed in the Draft 2018 Rate EA. However, based on analysis of TVA's data, the declining block rates would result in a 0.05 c/kWh rate decrease.

SACE also elected to evaluate the 0.3% increase in residential rates due to the proposed cut in rates for large commercial customers. SACE elected not to evaluate the increased flexibility for local power companies to administering the hydro credit. Each of these proposals could impact residential rate structures, and hence power demand. But although TVA discussed options for redesign of the retail hydro credit with LPCs, none was discussed in the Draft 2018 Rate EA. At this point, SACE anticipates that LPCs would likely make minimal changes even with this additional flexibility since the hydro credit is relatively small compared to other elements of rates.

In order to study the impact of retail rate structures and the shift of rates away from large commercial customers, SACE performed an extended analysis of Alternatives C and D. To conduct this analysis, SACE made the following technical adjustments:

- The monthly energy charge above 1,000 kWh was increased from 8.571 c/kWh to 8.681 c/kWh in order to make the declining block rate a "revenue neutral" rate change.[1]
- The price elasticity of demand from the Draft 2018 Rate EA was applied based on the marginal rate at the assumed level of demand.
- All energy rates were increased by about 0.03 c/kWh (0.3%) to recognize the impact of the commercial rate cut.
- SACE performed the analysis using seasonal residential load data from one of TVA's presentations to TVPPA. SACE also made the following assumptions:
- For the declining block rates, TVA did not specify monthly energy charges under Alternative D. We used values that are 2.5 times those specified for Alternative C to reflect the higher GAC.
- For the monthly mandatory fee under Alternative C, SACE calculated the impact of a 1 cent per kWh GAC based on average residential retail sales for the 2012-2016 time period for all local power companies in the TVA system, and then allocated that cost based on an assumed 4.0 million residential customers in 2018. This resulted in a $12.12 per month mandatory fee.
- The $30.30 monthly mandatory fee under Alternative D is simply 2.5 times the $12.12 fee.
- Based on these analyses, it appears that the majority of TVA residential customers will see average bills increase under any retail rate structure change.

[1] Alternatively, rates below 1,000 kWh could have been increased, or a roughly $1/month mandatory fee could have been used to create a "revenue neutral" rate structure change.

The table below shows monthly bills at six levels of monthly energy use, in six retail rate structure scenarios:

- Base case - “current” rates as described in Draft 2018 Rate EA
- Declining Block Rate Structure - rates as described in Draft 2018 Rate EA (not revenue neutral) for Alternative C (Note: Alternative D rates not provided)
- Declining Block Rate Structure - Alternative C rates adjusted to be approximately revenue neutral, plus 0.3% rate increase for commercial rate shift
- Declining Block Rate Structure - Alternative D, “revenue neutral”{ rate adjustments multiplied by 2.5 (2.5 c/kWh GAC rather than 1.0 c/kWh GAC)
- Mandatory Fee Rate Structure - Alternative C - $12.12/month fee based on 1 c/kWh GAC
- Mandatory Fee Rate Structure - Alternative D - $30.30/month fee based on 2.5 c/kWh GAC
- The Monthly Electric Bill is simply the sum of the mandatory fee plus the energy charges based on power use above and below 1,000 kWh.

Appendix D

SACE Analysis of TVA's Residential Rate Impact Data

Base Case – Rates As Described in Draft 2018 EA

Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.0895/kWh)	Monthly Energy Charge above 1,000 kWh ($0.0895/kWh)	Monthly Electric Bill
250	$ 18.41	$ 22.38	$ –	$ 40.79
500	$ 18.41	$ 44.75	$ –	$ 63.16
1000	$ 18.41	$ 89.50	$ –	$ 107.91
1500	$ 18.41	$ 89.50	$ 44.75	$ 152.66
2000	$ 18.41	$ 89.50	$ 89.50	$ 197.41
2500	$ 18.41	$ 89.50	$ 134.25	$ 242.16

Declining Block Rate Structure, Alternative C, Rates as Described in Draft 2018 EA

Rate-Induced Consumption Change (kWh)	Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.0915/kWh)	Monthly Energy Charge above 1,000 kWh ($0.08571/kWh)	Monthly Electric Bill
-1	249	$ 18.41	$ 22.80	$ –	$ 41.21
-2	498	$ 18.41	$ 45.60	$ –	$ 64.01
-3	997	$ 18.41	$ 91.19	$ –	$ 109.60
10	1510	$ 18.41	$ 91.50	$ 43.67	$ 153.58
13	2013	$ 18.41	$ 91.50	$ 86.80	$ 196.71
16	2516	$ 18.41	$ 91.50	$ 129.93	$ 239.84

Declining Block Rate Structure, Rates Adjusted to be Revenue Neutral, Plus 0.3% Rate Increase for Commercial Rate Shift

Alternative C

Rate-Induced Consumption Change (kWh)	Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.09177/kWh)	Monthly Energy Charge above 1,000 kWh ($0.08708/kWh)	Monthly Electric Bill
-1	249	$ 18.41	$ 22.86	$ –	$ 41.27
-2	498	$ 18.41	$ 45.71	$ –	$ 64.12
-4	996	$ 18.41	$ 91.42	$ –	$ 109.83
6	1506	$ 18.41	$ 91.77	$ 44.07	$ 154.25
8	2008	$ 18.41	$ 91.77	$ 87.79	$ 197.97
10	2510	$ 18.41	$ 91.77	$ 131.51	$ 241.69

Alternative D

Rate-Induced Consumption Change	Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.09477/kWh)	Monthly Energy Charge above 1,000 kWh ($0.08305/kWh)	Monthly Electric Bill
-2	247	$ 18.41	$ 23.40	$ –	$ 41.81
-4	494	$ 18.41	$ 46.81	$ –	$ 65.22
-9	988	$ 18.41	$ 93.62	$ –	$ 112.03
16	1526	$ 18.41	$ 94.77	$ 43.66	$ 156.85
22	2034	$ 18.41	$ 94.77	$ 85.90	$ 199.08
27	2543	$ 18.41	$ 94.77	$ 128.14	$ 241.32

Increased Monthly Mandatory Fee Structure, Rates Calculated as Described in Comments

Alternative C

Rate-Induced Consumption Change	Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.0795/kWh)	Monthly Energy Charge above 1,000 kWh ($0.0795/kWh)	Monthly Electric Bill
4	254	$ 30.53	$ 20.21	$ –	$ 50.74
8	508	$ 30.53	$ 40.42	$ –	$ 70.95
17	1017	$ 30.53	$ 79.50	$ 1.33	$ 111.36
25	1525	$ 30.53	$ 79.50	$ 41.75	$ 151.78
34	2034	$ 30.53	$ 79.50	$ 82.16	$ 192.19
42	2542	$ 30.53	$ 79.50	$ 122.58	$ 232.61

Alternative D

Rate-Induced Consumption Change	Monthly Electricity Used (kWh)	Monthly Mandatory Fee	Monthly Energy Charge up to 1,000 kWh ($0.06495/kWh)	Monthly Energy Charge above 1,000 kWh ($0.0645/kWh)	Monthly Electric Bill
10	260	$ 48.71	$ 16.80	$ –	$ 65.51
21	521	$ 48.71	$ 33.60	$ –	$ 82.31
42	1042	$ 48.71	$ 64.50	$ 2.70	$ 115.91
63	1563	$ 48.71	$ 64.50	$ 36.30	$ 149.51
84	2084	$ 48.71	$ 64.50	$ 69.91	$ 183.12
105	2605	$ 48.71	$ 64.50	$ 103.51	$ 216.72

Attachment 1: Strategic Pricing Plan White Paper

Tennessee Valley Authority

Strategic Pricing Plan

Development through Stage 1 of the Strategic Pricing Plan

May 3, 2016

TVA

Strategic Pricing Plan

Table of Contents

Executive Summary

Under the traditional business model, electricity usage grew steadily. Utilities built larger, more efficient plants to serve the growing load, and the unit cost for electricity steadily declined while utility revenues increased. Fixed costs related to generation, transmission, and distribution infrastructure, a large component of total utility costs, could be reliably collected over steady variable sales units. However, the traditional model is changing due to several factors including continued effects of the recession, greater use of renewable energy, and energy efficiency. Utilities can no longer be certain of increasing loads to support the building of large plants, and while energy sales have flattened, peak demands have continued to climb. This decay in load factor is a continuing challenge for TVA and many local power companies who still are dependent on volumetric sales for margins. New regulations have resulted in higher costs for coal and nuclear plants while natural gas prices have declined. In addition, utilities are facing high costs for grid modernization amid policies targeted to increase energy savings and encourage distributed generation and rooftop solar. These changes point to the need for utilities to properly value and recover fixed costs and to allow customers to make informed choices regarding energy usage.

TVA is responding to the changing marketplace and engaging customers to define the long-term direction for rates and pricing in the Valley. Realization of the long-term direction is expected to take many years with multiple incremental changes. A first step was taken with a rate change in 2011 providing renewed incentives for customers to manage electricity usage in a cost effective way. TVA and customers generally agreed that this was an important transitional step, but that a next step was needed to focus on the long term direction for rate structure, pricing and programs. Development of guidelines and processes for this ongoing effort has become known as the Strategic Pricing Plan (SPP).

Early in discussions an agreement was made between customers and TVA that there would be another rate change no later than October 2015. In the interim between 2011 and 2015, the TVA Board approved three adjustments to rates and programs to address some of the more immediate needs of customers. The first of these actions was a rate change in 2012 that updated the 2011 TOU rate offering and added a non-time-of-use rate for wholesale customers, to allow customers more time to transition. The second and third adjustments targeted rate relief to industrial customers, implemented through a 2013 Board action instating the Valley Commitment Program and optional Small Manufacturing (MSA) rate.

Concurrent with some of these actions, the SPP was entering the strategic alignment phase, focusing on understanding customer needs and expectations and ensuring internal alignment within TVA. This engagement continued throughout the process with over 150 meetings between TVA and stakeholders during the more than two years leading up to the 2015 rate change.

The first stage of the Strategic Pricing Plan was implemented in October 2015 with broad-scope changes to rates, pricing, and programs. The new rates are intended to improve cost alignment and fixed cost recovery with a narrowed on-peak window closer to TVA's monthly coincident peak, new demand charges, and a declining block hours-use-of-demand energy rate for large customers. The total fuel cost formula has been re-engineered to minimize cost-shifting between customer classes, and pricing products have been re-positioned in terms of value to the customer and to TVA and to better align with the new rates.

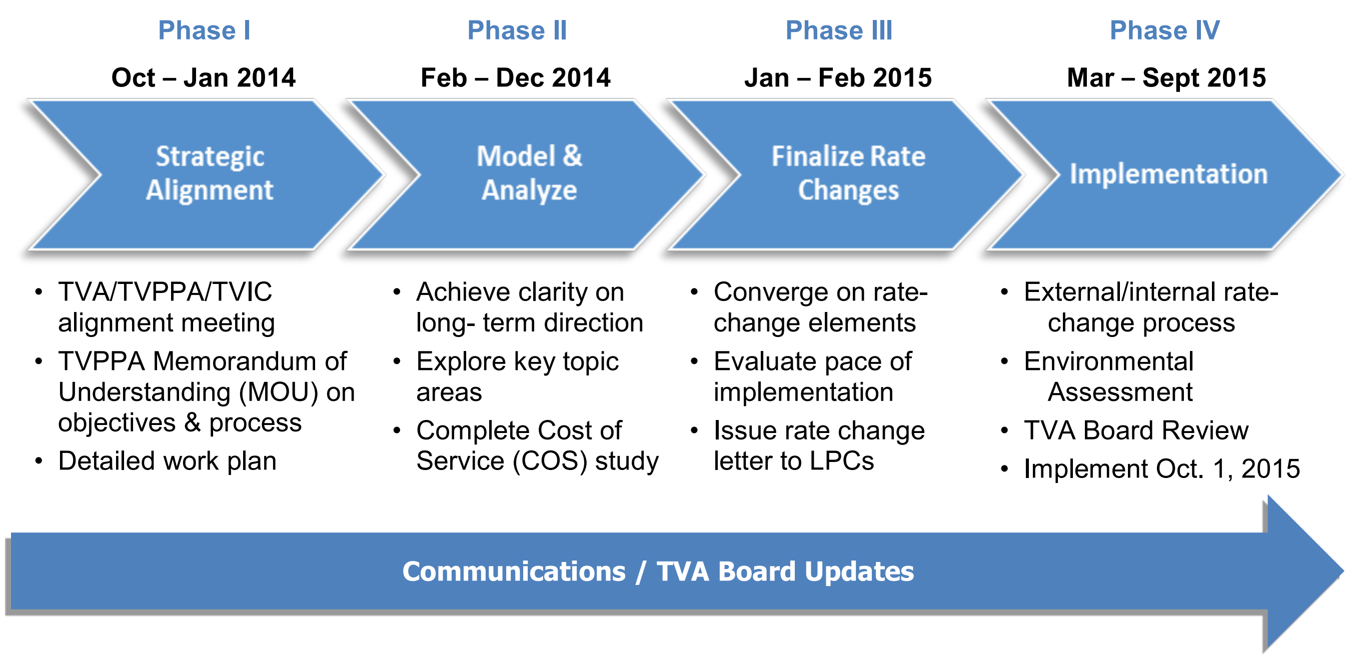
As TVA and customers begin to contemplate the next stage of the Strategic Pricing Plan, discussions around retail rate alignment and the initial scope for the next wholesale rate structure changes are being addressed. Both of these efforts will continue in the collaborative format used for the first stage and build upon the foundations laid in both the 2011 and 2015 rate changes, to become better prepared for the changing marketplace.

Introduction

A rate change in 2011 ended almost 20 years of end-use wholesale rates with new rate structures allowing customers to once again make informed decisions regarding electrical usage during high cost periods. TVA and customers generally agreed that this was an important transitional step, but that a next step was needed to focus on the long term direction for rate structure, pricing and programs for the Valley. Development of guidelines and processes for this ongoing effort has become known as the Strategic Pricing Plan (SPP).

