Before the Arizona Corporation Commission

COMMISSIONERS
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IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT 2015 AND 2016

Docket No. E-00000V-15-0094

Sierra Club Comments on Tucson Electric Power's 2017 Integrated Resource Plan

1. Introduction

Sierra Club appreciates the opportunity to comment on Tucson Electric Power's (TEP) 2017 Integrated Resource Plan (IRP). These comments were prepared with the assistance of Synapse Energy Economics, and are based on our examination of TEP's input assumptions, portfolio construction, and evaluation of its resource options. Sierra Club was an active participant in planning dockets in the development of TEP's 2017 IRP, and actively contributes to planning proceedings in jurisdictions across the United States, as stakeholders, intervenors, and commenters. From our perspective, the TEP 2017 IRP represents two ends of a planning spectrum: it demonstrates intent, but lacks substance, meaning and value to this Commission and stakeholders.

Arizona's planning guidelines, AAC R14-2-703, are some of the most comprehensive in the nation, and yet the TEP 2017 IRP barely complies with the Commission's rules. Below, Sierra Club describes its concerns with the lack of substance in the IRP, as well as detailed concerns around t key assumptions and omissions.

IRPs cannot be treated as simply *pro forma* proposals. IRPs serve multiple purposes – as guiding documents for future utility investments, but also as the framework for utility strategy discussion, state priorities, utility vulnerabilities, risks, and uncertainty. An IRP must provide a forum for open discussion and transparency. The IRP process should ensure that regulators, stakeholders, and the public are not only informed of the utility's impending plans, but are assured that the utility's planning process is robust and complete. TEP's 2017 IRP provides no such assurances. The planning process here is neither robust nor complete, and has failed to explain a number of key ratepayer risks. Worse, TEP's IRP seeks to actively obscure key risks, and much of its data was stale before it was published.

Our concerns are oriented around five key topic areas:

1. **Analysis structure and portfolios.** TEP's 2017 IRP uses an analytical framework that is inappropriate for the questions facing the Company, and relies on apparently subjective portfolios. Those portfolios are narrow in scope, do not test a reasonable range of assumptions or futures, and obscure the value proposition of alternative energy resources, rather than provide a fair valuation. In failing to assess a reasonable range of alternatives and in the selection of subjective portfolios, the IRP fails to meet the criteria of AAC R14-2-703(F): the IRP fails to demonstrate that the finalized portfolio is based on a comprehensive consideration of a wide range of supply- and demand-side options, it fails to effectively manage uncertainty and risks associated with the Company's current fleet, and it fails to provide evidence that it achieves a reasonable long-term total cost.

2. **Coal plant economics.** TEP's coal fleet is in trouble, and yet the Company has played a surprisingly backseat role in the robust discussions around three of four of its remaining coal plants. We show that even TEP's current assumptions of near-term retirements at San Juan and Navajo Generating Stations are insufficient – the Company's economic risks at Four Corners and even Springerville Generating Stations are substantial, but not a part of this IRP in any meaningful way.

3. **Renewable energy value**. TEP's IRP dismisses the capacity value of primary renewable energy resources, dismissing the potential of these options to contribute to the Company's reserve margin. The Company's outright dismissal does not appear to be based in analytical evidence.

4. **Energy efficiency value**. For three decades, utilities have recognized energy efficiency as one of the most cost effective mechanisms of meeting incremental load, and in recent years, the advances in efficient lighting, air conditioning, weatherization and the marketing of efficiency have made it available to more customers. The IRP underestimates the amount of energy efficiency available to TEP, and incorrectly assesses incremental energy efficiency as a cost, rather than as a net incremental value by use of an inconsistent valuation methodology.

5. **Clean power plan assessment**. TEP's assessment of the Clean Power Plan's requirements is flawed and inconsistent with reasonable risk aversion practices.

Of the planning processes conducted by large utilities, TEP's IRP is one of the least transparent and least valuable to regulators and stakeholders. Sierra Club has found substantially greater transparency on both the value of existing coal resources in Louisiana, Georgia, Kentucky, Indiana, Oklahoma, Idaho, and New Mexico. In addition, utilities in Utah, Oregon, and Washington offer far deeper analyses of renewable energy options and value. While TEP's narrative in the 2017 IRP offers a productive discussion of the value proposition for renewable energy, efficiency, distributed generation, and storage, the Company's analysis underlying its planning belies this narrative. In short, TEP's decisions will be based on its modeling – and that modeling must be robust, transparent, and geared towards reasonable customer outcomes. Instead, TEP offers an IRP with a predetermined outcome and poorly structured alternatives.

