STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their distribution investment and maintenance plans and for other related, uncontested matters.	)	Case No. U-20147

THE ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY COMMENTS REGARDING DTE ELECTRIC COMPANY'S
<u>2021 DISTRIBUTION GRID PLAN DRAFT REPORT</u>

Paul Alvarez and Dennis Stephens

Wired Group

September 29, 2021

TABLE OF CONTENTS

I. INTRODUCTION 1

II. COMMENTS 1

A. DTE's "scenarios" and plan foundations are unreasonable. 1

1. Electric vehicle impact on circuit and substation capacity are likely exaggerated. 2
2. DTE's concerns regarding DER accommodation are unfounded. 4
3. "Hardening" is an unproven approach to cost-effectively reducing storm impact. 7

B. DTE's use of "lease cost, best fit" to justify investment increases is inappropriate. 8

C. Projected reliability improvements resulting from the plan are insufficient to justify plan costs. 13

1. Stakeholders' ability to hold DTE accountable for reliability improvements is low. 13
2. The projected reliability improvements are insufficient for the $3.6 billion cost. 14
3. The economic valuation DTE attaches to these reductions is exaggerated. 15
4. DTE's track record of improving reliability through capital investments is poor. 17

D. Stakeholder engagement was of limited value and inadequate for addressing the questions at hand. 18

1. The customer research DTE completed was of limited value. 19
2. Elements and characteristics of a participatory distribution planning process. 21

E. The Plan includes far too much investment for capabilities of unproven risk reduction value. 21

1. There is no research indicating that the departures from standard industry practices in DTE's Plan deliver incremental benefits in excess of incremental costs. 22
2. The need for many other programs has not been sufficiently justified. 27
3. DTE's pole and pole-top replacement program is neither standard nor justified. 30

F. Recommendations. 30

1. Investments DTE claims are "required" for DG/DS and electric vehicles are overstated and potentially unnecessary. 30
2. Investments DTE proposes for reliability/resilience ("hardening"). 32
3. Investments DTE proposes to address capacity constraints. 33

III. CONCLUSION 34

CLARKHILL\07411\426546\264192357.v4-9/29/21

I. INTRODUCTION

On August 20, 2020, the Michigan Public Service Commission ("MPSC" or "Commission") issued its most recent Order in this proceeding regarding the five-year distribution investment and maintenance plans required of regulated utilities. The Order specified that the utilities were to file draft distribution and maintenance plans in advance of their respective due dates, thereby providing opportunities for feedback by stakeholders and Staff before utilities filed final plans.

On August 2, 2021, DTE Electric Company ("DTE" or "Company") filed its draft distribution and maintenance plan ("DGP" or "Plan") in this proceeding. In these comments the Association of Businesses Advocating Tariff Equity ("ABATE") provides its observations on and recommendations for the DTE DGP.

II. COMMENTS

A. DTE's "scenarios" and plan foundations are unreasonable.

The Commission's concern that the distribution grids owned by Michigan's regulated utilities must be "prepared" for a future of electric vehicles, more frequent and severe storms, and increasing distributed energy resource ("DER") capacity are certainly valid. Particularly important to ABATE are its members' considerations regarding delays in fleet electrification, delays in DER installation, and the opportunity costs of service outages. Further, while Michigan, as a global leader in personal transportation manufacturing, has a special rationale for electric vehicle readiness, it is important to weigh the proposed scope of readiness measures against the impact of electric rate increases on Michigan businesses, consumer discretionary spending, and Michigan's overall economy, as well as electric vehicle adoption rates and charging characteristics.

With interests in both sides of the grid investment debate, from its somewhat unique vantage point ABATE provides its perspective on the future state scenarios DTE employs as the foundation for its DGP below.

1. Electric vehicle impact on circuit and substation capacity are likely exaggerated.

DTE makes claims in its Plan which the Company failed to support with details in response to ABATE requests.[1] For example, DTE claims 20% of its substations are already overloaded relative to firm capacity.[2] Despite this claim, there are a number of ways to forecast circuit loads, consolidate the forecasts into substation impacts, and determine substation firm capacity, not all of which will likely lead to DTE's conclusion regarding the percentage of substations which are overloaded. Further, the concepts of net overload limits and various degrees of risk can be misleading. For example, a substation power transformer may exceed its nameplate capacity several times a year for several hours at a time with no increase in failure risk. Substation equipment is specifically designed to operate for periods of time in excess of nameplate capacity (called the net overload limit). Nameplate capacity and net overload limits are key determinants of firm capacity, along with multiple other factors and incident probabilities. In other words, without supporting details it is impossible to validate DTE’s claim.

DTE also claims 55% of its substations will be overloaded at just 10% electric vehicle adoption.[3] DTE’s estimate is based on a charging demand of 12 kW per vehicle, though this is not typical. For example a 240V outlet (such as for a clothes dryer) drawing 24 amps (a “Level 2”

[1] See Appendix A for a list of questions ABATE submitted to DTE regarding its DGP.

[2] DTE Electric Distribution Grid Plan (August 1, 2021), p 43.

[3] *DTEE Grid Modernization Study 2021-2035* (provided with Plan). ICF/EnerNex. Fig. 5, p 18. February, 2021.

charger) is only 5.76 kW, or less than 50% of DTE's estimate. A 120V outlet drawing 12 amps (a "Level 1" charger) is only 1.44 kW (1,440 watts), or only 12% of DTE's estimate, and about the same as a high-powered hair dryer or microwave oven. These charging levels are well within most electric vehicle drivers' daily needs and commuting distances. The Level 2 example will add 70 miles of range to a Tesla Model 3 in less than three hours; only eight hours of Level 1 charging will add 40 miles of range to the Tesla Model 3. These ranges easily exceed average commuting distances, with the median in Michigan amounting to just 8 miles one-way daily.[4]

Further, DTE estimates appear to assume unmanaged charging, including 10% at peak and another 20% during the balance of daytime hours. This conflicts with research indicating that as few as 8% of electric vehicles are even plugged in (let alone charging) before 6 pm on weekdays.[5] The 8% figure was measured in 2012, before time-of-use rates and managed charging, which are very likely to reduce daytime charging even further. DTE also alludes to other electrification concepts, such as electric heating. Given Michigan's multi-billion dollar investment in natural gas infrastructure, it is unlikely electric heating will mount a serious challenge anytime soon. Abandoning that infrastructure in favor of electrification would result in natural gas rate increases to an extent that is unlikely to be approved by the Commission. Indeed, in California, where just a few communities have passed natural gas construction moratoria, 44% increases in natural gas rates have been proposed,[6] driven in large part by projected reductions in natural gas sales volume.

---

[4] *Commutes Across America*. Street Light Data, p 8, February, 2018 (Survey September, 2017)

[5] Schey, S, Scoffield D, and Smart J. A First Look at the Impact of Electric Vehicle Charging on the Electric Grid in the EV Project. ECOTality North America and the Idaho National Laboratory. May, 2012.