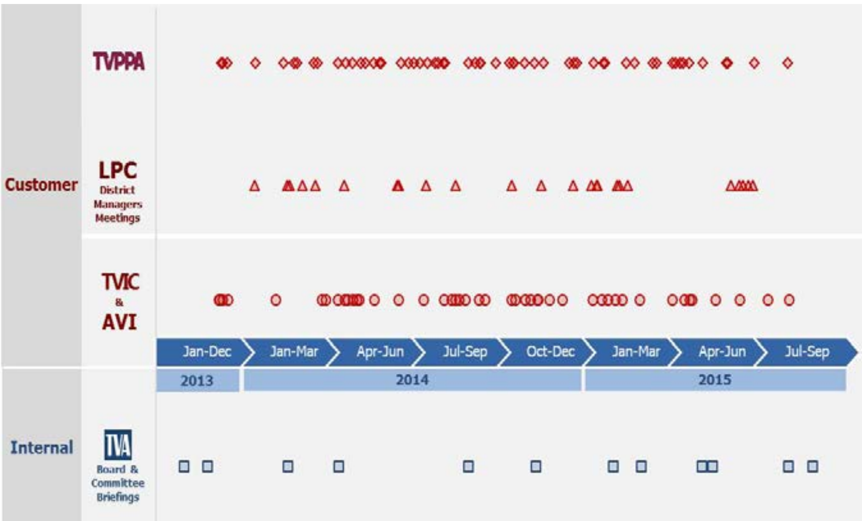
The process depicted in Figure 1 below was followed to implement the 2015 Rate Change, the first of multiple incremental changes under the SPP. The process utilized for the large-scope rate, pricing and product changes for the first rate change under the SPP (in October 2015) was comprised of four distinct phases – Strategic Alignment, Model & Analyze, Finalize Rate Changes, and Implementation, in Figure 1.

Figure 1: Strategic Pricing Plan Process



In order to develop an understanding of customer needs and expectations and ensure internal alignment within TVA, over 150 meetings were held between TVA and stakeholders during the more than two years leading up to 2015 rate change. In addition to regularly scheduled committee meetings focusing on TVA's rates with the Tennessee Valley Public Power Association (TVPPA) and Tennessee Valley Industrial Committee (TVIC), frequent subcommittee meetings on focus areas including competitiveness of TVA's rates, metering, margin management, and the Total Fuel Cost (TFC) took place throughout the process. Internal support was provided by many organizations within TVA including External Relations, Financial Services, Operations, and Communications. In addition, TVA met individually with many customers upon request and traveled to numerous district meetings. Throughout the process the TVA Board was frequently updated with a total of eleven Board Reviews (see Figure 2).

Figure 2: Customer meetings and TVA Board reviews

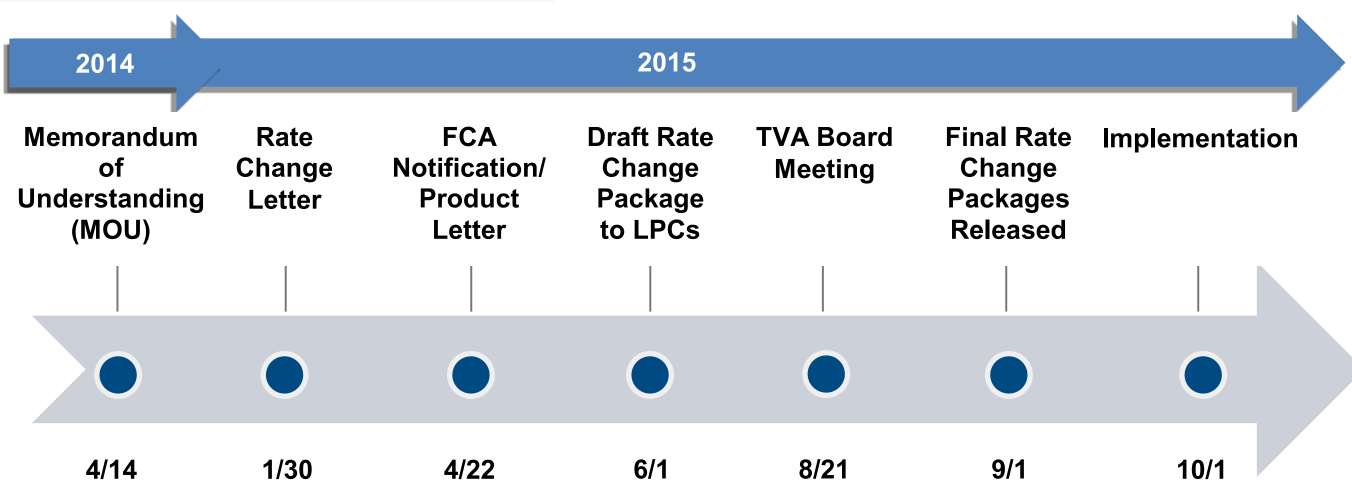


TVA Board Reviews

Apr 3, 2013	Rates Overview Environmental Adjustment Long-Term Pricing Strategy
Aug 13, 2013	Environmental Adjustment Valley Commitment Program MSA Rate Option
Jan 30, 2014	Long-Term Pricing Strategy
Apr 11, 2014	Strategic Pricing Plan
Aug 20, 2014	Strategic Pricing Plan
Nov 5, 2014	Strategic Pricing Plan
Jan 28, 2015	Off-Peak Pricing Extension
Feb 25, 2015	Strategic Pricing Plan
Apr 21, 2015	Strategic Pricing Plan
May 6, 2015	Strategic Pricing Plan
Aug 5, 2015	Strategic Pricing Plan

Throughout each of the phases, there were key milestones and deliverables including: the Memorandum of Understanding (MOU) between TVA and its wholesale customers in Phase I, the contractually required Rate Change Letter in Phase III, and the Board Meeting approving the rate change, and a final implementation on Phase IV. These and other important milestones are depicted in Figure 3, Key Milestones.

Figure 3: Key Process Milestones



Customers and TVA worked through the four phases of the SPP Process - Strategic Alignment, Model & Analyze, Finalize Rate Changes, and Implementation, taking additional time as needed to build understanding in topic areas while adhering to major deliverables dates. Key activities under each phase of the SPP will be given in the sections below.

Phase I - Strategic Alignment

During the Strategic Alignment phase, from October 2013 through January 2014, TVPPA, and TVIC met individually with TVA to discuss guidelines, desired results, key assumptions, guiding principles, and milestones relating to long-term pricing strategy - including plans for implementation of a rate change by October 1, 2015. Wholesale customers and TVA agreed that a guide was needed for setting rates to provide pricing signals and stabilize rates by preventing fixed cost bypass. The effort would define the pricing objectives and then the rate structure and pricing product options that would best serve the Valley. The process would also include assessment of TVA's competitive position across rate classes to ensure that rates remain affordable and competitive.

The agreement reached between TVPPA and TVA was formally established with the Strategic Pricing Plan Memorandum of Understanding (MOU). The primary Objective, as stated in the MOU, was "development of a long-term pricing plan which would stand the test of time, be flexible enough to accommodate customer diversity and the changing marketplace, and ensure that Valley electric rates would remain competitive and affordable." The MOU also gave direction on process and milestones as follows.

Process: It was established in the MOU that the TVPPA Leadership Council (LC) would represent TVPPA in discussions regarding the SPP. After confirmation by the LC, topics would be directed back to the TVPPA Rates and Contracts committee for implementation preparation. District and individual meetings were to be utilized to keep LPCs informed of progress and receive individual LPC input. TVA would utilize the Pricing Committee for internal communication and alignment and would provide regular progress updates to the TVA Board.

Milestones: It was established that the elements of a rate change proposal would be finalized by January 2015, with a goal of implementing a rate change in October 2015. For more information on the MOU, please refer to Appendix 1, the Strategic Pricing Plan Memorandum of Understanding.

Also in the Strategic Alignment phase TVA and customers developed a work plan including additional detail regarding engagement, milestones, work sequence and communications.

Phase II – Model & Analyze

With completion of the MOU and detailed work plan, TVA and customers entered the Model & Analyze phase. This phase lasted nearly a year from February through December 2014, and encompassed much of the detailed work required to develop the rates and pricing for the 2015 Rate Change. In this phase, TVA and customers achieved clarity on long-term direction for the Strategic Pricing Plan with three key directives shown below.

Three Key Directives of the Strategic Pricing Plan:

(1) Improvement of Fixed Cost Recovery

- Appropriately value infrastructure investment
- Increase fixed cost recovery at wholesale and retail

(2) Improvement of Pricing Signals

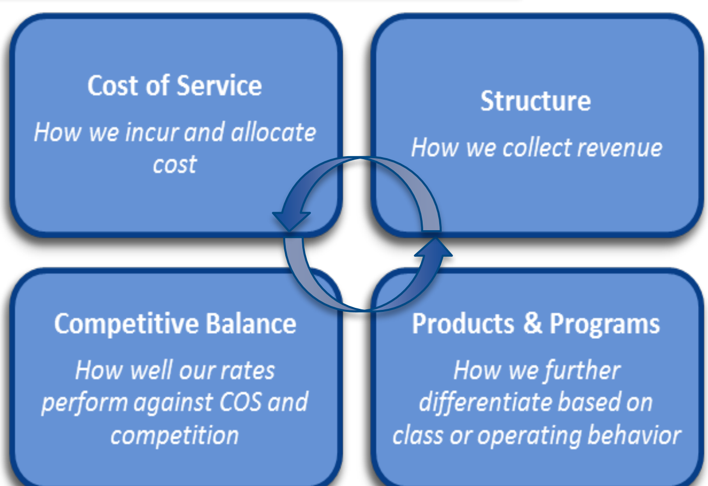
- Provide signals more reflective of embedded and marginal cost
- Move toward more dynamic pricing
- Improve local power company margin management

(3) Encouragement of Technology Investment

- Interval metering and data management
- Load control and load shaping technology

The Model & Analyze phase provided opportunities for customers and TVA to present diverse views, provide information, answer questions, and otherwise work toward an understanding of a broad range of topics. The Cost-of-Service Study, a major 2015 rate change deliverable, was performed, vetted and finalized in the Model & Analyze Phase. Rate structure, competitive balance, and products & programs also received focus and study in Phase II. Figure 4 shows the process used to develop pricing under the SPP.

Figure 4: Process for developing pricing under the Strategic Pricing Plan



In Phase II – Model & Analyze, Cost-of-Service, Competitive Balance, Rate Structure and Products received focus and study

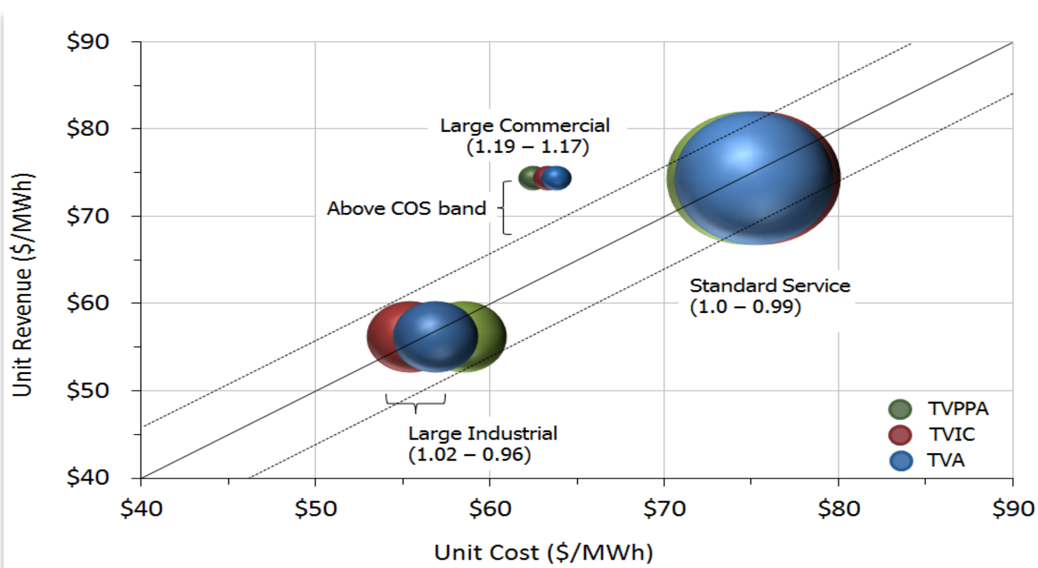
Cost-of-Service

A cost-of-service study is a detailed analysis of financial and operational data to assign costs to rate classes (e.g., Standard Service, Commercial, Industrial) and to customers within rate classes. Each year as part of the Cost-of-

Service Study, revenue-to-cost relationships are analyzed to determine how well the rates and the rate design structures worked in the historical period studied. Ideally, the revenue received from each customer or rate class equals the costs incurred to serve that customer or rate class.

While there was general consensus among TVA, TVPPA, and TVIC regarding the functionalization and the classification of costs[1], there were different opinions regarding cost allocation. Allocation assigns costs to rate classes and to customers within rate classes based on their contribution to system costs. Capacity (generation and transmission) cost allocators generally assign costs based on the rate class or customer contribution to system peak. Energy cost allocators generally assign costs based on energy usage with a time-of-use element. Common variations of energy cost allocators include average usage, usage by generating unit, and cost-weighted usage (as in TVA's Resource Cost Allocation (RCA) methodology). In TVPPA's preferred methodology, time-of-use factored less into the cost equation while TVIC's preferred methodology put more emphasis on usage levels during the highest load hours (top 50). TVA's RCA methodology falls between the two, with a time-of-use methodology based on a larger number of top load hours (top 200).

Figure 5: COS revenue-to-cost relationships from three perspectives, TVA, TVPPA, and TVIC



TVA, TVPA, and TVIC COS methodologies indicated approximately the same revenue-to-cost ratios for all rate classes

Figure 5 compares revenue to cost by rate class based on the most recent complete historical year. The size of each marker represents the relative size of the rate class and the marker color indicates methodology[2] used to determine cost. The center diagonal line depicts a perfect one-to-one relationship between revenue and cost. The outer two diagonal lines depict a 10% tolerance band. The chart may be interpreted to mean that markers falling

[1] A change was made to classification methodology to re-classify certain administrative and general costs as capacity costs.

[2] Multiple COS Perspectives:

1. *TVA perspective: Top 200 hour allocated capacity, weighted incremental energy, and 12 monthly peak allocated transmission*
2. *TVPPA perspective: 12 monthly peak allocated capacity, average allocated energy, and 12 monthly peak allocated transmission*
3. *TVIC perspective: Top 50 hour allocated capacity, weighted incremental energy, and Top 50 hours allocated transmission*

within the boundaries of the 10% tolerance band indicate reasonably good revenue to cost relationship and rate design reflective of cost of service.