2. Analysis Structure and Portfolios

Portfolio is non-optimized

TEP's 2017 IRP presents a "Reference Case" and four alternative portfolios. There is no explanation in the IRP as to how the portfolios were developed. For example, it is impossible to know whether TEP's portfolio achieves a reasonable long-term total cost, because we cannot assess whether substantially lower cost options exist.

There are three key stages in any electric system resource planning process: (1) define the assumptions and boundary conditions, (2) find the least cost portfolio of resources that meet requirements while adhering to the assumptions and boundary conditions, and (3) test the resulting portfolios to assess risk and uncertainty. TEP discusses many of the boundary conditions and assumptions (Stage 1) underlying their cost structure in the IRP, including the scenarios developed by PACE Global. The utility also has an extensive discussion of risk and uncertainty testing using stochastic analysis (Stage 3). However, there is no discussion in the IRP at all of how system planning – the actual selection of resources to make a portfolio (Stage 2) – was conducted.

When IRPs lack adequate disclosure of how the utility selected the resources in its plan's portfolio, Sierra Club has found that the resource portfolio development process is somewhere between a subjective "expert" driven process and an iterative "test-and-replace" process where a modeler tries various options until something "fits." Neither of these processes results in least-cost / least-risk – or even reliable system planning. Capacity expansion modeling and sophisticated electric system planning tools have been available to the industry for more than three decades. Indeed, the Company's modeling platform used for stochastic risk testing, Aurora is structured to be able to provide capacity expansion modeling capability, but there is no indication that TEP used this capability, and indeed the description of the resource portfolios suggests that TEP chose not to use an expansion modeling capability.

Through Sierra Club's experience, we have learned that it can be problematic for utilities to build a resource based on expert opinion or trial and error, the likelihood of error is substantial. The number of potential combinations of resources to build a robust, long-term, low cost portfolio is substantial. A portfolio may include any one of a dozen or more resource types,[1] any combination of which may be built in any given year. In addition, sophisticated IRPs may evaluate multiple cost tiers of energy efficiency, renewable energy options in different locations with different characteristics, market energy or capacity, different types of storage, and the

[1] See TEP 2017 IRP, Chart 20 on page 93

retirement of existing resources. Taken together the number of feasible portfolios that meet minimum reliability criteria and other constraints can be well into the hundreds of thousands. A failure to optimize, or demonstrate a sufficiently robust portfolio testing means that the portfolio is likely not least -cost, and may exclude solutions that were not captured in review by the planner.

Overall, TEP's focus on stochastic risk analysis using the Aurora model is a misplaced allocation of modeling and planning resources. Running stochastic risk analysis on a subjective portfolio is like adjusting a golf swing for wind, but shooting for the parking lot.

Alternative portfolios are neither robust nor reasonable

A critical purpose of an IRP is to illustrate risks, and determine the best course of action considering requirements and uncertainty. Part of the process of developing a robust resource plan is to examine key risks and opportunities – including options that may not otherwise have been considered in different constructs. Some utilities use a variety of constraints (e.g. gas prices, renewable portfolio standards, emissions constraints, etc.) to elicit a range of portfolios and then test these portfolios; other utilities test a wide variety of specific scenario conditions (e.g. unit replacement, specific resource decisions, combinations of demand- and supply-side resources).

TEP tested just four alternative scenarios, termed the "energy storage case plan," "the small nuclear reactors case plan," the expanded efficiency case plan," and the "high solar case plan." These scenarios are insufficient, and three of the four are deeply flawed.

According to the IRP, the "high solar case plan" is a substitution for an "expanded renewables case plan," required by the Commission. TEP explains that its reference case already includes renewable energy penetration above mandated requirements, and thus the utility meets the mandate to examine higher levels of renewable energy. While this may meet the letter of the requirement, it fails to show whether ratepayers would be better served through improved penetrations of renewable energy. Instead, the Company uses this scenario to drive a point it seeks to repeat throughout the IRP – that incremental solar simply shifts the Company's peak to later hours of the day and increases ramping requirements.

A reasonable high penetration scenario would have examined whether increasing wind from diverse regions, or installing tracking solar, or coupling increased solar with demand-response, evening-targeted efficiency programs, and storage could help the Company meet requirements. Rather than seeking solutions, the Company uses the "high solar case" as a forum to reject cost-effective solar energy.

The "expanded efficiency case plan" increases the Company's long-term trajectory of energy efficiency, ultimately saving the Company just under 20% of retail load by 2032, instead of 17.5% in the reference case. As we show later, the case represents a contraction of annual energy efficiency growth relative to today's programs, and only a minor increase over the reference case. A reasonable expanded efficiency program would have assessed the impacts – and avoided fixed and variable expenditures – of an aggressive buildout of demand-side management programs, including efficiency and demand response, on the order of that being achieved by leading states today.