[6] California PUC A.21-06-021. Pacific Gas and Electric Company General Rate Case Application dated June 30, 2012. Exh. 12, Chapter 5, Appendix C, Table 1, "Illustrative Gas Bill Impacts",p D-14.

As such, it is unlikely electrification of heating will require significant distribution system investment over the time period relevant to DTE's Plan.

To summarize, before investing hundreds of millions of dollars to increase circuit capacity due to electrification, extensive research is clearly needed into current circuit capacity, electric vehicle adoption rates, internal combustion vehicle longevity, electric vehicle charging patterns, and potential modification of those charging patterns by time-of-use rates and managed charging programs, to name just a few missing data points.

2. DTE's concerns regarding DER accommodation are unfounded.

DTE cites multiple concerns for DER accommodation, stating that "[m]oderate to high levels of DG/DS on one or more circuits on a substation can cause several issues, including potentially problematic reverse power flow, mainline and lateral voltage and thermal issues, as well as protection malfunctions."[7] Before diving into the uncertain nature of these issues, contextual observation regarding the size and rate of growth of DG/DS capacity on the DTE grid are necessary.

DTE projects DG/DS capacity equal to 10.8% of system capacity by 2035.[8] This is not a relatively "moderate-to-high" level, as the same statistic for the Hawaiian island of Oahu is 35%. Yet, Hawaiian Electric Company is only now proposing some of the same investments DTE is proposing in its Plan for the next four years. As such, DTE's proposed preparations for increasing DG/DS capacity are likely many years, if not a few decades, premature.

[7] DTE Electric Distribution Grid Plan (August 1, 2021), p 36. DTE failed to respond to ABATE's requests for technical details behind these claims.

[8] Ibid, p 35. Exhibit 3.3.3.1. 2035 forecast of 1,197 MW of DG/DS, of which 1,121 MW (94%) is asynchronous. As a percentage of DTE system capacity, 11,084 MW, this is 10.8%.

Considering this context, DTE provided no details regarding the technical challenges presented by "potentially problematic" reverse power flow when asked by ABATE. Again, reverse power flow (energy flows towards the substation, not away from the substation) on the Hawaiian island of Oahu is a daily occurrence. Despite the lack of capabilities DTE claims are essential, and indeed required for safe and reliable operation, Hawaiian Electric Company's interruption frequency performance is much better than the U.S. investor-owned utility average (0.836 vs. 1.12), and 27% better than DTE's (1.14).[9] Specifically, Hawaiian Electric Company's interruption duration performance is about average among U.S. investor-owned utilities, and 66% better than DTE's (89.4 minutes vs. 202.4 minutes).[10]

Regarding "potentially problematic" thermal (equipment capacity) and voltage issues, the National Renewable Energy Lab reports that claims regarding severe negative impacts of distributed generation and storage on distribution systems are unfounded.[11] This is logical, as loads co-located with DG/DS are extremely likely to mitigate these issues. Further, given routine distribution planning processes which incorporate load and DG/DS forecasts, and given advance warning of any potential equipment capacity constraints, such constraints can be addressed locally, in advance, to avoid DG/DS interconnection delays.

Further, regarding routine distribution planning processes, DTE's statement that "the Company is currently planning to develop robust '8760' forecasts to have accurate load forecasting

---

[9] All SAIFI statistics are without major event days as reported to the U.S. Energy Information Administration on form 861 for 2019.

[10] All SAIDI statistics are without major event days as reported to the U.S. Energy Information Administration on form 861 for 2019

[11] Hoke A. Et al. *Maximum Photovoltaic Penetration Levels on Typical Distribution Feeders*. National Renewable Energy Laboratory. Journal Article NREL/JA-5500-55094. July, 2012.

for its circuits and substations all 8,760 hours of the year," which "forecasts will (en) able (DTE) to modularly account for newer technologies such as EVs, PVs, and storage, as well as enable DTE to adequately identify when and where distribution improvements will be needed"[12] prompts obvious questions.[13] These include how DTE will accurately identify the locations of equipment being installed per this Plan without this information, why DTE didn't use these robust forecasting procedures to develop the current Plan, and how DTE knows the speed and magnitude of investments proposed in this Plan are required without this information.

DTE also cites "potentially problematic" protection malfunctions. With this concern DTE is likely referring to synchronous (spinning) generation on the distribution system, which is known to "confuse" circuit breakers, causing them to remain closed when grid conditions call for them to open. While this is a potentially problematic situation, it is associated only with spinning generation, such as combined heat and power ("CHP") generators owned by some industrial customers. There is no documented evidence that asynchronous (non-spinning) generation, such as PV solar and battery storage, confuses circuit breakers or causes protection malfunctions. As DTE predicts that synchronous generation will represent less than 6% of projected DG/DS by 2035,[14] and less than 1% of current system peak, the need for solutions against "potentially problematic" protection malfunctions appears overstated, if not entirely non-existent. Further, protection problems with synchronous generation are not a given, and can be addressed on a case-by-case basis if and when they arise.

---

[12] DTE Electric Distribution Grid Plan (August 1, 2021), p 46.

[13] Of course, due to the nature of this proceeding, DTE is under no obligation to answer.

[14] DTE Electric Distribution Grid Plan (August 1, 2021), p 35 (Exhibit 3.3.3.1. 2035 forecast of 1,197 MW of DG/DS, of which 1,121 MW (94%) is asynchronous).

As such, before investing hundreds of millions of dollars to prepare for DG/DS capacity increases, extensive research is clearly needed into DG/DS growth forecasts, the actual technical challenges presented by high levels of DG/DS capacity, the definition of high levels of DG/DS capacity, and the pros and cons (technical and economic) of various solutions to technical challenges documented at "high levels."

3. "Hardening" is an unproven approach to cost-effectively reducing storm impact.[15]

As set out below, a number of issues raised in DTE's Plan lacked adequate support. Specifically, DTE justifies its circuit hardening proposal by the reliability improvements (50-70%) recorded on circuits which DTE had already completed hardening.[16] Despite requests from ABATE DTE provided no data regarding this claim.

Further, DTE has acknowledged that tree trimming is a critical part of the hardening process and was completed for all the hardened circuits. Thus, it is impossible to distinguish the reliability improvements from tree trimming (relatively inexpensive) from the reliability improvements from capital investments (extremely expensive).

In the aftermath of the August 11, 2021 storms which resulted in lengthy outages, DTE's own press release indicated tree trimming spending would deliver more benefit than capital investment. "In areas where tree trimming has been completed, communities have experienced, on average, 60% fewer outages."[17] There is a notable similarity between this statement and the 50-70% improvement DTE claims from circuit hardening. The press release continues, stating that

---

[15] Additional comments on this topic are included in ABATE's Comments filed in Case No. U-21122 on September 24, 2021, which Comments are incorporated herein by reference.

[16] DTE Electric Distribution Grid Plan (August 1, 2021), p 481.

[17] *DTE announces an additional $70 million investment to combat extreme weather-related power outages*. DTE press release dated September 1, 2021.