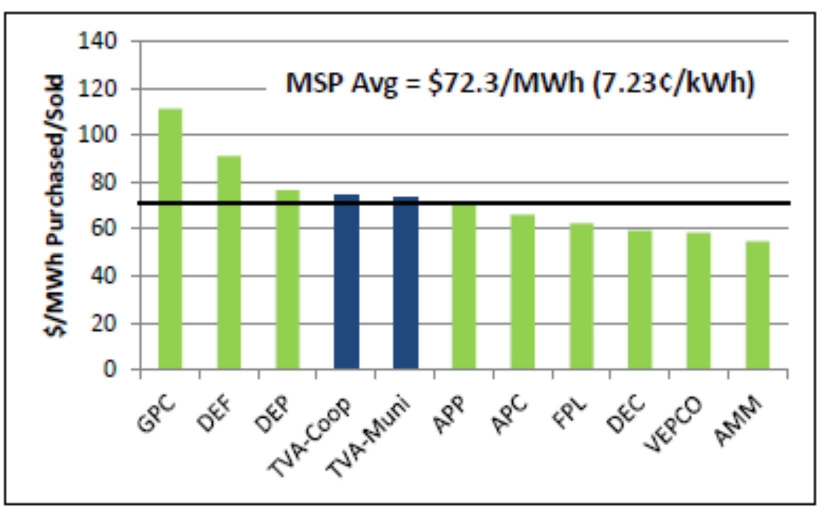
In recognition of the diversity among TVA's customers, the results of the cost-of-service study were presented from three perspectives: TVA's, TVPPA's, and TVIC's. This multi-perspective presentation allowed TVA and customers to see the impact that the choice of methodology can have on revenue allocations for their customer group and others. The three perspectives analyzed indicated approximately the same revenue-to-cost ratios for all three rate classes (Standard Service, Large Industrial Service, and Large Commercial Service). Furthermore, all three perspectives showed that the aggregated Large Commercial Service class rates were generating revenues considerably in excess of their allocated costs (outside the 10% tolerance band depicted in Figure 5). Detailed information on TVA's Cost-of-Service Study is available in the white paper "Cost-of-Service Fiscal Year 2013 White Paper," October 2014.

Wholesale Rate Competitiveness

In addition to the industrial rate competitiveness assessment, TVA and TVPPA Rates & Contracts Competitiveness Subcommittee partnered in 2014 to conduct a wholesale rate competitiveness and cost performance benchmarking study. The work, completed by Christensen Associates Energy Consulting, TVA and TVPPA, had four components: (1) competitive analysis of wholesale rates and power cost components (2) relationship of wholesale rate to retail rate (3) assessment of the unique components of TVA's business model and mission (4) identification of components that impact rate stability/volatility and southeast wholesale rates.

Key findings of the Christensen study included that TVA's local power company (LPC) purchased power cost per MWh (wholesale rate) is neutral as compared to peer average rates, with performance near the middle for two peer groups[3]. In addition, the study showed that LPC retail margins, used as a proxy for distribution costs, are at the upper end of the distribution cost metrics for investor-owned utility peers, but margins are low compared to non-TVA LPC coops' retail margins.

Figure 7: TVA Wholesale rate compared to More Similar Peer Group Utilities



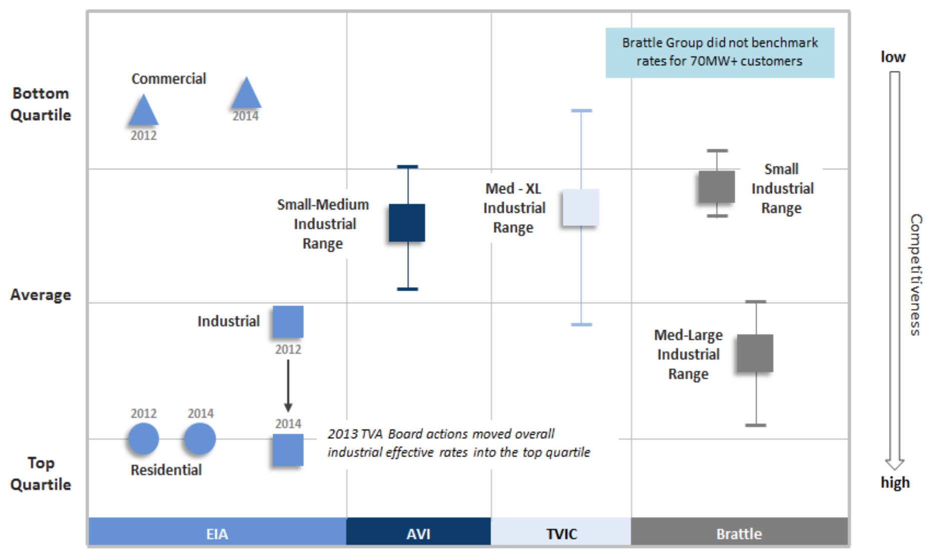
TVA's wholesale power rate is close to the average of the peer utility distribution.

[3] *TVA, TVPPA and Christensen jointly established two peer groups to be used for comparison purposes. One, called the More Similar Peer Group, consists of 9 investor-owned utilities deemed to be most like TVA in terms of revenue, sales, capacity mix, and geographic location. The second peer group, the Less Similar Peer Group, contains 11 investor-owned utilities, 10 generation and transmission coops, and 5 municipal power agencies.*

Industrial Rate Competitiveness

TVA and customers periodically review the competitiveness of TVA's rates relative to other power suppliers. For the SPP, a thorough competiveness assessment was performed during the Model & Analyze Phase. TVA integrated information from multiple sources: (1) the United States Energy Information Administration (EIA) benchmarking of utility rates[4] (2) sample survey information provided by the Tennessee Valley Industrial Committee (TVIC) and Associated Valley Industries (AVI) on power-cost levels for member companies with plants outside the TVA service territory[5], and (3) a third party assessment from rate consultants at the Brattle Group, see Figure 6 for results.

Figure 6: Overall industrial rates top quartile, industrial rates less competitive by segment



TVA has more large industrial customers relative to peers which improves TVA's overall blended industrial rate

On a cursory level the TVIC and AVI studies appeared contradictory to the TVA EIA-based analysis, with the customer information showing rates to be less competitive than the TVA analysis of EIA data. However, the samples considered did not completely overlap so it was unclear whether the discrepancies were based on sampling or on a true difference in rate reporting. The Brattle Group was engaged to address this discrepancy by using elements from each of the studies to design a complete survey set. The Brattle Group stratified the industrial class based on size and found individual segments to be less competitive than the industrial class as a whole.[6] In particular, the Brattle Group identified small industrial rates (customers with 1,000 to 5,000 kW demand) as a sub-group for whom TVA's rates were less competitive.

The Brattle Group went on to analyze the make-up of TVA's industrial class and found a high proportion of large manufacturing customers (with lower costs and lower rates) than peers, improving the overall blended rate for the industrial class. This finding provided an explanation for how industrial rates could be competitive overall but not as

[4] *Includes United States utilities only*

[5] *Limited sample sizes with potential for self-selection bias*

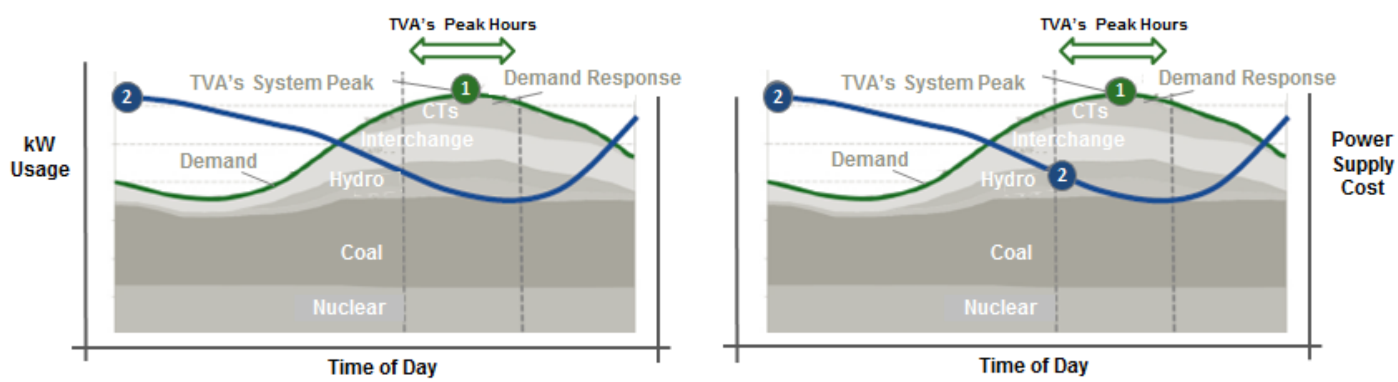
[6] *The Brattle Group was unable, however, to find third-party data on electric rates for customers larger than 30 MW*

competitive for certain segments, validating many of the findings from both the TVA-EIA results and the customer association surveys.

Structure

Rate structure refers to a set of pricing mechanisms that a utility uses to compute customer bills. Electricity bills can be very complex due to the inclusion of a variety of factors such as demand charges, fuel charges, power factor charges, time-of-use billing, etc. While there are many ways to structure rates, variable costs are typically collected based on customer's total usage in a billing period or "energy", while fixed costs are often recovered in part based on a customer's highest electricity use in a billing period or "demand." An electrical system must be able to reliably cover the total peak demand of all customers, therefore an individual customer's contribution to this peak, or coincident demand, may also be used as a rate structure element. Due to the realities of market changes placing utility revenues at risk, many utilities are moving to provisions for fixed charges or higher minimum bills. See Figure 7 for an example of coincident versus non-coincident peak billing.

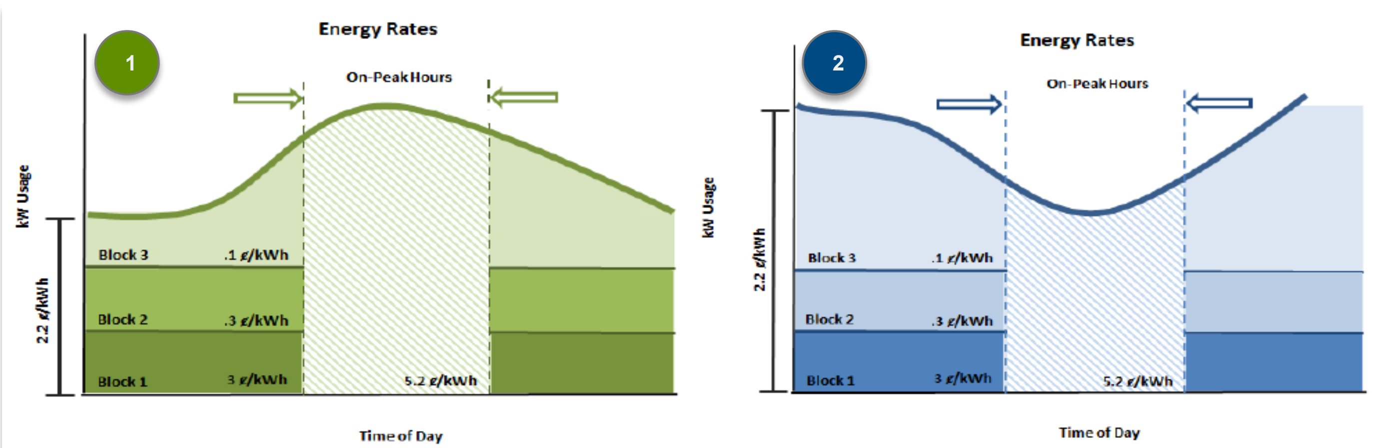
Figure 8: On-peak demand charge moves rates closer to coincident peak billing



Customer	Before Rate Change		After Rate Change	
1	5MW X $9.28/kW	$46,400	5MW X $9.38/kW	$46,900
2	5MW X $9.28/kW	$46,400	5MW X $2.75/kW + 3MW x $6.63/kW	$33,640

During the Model & Analyze Phase customers and TVA discussed various rate structure options and their technical merits, feasibility, and impacts. Key structure topics discussed included the feasibility of moving large Local Power Company served customers into standard service, the Base, Intermediate, and Peaking Model, coincident peak billing, on-peak demand charges, time-of-use rate structure, on-peak hours, hours'-use-of-demand declining block rates for large customers, and minimum bill requirements. For an example of the declining block rate structure see Figure 8. In addition there were discussions regarding topics closely related to rate structure including the Small Manufacturing Credit, high load factor rates, the Valley Commitment Program, etc. The final results of these discussions are presented below under the "Outcomes" heading, p.14.

Figure 9: Time-of-use rate structure with declining block hours-use-of-demand off-peak pricing



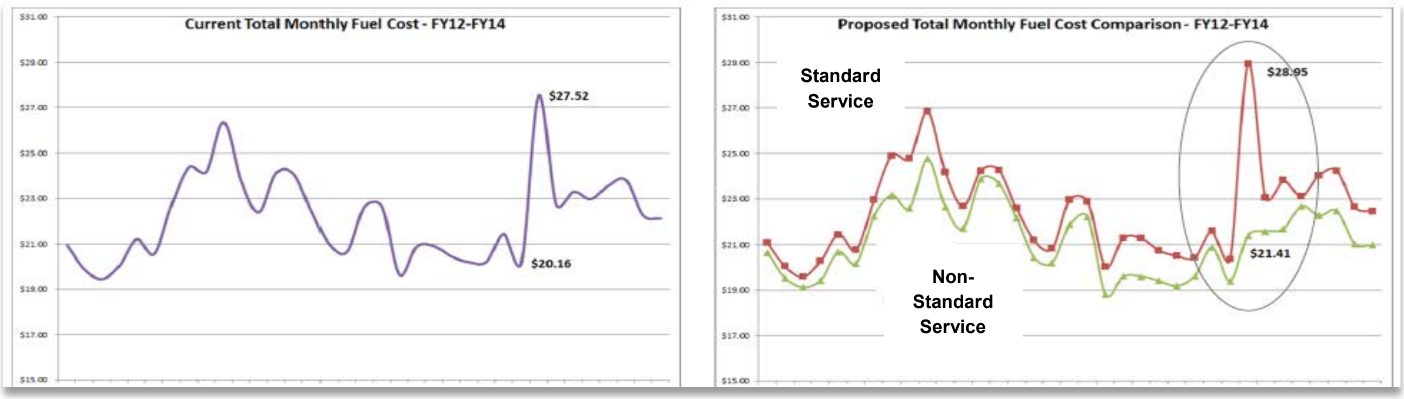
Total Monthly Fuel Cost

The Adjustment Addendum (to the Schedule of Rates and Charges) includes a Total Fuel Cost (TFC) formula used to recover fuel costs on a monthly basis. The TFC formula is comprised of a fuel forecast and a true-up mechanism called the deferred account. Prior to the SPP, all customers paid the same monthly fuel rate (before losses) regardless of when they used energy. During the Model & Analyze Phase of the SPP, several discussions between TVA and customers (TVIC and TVPPA) were held on the TFC.