The "small nuclear reactors case plan" is by far the most problematic and least useful of TEP's alternative portfolios. TEP combines two cases – a "small nuclear reactors case" and a "full coal retirement case" using extremely high cost nuclear reactors to replace retired coal units. This case inappropriately combines two separate issues: the value of TEP's existing coal fleet, and the economics of new nuclear power. By merging the coal unit retirements with nuclear expansion, the Company obscures the economic risk (or value) of its existing coal fleet. The assumption that coal must be replaced with a "baseload" resource is absurd – to date, no coal unit in the US has been replaced with nuclear, and no new nuclear has been built due to cost restrictions. While testing the cost impacts of building new nuclear is a reasonable boundary case, hiding the economic risk of the Company's existing coal generation by combining it with a nuclear buildout is not. It would have required little effort by TEP to create two separate scenarios for coal retirement and nuclear additions. Of yet more value would have been multiple portfolios to test the economic value of each of TEP's coal units separately, seeking an optimal retirement date.

Overall, the alternative portfolios tested by TEP do not create a reasonable set of boundaries or provide substantial incremental value.

In failing to assess a reasonable range of alternatives and in the selection of subjective portfolios, the IRP fails to meet criteria in AAC R14-2-703(F):

1. The IRP fails to demonstrate that the finalized portfolio is based on a comprehensive consideration of a wide range of supply- and demand-side options. The portfolios were created through a subjective selection process and did not test demand-side options beyond "expanded efficiency." As such TEP cannot show that the preferred portfolio was based on a comprehensive consideration of supply- and demand-side options.

2. It fails to effectively manage uncertainty and risks associated with the Company's current fleet. In combining the retirement and nuclear scenario and not testing for cost-effective coal retirement, the IRP completely fails to address the costs, much less the risks of the Company's current coal fleet (discussed in more depth later). Uncertainties in environmental regulations, long-term fuel procurement, and economics, are completely unaddressed.

3. It fails to provide evidence that it achieves a reasonable long-term total cost. The IRP's reference case scenario appears to have been selected through manual selection, and is not based on an optimization mechanism. As such, it cannot demonstrate that it achieves a reasonable long-term cost relative to other potential portfolios.

3. Coal Plant Economics

TEP's portfolio – and planned portfolio – has changed substantially since the last IRP. In that time, TEP acquired the remainder of Springerville 1, and saw its co-owners at San Juan and

Navajo determine that those units were no longer economically viable. The 2017 IRP makes no attempt to assess if these decisions – made as recently as early 2017 – are economically reasonable. In addition, the IRP makes only a passing attempt to establish that the coal remaining online is in ratepayers' best interest. The lack of meaningful analysis with respect to a demonstrably marginal resource is problematic for the IRP.

Planned Retirement of San Juan 1 & 2

TEP is a minority owner of San Juan units 1 & 2, with a 170 MW share in each unit. In 2013, Public Service Company of New Mexico (PNM), the majority owner-operator of San Juan, negotiated with EPA to meet Clean Air Act requirements by retiring Units 2 and 3 and installing less rigorous controls at Units 1 and 4 with the intent of maintaining those units. As part of a restructuring deal at the plant with co-owners, PNM signed a new coal supply agreement to fuel the remaining units through 2022, and agreed to reevaluate the economics of units 1 and 4. In early 2017, PNM conducted that analysis and determined that it was not in ratepayers' interest to retain San Juan past 2022.[2] TEP states that it will also plan to exit San Juan in 2022.[3]

Planned Retirement of Navajo

TEP is also a minority owner in Navajo, with a 168 MW share. Like San Juan, Navajo faced the prospect of a lease renewal for the Kayenta mine in 2019. In early 2017, Salt River Project, the majority owner-operator determined that renewing the lease on the mine and extending the life of Navajo Generating Station was not cost effective and announced that it would withdraw from the plant in 2019. TEP states that it is planning on the plant's shutdown in 2019.

Acquisition of Springerville 1

TEP has added substantial new coal-fired capacity at Springerville unit 1. Originally an owner of 49.5 percent of Springerville unit 1, in 2015 TEP determined that its co-owners had effectively abandoned the majority share, and acquired the remainder in September 2016.[4] Unlike at San Juan or Navajo, TEP is the majority owner at Springerville and bears the primary responsibility to determine if the continued use of the plant and acquisition of the incremental share is in the best interests of ratepayers.

The analysis to determine whether Springerville is in the interests of TEP costumers, while fundamental to the Company's acquisition and plan, was not presented in the 2017 IRP or in the interim 2016 IRP. Instead, it is mentioned in passing in the Company's 2015 rate case rebuttal, filed mid-2016.[5] The Company states that this analysis favored maintaining Springerville past 2020 by a margin of $326 million. While TEP describes the analysis process in broad outlines in

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[2] http://www.daily-times.com/story/money/industries/coal/2017/03/16/pnm-looks-possible-power-plant-closure-2022/99276420/

[3] 2017 IP page 27

[4] 2017 IRP page 27.