"[t]rees are responsible for almost all of the time DTE customers are without power during extreme high wind events."[18] This is consistent with data DTE presents in its Plan which indicates that almost 75% of all outage minutes result from Trees/Wind.[19] This is 7.5 times greater than the next highest cause of outage minutes (equipment failure), yet DTE's Plan calls for twice as much capital spending on "Resilience and Hardening" ($1.65 billion) as it does for operations and maintenance spending on tree trimming ($825 million).[20]

Before investing billions of dollars in circuit hardening, extensive research is clearly needed into the "risk reductions per dollar" secured through circuit hardening relative to tree trimming, and relative to other approaches which could reduce storm impact, including better storm forecasting, mutual aid request processes, resource staging, and other low-cost approaches.

B. DTE's use of "lease cost, best fit" to justify investment increases is inappropriate.

DTE touts its Global Prioritization Model ("GPM") as a "rigorous and accepted methodology for evaluating investments to meet the grid needs identified in our grid modernization process."[21] DTE presents the GPM in its Plan's Benefit-Cost Analysis section. In so doing, DTE implies that proposed projects which, when assessed a top "Benefit-Cost Score" per the GPM, are expected to deliver benefits in excess of costs to customers. These statements and implications are inaccurate and unreasonable.

---

[18] Ibid.

[19] DTE Electric Distribution Grid Plan (August 1, 2021), p 114.

[20] DTE Electric Distribution Grid Plan (August 1, 2021), p 98-101 (Exhibits 6.1 and 6.2, pages 98-101).

[21] DTE Electric Distribution Grid Plan (August 1, 2021), p 79.

Before beginning its critique, ABATE notes that DTE did not respond to additional questions regarding the GPM as ABATE was evaluating DTE's Plan. Further, the absence of Commission rejection of DTE's GPM in a previous rate case does not connote Commission acceptance of the methodology. Despite these deficiencies, ABATE presents its understanding of what the GPM is, what the GPM is not, and its experts' educated guesses on how DTE used the GPM to develop a list of projects to include in its DGP.

At any given moment DTE, like other utilities of its size, has presumably thousands of programs and project options on which capital could conceivably be spent. GPM is simply a way to prioritize from among the thousands of spending alternatives available to DTE. DTE makes no guarantees, nor assurances, nor does DTE appear to claim, that any of the projects which have been evaluated via the GPM will deliver benefits to customers in excess of costs. This is because the GPM is clearly not a benefit-cost analysis; it is simply a prioritization tool.

DTE's GPM process appears to involve a subjective evaluation of each program and project spending option on seven "impact dimensions," including safety, load relief, regulatory compliance, major event risk, reliability, O&M cost avoidance, and reactive capital avoidance. This results in a score for each dimension and each impact dimension is subjectively assigned a weight. By multiplying each dimension's subjectively-assessed score by its subjectively-assigned weight and adding up the products, DTE determines a "Benefit-Cost Score." For example, the "Benefit-Cost Score" for DTE's top-priority project, ADMS (Advanced Distribution Management System), is close to 3,000. Despite this framing, however, this score measures neither benefits nor costs, and essentially means nothing. It is certainly not an indication of the benefit-cost ratio of ADMS, nor any other quantitative assessment of the benefits delivered to customers in relation to the costs customers will have to pay. Yet, because "3,000" is a numerical value DTE describes its

GPM as "quantitative," and its subjective assessment scores and assigned weightings as "rigorous." As explained above this description is inaccurate.

DTE defends this lacking approach to justifying Plan projects and programs as consistent with the cost-effectiveness determination recommended by the US Department of Energy's ("DOE") distribution planning model, "DSPx." A companion piece to the DSPx compendium focused on benefit-cost analyses in distribution planning states that, for capabilities that are determined to be "required" -- for example to comply with state policy -- a benefit-cost test is not required. Instead, a policy of "least-cost, best fit" (or, as DTE notably recasts it, "best fit, most-reasonable cost") can be used as a substitute for a benefit-cost test.[22] However, this companion piece clearly points out that the "least-cost, best fit approach is (only appropriately) applied when the need for a particular project or investment is already established."[23] As clearly described in Section II of this commentary, DTE has not established the need for any of the projects or programs in its Plan, and did not respond to ABATE attempts to obtain the data which might support such conclusions.

A closer examination of the GPM illustrates the further deficiencies of this approach. DTE cites the Commission's service restoration standards[24] as rationale for the GPM Impact Dimension "Regulatory Compliance." Because the Commission has established these restoration standards, and because DTE claims that its projects and programs are "required" to comply with these

---

22 Woolf, T. et al. *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments: Trends, Challenges, and Considerations*. Grid Modernization Laboratory Consortium, U.S. DOE. Page 13. February, 2021.

23 Ibid.

24 Michigan PSC Docket U-12270. States that service should be restored within 8 hours under normal conditions and within 60 hours under catastrophic conditions.

regulatory standards (with no supporting data), DTE essentially appears to argue that projects and programs associated with improving reliability and resilience need not pass a benefit-cost test, but only the lesser "least cost, best fit" cost-effectiveness determination. There are multiple approaches DTE could use to meet the Commission's restoration standards, and DTE did not provide data to indicate DTE's selected approaches are either least cost or best fit.

DTE did not adequately support its position that the proposed solutions are required due to policy, nor its position that the proposed solutions are "least cost, best fit." In the extreme, these positions imply that a multi-billion dollar reliability or resilience investment program would be appropriate even if, for example, it improves system average interruption duration ("SAIDI") by less than one minute (DTE's 2019 SAIDI was 202.4 minutes), or even if, as another example, it improves system average interruption frequency ("SAIFI") from once every 45 weeks (DTE 2019 SAIFI of 1.14) to once every 46 weeks.

An attempt to understand the GPM and the application of "least cost, best fit" from a different perspective results in similarly troubling conclusions. DTE appears to have determined the Plan's "Strategic Capital Program" budget ($3.6 billion)[25] simply by selecting the 50 programs and projects which deliver the highest GPM "Benefit-Cost Scores."[26] There does not appear to be a sufficient description of why this figure (as opposed to the top 10 or 100 projects) was chosen. Without true benefit-cost analyses incorporating documented and quantified capabilities to increase DG/DS hosting capacity (in MW), electric vehicle charging capacity (in vehicles, given normalized charging profiles), or improve reliability and resilience (SAIDI and SAIFI with and