Discussions initially between TVA and customers (TVPPA and TVIC) focused on ways to avoid cost shifting between customer groups including a time-of-use (TOU) fuel cost methodology. However, recognizing there were challenges in administering the TOU fuel cost methodology at retail, TVA and customers discussed an alternative based instead on multiple TFCs. Under this model, customers would be split into two or more groups and pay different monthly fuel charges more reflective of their group’s contribution to total fuel costs. Ways to improve the fuel forecast were also discussed. Together these measures -if implemented- would serve to reduce two root causes of fuel cost shifting between customers: (1) high deferred account balances and (2) the impacts of differences in seasonal usage patterns among customers.

TVA performed a back-cast of the new methodology, splitting fuel costs based on two categories of customers: (1) Local Power Company Standard Service and (2) non-Standard Service (larger customers). For an illustration of the back-cast results, see Figure 9. The historical practice of applying a loss factor to fuel for customers taking delivery at transmission level voltage was also discussed. A description of the TFC changes implemented for fiscal year 2016 is included below under the heading “Outcomes,” p.14.

Figure 10: Back-cast of proposed split Total Monthly Fuel Cost fiscal year 2012-14 – the oval emphasizes a severe weather month during which the new split FCA would have more fairly allocated fuel costs



Products

Pricing products are a broad category of TVA Board approved overlays or firm rate alternatives for customers with power utilization that is non-firm, start-up, standby, price-responsive, or otherwise different from default service. A major scope item for the first stage of the SPP was a re-positioning of the suite of products with a new name - Valley Pricing and Products – with simplified and streamlined offerings, valued appropriately for TVA and the customer, and aligned with the long-term direction under the SPP. The re-positioning effort included re-design of the pricing and terms related to three major categories of products – (1) non-firm (interruptible) products known as Response Products, (2) marginally-priced products for special customer situations known as Operational Flexibility Products, and (3) Price Responsive rates for customers who are situated to take advantage of lower off peak pricing or prefer to make informed choices about their energy consumption via real time pricing.[7] During the Model & Analyze Phase, TVIC, TVPPA – Rate Analysis and Design Sub-Committee (RAD), and TVA discussed strengths, weaknesses, and fit of the existing suite of products and proposed new options and alternatives.

Key topics related to Response Products included product valuation – to be standardized based on least cost planning (evaluated by TVA Enterprise Planning), credit payment structure given contract terms, and call type (reliability and economics, or reliability only). Other considerations included notice period to reduce load in the event of a call and testing requirements if a reliability only option was provided. Several product enhancements were also discussed including choice in termination notice, other options for adding economic hours and buy-through options for economic calls. In parallel, these products were discussed with TVA Balancing Authority and Power Trading to ensure the value to TVA as demand side resources.

TVA offers three Operational Flexibility products - Standby Power (SP), and Interruptible Standby Power (ISP), Start-up and Testing Power (STP). Currently these programs have minimal risk for economic impact in terms of cost-shifting due to the low level of customer participation (total of three programs is currently approximately 300

[7] Discussions of potential rate and product solutions to competitiveness issues stemming from the Georgia territorial Act were also discussed including Real Time Energy (RTE).

MW). Discussions on SP and ISP focused on fixed cost recovery and a much needed near-term rate adjustment to SP to cover costs (SP was last adjusted in 2002), with the intention to return to the valuation methodology and rate structure at a future date. There were also discussions on changing STP term extension eligibility requirements to accommodate smaller manufacturing customers. Previously extensions were limited to customers over five MW.

Price Responsive Rates include Off-peak Pricing (OPP), Two-Part Real-Time Pricing (Two-Part RTP) and Modified Two-Part Real-Time Pricing (Modified Two-Part RTP). Discussions focused primarily on OPP, an overlay which provides lower pricing to large customers during off-peak hours. TVA proposed incorporation of the overlay into the firm TOU rate schedule as part of the standard offering for large customers. For the two RTP products the plan was to re-visit the topic following the October 2015 rate change. The final negotiated results of the product discussions are presented below under the heading "Outcomes," p.14.

Phase III – Finalize Rate Changes

After achieving greater clarity on rate structures and products that would best suit the long term objectives, TVA adopted the 2015 rate change elements and pace of change in Phase III, Finalize Rate Changes.[8] Local Power Companies received a formal draft of the negotiated proposal for the new wholesale rate structure in the Rate Letter, a major milestone of the Strategic Pricing Plan. The rates proposed incorporated a number of modifications made in response to customer suggestions. In addition, during this phase, TVA provided Local Power Companies with a comprehensive set of draft documents to facilitate and prepare for an October 1, 2015 effective date, including a rate change amendment, wholesale and resale rate schedules, and a draft Adjustment Addendum.

Rate Letter, Total Fuel Cost Notification and Product Letter

In a letter dated January 30, 2015, as required by the Power Contract, TVA notified all Local Power Companies of changes being proposed by TVA in the Schedule of Rates and Charges. Each Local Power Company, or its representative, was asked to meet with TVA to try to reach agreement on the proposed changes. Following distribution of the letter, TVA conducted numerous meetings with customer representatives to explain and seek input on the proposed rate change. TVA staff met with Local Power Companies at TVPPA meetings and individually with companies not represented by TVPPA in the Rate Change process.

Also in Phase III, changes to the TFC and products that were discussed and developed with input from customers as part of the Model & Analyze phase were communicated to Local Power Companies in April 22, 2015 in the TFC Notification and Product Letter.

[8] The first of several incremental steps to allow time to invest in technology while minimizing impacts, including interval metering and data management, and load control and load-shaping technology.

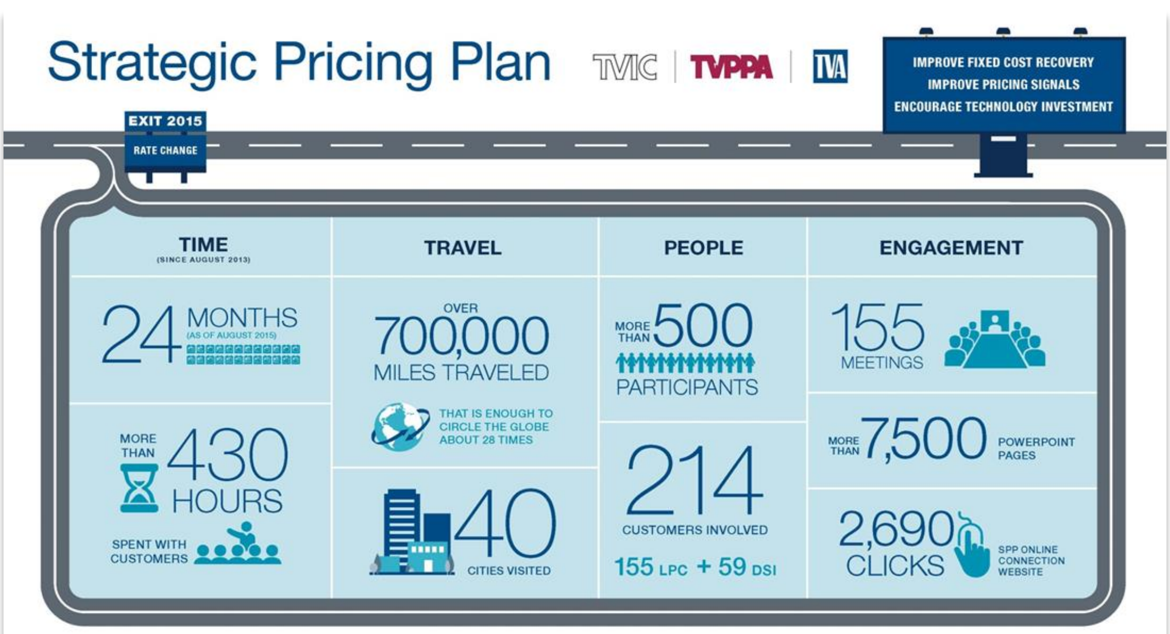
Phase IV – Implementation

The final phase of the process, Implementation, included the final approvals and detailed actions required to implement the 2015 rate change. During Phase IV - Implementation, the TVA Board received the proposed Rate Change Package and approved the Rate Change on August 21, 2015. Upon Board approval, contractually required Rate Change Notices were provided to customers along with necessary contractual amendments. Both of these events were major milestones, after which customers and TVA were able to begin final preparations for October 1, 2015 implementation. Among these preparations were external and internal rate change processes involving customer elections of rate and product offerings. Webinars were conducted to assist Local Power Companies and billing service agencies in billing and reporting information resulting from the changes. The Environmental Assessment, a formal review of the environmental impacts of the proposed changes, and another major milestone, was also completed during Implementation with a positive finding of no significant impact.

Outcomes

The changes made and implemented in the first stage of the SPP are the result of a major commitment by customers and TVA in terms of time, travel, people, and engagement. An infographic depicting the effort is shown in Figure 10 below:

Figure 11: Strategic Pricing Plan Infographic



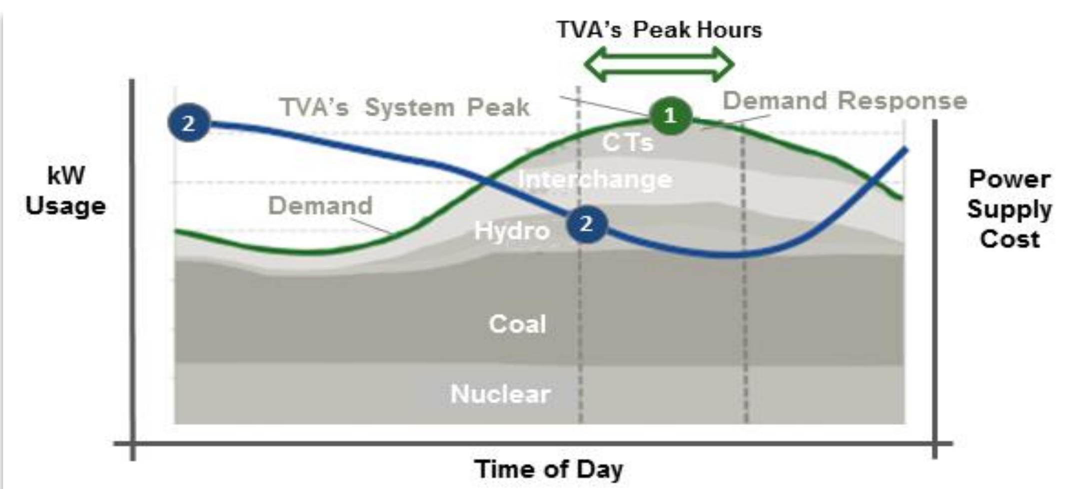
The final TVA Board-approved changes to rate structure and products, including many enhancements and improvements based on customer recommendations are summarized below:

Wholesale

Given Local Power Company elections and other indications of preference, a single TOU wholesale rate structure was approved by the TVA Board, Schedule WS. Wholesale rate schedules will continue to be applied to Local Power Companies using Standard Service rates with large customers netted out and billed using either TOU Service or SDE Service charges (described under the heading Large Customers, below). Local Power Companies will also continue to have the option of having all power billed in accordance with the Standard Service rates.

Prior to the 2015 rate change, Local Power Companies were billed based on their individual system peaks. In a first step toward a coincident peak billing structure, the new wholesale rate schedule applies an on-peak demand charge to the highest demand occurring in the on-peak period. All months include on-peak periods (previously only summer and winter) and on-peak periods have been narrowed (from 8 hours to 6). A lower maximum demand charge is applied to the highest demand in the billing period, whether that occurs in the on-peak or off-peak period. The SPP rates also have minimum bill provisions to reduce the uncertainty and variability of fixed cost recovery.

Figure 12: Customer 1 pays a higher On-Peak Demand charge than Customer 2



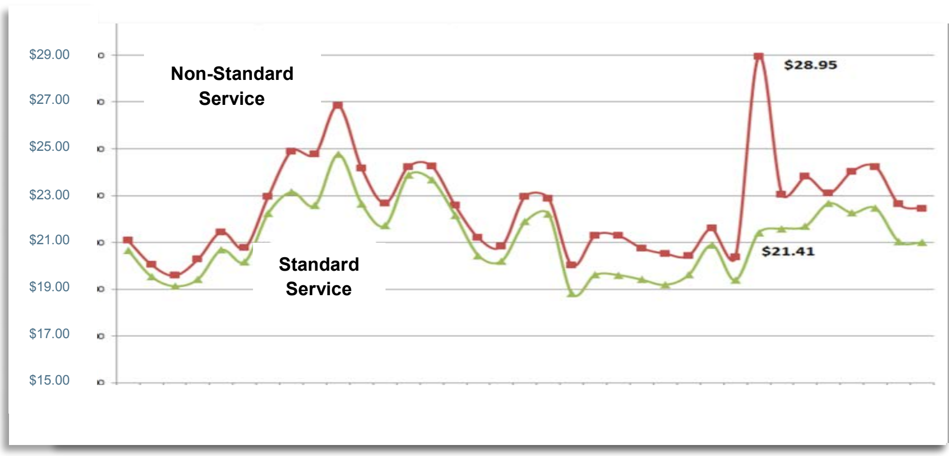
Customer 1 has higher demand during the on-peak hours driving incremental capacity requirements and higher fixed costs.

Total Monthly Fuel Cost

In an effort to more accurately allocate fuel costs, revisions have been made to the TFC by splitting fuel cost allocation between Standard Service (residential and commercial customers) and Non-Standard Service (large commercial and industrial customers). The total (load weighted) contribution to monthly fuel cost is split between the two customer class categories, more accurately allocating the costs associated with each category. TVA continues to forecast the total fuel forecast for the month ahead and then applies seasonal adjustments to each of the classes (Standard Service and Non-Standard Service) to reflect the anticipated outcome of applying the RCA methodology at the end of the month. The intent of applying the Seasonal adjustments is to minimize the deferred account balances of each class and were developed based on historical analyses. The method used for allocation will be TVA's RCA methodology discussed above (p.8).[9]

Historical impacts (fiscal years 2012 through 2014) indicate that the fuel cost allocation to Local Power Companies (having more weather sensitive loads) would be approximately 1% higher while large commercial and industrial customers would have lower fuel expense of 2-3%. See Figure 12 for the monthly results of the fiscal year 2012-14 TFC back-cast.