[5] Arizona E-01933A-15-0239, TEP Rebuttal Testimony of Michael Sheehan (July 2016).

rebuttal testimony, the assumptions underlying the modeling are not made explicit, nor are the sensitivity of the results to evolving assumptions.

In the absence of this information, we ran our own assessment of Springerville on the basis of publicly available information. We estimate that in 2016, Springerville 1 & 2 operated at roughly the average cost of market energy (between $26 and $31/MWh).[6] Due to the high fixed cost of operation, Springerville 1 & 2 likely lost between $25 and $48 million in revenue relative to market energy in 2016.[7] TEP does not operate Springville as a merchant generation unit, but a comparison against cost effectiveness as a merchant generator provides a reasonable benchmark for cost effectiveness on behalf of ratepayers.

Going forward, it appears that TEP estimates that Springerville will start generating energy revenues (again, on a hypothetical merchant operator basis) in 2019 as market prices start to exceed the production cost of Springerville.[8] If so, TEP's assumptions are based on flawed assumptions with respect to coal and market prices, as well as risk.

Coal prices at Springerville: According to the IRP, TEP assumes that coal prices received at Springerville will rise only with inflation,[9] a relatively high-risk assumption. TEP receives the vast majority of its coal under a single contract with El Segundo mine in northwest New Mexico since the mine's opening in 2008. That contract expires in December 2020, and there is no guarantee that TEP will be able to sign a contract at similar pricing. In 2015, Peabody Energy Corp., the owner of El Segundo, agreed to sell El Segundo to Bowie Resource Partners.[10] The deal fell through in April 2016.[11] Notably, Springerville receives about half of the coal produced at El Segundo; the remainder has been sold to Cholla. In mid-2016, Arizona Public Service (APS) and PacifiCorp decided to cancel their contract with El Segundo for coal received at Cholla. Peabody sued APS and PacifiCorp, claiming that there are no other customers – existing or prospective – for the coal produced at El Segundo.[12] The resulting risk to the coal price received at Springerville post-2020 is tremendous. Coal mines typically have high fixed costs in the form of necessary capital, equipment procurement and labor expenses; declining volume at existing coal mines can drive up prices substantially. TEP has not considered this very real risk as part of its portfolio planning.

Market prices: TEP estimates rapidly increasing market energy prices in the baseline case, rising at 2% above inflation (4% annual growth) and apparently driven by an assumption that gas

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[6] Range depends on assumed fuel price in 2016. According to TEP reported fuel price deliveries in EIA form 923, coal costs received at Springerville averaged $1.99/MMBtu in 2016. According to TEP 2017 IRP Chart 40, prices were closer to $2.45/MMBtu.

[7] Hourly wholesale market price equivalents from FERC Form 714 (system lambda for TEP). Hourly gross generation and heat rate in 2016 derived from US EPA Clean Air Markets Division (CAMD) Continuous Emissions Monitoring System (CEMS) data reported by TEP. Variable O&M (VOM) of $5.6/MWh in 2016 from FERC Form 1 derivation (TEP). Fixed O&M of $33.5/kW in 2016 from FERC 1 Form (TEP).

[8] Based on comparison of 2017 IRP Chart 44 (Palo Verde market prices) and TEP projected coal prices plus VOM.

[9] Assuming 2% inflation, coal prices in the baseline case are fixed at $2.45/MMBtu.

[10] http://www.steamboattoday.com/news/officials-view-coal-mine-sale-as-positive/

[11] https://www.bizjournals.com/albuquerque/news/2016/06/03/peabody-seeks-termination-fee-bowie-resource.html

[12] https://www.platts.com/latest-news/coal/houston/peabody-suit-alleges-coal-customers-violated-21674272

prices will rise by 150% by 2020. TEP's rapidly increasing energy prices rise faster than gas prices – an assumption or finding inconsistent with the increasing penetration of renewables in the West, rapidly falling wholesale market prices, and the findings of other major regional utilities. For example, in PNM's recent 2017 IRP, the utility only reached similar market prices with the inclusion of a \$5/ton CO2 price.[13] Similarly, APS reaches similar market price assumptions only with \$15/ton market prices. In contrast, TEP assumes no market price of CO_2, but instead assumes a benefit of such pricing. Finally, TEP itself suggests that prices will remain low, stating that "as noted in the Wood MacKenzie Base Case, despite uncertainty regarding U.S. energy policy changes, recent analysis suggests low natural gas prices are one of the biggest disruptors of the power sector. This low price trajectory will cause natural gas to increasingly displace coal in the foreseeable future. Because of this trend and steady growth in renewables, wholesale power prices will likely stay depressed over the long term."