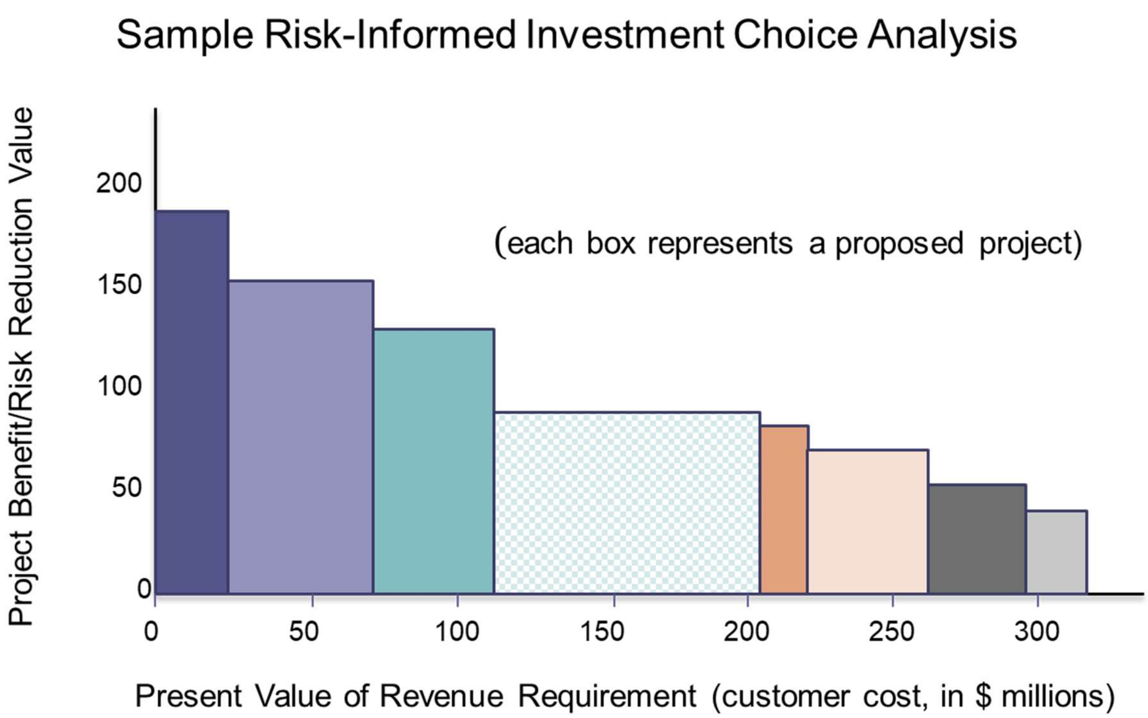
[25] DTE Electric Distribution Grid Plan (August 1, 2021), p 98 (Exhibits 6.1).

[26] Ibid, pp 84-86.

without major event days), these questions cannot be answered. This supporting documentation should be provided.

A more prudent approach to investment decision-making may be the risk informed decision support approach to project selection and capital budget determination ABATE experts presented at a U-20147 distribution planning working group meeting on August 14, 2019. A key diagram from that presentation, representing benefits and costs in dollars of various spending opportunities, is provided below. Note that the revenue requirement of the project represented by the patterned box exceeds the project's benefits. For approximately the same revenue requirement, the three projects to the right collectively deliver more than double the benefit of the project represented by the patterned box. In other words, this approach demonstrates the prudence of avoiding the project represented by the patterned box in favor of the next three projects to the right of the patterned box.

Figure 1: Representation of the improved decision-support offered by true benefit-cost analyses



CLARKHILL\07411\426546\264192357.v4-9/29/21

This type of analysis is simply not possible using the subjective GPM assessments and "least cost, best fit" approaches to cost effectiveness DTE employed in the development of its Plan. DTE's GPM does not sufficiently justify the proposals in DTE's Plan, nor is the associated application of the "least cost, best fit" approach to cost-effectiveness determination appropriate for distribution planning in Michigan or elsewhere.

C. Projected reliability improvements resulting from the plan are insufficient to justify plan costs.

DTE's Plan estimates the reductions in outage frequency (SAIFI) and duration (SAIFI) the Company expects to secure from its Plan, both with and without major event days. These estimates are concerning for several reasons, as set out below.

1. Stakeholders' ability to hold DTE accountable for reliability improvements is low.

While DTE offers reliability improvements with major event days (storms) which appear impressive at first glance, a more detailed examination tempers first impressions. Exact values are not provided, but from the charts provided DTE appears to project a greater than 50% reduction in average outage duration (with storms), and a greater than 20% reduction in outage frequency (with storms).[27] However, given that reliability with storms can be highly variable, it can be almost impossible to hold DTE accountable for projected reliability improvements. After all, DTE cannot control the weather, and DTE is likely to say as much if projected reliability reductions are not met. (DTE reported 793 minutes SAIDI in 2014 and 1,068 minutes in 2017, which is more than 3

[27] DTE Electric Distribution Grid Plan (August 1, 2021), p 90.

times and 4 times, respectively, the average of the SAIDI with storms reported in the intervening years.)[28]

Further, DTE already admits it will be difficult to hold it accountable for projected reliability performance due to storm variability. A closer examination of the reliability improvement charts indicates that the high end of the projected variation in reliability performance attributable to storms is not much better than baseline reliability performance with storms. Given that DTE's "Strategic Capital Program" budget is $3.6 billion before carrying charges (ABATE estimates $7.2 billion in nominal revenue requirements over 30 years, or over $3,250 per customer), this is a lot to ask of customers with potentially little in return. As a result, reliability performance without storms should be used to judge DTE performance. This too presents a problem, however, as DTE projects reliability improvements without storms resulting from its investments to be relatively small.

2. The projected reliability improvements are insufficient for the $3.6 billion cost.

As noted above DTE projects reliability improvements without storms from its Plan to be substantially less than the reliability improvements with storms. Projected reductions in average outage duration without storms appears to be about 30%, while projected reductions in in average outage frequency without storms appears to be about 10%.[29] While these improvements may seem substantial to some, the resulting outage duration performance (118 minutes SAIDI) would be slightly below the 2019 US investor-owned utility average of 114, and the resulting outage frequency performance (one outage every 13.5 months) would not have been good enough for top

[28] All reliability data is sourced from form 861 DTE submits to the Energy Information Administration annually.

[29] DTE Electric Distribution Grid Plan (August 1, 2021), pp 91-92.

quartile performance in 2019 (one outage every 13.8 months). At a cost of $3,250 per average customer, top quartile duration and frequency performance should be a minimum expectation. If DTE cannot commit to reasonably significant performance improvements relative to other utilities for DTE's exceptionally large capital requests, it is reasonable to question whether DTE should be making such large investments. See Appendix B for charts examining DTE current and projected SAIDI and SAIFI performance relative to other U.S. investor-owned utilities.

3. The economic valuation DTE attaches to these reductions is exaggerated.

DTE used the U.S. Department of Energy's online Interruption Cost Estimator ("ICE") tool to estimate the economic value of reliability improvements to its customers. Unfortunately, the ICE tool dramatically overstates the benefits of reliability improvements to customers and communities. Flaws in the tool range from overall design issues to irregularities and inconsistencies in the collection of data used to develop the tool.

A significant design flaw hobbles the ICE tool from the start. To estimate the economic impact of outages (or, conversely, the economic benefit of outage reductions), the tool simply adds up the costs to individual customers experiencing an outage. This is wholly inaccurate and overstates the economic benefits to a community or service territory from outage reductions.

Consider a customer, faced with no electricity for cooking and air conditioning, who decides to go out to dinner, or to a shopping mall. In this instance an outage would benefit some businesses and the local economy. Or, consider a motorist in need of gasoline, who bypasses a gas station without power for one with power. While one business lost revenue, another business gained revenue, resulting in no net economic loss to the community as a whole. The ICE tool does not account for these types of economic impact offsets in any way.