Figure 13: Back-cast of FCA fiscal year 2012-14 based on the new allocation



FCA cost allocation now split by customer type – Standard Service and Non-Standard Service

In addition, the parties agreed that TVA would not charge TFC losses to Direct Serve Customers who own their transformation equipment, i.e. are served at transmission delivery level and that Local Power Companies could elect to do the same. A Local Power Company may elect to set the loss adjustment at zero percent or make other adjustments to resale rates that better reflect where losses actually occur.

Other Adjustments

Under the new wholesale schedules, the value of the hydro generation benefit continues to be allocated to residential customers. The Environmental Adjustment was preserved and aligned with the new rate structure to apply to the new rates.

Resale

The wholesale rate change is designed to be revenue neutral to TVA. Individual Local Power Companies, however, may see increases or decreases in wholesale power costs. An optional monthly Power Cost Adjustment (PCA) was introduced in April 2011 to provide a mechanism to ensure that the power cost collected at resale matches the power cost incurred by the Local Power Company at wholesale. The PCA will continue to be available after October 1, 2015.

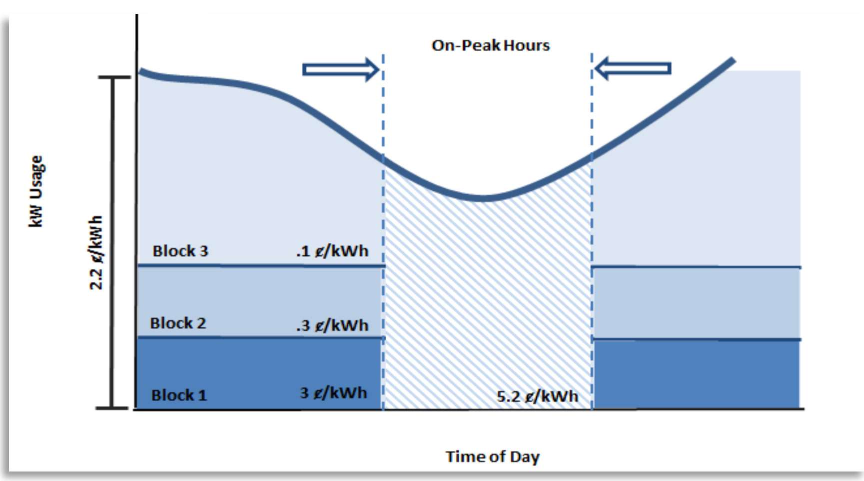
[9] RCA will be applied to determine the seasonal amounts and also the deferred account amounts, for large and small customers, used to true-up FCA charges

TVA provided distributors with three options for modifying existing rates to reflect changes in the wholesale rate structure. The options include: (1) no adjustment (2) maximum-fiscal-year adjustment (highest of most recent three fiscal years' modeled power cost recovery rate) (3) maximum 12-month-rolling adjustment (highest of most recent three years' rolling modeled power cost recovery rate).

Large Customers

Two rate structures are available for large customers: (1) time-of-use (TOU) and (2) a modified seasonal demand and energy rate (SDE). TOU is similar to the previously existing rate structure offerings, except that time-of-use on-peak and off-peak periods have been developed for all months (consistent with wholesale structures), including transition months. Also consistent with the wholesale rates, two demand charges apply (an "on-peak demand" charge and a "maximum demand charge.") The new TOU rate schedule for large customers also includes modified on-peak and off-peak energy charges with a declining block hours-use-of-demand structure in the off-peak period[10] to (1) contribute to fixed cost recovery and (2) to benefit customers with more usage in the off-peak (lower cost) period, see Figure 14.

Figure 14: Rates for large customers include on-peak and off-peak rates with a declining block structure



Customers taking more energy during the off-peak period and demanding less during the on-peak period benefit from lower rates than otherwise under the new SPP TOU rate structure.

Guided by the results of the Cost-of-Service Study and supported by the competitiveness assessment, the TVA Board extended and expanded the manufacturing credit[11] and Manufacturing Schedule A for manufacturing customers with demands between 1001 and 5000 kW. In addition, the Valley Commitment Program funding was extended and rolled into manufacturing TOU rates for larger industrial (manufacturing) customers. Including these actions, revenue allocations to Standard Service Residential and Commercial customers have been slightly increased while revenue allocations to Industrial and Large Commercial customers have been slightly decreased, see Figure 15.

[10] Off-peak usage blocks are based on an hours'-use-of-demand structure. The hours' use basis changed from maximum demand to on-peak demand benefitting customers with low demand during TVA's peak periods.

[11] The Small Manufacturing Credit has been renamed to the General Manufacturing Credit.

Figure 15: Adjustments to Revenue Allocations by Customer Class

Standard Service – Residential and Small Commercial	Small Manufacturing (1,001 - 5,000 kW)	Large Commercial (>5,000 kW)	Large Industrial (Manufacturing) (>5,000 kW)
+0.4%	-3.6%	-2.8%	-1.7%

Products

The most heavily subscribed product category is Response Products which includes products that TVA and Local Power Companies (at their option) offer to medium to large (>1 MW) customers who are willing to reduce load when called upon in exchange for a monthly credit on their bill. After fiscal year 2015, existing Response Products (5MR, 60MR, and RP) will be replaced and phased out by a single product offering called Interruptible Power (IP). IP offers the option for customers to be interrupted for (1) reliability only or (2) for reliability and economics - when TVA's alternative energy cost is high. Customers electing the reliability-only-option have five minutes to reduce power takings after a TVA call. Customers electing the reliability-plus-economics-option have thirty minutes to respond any calls, including economic calls (twelve hours annually).

IP aligns better with the new SPP TOU base rate schedules with demand credits based on the customers' average interruptible on-peak demand (previously maximum). The demand credit per kW is now levelized across all months of the year. Customers have choices regarding term and termination with higher credits for longer commitments. Customers also have the option to add additional economic hours in exchange for additional credit. Post implementation, TVA s working with customers to develop provisions for limited buy-thru on economic calls. TVA also agreed to reduce the number of base economic hours to 12. IP makes allowances for planned or forced outages without credit reduction for a set number of days (requires customer to notify TVA).

Start-up and Test Power (STP) accommodates new loads, expansion loads or testing of new processes or equipment on a temporary basis with reduced demand charges and marginally priced energy. Eligible customers must execute contracts for STP with base term of up to six months period prior to executing a firm contract. Effective Oct 1, 2015, TVA extended STP eligibility for term extensions (to a total term of twenty four months) to include smaller manufacturing (industrial) customers down to one MW. Commercial customers are now eligible for extensions to a total term of twelve months.

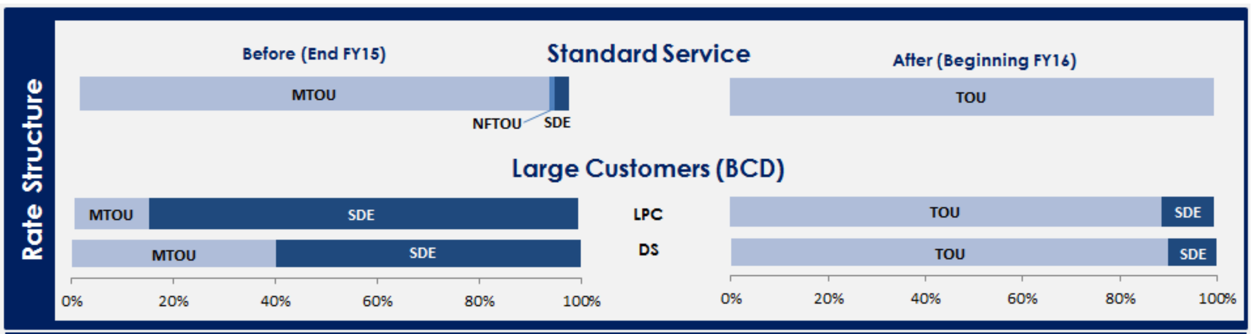
Back-up power for self-generators is offered by TVA in two products - Standby Power (SP) and Interruptible Standby Power (ISP). Effective fiscal year 2016, consistent with the long term directive to improve fixed-cost recovery, demand charges for SP (firm) were increased under the existing structures cover increases in TVA's costs. The basis for the energy charge was also updated to be consistent with other marginally priced products. ISP hours'-use-of-demand energy adders were increased however overall ISP pricing was adjusted less than SP (SP was last adjusted in 2002).

Price Responsive Rates activity was primarily focused on Off-peak Pricing (OPP) in 2015. To better align with new rate structures, OPP was incorporated into the new TOU rate structure for large customers. OPP is still available to customers who elect service under the modified SDE. Two-Part Real-Time Pricing and Modified Two-Part Real-Time Pricing now require pricing for qualifying customer's Baseline Loads to be based on the TOU rate structure.

Customer Elections

Figure 14 provides a summary of customer elections of the new rates and products as of January 2016. One hundred percent of LPC's either elected or defaulted to the TOU rate. Eighty nine percent of large customers (>5MW, termed BCDs) elected TOU compared to eleven percent for SDE. As of January 2016, 85% of interruptible load has or plans to transition to the new interruptible product, IP.

Figure 16: Customer elections dashboard as of January 2016



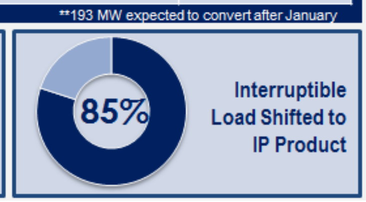
Products

Product	Interruptible Load Before Approx. Average MW	Interruptible Load After Approx. Average MW	Extended Valuation Term	Real – Time Load Visibility
5MR*	520	311**	----	0%
IP5	----	329	96%	100%
RP*	624	55	----	75%
IP30	----	518	100%	100%
60MR*	33	16	----	0%

*Programs terminating end of FY18

**193 MW expected to convert after January

- **94** Local Rate Adjustments
- Improved alignment with **Cost of Service and Competitiveness**
- SPP **Lessons Learned** review underway



Next Steps

The rate change in October 2015 represented a major accomplishment and important step toward the long-term direction for rates in the Valley. As a next step, post-October 2015 actions are being assessed and prioritized. These include process documentation (including this paper), development of performance metrics, and a lessons learned initiative. Performance metrics will be defined for initial performance review and also to facilitate ongoing evaluation and potential refinements to the rate structure. Customer feedback provided through the lessons learned process regarding the 2015 Strategic Pricing Plan change will be incorporated into future rate changes.

As TVA and customers begin to contemplate the next stage of the Strategic Pricing Plan, retail rate alignment and the initial scope for the next wholesale rate structure changes are being discussed. Both of these efforts will continue in the collaborative format used for the first stage of the Strategic Pricing Plan and build upon the foundations laid in both the 2011 and 2015 rate changes.

Appendix 1 – Strategic Pricing Plan Memorandum of Understanding

Memorandum of Understanding

between the
Tennessee Valley Authority
and the
Tennessee Valley Public Power Association

Subject: Long-term Pricing Strategy Development and Implementation

Purpose: Tennessee Valley Authority (TVA), working with its customers, identified a need for a strategic plan to focus on TVA's pricing. The development of a Long-term Pricing Strategy (LTPS) will provide a guide for setting rates that incent cost saving behaviors to keep rates as low as feasible, and strive to stabilize rates by preventing fixed cost bypass by certain customers and industry operatives. This will be a collaborative effort to define the pricing objectives and then the rate structure and pricing product options that will best serve the Valley. The process will include a look at TVA's competitive position across rate classes to ensure that rates remain affordable and competitive.

Objectives: TVA and its wholesale customers agree that we have taken recent important transitional steps; however, more focus is now needed on the long-term direction for the rate structure, pricing, and programs. The objective is development of a long-term pricing strategy which can stand the test of time, be flexible enough to accommodate customer diversity and the changing marketplace, and ensure that Valley electric rates remain competitive and affordable. By October 1, 2015, TVA will endeavor to implement a rate change consistent with the following guidelines and results expectations:

Guidelines

- Utilize transparent and collaborative process
- Recognize diversity among customers
- Challenge and clarify roles and responsibilities
- Manage impacts via pace of change, not sub-optimization of solution

Desired Results

- Focus outcome on long-term best interest of the Valley
- Eliminate unnecessary and uneconomic complexity, options and programs
- Ensure flexibility to accommodate generation and market evolution
- Be durable and sustainable to provide customer investment confidence
- Improve cost recovery with stable and predictable rates
- Establish vertically integrated cost of service methodology
- Provide appropriate cost/price signals
- Properly value rate products and options

Key Assumptions: The Key Assumptions will serve as the basis for the strategy.

- LTPS will focus on current TVA business model and policy

- Changes in structure or methodology will be reflected in aggregate at time of rate change
- Rate levels and structural changes will be guided by Cost of Service

Guiding Principles: Rate structures and pricing product options that are developed as a result of the strategy will be based on the following Guiding Principles (adapted from the December 2008 TVPPA/TVA Guiding Principles.)

- Decisions regarding the development and implementation of rate structure changes will be made with the long-term best interest of the end use customers in mind.
- The goal of the rate structures will be to facilitate the most efficient use of electricity by consumers by establishing rates that consider the cost of electricity as it is consumed.
- TVA and TVPPA will seek to reduce iterations during the development process to bring about programmatic changes in various strategic areas through collaborative efforts.
- The rate structure may provide for a phased approach to better load management through price signals to distributors and/or end use customers.
- Implementation of any pricing changes will seek to embody simplicity and provide stability and predictability to support long-term economic investment decisions.
- The rate structures will promote fairness and equity in pricing between distributors and directly served customers.
- The new rate structure may provide for a uniform wholesale rate option available to all distributors.
- The wholesale rate options may provide for a phased approach that better reflects actual costs and encourages retail rate making by the distributors.
- Implementation of any pricing changes will provide adequate time for customer communications and process revision.

Process: The TVPPA Leadership Council (LC) will represent TVPPA in discussions regarding the long-term pricing strategy. The LC will assist TVA in development of a work plan to govern the LTPS activities. It is anticipated that the LC and TVA counterparts will define areas for exploration and evaluate initial modeling in order to provide direction to the working group for detailed analysis and to the TVPPA Rates and Contracts committee for review and recommendation. After review and confirmation by the LC, the topical area would be directed back to the TVPPA Rates and Contracts committee for implementation preparation. District and individual meetings will be utilized to keep LPCs informed of progress and receive individual LPC input into rate discussions and the LTPS.

TVA will utilize the Pricing Committee for internal communication and alignment and will provide regular progress updates to the Executive Management Council and TVA Board. The collaboratively developed LTPS work plan shall include additional detail regarding engagement details, milestones, work sequence and communications.