TEP had an obligation to assess, in detail, the ratepayer costs and benefits of acquiring the remainder of Springerville 1. This IRP is correct forum for this assessment. It is unacceptable that between three IRPs in 2014, 2016, and 2017, TEP was unable to provide this assessment in a timely manner. However, our review of cost and risk shows that Springerville may not provide the economic benefit claimed by TEP in the 2015 rate case.

4. Renewable Energy Value

TEP's IRP discusses a commitment to diversifying s its generating fleet "with a [2030] goal of serving 30% of its retail load with cost-effective renewable resources."[14] TEP's drive towards that relatively modest goal only really begins in 2025, with effectively little action from 2019 to 2024. In planning, long-term goals are only as real as the actions taken to realize those goals – in this case, TEP has set a 2030 target that only starts in 2025. TEP's first move towards the IRP goal was released simultaneously with the IRP, with a deal to acquire 100 MW of solar and storage, announced in May 2017.[15]

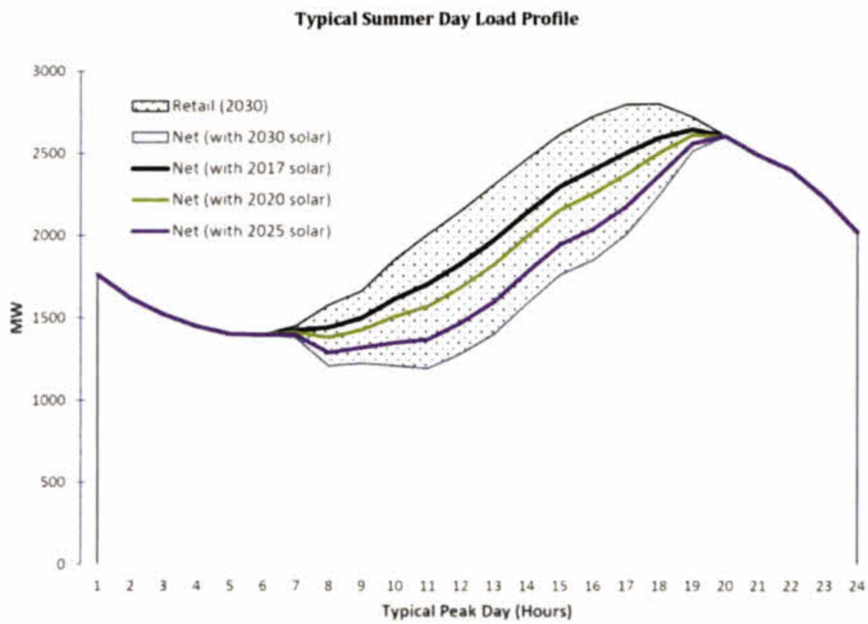
Unlike other utilities that require substantial transmission to connect renewable resources with load zones, TEP's service territory sits in one of the richest solar zones in the country. Yet TEP's IRP shows a reticence towards substantial renewable buildout, even while other utilities are racing to harness tax credits and falling renewable energy prices. The problem lies in TEP's assessment of two features of solar energy: its timing relative to demand and the rapid response required to meet fluctuating solar.

Noting that solar peaks mid-day, while TEP's demand remains high through the early evening, TEP effectively assigns a zero capacity value to new solar as of 2020. Chart 12 of the IRP (shown below) shows a "typical summer day" load profile, and imposes the net retail load after

[13] See PNM 2017 IRP Appendices, page 75 (CO2 prices) and 76 (Palo Verde), real prices. https://www.pnm.com/documents/396023/396193/PNM+2017+IRP+Appendices+Final.pdf/84196a57-1ba5-4c33-b346-1f15fc7bdaf6
[14] 2017 IRP, page 234
[15] http://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/

solar, showing a substantial reduction in peak requirements from solar to 2017, but then effectively no peak reductions thereafter. In fact, the IRP claims that new incremental solar only exacerbates an afternoon peak, and thus not only loses incremental value but requires substantial balancing capacity to meet load requirements.

Figure 1. Chart 12 of TEP 2017 IRP



This view of solar's contribution is flawed and inconsistent with reasonable planning practice.

First, peak contributions of uncertain or variable resources are typically assessed through a more rigorous modeling assessment to derive Effective Load Carrying Capability (ELCC). In this type of study, a stochastic model tests variable renewable resources with realistic variability against load requirements, and assesses how existing resources and the renewable energy project would, or could, meet load requirements. The resulting capacity value (in the form of a fraction) can be applied to the resource to assess the extent to which it reduces peak requirements.