A second design flaw relates to outage duration. The ICE tool was not designed to estimate the economic impact of outages longer than 24 hours. Given that DTE's Plan includes billions of dollars for grid resilience (to storms, like those experienced on August 10, for example, which resulted in days-long service outages), this is a significant limitation.

As troubling as these fundamental design flaws are, irregularities and inconsistencies in the collection of data used to develop the tool portend further overstatements in the economic benefits derived from reliability improvements. The data used to develop the tool was not collected with the intention of using it to estimate the economic impact of outages over a defined geography, nor was the data collected (via survey) in an appropriate manner. Instead, the Department of Energy found some customer outage cost data a few utilities had collected by survey – in some cases more than 30 years ago – and applied it to the development of the ICE tool. This data is inappropriate for use in making grid investment decisions of hundreds of millions of dollars.

Several abnormalities in survey administration biased the results in ways which exaggerated the costs of service outages to non-residential customers. These include the following:

- The survey efforts were limited in number (15), conducted decades ago, and collected only from C&I customers in manufacturing and retail businesses. The cost of service outages to this subset of C&I customers are likely higher than that of the average C&I customer, and manufacturing and retail business are now a minority among non-residential customer classes.
- The identities of the survey takers – utilities – were known to the C&I customers surveyed. It is likely that C&I customers hoping for financial compensation for outage costs exaggerated outage cost estimates in survey responses.

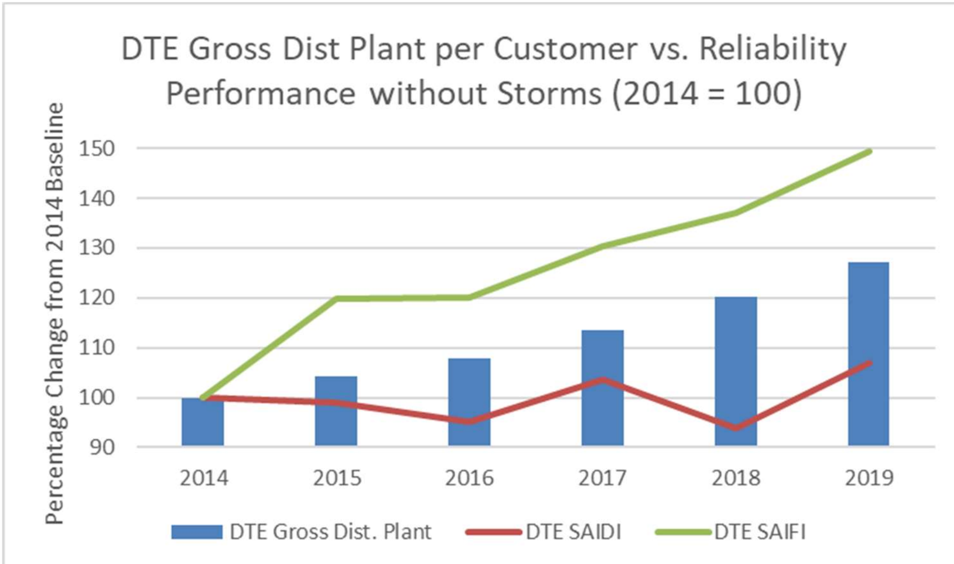
- The 15 survey projects were completed in just five U.S. geographies. Only two survey projects were completed in the Midwest, with the most recent now almost 20 years old. Data collection efforts were not prescribed in advance to be geographically or statistically valid through standard research design protocols.
- There is no consistency in how survey respondents took back-up generation and uninterruptible power supplies into account when completing surveys.

As a result of fundamental flaws in the design of the ICE tool, and due to irregularities and inconsistencies in the collection of data used to develop the tool, the ICE tool cannot be used to translate projected reliability improvements into economic value to communities or utility service territories.

4. DTE's track record of improving reliability through capital investments is poor.

Finally, it is concerning that DTE has been steadily increasing grid investment in recent years without securing significant reliability improvements as a result. In fact, reliability without storms has deteriorated significantly in recent years despite growth in DTE gross distribution plant. Figure 2 shows this relationship.

Figure 2: DTE Gross Distribution Plant vs. Reliability Performance without Storms, 2014-2019



This track record appears to indicate one of two (or both) conclusions. Either DTE has been making the wrong investments to improve reliability performance, or capital investments are not very effective at improving reliability.[30] Both conclusions likely hold some merit.

D. Stakeholder engagement was of limited value and inadequate for addressing the questions at hand.

DTE, like all utilities, touts its stakeholder engagement efforts.[31] While DTE's Plan describes the efforts DTE has taken to hear what its customers and community leaders have to say, the information obtained is colored by the questions DTE asks, and how DTE asks them. Further, the presentation of plans DTE has already developed to stakeholders is not equivalent to the joint development of plans by the utility, Staff, and stakeholders, as ABATE has recommended from

[30] The latter conclusion is confirmed by research completed by Lawrence Berkeley National Laboratory. Larsen, P. et al. *Assessing Changes in the Reliability of the U.S. Electric Power System*. Lawrence Berkeley National Laboratory Report LBNL-188741, pp 37-38.

[31] DTE Electric Distribution Plan (August 1, 2021), pp 10-20.

the beginning of this proceeding[32] and more recently in comments provided in the August 10th Storm Response proceeding.[33]

The reality is that DTE, like all utilities, will likely receive critical feedback from unbiased customer answers to questions DTE finds difficult to ask.[34] DTE also benefits from stakeholder information and expertise asymmetry. In short, stakeholders' opportunity to shape, review, and comment on the Plan and distribution system investment in general was inadequate.

1. The customer research DTE completed was of limited value.

DTE's Plan describes the customer and community leader research DTE completed as part of Plan development. This research appears to be of low value. It consisted of focus groups in which participants were shown an industry-produced (Edison Electric Institute) video, which residential participants did not appear to buy into. Additional information summarizing the benefits of a "grid overhaul" presented to commercial customers was still unsuccessful in winning over participants. Instead, DTE's research vendor reports "it wasn't until they (participants) were made aware of the downside risk of NOT modernizing the grid that customers ultimately saw enough value in the modernization to pay more to get it."[35]

No one can be in favor of deteriorating reliability, or delays in DG/DS interconnections, or electric vehicle charging capacity delays. Similarly, in the abstract, no one is likely to oppose a "modern" grid. As a result, DTE and other utilities are most successful in securing approvals to

---

[32] Michigan PSC Docket No. U-20147. ABATE Comments dated September 11, 2019.

[33] Michigan PSC Docket No. U-21122. ABATE Comments dated September 24, 2021.