Milestones: During calendar year 2014, scenarios will be evaluated and rate change proposals will be modeled and analyzed. The elements of a rate change proposal will be finalized by January 2015, with a goal of implementing a rate change in October 2015. This rate change is expected be the first in a series of rate changes which will meet the objectives of the LTPS.

Signature Page

H. Wayne Henson
Wayne Henson
Chairman of the Board
Tennessee Valley Public Power Association

3-26-14
Date

Jack Simmons
President/CEO
Tennessee Valley Public Power Association

3/28/14
Date

John Thomas
Executive VP & Chief Financial Officer
Tennessee Valley Authority

4/14/14
Date

Dan Pratt
VP, Pricing & Contracts
Tennessee Valley Authority

4-4-2014
Date

Rob Manning
Executive VP & Chief External Relations Officer
Tennessee Valley Authority

3-28-14
Date

Van Wardlaw
Senior VP, Customer Resources
Tennessee Valley Authority

3-28-14
Date

References

"Rate Adjustments and Changes," Tennessee Valley Authority, January 2013

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"Cost of Service Fiscal Year 2013 White Paper," Tennessee Valley Authority, October 2014

"Long-term Pricing Strategy White Paper," Tennessee Valley Authority, January 2014

"Strategic Pricing Plan White Paper," Tennessee Valley Authority, September 2014

"Rate Archaeology Report," Tennessee Valley Authority, April 2014

"Generic Rate Change Letter," Tennessee Valley Authority, January 30, 2015

"Pricing Products and Overlays," Tennessee Valley Authority, March 15, 2013

Attachment 2: TVA General Manufacturing Credit (GMC)

GENERAL MANUFACTURING CREDIT (GMC)

Provides credits on monthly demand and energy charges to qualifying manufacturers, making rates more competitive and helping retain manufacturing load in the Tennessee Valley.

WHY YOU SHOULD PARTICIPATE:

The General Manufacturing Credit offers significant power cost savings to qualifying manufacturers, which in turn helps retain manufacturing load in the Tennessee Valley. A strong manufacturing base helps TVA keep rates low for all consumers.

ELIGIBILITY REQUIREMENTS:

- Delivery points served under Part 3 of either Schedule GSA or TGSA, or Schedule MSA
- Major use of electricity for activities are classified with SIC codes 20 through 39, or 2002 NAICS code 5181, or 2007 NAICS codes 5182, 522320, and 541214

HOW IT WORKS:

For each month[*] in which an eligible customer has a metered demand that exceeds 1,000 kW[**], the General Manufacturing Credit is calculated as:

General Manufacturing Credit =

$$(\$1.38 \times 1{,}000\ \text{kW}) + (\$1.63 \times (\text{firm billing kW} - 1{,}000\ \text{kW})) + (1.076¢ \times \text{firm billing kWh})$$

HOW TO SUBSCRIBE:

Contact your local power company for more information on program details and the subscription process.

[*] General Manufacturing credits will be issued once per billing month for each eligible customer account.
[**] Metered demand for the billing month must exceed 1,000 kW.

https://onlineconnection.tva.gov/Pages/GenmanufacturingCredit.aspx

Attachment 3: Synapse Paper

Electricity Prices in the Tennessee Valley

Are customers being treated fairly?

Prepared for the Southern Alliance for Clean Energy

January 29, 2018

Updated January 31, 2018

AUTHORS

Melissa Whited
Tim Woolf

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 2
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

CONTENTS

January 31, 2018 Update

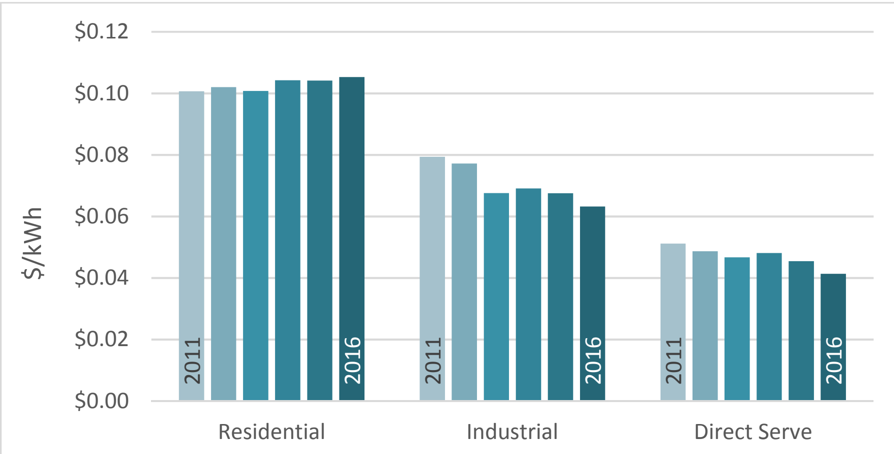
This update removes Paducah Power System from the list of Tennessee Valley Authority local power companies. Although still listed as within the TVA balancing authority, we have learned that Paducah left TVA in 2010. No results are materially affected by the removal of Paducah from the analysis.

In addition, we have added additional details regarding the methodology used in the analysis of rate impacts on the revenues collected from each customer class. See Footnote 10 for this detail.

Introduction

Since 2011, the Tennessee Valley Authority's industrial and direct serve customers have benefitted from a nearly 20% cut in the price of energy, while residential customers have experienced steady rate increases.[1] As illustrated in Figure 1, the average price of electricity for residential customers has increased above 10 cents per kilowatt-hour for residential customers, but industrial customers directly served by TVA have seen prices drop to approximately 4 cents per kilowatt-hour.[2]

Figure 1. TVA Average Revenue per Kilowatt-Hour 2011-2016



Electricity rates can be expected to change as costs rise, but they can also change if TVA modifies the underlying method used to set rates for each customer class. The divergence in electricity costs for residential and industrial customers raises several questions:

- What is the reason for residential customers shouldering rising rates while large industrial customer rates decline?
- Has TVA modified the methodology by which costs are allocated to customer classes?
- Are the rates charged to customers fair?

This white paper reviews trends in the prices paid by industrial and residential customers in the Tennessee Valley to determine whether

TVA is the nation's largest public power provider, supplying electricity to millions of customers in Tennessee, as well as portions of Alabama, Mississippi, Kentucky, Georgia, North Carolina, and Virginia. TVA's customers include approximately 60 large "direct serve" industrial customers, as well as 154 individual local power companies (LPCs) who resell the electricity to retail customers.

TVA recovers the costs of providing electricity through contracts with its direct serve customers, as well as through wholesale electricity rates that it charges distributors. Despite primarily being an electricity wholesaler, TVA also has broad authority over the retail rates that the LPCs charge their residential, commercial, and industrial retail customers. Thus, the manner in which TVA develops and sets rates has broad implications for TVA's direct-serve industrial customers and the more than six million retail customers served by LPCs.

[1] The rate increases for non-direct-serve customers reflect the total bundled rate (supply and distribution), rather than just the wholesale supply cost. These bundled rates are collected by Local Power Companies, but are under TVA's regulation.

[2] Calculated using U.S. Energy Information Administration Form 861 data, 2011-2016.

costs are being fairly allocated across customer classes. Due to limited information regarding TVA's ratemaking methodologies, many questions remain unanswered and point to a need for greater transparency in TVA's ratemaking.

We note that the analysis presented here relies primarily on cost of service studies as an indicator of whether rate changes are justified. This approach is consistent with the standards typically applied to assessing rates at investor-owned utilities. However, the TVA Act (48 Stat. 65, 16 U.S.C. sec 831) imposes additional considerations on TVA. For example, Section 831 states, in part, that the TVA projects "shall be considered primarily as for the benefit of the people of the section as a whole and particularly the domestic and rural consumers to whom the power can economically be made available, and accordingly that sale to and use by industry shall be a secondary purpose…." Although not specifically addressed here, it is worth investigating whether TVA's actions have been consistent with the Act.

Allocating Costs among Customer Classes

Numerous investments are required to provide electricity to customers. Energy must be generated at power plants, transmitted over high-voltage lines, and then distributed over a low-voltage network of wires to customer premises. Fairness requires that these costs should be apportioned among customers according to who bears responsibility for causing the cost. Of course, many costs are incurred to serve all customers, which makes fair apportionment of costs difficult. A baseload power plant, for example, serves residential, commercial, and industrial customers alike. However, some costs are caused more by certain types of customers and the particular characteristics of how they use the electricity system, such as the degree to which customer load causes spikes in system peak demand.

A cost of service study is the primary mechanism by which determinations are made regarding how costs should be allocated among the various customer classes. Such studies consider key factors such as the number of customers, class peak demand, and annual energy consumption in allocating costs.

However, there are numerous competing methodologies for performing cost of service studies and a variety of assumptions that an analyst must make regarding cost drivers and allocation methods. The methodology and assumptions selected can have substantial implications for the share of costs allocated to each class.

Over time, TVA has adjusted its cost of service methodology and rate designs. For example, in 2010, TVA implemented time-of-use pricing at the wholesale level, which was not expected to substantially alter the revenues collected from each class.[3] Then, in 2015, TVA changed the method that it uses to allocate fuel costs – one of the largest components of TVA's rates. Prior to 2015, TVA allocated fuel costs on an average cost basis, whereby all types of customers paid the same price for fuel costs, regardless of when they used the energy. In 2015, TVA adopted the resource cost allocation (RCA) methodology, which

[3] Tennessee Valley Authority, "Final Environmental Assessment: Elimination of End-Use Wholesale Rate Structure and Introduction of Time-of-Use Pricing for Electricity at the Wholesale Level," July 2010, 25.

allocates total fuel costs among large and small customers in proportion to when each class uses electricity and the incremental cost of the electricity.[4]

This change did not impact customers equally; rather, it was expected to increase rates paid by small, standard service customers and reduce rates for large commercial and industrial customers.[5] According to TVA's 2015 assessment, the new rate structure was expected to be revenue neutral overall, but increase residential rates by about 0.4% while reducing rates for large commercial and industrial customers by between 1.7% and 3.6%. However, the actual changes appear to have been approximately three times larger. From 2015 to 2016, residential rates increased 1.1%, while industrial rates fell by 6.4% and direct serve rates dropped by 9.0%.[6] The apparent discrepancy between what TVA anticipated would happen as a result of its 2011 and 2015 rate reforms, and what actually occurred, does not prove that TVA intended to cause such a disparate impact, but it highlights how small changes can result in large impacts on customers.[7]

Because such changes can significantly impact customer rates, the underlying assumptions and methodologies should be carefully reviewed to ensure that each class is treated fairly. A cost of service study provides important information regarding:

1) The method by which costs are classified,

2) The allocation factors used, and

3) Whether current rates would under- or over-recover a class's share of costs.

Without access to TVA's cost of service study, we are only able to evaluate the fairness of TVA's rates indirectly. Below we describe these indirect factors and what they may signify regarding TVA's cost allocation methodologies.

Trends in TVA Electricity Rates

Customers in the Tennessee Valley are billed for electricity through a combination of charges. Residential customers are primarily billed based on the total kilowatt-hours (kWh) consumed per month, but large commercial and industrial customers are also billed based on the peak amount energy consumed during a billing cycle (measured in kW). Thus, to compare electricity rates across classes,

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[4] Tennessee Valley Authority, "Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers: Final Environmental Assessment" (Knoxville, TN, July 2015).

[5] Chris Mitchell, "Potential Impacts from Oct 2015 Rate Change," May 14, 2015; Tennessee Valley Authority, "Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers: Final Environmental Assessment," 19.

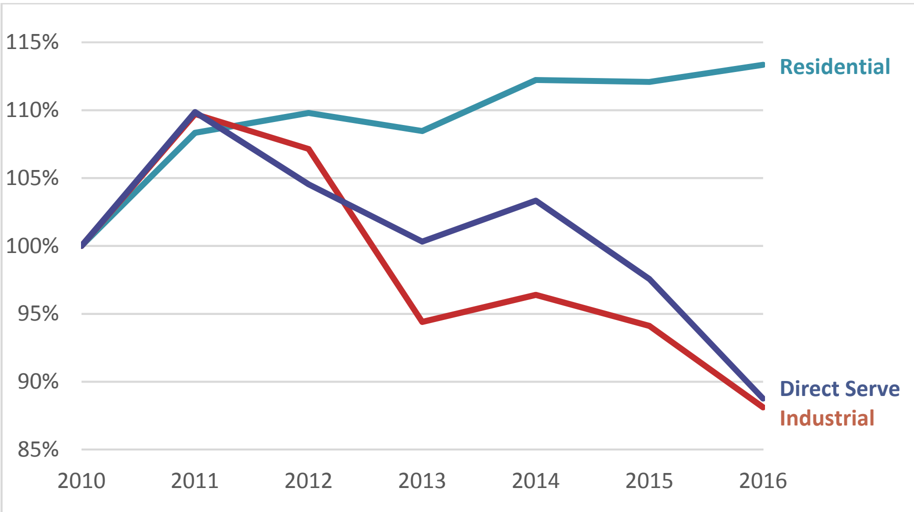
[6] As measured in terms of average revenue per kilowatt-hour, EIA 861 data.

[7] We also note that the rate impacts for non-direct-serve customers include any changes at the distribution level, which may have compounded the impacts TVA made at the wholesale supply level.

rates must be converted to a common metric, such as the average revenue the utility receives per kilowatt-hour ($/kWh).[8]

Sales, revenue, and customer data for this analysis were obtained from the U.S. Energy Information Administration Form 861 for TVA and the LPCs served by TVA. Using this data, we calculated the average revenue per kilowatt-hour by dividing total revenues by sales and normalized the data to the year 2010. The graph below depicts trends in average revenue per kilowatt-hour for residential customers (light blue) compared to industrial customers (red) and TVA's direct serve customers (dark blue) for 2010 through 2016.[9]

Figure 2. Average Revenue per Kilowatt-Hour at TVA and LPCs



As shown in the graph, from 2010 to 2011, the average revenue per kilowatt-hour increased for all classes of TVA's customers, including those served by local power companies as well as direct serve customers. However, from 2011 to 2016, rate trends diverge.

From 2011 to 2016, average revenue per kilowatt-hour for the residential class rose steadily, while the industrial and direct serve average revenue per kilowatt-hour fell. By 2016, average revenue per kilowatt-hour for residential customers was more than 5% higher than in 2011, while average revenue for industrial and direct serve customers had fallen by 20% and 19%, respectively.