Second, TEP's assessment of solar is timely, and should allow the Company to re-assess its existing and required resource mix to optimally incorporate as much cost effective renewable energy as possible. Assuming that new solar can be procured at below system cost – as evidenced by the recent deal with NextEra[16] – a reasonable system planning process would look at the best combination of demand- and supply-side resources to take on as much of that resource as possible. TEP mentions that it "intends to shift towards designing DLC [demand response] programs that are capable of cost-effectively addressing periods of significant ramping,

[16] https://pv-magazine-usa.com/2017/05/23/tep-to-buy-solar-power-at-under-3-cents-per-watt/

anticipated with high penetration of renewable resources."[17] But this concept should lead, not be an afterthought.

TEP identifies that additional solar makes it more difficult to dispatch its existing coal resources,[18] and that its existing coal resources contribute minimally to TEP's ability to meet fast ramping requirements.[19] As a solution, TEP states that it "is beginning to explore solutions at its power plants for modifications to generating units that will allow for lower minimums and/or potential cycling capabilities. If a plant is capable of cycling during the day, larger measures such as seasonal shut-downs may be avoided."[20] This is an inadequate solution. TEP's coal plants have high fixed costs. As they are displaced by lower cost energy resources like solar, their cost effectiveness will continue to drop. Investing additional resources in propping up the dispatch of these units will lead to long-term losses and stranded costs. Instead, TEP should evaluate, at an equal level of rigor, the potential for incrementally retiring non-cost effective coal and replacing it with demand and supply-side resources capable of integrating solar and meeting demand.

Ultimately, TEP's portfolio shows a rapid buildout of new fossil resources and a gradual procurement of renewable energy over the long run. TEP's IRP should have focused instead on maximizing the near-term opportunity to capture low cost renewable energy, and optimizing its portfolio to balance new renewable energy.

5. Energy Efficiency Value

TEP's assessment of energy efficiency has two substantial flaws: (a) the Company, inconsistently with other resources, assessed the upfront costs, but failed to account for long-term benefits; (b) the Company assumed that cost-effective energy efficiency will cease being available by 2020.

Mismatched costs and benefits

Energy efficiency programs typically entail a relatively high upfront cost in the form of incentives, marketing and administration, but yield benefits through an extended period of years. "First year costs" represent the fully loaded utility cost of energy efficiency applied to the energy saved in first year alone; the cost of saved energy, or the "lifetime cost" of energy efficiency represents the total cost spread out over the energy saved during the full life of the efficiency measure. For planning purposes, it is critical to use the lifetime cost of saved energy, rather than the first year cost. This aligns the costs of the program with the timing of the benefits.

TEP assesses energy efficiency first year costs, and applies these costs to efficiency programs. Problematically, efficiency programs that fall within a decade of the end of the analysis period

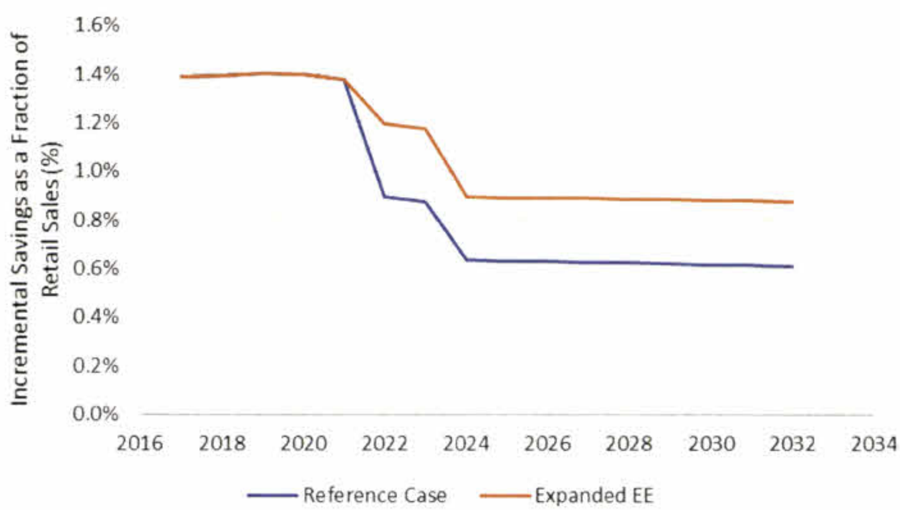
[17] TEP 2017 IRP, page 239
[18] TEP 2017 IRP, page 210
[19] TEP 2017 IRP, page 265, Chart 56
[20] TEP 2017 IRP, page 210

(e.g. 2022 and beyond) realize the full cost of the program, but not the saved energy benefits such as displaced fuel, new capacity, transmission loss reductions, or emissions reductions. In creating this mismatch, TEP effectively overprices efficiency and fails to account for "end effects," or benefits that occur after the end of the analysis period. The utility's assessment of the cost of the "expanded efficiency" program should therefore be rejected.