[34] *"Absolutely Awful": Nessel Holds Novi Town Hall on Power Outages*, The Detroit News (September 20, 2021) <https://www.detroitnews.com/story/news/local/oakland-county/2021/09/20/absolutely-awful-nessel-holds-novi-town-hall-power-outages/5786981001/>

[35] DTE Electric Distribution Grid Plan (August 1, 2021). *DTE Distribution Grid Study, Final Report*. Emicity. Slide 16. May 20, 2021.

grow rate base by focusing on the negative consequences of failing to maintain distribution systems without providing adequate supporting technical details to justify specific investment proposals. Stakeholder information and expertise asymmetry only exacerbates these issues.

To summarize, DTE's Plan indicates that the greater the details DTE provided to stakeholders and customers, the weaker DTE's case for massive grid investments became. A best market research practice offers an alternative approach: willingness to pay research. Such research answers a very important question: what would a customer be willing to pay for attribute A, B, or C? As examples, customers might be asked "What amount would you be willing to pay on your monthly bill:

- To ensure outage frequency and duration remain the same as that provided today?
- To secure a reduction in outage frequency from DTE's current levels, once every 45 weeks on average, to once every 52 weeks? To once every 90 weeks?
- To secure a reduction in outage frequency from DTE's current levels, 2 hours on average, to 1.5 hours? To 1 hour?
- To avoid an outage of five days once every 20 years?
- To avoid a delay upon a request to install a PV solar system?"

This is the type of information from customer research DTE, the Commission, and stakeholders can use to inform distribution planning decisions. General research indicating that customers and communities want better reliability, or that customers and communities wish to avoid rate increases, is not an adequate basis upon which to determine the reasonableness and prudence of specific costly investments.

2. Elements and characteristics of a participatory distribution planning process.

While "willingness to pay" research is important, the long-term value of involving stakeholders throughout the distribution plan development process is extremely high. Over time, a transparent and participatory distribution planning process will reduce the information and expertise asymmetry which disadvantages stakeholders in the current distribution planning and ratemaking construct. ABATE comments submitted in Case No. U-21122 on September 24, 2021, explain the shortcomings of the existing distribution planning process as they relate to storm impact reduction. ABATE comments to be submitted in this docket on October 1, 2021 will describe resulting deficiencies in the Michigan utilities' distribution Plans and provide the outline of a transparent distribution planning process featuring stakeholder participation.

These documents provide a better understanding of the differences between stakeholder engagement, as practiced today, and stakeholder participation in plan development as contemplated by ABATE.

E. The Plan includes far too much investment for capabilities of unproven risk reduction value.

While the Plan contained deficiencies regarding certain strategic issues addressed above (such as DTE's "Scenarios" and Global Prioritization Model, projected reliability improvements, and stakeholder engagement), the Plan also raised more detailed concerns regarding specific components of DTE's proposed investments, as discussed below.[36]

---

[36] These concerns also serve to illustrate the challenges of the current distribution planning process through specific examples.

1. There is no research indicating that the departures from standard industry practices in DTE's Plan deliver incremental benefits in excess of incremental costs.

A large number of very costly proposals in DTE's Plan represent departures from standard industry practices. There is no research indicating that the departures from standard industry practices in DTE's Plan deliver incremental benefit in excess of incremental costs.

One such standard practice is critical substation asset testing. Substations typically serve thousands of customers each, so the failure of a substation asset typically impacts large numbers of customers. Over time, standard practices have evolved to test each critical substation asset, generally every three to five years. A piece of substation equipment which fails its test is replaced promptly, thereby avoiding a failure in service resulting in a service outage. Critical substation assets subject to routine testing include power transformers (chemical testing of transformer oil), circuit breakers (physical testing), and relays (physical testing).

Another such practice is utility pole testing. The failure of a utility pole presents a significant public safety issue (downed wires). As a result, standard practices have evolved to test (through drilling samples) and inspect (using formal checklists) each utility pole on a periodic basis, typically every 10 to 12 years. Poles which fail formal testing and inspection are scheduled for replacement.

Run-to-failure is another standard practice. Due to the high consequences associated with critical substation assets and utility poles, routine testing practices have evolved as standard practices. However almost all distribution equipment is characterized by low failure consequences. For example, fuses generally serve 30 to 50 customers at most. Distribution transformers typically serve three to five customers each. Thus, the failure of any one piece of distribution equipment generally impacts very few customers. On top of low consequence risk, distribution equipment is characterized by a low probability of failure. Like substation assets and utility poles, most distribution equipment is designed to last for many decades. Indeed, due to the combination of low consequence risk and low probability of failure, the standard practice which has evolved for almost all distribution equipment is "run-to-failure" (i.e. simply run the equipment until it fails and replace it when it does). Run-to-failure is the lowest-cost approach, as testing and/or presumptive replacement (meaning, simply due to age or a subjective assessment of condition) are not justified by improvements in reliability. For example, DTE probably operates hundreds of thousands of distribution transformers. They typically operate 50 years or longer before failing. It simply does not make sense to test and/or presumptively replace distribution transformers, because when they fail – typically after 50, 60, 70 or even more years of operation – they only impact three to five customers. The incremental cost of testing and/or presumptive replacement is simply too great relative to the value of avoiding one outage for three to five customers once every 50, 60, 70, or more years.

Worst performing circuit programs are also a standard practice. Most utilities track the frequency (SAIFI) and duration (SAIDI) of outages on each circuit annually. "Customers experiencing multiple interruptions" ("CEMI") is another frequently-tracked statistic. At most utilities, circuits performing significantly worse than average on these metrics are placed into a "Worst Performing Circuit" program. Most utilities identify circuits performing 2.5 to 3 times worse than average for qualification into such programs. Circuits which qualify for a utility's worst performing circuit program are subjected to root cause analysis. Utility engineers examine the locations and causes of problems to identify those occurring repeatedly on a circuit. When recurring problems are found, remediation plans are developed and implemented. Actions taken on a circuit should not be generalized into programs for rote application to other circuits. In the experience of ABATE's experts, remediation plans most commonly involve tree trimming, particularly for utilities employing tree trimming cycles greater than four or five years.

A comparison of these standard industry practices to proposals in DTE's Distribution Grid Plan identifies many departures. There is no research indicating that the incremental benefits of any of these departures exceed these departures' incremental costs. DTE Plan proposals that represent departures from standard practices include the following: (i) Circuit breaker replacement and substation outage risk reduction programs, which depart from standard substation asset testing practices; (ii) URD cable replacement, which departs from the standard run to failure practice; and (iii) the system cable replacement, 4.8kV hardening, and circuit renewal programs, which depart from standard worst performing circuit practices.