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[8] The average revenue per kilowatt-hour metric is a close approximation of actual energy rates paid by residential customers, as residential customers are primarily billed on an energy consumption (kWh) basis. Residential customers also pay a mandatory monthly fee for service, which varies widely among TVA's local power companies. For industrial and direct serve customers, however, the average revenue per kilowatt-hour metric differs from the actual energy rate, since these customers are also billed on the basis of the customer's maximum demand during the month. Thus, the average revenue per kilowatt-hour collected can vary due to changes in the ratio of customer demand (kW) to energy consumption (kWh), even though the actual electricity rates may not have not changed. Still, the average revenue per kilowatt-hour metric is useful for identifying general trends, and is one of the key metrics reported by TVA in its annual performance reports to Congress. In its FY 2017 performance report, TVA refers to this metric as "Retail Rates (cents/kWh)," defined as the "average of the previous twelve months' LPC reported retail power revenue and directly served power revenue divided by LPC reported retail power sales and directly served power sales." *See:* Tennessee Valley Authority, "Budget Proposal and Management Agenda (Performance Report) for the Fiscal Year Ending September 30, 2017," February 2016, 24.

[9] Direct serve customers are primarily industrial customers. However, beginning in 2015, it appears that some direct serve customers were reclassified as commercial customers.

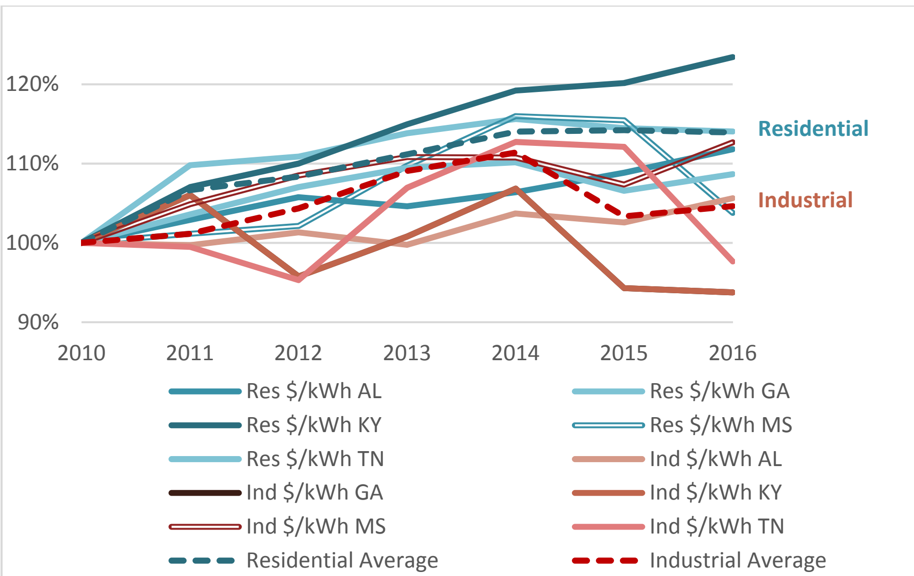
For simplicity, we have focused on the residential and industrial classes. However, it is important to note that commercial customers have also seen rising rates, but at a slightly slower pace relative to the residential class.

Comparison to Other Utilities

To determine whether the trends in average revenue per kilowatt-hour could be explained by regional trends (such as macroeconomic factors), we also analyzed average revenue per kilowatt-hour for non-TVA utilities in the region (Alabama, Georgia, Kentucky, Mississippi, and Tennessee). The figure below shows average revenue per kilowatt-hour for non-TVA utilities in each state.

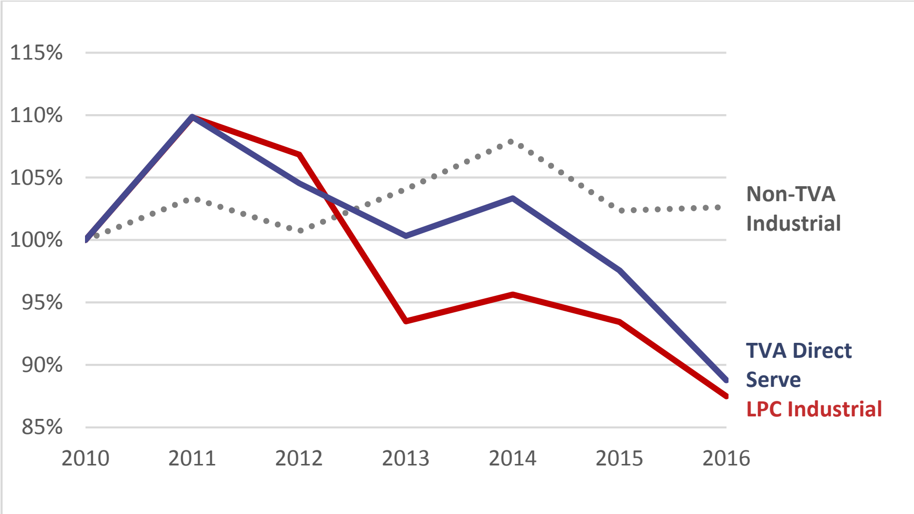
The residential data (shown in blue) indicate that average revenue for residential customers of non-TVA utilities has generally increased at a pace similar to that at TVA distributors. However, the trends for industrial and direct serve customers of TVA distributors do not closely mirror trends at non-TVA utilities.

Figure 3. Average Revenue per Kilowatt-Hour at Non-TVA Utilities



The difference in average revenue per kilowatt-hour for industrial customers of TVA utilities and non-TVA utilities can be seen more clearly in the Figure 4 below. For customers of TVA utilities, average revenue per kilowatt-hour for both industrial customers and direct serve customers has declined substantially since 2011. In contrast, non-TVA utilities' average revenue per kilowatt-hour (dotted line) exhibits no clear trend upward or downward relative to 2011.

Figure 4. Industrial and Direct Serve Average Revenues for TVA and Non-TVA Utilities



Magnitude of Rate Impacts

As shown above, since 2010 the average revenue per kilowatt-hour has increased by more than 13% for residential customers served by TVA's local power companies. In contrast, TVA direct serve customers paid 11% less per kilowatt-hour in 2016 than in 2010, and industrial customers paid 13% less. The magnitude of these trends is clearly visible when translated into dollars. If each rate class had experienced the same percentage increase in rates each year from 2011 to 2016, then revenues collected from each class would have changed as follows:[10]

Table 1. Class Revenue Increase or Decrease Under Uniform Percentage Rate Changes (2011-2016)

	Residential Revenue Change	Commercial Revenue Change	Industrial Revenue Change	Direct Serve Revenue Change
2011	-$9 million	$69 million	-$37 million	-$24 million
2012	-$102 million	$36 million	$18 million	$49 million
2013	-$242 million	$27 million	$174 million	$41 million
2014	-$259 million	$10 million	$211 million	$38 million
2015	-$324 million	-$18 million	$223 million	$119 million
2016	-$439 million	-$74 million	$315 million	$197 million
Cumulative	**-$1,374 million**	**$50 million**	**$905 million**	**$420 million**

In other words, had rate increases for 2011 through 2016 been allocated equally across the classes, residential customers would have paid $439 million less in 2016. On a cumulative basis, nearly $1.4

[10] Note that these revenues reflect total (supply and distribution) revenues, not only wholesale supply revenues. This analysis was performed on a revenue-neutral basis. That is, it assumes that revenues in each year do not deviate from those actually collected by TVA utilities in that year. Instead, only the allocation of revenues across classes was changed so that the percentage increase in rates relative to 2010 levels would be borne equally by each class.

billion less would have been collected from residential customers in the Tennessee Valley from 2011 through 2016.

The 2015 Environmental Assessment and Changes to Utility Tariffs

Electricity rates are generally developed based on cost of service studies, as well as other considerations, such as customer equity, simplicity and understandability, and efficient price signals.[11] In 2015, TVA filed its Environmental Assessment for its proposed rate change, which provides a high-level overview of the proposed changes to electric tariffs and the rationale for such changes.

In the Environmental Assessment, TVA outlined the objectives associated with its rate proposal, including improving price signals and enhancing the competitiveness of industrial rates.[12] TVA explained that the proposed 2015 rates reflected a reallocation of costs among customer classes, as well as revisions to credit programs, such as a $22 million increase in the credits provided to general manufacturing customers.[13]

However, TVA provided little data to justify its proposals, and only vague descriptions of how it intended to reallocate costs across classes. We are aware of a change in TVA's fuel cost allocation methodology in 2015 (discussed above), but other changes may also have been made. A change in the underlying cost of service methodology, such as a change in how demand-related costs are allocated or defined, would lead to a change in the total costs allocated to each class, which could have significant impacts on the rates of certain classes.

To determine the impact of TVA's rate changes, we analyzed tariffs from an LPC (Johnson City Power Board, now BrightRidge) for both residential and industrial customers. Utility tariffs contain all of the rate components (energy charge, demand charge, customer charge) that customers see on their bills. Tariffs were available for the residential class for each month from January 2015 to November 2017. For the industrial class, tariffs were available annually for 2013 through 2017. To most consistently compare industrial tariffs across years, we focused on the rate structure for large manufacturing customers (MSB).

The MSB tariff consists of several fixed charges, on-peak and off-peak demand charges, and on-peak and off-peak energy charges combined with declining block rates. Since 2013, the MSB tariff has shifted more revenue recovery into the energy charge, with a reduced emphasis on the demand charge and steeper declining block rates. Specifically, in 2015 most demand charges for MSB customers were reduced by approximately 45%, while winter on-peak energy charges were increased by 53% and the first block of energy charges were increased. Subsequent blocks of energy were priced lower, however, further emphasizing the declining block rate structure. Since 2015, the energy charge for MSB customers

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[11] These principles are discussed extensively in James Bonbright's 1961 book, Principles of Public Utility Rates. In addition, as discussed above, the TVA Act specifies additional guidance for rate setting.

[12] Tennessee Valley Authority, "Refining the Wholesale Pricing Structure, Products, Incentives and Adjustments for Providing Electricity to TVA Customers: Final Environmental Assessment," 2.

[13] Tennessee Valley Authority, 11.

has remained relatively constant, with modest increases of 5% to the first blocks of energy, and 4% decreases to the tail block.

An analysis of the residential tariffs reveals that in 2015, the residential fixed charge was increased by 27%, while the energy rate did not change. In 2017, the fixed charge was again increased by 13%, while energy rates increased by 7%. This change is not yet reflected in the EIA data used in the graphs above, but points to a continued rise in residential rates.

These changes to the industrial and residential customer rates help explain how rates were modified to result in higher average revenue per kilowatt-hour for residential customers and lower average revenue for industrial customers. However, neither the tariffs nor TVA's 2015 Environmental Assessment adequately explain why the relationship between various rate elements were modified so significantly, or what changes were made to cost of service methodologies that may have prompted these changes. Without such support, it is not possible to determine whether such changes were truly justified, or whether the changes result from a bias toward large industrial customers who may exercise considerable leverage in rate negotiations.

Summary

Our analysis reveals that significant changes have been made to TVA rates in recent years. These changes have not only altered the proportion of costs borne by each class, but have also changed *how* costs are collected. Specifically:

1) Since 2011, average revenue per kilowatt-hour (a proxy for electricity rates) for TVA direct serve and industrial customers has decreased substantially relative to residential customers. This trend contrasts with non-TVA utilities in the region, where industrial average revenue per kilowatt-hour has slightly increased.

2) Considerable modifications have been made to the rate designs by which revenues are collected. For industrial customers served on the MSB rate, this means lower demand charges and steeper declining block rates. For residential customers, fixed charges have increased much more rapidly than energy rates, leading to a higher proportion of customers' bills which are fixed, and reduced customer control over their bills.

Because we have not been able to review TVA's cost of service studies over the past decade, we do not know the extent to which these changes are justified. Without this information, numerous questions and concerns remain unaddressed. In particular:

1) Why does the average revenue per kilowatt-hour for direct serve and industrial customers at TVA utilities decline more than at other regional utilities? Have costs been unfairly shifted away from TVA direct serve and industrial customers onto other classes?

2) What was the rationale for the change in the proportion of revenues collected through the MSB demand charges and energy charges in 2015? Is this reflective of a change in the cost of service methodology?

3) Why have residential fixed charges at certain TVA utilities increased dramatically over the past decade? Are these increases driven by changes in TVA's cost of service methodology? Does TVA recognize that increased fixed charges represent less efficient price signals to customers and reduce customer control over their bills?

Attachment 4: 5 Lakes Cost of Service Analysis

Comments on TVA Cost of Service Analysis[1]

Douglas Jester, Partner
5 Lakes Energy

This commentary is based on review of the Tennessee Valley Authority's *Cost of Service Fiscal Year 2016: A Summary of Wholesale Cost of Service Methodologies and Results*, presented in May 2017, TVA's 2018 Wholesale Rate Change: Draft Environmental Assessment dated March 2018 and select additional public documents and presentations prepared by TVA. These comments are intended to identify the main topics regarding TVA's cost of service methods and approach to rate design that are important for TVA and the local power companies ("LPCs") to reconsider.

For purposes of wholesale cost of service analysis, TVA uses standard accounts as specified by the Federal Energy Regulatory Commission and groups these into five "functions": capacity, energy, transmission, other, and taxes. As I discuss at greater length below, the group of accounts that TVA summarizes as "capacity" should properly be labeled as "plant" and the group of accounts labeled as "energy" should be labeled as "fuel and net purchased power". Otherwise, this grouping of accounts is reasonably consistent with industry practice. TVA's functionalization of "plant" as "capacity" and "fuel and purchased power" as energy is not conceptually sound.

Fixed and Sunk Costs

TVA's cost of service analyses are founded in an incorrect idea that then infects much of their analysis. TVA claims that "[c]osts fall into two broad categories: fixed and variable." And further elaborates that "Generation costs are classified as capacity or energy. Capacity costs are costs incurred to generate electricity that do not vary with generation, and are considered fixed. Energy costs are costs incurred to generate electricity that vary with generation and are considered variable."

TVA has clearly conflated and confused fixed costs and sunk costs.

The carrying cost of a power plant (deprecation, cost of capital, fixed maintenance, etc.) do not vary with generation in the short term but do vary with generation in the long-term. Power plants are built in anticipation of generation requirements. Once built, the costs of a power plant are **sunk** in that they cannot be avoided by not running the plant but that does not make them **fixed**.