Falling efficiency opportunity

The "expanded efficiency case plan" increases the Company's long-term trajectory of energy efficiency, ultimately saving the Company just under 20% of retail load by 2032, instead of 17.5% in the reference case. This incremental savings level does not represent a substantial increase in savings. According to the IRP, the Company expects to increase efficiency savings by an incremental 1.4% per year – modest relative to leading states. In the reference case, the savings rate drops precipitously to 0.6% from 2021 to 2024 (see figure below), and in the "expanded efficiency case plan" it drops to 0.9% per year. It is unreasonable to consider this either aggressive or expanded efficiency.

Figure 2. Incremental energy efficiency in TEP IRP (author's calculations from TEP IRP)



In addition, while TEP explains that the cost of saved energy is kept consistent between the two cases, this does not appear to be the case. TEP shows that the cost of EE in the Reference case is $365 million (net present value) while in the expanded case, the cost of EE is $584 million, 60% more expensive. However, the expanded EE case only saves 6% more energy. Calculating backwards, the cost of EE in the "expanded" case appears to be anywhere from 35-50% more expensive than the reference case.

Missed opportunity for efficiency capacity contributions

The IRP is clear that TEP expects to face a new challenge in the form of an evening peak after sundown. As part of the portfolio to meet this shifted need, TEP should have rigorously assessed demand-side options to meet afternoon demand. In part, this would entail assessing the core components of the evening peak and then seeking cost effective demand-measures that could work to alleviate this need. TEP explains that it relied on efficiency load shapes for energy efficiency from two California-based studies and a national database.[21] While not an unreasonable set of data sources given a lack of utility-specific data, it is clear that TEP should be investing substantial effort and resources towards using the most cost-effective means to meet its new needs, rather than simply investing in new gas capacity.

For example, TEP claims that it does not project significant need for short-term capacity over the long term, and therefore did not include demand response – a capacity resource – in its Expanded Energy Efficiency Case. However, the Reference Case plan calls for more than 140 MW of reciprocating engine (RICE) to be built in 2031, a resource that could have been displaced by well-timed efficiency or ramping-oriented demand response.

6. Battery Storage

TEP's IRP undervalues the role of battery storage, ignores recent Commission mandates on storage alternative cost/benefit analysis, fails to account for future battery storage cost drops, and lacks fails other value propositions for grid-scale storage, such as ancillary services, distribution-level support, or grid resiliency.

As Commissioner Tobin's amendment recently mandated when acquiring new resources, "APS shall demonstrate that its analysis of resource options include[s] a storage alternative."[22] The analysis "must demonstrate that it has reasonably considered all of the costs and benefits of each resource option, allowing for comparisons to be made on similar terms and planning assumptions."[23] In addition, the analysis "shall account for the forecasted decline in energy storage costs and ensure that storage resources are modeled in such a way that the Integrated Resource Planning model captures their impact. Costs shall be transparent by providing the cost of each technology with and without state and federal tax incentives and/or credits."[24] While the Tobin Amendment may specify APS, these are generally good practices that TEP should also be adhering to.

Despite this directive from the Commission, while the TEP IRP does include some analysis of battery storage technologies, the analysis is deficient. As such, we recommend that TEP revise this section of the IRP to fix these flaws.

TEP Undervalues Role of Battery Storage

[21] TEP 2017 IRP, page 113

[22] Tobin Amendment, August 14, 2017, APS, Docket Nos. E-01345A-16-0036, E-01345A-0123.

[23] Tobin Amendment, *Id.*

[24] Tobin Amendment, *Id.*

TEP substantially undervalues the role of battery storage, a story inconsistent with the utility's recent acquisition of solar and battery storage from NextEra for less than 4.5 cents/kwh.[25] While TEP just signed for 30 MW of storage, the Reference case assumes that TEP will only have 30 MW total by 2020 (on top of its existing 5 MW) and will only add another 20 MW in addition (for a total of 55 MW) through 2030.[26] This

TEP's valuation of storage is also clearly inconstant with the actual projects it is procuring. TEP's IRP assumes that storage can only discharge for an hour at a time and provides a 50% capacity value (meaning it is unavailable half the time during peak requirement hours).[27] In contrast, the recent agreement provides cost-effective storage with four hours of discharge.

TEP Lacks Cost Assumptions for Future Battery Storage and other value propositions

Battery storage costs have dropped markedly over the last few years, and recent projections suggest that prices will continue to drop on key technologies over the next years, declining by 25-40% on utility-scale storage.[28] Nonetheless, TEP's IRP does not include a projection of future storage costs, or how increased storage could impact the utility's assumptions for renewable integration or new gas requirements.