Regarding circuit breaker and substation outage risk reduction programs, DTE uses equipment age and subjective assessments of asset health condition to justify replacing circuit breakers and other substation equipment in these programs. In other words, it appears replacement is dictated by various subjective component analyses (e.g. oil leaks, minor capability inadequacies, etc.) which may lead to a significant holistic solution (i.e. replacement) which is not actually necessary. ABATE's experts have personally participated in conversations with field personnel in which a bit of oil on the outside of a device, combined with the lack of some optional capability or another, and a device's age, are used to justify replacement of an asset operating in a perfectly safe and reliable manner. ABATE's experts note that oil leaks can be repaired; various components can be replaced independently to add optional capabilities; and age is a poor predictor of failure. A new piece of substation equipment installed last year can fail tomorrow, and a 50-year-old piece of substation equipment can last for another 30, 40, or even 50 years before failing.[37]

By replacing assets based on age and subjective condition assessments, DTE can be depriving customers of decades of safe and reliable service from an asset that is fully depreciated. In other words, DTE may be increasing its rate base through unnecessary equipment replacement. The standard testing practices provide objective rationale for equipment replacement. Subjectively-determined replacements are unnecessary, extremely costly, and unlikely to provide any but the most insignificant reliability improvements. The circuit breaker replacement and substation outage risk programs are $87 million and $53 million components of the Plan, respectively.[38]

Similarly, while underground residential distribution cable does fail at an earlier age than overhead conduit, this is no reason to abandon the run-to-failure practice. At most utilities, underground residential cable is subject to a "three strikes and you're out" policy. This means that when a section of underground residential cable experiences three faults, that section is replaced.[39] This is a rational and simple-to-follow policy which balances cost against reliability concerns and is in keeping with the standard run-to-failure practice. With minimal exceptions for specific types of underground residential cable, there is no reason to presumptively replace URD cable sections which have not experienced three faults. As with substation equipment or any other presumptive action which replaces equipment earlier than necessary, presumptive cable replace can deprive

[37] ABATE experts are aware of a 93-year-old substation power transformer operating safely and reliably in Washington state. Washington UTC Case No. UE-200900. Response by Avista Corporation to data request PC-108(f) submitted by Public Counsel. February 10, 2021.

[38] DTE Electric Distribution Grid Plan (August 1, 2021), p 99.

[39] This explanation assumes a definition of underground residential cable as the runs between significant underground equipment, such switch cabinet to switch cabinet.

customers of years of reliable service. The URD cable replacement program constitutes $60 million of DTE's Plan.[40]

DTE's system cable replacement, 4.8kV hardening, and circuit renewal programs are also concerning. The equipment being replaced in these programs would all be identified over time through a standard worst performing circuit program. There is no evidence that presumptive replacement outside that identified through the root cause analyses of worst performing circuit programs delivers incremental costs in excess of incremental benefits. Further, the potential capital waste these programs could entail is troubling. DTE's Plan includes huge investments in converting 4.8 kV circuits to 13.2 kV, and there is a discussion of potential further upgrades to 25 kV.[41] Equipment of various voltages are not interchangeable. Cable and equipment installed as part of these programs will be taken out of service when a circuit is converted from 4.8 kV to 13.2 kV, or from 13.2 kV to 25 kV.

Finally, DTE's circuit renewal program appears to provide for unnecessarily replacing assets which will be capitalized. For example, a pole crossarm which appears cracked as part of a routine, periodic pole inspection is replaced as an O&M expense. A pole crossarm replaced as part of a "circuit renewal" capital program approved in a rate case can be added to rate base. Further, such programs employ copious amounts of presumptive replacement. A slightly warped crossarm, or a transformer with a bit of rust or oil on the outside, does not indicate imminent failure. Such assets can have full lives of 50, 60, or 70 or more years. When tasked with finding assets to replace, field personnel will dutifully comply. This does not mean these actions will avoid failures and improve reliability, or that the reliability improvements will be significant enough to outweigh the

[40] DTE Electric Distribution Grid Plan (August 1, 2021), p 99.

[41] Ibid, p 44.

incremental costs of presumptive replacement. To identify circuit reliability issues, the standard worst performing feeder and run-to-failure practices work just fine, and better-focus spending on known problems rather than potential problems. DTE's Plan includes $256 million system cable replacement, $535 million for 4.8 kV circuit hardening, and $115 million for "circuit renewal."[42]

2. The need for many other programs has not been sufficiently justified.

As set out in greater detail below, the Plan provides insufficient justification for DTE's system loading, subtransmission redesign and rebuild, 4.8kV conversion and consolidation, and City of Detroit infrastructure programs. Combined, these programs constitute over $1.25 billion of DTE Plan capital.[43] Without adequate supporting detail these investments cannot be reasonably pursued.

Regarding system loading, the Plan calls for $138 million in capital to be spent across 17 projects for system load relief, not including an additional $258 million DTE estimates will be required to complete the projects in the 2026-2029 timeframe.[44] Only about half the substations involved appear to experience equipment and firm capacity issues, and DTE provided no documentation to support these claims. Rather than circuit- and substation-specific load forecasts, which are standard practice for distribution capacity planning, DTE uses a non-descript "strong load growth prospect" (yes or no) to prioritize efforts.[45] Given significant changes in office and retail real estate market prospects prompted by the pandemic, load growth forecasts are typically overstated. DTE's failure to provide load growth forecasts and capacity overload documentation makes this spending inadequately supported and unreasonable.

---

[42] Ibid, pp 99-100.

[43] Ibid, p 100.

[44] Ibid, Exhibit 11.1.3.3, p 279-280.

[45] Ibid, Exhibit 11.2.1.2, pp 286-287.

The Plan also calls for $441 million to be spent on 53 distinct subtransmission redesign and rebuild projects, with continued increases in future years.[46] As with the system loading program, DTE justifies these projects largely on the basis of load relief. But similarly, DTE did not respond to requests for load forecast details, equipment capacity ratings, reconfiguration options, and other details required to validate the need for these projects. DTE also cites improved reliability as a benefit of this program, though subtransmission network issues did not appear to be significant contributors to the lengthy outages caused by the August 10th storm.[47]

The Plan further calls for $252 million to be spent consolidating 4.8kV circuits and converting them to 13.2 kV across 23 different projects. An additional $149 million is estimated to be required to complete these 23 projects in 2026-2029 timeframe.[48] Standard practice is to convert 4.8 kV circuits and substations only when necessary due to load growth. DTE did not respond to ABATE requests for load forecasts, equipment capacity ratings, reconfiguration options, and other details required to validate the need for capacity increases.

Further, this program addresses just a very small fraction of DTE's 4.8 kV circuits, which dominate DTE's distribution grid. To convert all the 4.8 kV circuits would require billions and billions of dollars. Accordingly, DTE's 4.8 kV circuit situation appears to be a strategic one. It requires discussion, debate, consideration of alternatives, and out-of-the-box thinking that is fairly unique. It is not an issue that can be reasonably sorted out during the 60-day comment window allotted to distribution plan feedback in the current distribution planning process, nor can it be addressed in the relatively limited discovery framework of a rate case. This appears to be precisely

---

[46] Ibid, Exhibit 11.2.2.2, pp 297-300.

[47] *DTE announces an additional $70 million investment to combat extreme weather-related power outages*. DTE press release dated September 1, 2021.

[48] DTE Electric Distribution Grid Plan (August 1, 2021), Exhibit 11.3.4.2, pp 315-316.

the type of challenging issue the Commission hoped to flesh out through the distribution planning process. So far that process has proven valuable in identifying the issue, although it does not appear capable of permitting the utility, stakeholders, or Commission to resolve the same.