Given that the number of power plants owned by TVA and their sizes reflect accumulated decisions by TVA about how much generation is needed to serve its customers, it should be clear that none of the cost of power plants is **fixed.**

Plant vs Capacity

TVA claims that "Generation costs are classified as capacity or energy. Capacity costs are costs incurred to generate electricity that do not vary with generation, and are considered fixed. Energy costs are costs incurred to generate electricity that vary with generation and are considered variable." This assertion conflates and confuses plant costs with capacity costs. The FERC accounts that TVA functionalizes as

[1] Prepared for the Southern Alliance for Clean Energy

capacity are in fact **plant** costs and FERC clearly labels these accounts as **plant** costs. This error reflects the confusion of fixed and sunk costs discussed above.

Conflating plant costs with capacity costs then leads TVA to allocate plant costs in total to customer classes and to LPCs based on a measure of system peak demand. TVA provides some discussion and analysis of different ways to measure and allocate responsibility for capacity but none of these overcome the original sin of calling **plant** costs **capacity** costs.

The simple way to see the defect in conflating **plant** and **capacity** costs is to think about the various types of plants in TVAs fleet. Allocating plant costs based on class contribution to system peaks means that the vast majority of the cost of nuclear plants is allocated to peak demand, most of the cost of coal plants is allocated to peak demand, and presumably any TVA owned wind and solar plants would be allocated to peak demand. Most utilities would also allocate virtually all costs of hydropower facilities to plant; to the extent that TVA allocates costs of dams and related facilities to hydropower these also appear to be counted as capacity costs and allocated to peak demand.

But, if the only reason to build a power plant was capacity at peak times, TVA would build a natural gas combustion turbine because the carrying cost per unit capacity of a combustion turbine plant is much cheaper than the carrying cost per unit capacity of a hydropower plant, nuclear plant, coal plant, wind plant, or solar plant. The only reason for TVA to have built hydropower, nuclear, or coal plants instead of combustion turbines (or the predecessor reciprocating engines) is to produce energy. It is therefore inappropriate to allocate the carrying costs of hydropower, nuclear, coal, solar, or wind plants based on peak demand. That misallocation is the direct result of conflating **plant** costs with **capacity** costs.

A correct cost of service analysis would split **plant** carrying costs into an allocation to **capacity** costs and an allocation to energy costs. Utility regulators use a variety of practices to split plant carrying costs into an allocation to capacity costs and an allocation to energy costs, but the most theoretically sound is to allocate to capacity the carrying cost of a combustion turbine times the peak-time capacity of each plant and to allocate the remaining carrying cost of the plant to energy. TVA has simply relabeled plant costs as capacity costs rather than providing a fair and careful functionalization of **plant** costs to **capacity** and **energy**.

Based on review of TVA's Integrated Resource Plan, 2015 Final Report, TVA implicitly uses this distinction between plant and capacity in its Integrated Resource Planning. The Integrated Resource Plan clearly discussed capacity as the maximum output from plants and capacity requirements as the total capacity required to meet peak demand with a reserve margin. It also discusses energy as the output of plants delivered over time. The software used by TVA in its least-cost planning clearly performs mathematical optimization of a generation portfolio in a way that would choose a combustion turbine if capacity is only needed to meet peak load and reserve margin and uses other plants based on their ability to produce energy over the year at a variable cost that is enough less than the variable cost of operating a combustion turbine to justify the extra investment in plant of some type different than a combustion turbine. Putting it less mathematically, the extra carrying cost of a plant other than a combustion turbine is justified by its ability to produce energy more cheaply than a combustion turbine will.

TVA also recognizes this distinction between plant and capacity in its consideration of interruptible rates. For example, in the TVIC Pricing Committee Strategic Pricing Plan Presentation of September

2014, slides 15-23 discuss the pricing of interruptible service by assessing its value relative to the economic carrying charge of a combustion turbine. Because interruptibility only provides capacity at peak times it would be inappropriate to credit it with the full embedded cost of plant per unit capacity; TVA is correct in that analysis, but the point applies to all capacity.

Sometimes, capacity costs are based on the cost per unit capacity of new entry of a combustion turbine, which is the economic carrying cost of a new combustion turbine in its first year. The argument for this is that this is the marginal cost of capacity in an environment of growing peak demand. However, it can be argued that over a longer period, marginal demand only needs to cover the life-cycle cost of new capacity; this is more clearly true in an environment without systematic demand growth. Thus, the cost of service study should use the levelized carrying cost of a combustion turbine as the appropriate measure of carrying cost.

Energy vs Fuel and Purchased Power

TVA claims that "Generation costs are classified as capacity or energy. … Energy costs are costs incurred to generate electricity that vary with generation and are considered variable." This claim reflects the same point of confusion as TVA's conflation of **plant** and **capacity**. **Energy** is not another word to summarize **fuel and net purchased power.** Rather, the word **energy** should be used to functionalize both these variable costs and the portion of plant costs that are incurred to energize the grid throughout the year. It is simply not the case that all plant costs are incurred to meet peak demand and are "free" for generation the rest of the year. TVA has simply relabeled fuel and net purchased power costs as energy costs rather than providing a fair and careful functionalization of **plant** costs to **capacity** and **energy**.

As discussed above, the cost of service study should functionalize a portion of plant costs to energy by assigning the carrying cost of a combustion turbine times the capacity of each generation asset to **capacity** and assigning the remainder of the embedded cost of the plant to **energy**.

TVA's Wholesale Cost of Service Allocators

Having functionalized direct costs as capacity, energy, transmission, other and taxes, TVA allocates these costs to customer classes in fairly conventional ways.

TVA allocates capacity costs based on the top 200 hours. This is an appropriate method and is superior to the narrower allocation basis recommended by TVIC. If TVA were to actually price capacity costs to demand during peak hours based on a small number of hours, customer response to the resulting very high prices would lower demand during those peak hours to a level lower than at other hours not currently in the peak demand period. 200 hours is a more reasonable approximation of the customer responsibility for capacity costs that would result from actually pricing capacity during peak hours and is therefore economically more efficient than a narrower basis for cost allocation.

TVA allocates fuel and net purchased power costs (which they have unreasonably labelled as energy costs) by using hourly average fuel and net purchased power cost and assigning these costs to customer classes based on customer-class load shares of each hour. This practice would be appropriate for the allocation of energy costs, and marginal cost of energy would be even better, if plant costs were functionalized to capacity and energy as I discussed above. Unfortunately, TVA's current practice double-charges certain costs to residential customers. Average fuel and net purchased power costs are higher when load is higher because that is when the plants with higher fuel costs are operated. Low fuel cost per unit energy when load is lower is accomplished by investing in more expensive plant that generates with a lower fuel cost. But, residential customers contribute a greater share of capacity than energy and therefore pay a disproportionate share of the cost of "baseload" power plants which provide energy at lower variable cost during the times when residential load is low. Consequently, TVA's current practice causes residential customers to pay for plant costs whose only justification is to reduce the costs of providing "baseload" power to non-residential customers.

TVA allocates transmission costs based on the 12CP method, meaning that transmission costs are allocated evenly to the 12 months, then allocated to customer classes based on their share of the peak hour of each month. This method is prescribed by FERC for FERC-regulated transmission tariffs and should be considered standard practice.

TVA generally allocates all other costs and taxes as "overhead" on capacity, energy, and transmission costs. This is appropriate and conventional, though there is one notable concern. TVA has previously included interest on regulatory assets under the heading of "Other Costs". Regulatory assets should generally be functionalized like the rest of rate base.

TVA's Treatment of Bellefonte Interest

Slide 57 of TVA's September 2014 presentation to the TVIC Pricing Committee indicates a past practice of allocating interest on regulatory assets related to the Bellefonte plant as "Other Costs", which then allocated as overhead to directly functionalized cost of capacity, energy, and transmission. That same slide indicates intent to functionalize regulatory assets of the Bellefonte plant similarly to TVA's treatment of other ratebase; this is more appropriate than treating it as "Other Costs". However, TVA's proposed functionalization to Capacity and Transmission is likely inappropriate because a portion of these costs should be allocated to Energy as discussed earlier in this commentary.

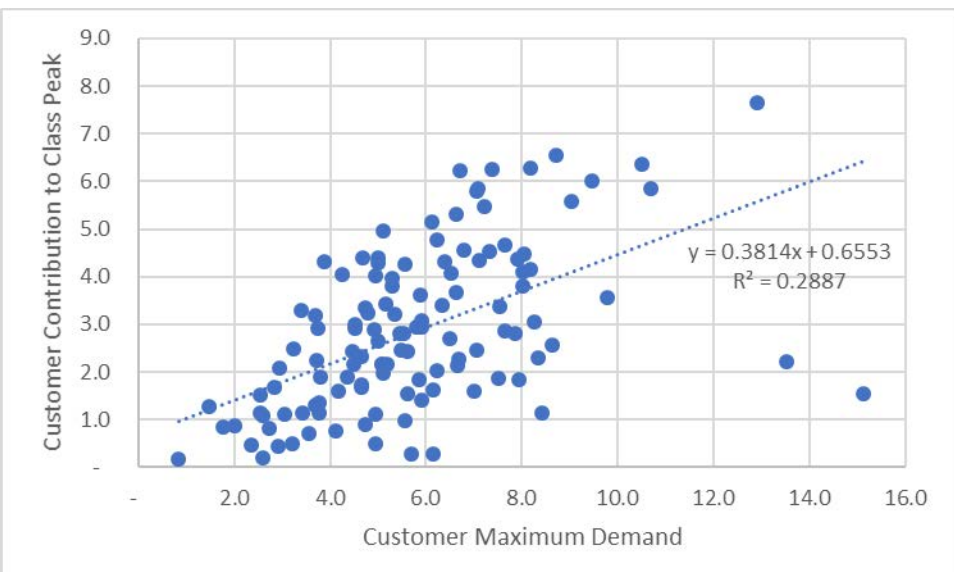
TVA's Approach to Rate Design

In establishing rates to its direct customers and to LPCs, TVA emphasizes demand charges for recovery of plant costs. Much of TVA's discussion about this focusses on "load factor", which is the ratio of average power demand to the individual customer's peak demand. Consideration of "load factor" is faulty reasoning for rate design related to generation plant because what determines a customer's contribution to plant costs is the customer's demand coincident with the system peak demand that drives capacity requirements. Individual customer peak demand is generally not coincident with system peak demand and often is not a very good predictor of the customer's contribution to coincident peak demand. For example, a processor of agricultural commodities will likely experience it's peak demand in the fall and will have a relatively low load factor while imposing little demand at the system peak. Significantly more accurate cost allocation and price signals are provided by using either time-of-use rates or critical peak pricing rather than customer demand charges to recover capacity costs. TVA should not allocate any generation capacity cost based on maximum demand and should allocate all such costs to either on-peak energy or on-peak demand. Statistical analysis of individual customer data is likely to show that on-peak energy is a more accurate predictor of customer contribution to the capacity allocator (top 200 hours) than is on-peak demand in which case on-peak energy would be the more appropriate billing determinant in the rate design.

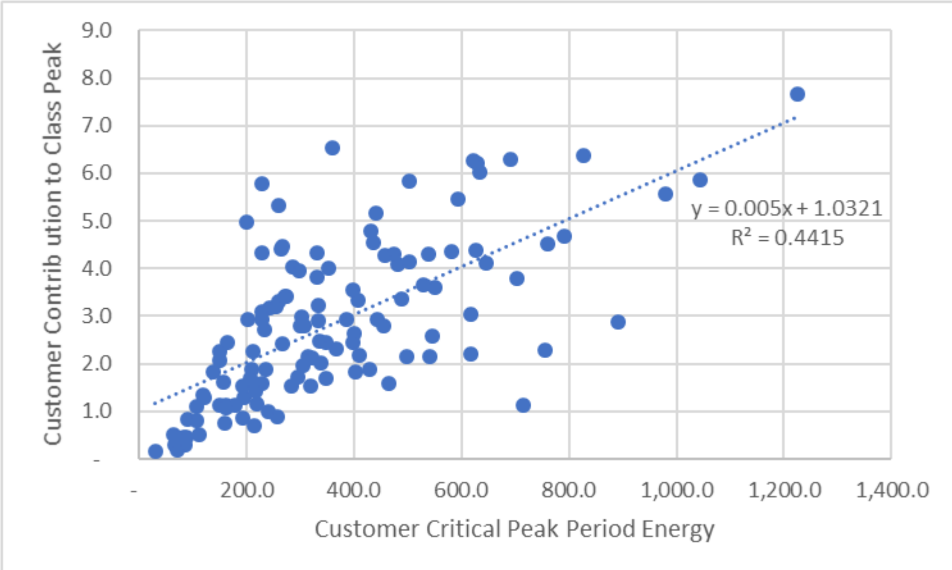
TVA's expectations about how LPCs will design their rates suffers from the same inappropriate use of demand charges. In particular, TVA proposes to change a portion of the energy charge into a "grid access charge" and then move toward recovery of the grid access charge through some combination of "a declining block rate structure, introduction of a demand charge where one did not previously exist, hours use of demand structure, and a demand ratchet on distribution delivery charges." TVA's stated motivation for this proposal is "to better align wholesale rates with their underlying costs to serve and to facilitate measured, managed change for retail customers". However, TVA has not produced any evidence that these rate design proposals accomplish this purpose. To do so, TVA would need to show that the proposed rate design is a better predictor of each customer's contribution to cost of service than is the current rate design. Indeed, TVA ought to demonstrate through a statistical analysis that a proposed rate design is the best practicable predictor of each customer's contribution to cost of service. TVA has not offered any such evidence.

As an example of the kind of analysis that TVA should undertake, the following graphs illustrate the relationship between individual customer maximum demand and their contribution to class peak in comparison to the relationship between individual customer critical peak period energy and their contribution to class peak. Class peak is often used in cost of service studies to allocate a portion of the costs of distribution systems.

These graphs present data from a random sample of residential customers of a midwestern utility in which distribution system peak occurs late on a summer afternoon and critical peak energy is the total kWh delivered between the hours of 2 and 5pm during the months of June through September. The first graph shows the relationship between customer contribution to class peak and customer annual maximum demand.



The second graph shows the relationship between customer contribution to class peak and customer critical peak energy.



The statistic R^2 is sometimes interpreted as describing the percentage of variation in the dependent variable that is explained by the independent variable. In this case, customer demand explains 28.87% of customer contribution to class peak while critical peak period energy explains 44.15% of customer contribution to class peak. Critical peak period energy is clearly a better billing determinant for recovery of distribution system costs that is customer maximum demand.

Absent such analysis, TVA's approach to rate design should be considered arbitrary. TVA is likely to assign costs to customers in a random manner with respect to what it truly costs to serve the customer.