Finally, TEP fails to include any other value propositions for grid-scale storage, including ancillary services (e.g. voltage support, frequency response), distribution-level support, or grid resiliency. TEP should make its assumptions clear, and provide an assessment of the value stream for battery storage.

7. CLEAN POWER PLAN ASSESSMENT

The Clean Power Plan (CPP) was promulgated in October 2015. In February 2016, the rule was stayed and the current administration has announced an intention to roll back the rule, but has not provided guidance on if or how it will seek to meet its court-mandated requirement to regulate emissions of CO_2. In the absence of clear guidance, some utilities have maintained the targets of the CPP, other utilities have postponed any consideration of carbon mitigation, and yet others have assumed a future compliance requirement not dissimilar – or possibly stricter – than that envisioned under the CPP but with a later compliance date.

TEP effectively applies no constraint to carbon dioxide emissions, and yet continues to imagine that the CPP remains in effect. The utility explains that under the CPP, Arizona utilities are benefited by a rate-based approach, according to a 2015 PACE study. Therefore, TEP concludes that it should just assess if its portfolios meet a rate-based target.[29]

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[25] http://www.utilitydive.com/news/updated-tucson-electric-signs-solar-storage-ppa-for-less-than-45kwh/443293/
[26] TEP 2017 IRP, p. 52.
[27] TEP 2017 IRP, p. 237.
[28] Lazard. December 2016. Lazard's Levelized Cost of Storage – Version 2.0. P. 20
[29] TEP 2017 IRP, page 77

Similar to our concerns with a non-optimized portfolio, TEP's assertion that Arizona is benefited by a rate-based approach and simple binary testing of if the rate-based approach is met substantially underplays the risk associated with a real carbon constraint and the benefits that could be realized by TEP ratepayers under a carbon constraint. Under a carbon constraint, a state that rapidly decarbonizes has the opportunity to earn revenue from neighboring states. For example, if Arizona reduces its coal fleet, but Utah, Wyoming, and Montana retain a substantial coal presence, Arizona could earn revenues through the sale of allowances. Conversely, if TEP retains a substantial coal fleet while betting on a long-term rate-based approach, it may risk being at the losing end of a carbon trading schema. While it is impossible to know at this time exactly what form a revised CPP or replacement structure might look like under the current – or future – administration, TEP's dismissal of the risk associated with carbon emissions is problematic and fails to assess reasonable ratepayer options.

8. Conclusions and Recommendations

In conclusion, TEP's IRP shows that the Company is considering future opportunities to integrate renewable energy, seek cost effective demand-side management projects, and absorb consumer-sided generation projects. Unfortunately, the IRP's execution focuses on the acquisition of traditional high-cost fossil resources, fails to appropriately assess the value of existing coal plants, and minimizes the contribution of renewable energy in the heart of the richest solar resource in the US. TEP has an opportunity in the 2017 IRP to pursue a truly transformative electric sector, phasing out fossil resources and pursuing cost effective renewables and storage. Instead, the utility has minimized any prospect of performing optimal planning, failed to assess the impacts or benefits of substantial renewable growth, and did not include reasonable assumptions for renewable energy or demand-side management integration.

Sierra Club recommends the following:

- TEP should be required to revise its modeling and scenarios to capture a wide range of scenarios, future outcomes, and potential portfolios. The utility should be required to use some form of optimization modeling, or be compelled to provide detailed assessments of its resource choices in the scenarios provided.
- TEP should be required to assess the economic value of Springerville 1 and 2, separately. This valuation should include a risk assessment for coal and market prices, carbon regulation, CAISO market integration, and integration with substantial renewable buildout.
- The Commission should not approve RFPs for new gas resources based on long-term assumptions of load growth, particularly the proposed 2022 combined cycle plant in the reference case. The Commission should demand a rigorous analysis of need and alternatives, including optimized portfolios, prior to giving even implied approval of the new facility.

- TEP should be required to rigorously model expanded renewables scenarios in which substantial new renewable energy, above the amounts in the reference case, are obtained and balanced by TEP.

- TEP should account for the full lifetime savings of energy efficiency measures in its modeling and should not assume that cost-effective energy efficiency programs will be unavailable after 2020.

- TEP should rigorously account for the ancillary and capacity values provided by already contracted and potential battery storage in determining the need for new NGCC and RICE capacity.

RESPECTFULLY SUBMITTED this 25th day of September, 2017.

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IN THE MATTER OF RESOURCE PLANNING AND PROCUREMENT 2015 AND 2016	Docket No. E-00000V-15-0094

Certificate of Service

I hereby certify that I have this day served the foregoing Sierra Club Comments on Tucson Electric Power's 2017 Integrated Resource Plan via email or U.S. Mail to all parties of record in the proceeding listed below.

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