The Plan further calls for $416 million to be spent upgrading infrastructure in a small area of Detroit serving just 31,800 customers.[49] That works out to over $13,000 per customer, not including the carrying charges customers will have to pay over the life of the assets.[50] These amounts do not include an additional $850 million DTE estimates for the program beyond 2025.[51] The program is essentially the downtown counterpart to the 4.8 kV consolidation and conversion program, but at even higher costs due to additional complexities and characteristics typical to dense downtown metropolises. As with the 4.8 kV consolidation and conversion program, DTE warns of load growth issues but provided none of the details required to evaluate the concerns.[52] DTE also warns of increasing outage frequency and duration in the downtown area, but provides no data to validate this claim.[53] Additionally, as with the 4.8 kV consolidation and conversion program, the strategic and existential nature of the challenge cannot be sorted out during the 60-day comment window allotted to distribution plan feedback in the current distribution planning process, nor can it be addressed in the relatively limited discovery framework of a rate case.

---

[49] Ibid, Exhibit 11.4.4, p 327-328 ($416 million); p 321 (31,800 customers).

[50] Based on an estimate that the revenue requirement would be about $26,000 per customer assuming an average 30-year depreciation period.

[51] DTE Electric Distribution Grid Plan, Exhibit 11.4.4, p 327-28.

[52] Ibid, p 321.

[53] Ibid.

3. DTE's pole and pole-top replacement program is neither standard nor justified.

DTE's pole and pole-top replacement program does not comply with standard pole testing and inspection and run-to-failure practices, nor does DTE's Plan provide sufficient justification for the program. As with any non-standard practice, the first step a utility should take is to complete a pilot of the non-standard practice on a few circuits. The pilot could involve a comparison of the reliability on those circuits before the program is implemented to the reliability on those circuits after the program is implemented. The per-circuit reliability improvements could then be compared to the per-circuit costs to determine the cost-effectiveness of the program. DTE should not spend $430 million on a pole and pole-top replacement program until a pilot of the program unequivocally demonstrates that the benefits of the program to customers exceeds the costs of the program to customers.

F. Recommendations.

While this is an informational proceeding and DTE's Plan is just that – a plan without spending forecasts for the forward test years of a rate case – it is important to consider that the Plan is a precursor to what stakeholders are likely to see in future rate cases. As such, recommendations for DTE's Plan and components are provided below.

1. Investments DTE claims are "required" for DG/DS and electric vehicles are overstated and potentially unnecessary.

DTE claims a number of investments are "required" for DG/DS and electric vehicles, from circuit breakers with adaptive protection capabilities to an advanced distribution management system.[54] In justifying these investments, DTE cites non-specific forecasts of DG/DS and electric vehicle growth ("scenarios") and vague references to "potential problems" like two-way power

---

[54] Ibid, p 36-52.

flow with no technical explanation of the issues supposedly presented.[55] Despite a lack of documentation regarding the technical challenges actually presented by DG/DS and electric vehicle growth, DTE goes on to prescribe various solutions as "required." As such, DTE claims a "least cost, best fit" approach to a determination of cost-effectiveness is adequate. Finally, DTE claims its chosen solutions have passed a "least cost, best fit" analysis.[56] The assertions are inadequately supported and incorrect.

First, the identification and scope of the problems identified should be accompanied by a detailed, technical explanation of the identified problem, including a description of the actual technical challenge, the conditions which cause it to occur, the likelihood of those conditions, the likelihood that the conditions will cause the problem, and the consequences if the problem is not mitigated. Citations to research are a minimal expectation, with documentation of actual situations encountered on the DTE grid preferred. In short, before proceeding to solutions, DTE must prove there is a problem which merits solving.

Once stakeholders fully understand the problem, and agree that it merits solving, DTE must present various options available to address it. In a rate case DTE would presumably have evaluated the technical and economic pros and cons of each alternative to solving a documented problem. All details of these analyses should be available for stakeholder review, along with DTE's justification as to why the solution it proposes is the "least cost, best fit" of those available. A solution is not "least cost, best fit" simply because DTE declares that it is; DTE has the burden to prove that its chosen solution truly is the least cost and best fit of all available alternatives.

---

[55] Ibid, p 36.

[56] Ibid, p 79.

Further, stakeholders must fully understand the projected benefits of the "required" solution and be able to hold DTE accountable for achieving them. Inadequately supported claims of "more" or "better" are not adequate. For example, if DTE claims a certain solution is required for DG/DS or electric vehicle growth, stakeholders should understand both the capacity of the grid to accommodate DG/DS or electric vehicles today (baselines), and the growth in the grid's DG/DS or electric vehicle capability available once the "required" solution is implemented (targets). Stakeholders should be able to hold DTE accountable for performance through objective measures, such as "DG/DS hosting capacity, in MW," or "count of electric vehicles the grid can accommodate" using normalized charging profiles based on research and approved by stakeholders.

Finally, DTE's GPM is a project prioritization tool; it is not a benefit-cost analysis or a substitute for a benefit-cost analysis, nor is it a substitute for a true least cost, best fit analysis as described above. The GPM does not justify the installation of any solution, nor should it be presented or perceived as such. As far as prioritization tools go, DTE's GPM is extremely weak in that it is completely subjective. DTE should replace its GPM with a more rigorous approach to solution selection and utilize risk-informed decision support. Risk-informed decision support analyses compare the risk reductions available from projects and programs to the cost of projects and programs, enabling stakeholders to make their own assessments of the value of associated capital budgets, and to understand the trade-offs (in terms of risk reductions not secured) associated with various cuts to the investment levels DTE proposes in a rate case.

2. Investments DTE proposes for reliability/resilience ("hardening").

DTE's Plan includes billions of dollars in investment to improve reliability and the grid's resilience to sever weather. Almost none of these investment proposals comport with standard distribution planning and operating practices, from substation testing and pole testing to "run-to-failure" and worst performing circuit programs. Before DTE proposes such investments in a rate case, DTE should complete formal pilots of the proposed programs and include a comparison of the incremental benefits and incremental costs of the proposed program relative to the associated standard practices, and relative to tree trimming. Programs DTE should pilot for cost effectiveness prior to proposing in a rate case are listed below.

- Circuit breaker replacement ($87 million)
- Substation outage risk reduction ($53 million)
- System cable replacement ($256 million)
- URD cable replacement ($60 million)
- 4.8kV circuit hardening ($535 million)
- Circuit renewal ($115 million)
- Pole and pole-top maintenance and modernization ($430 million)

Further, for a Plan which proposes capital investments $3.6 billion higher than historical levels, DTE's projected improvements in outage frequency and duration, both with and without storms, are unreasonable and insufficient. After completing pilots which document the types of reliability improvements which can be delivered, any rate case investment proposals should be accompanied by challenging, system-wide reliability improvement targets. These targets should be developed from the pilot results, with details of the translation from pilot results to system-wide targets to be provided for stakeholder review.

3. Investments DTE proposes to address capacity constraints.

DTE's Plan calls for billions of dollars in investment to increase circuit and substation capacity without providing details to help stakeholders evaluate the necessity of these capacity increases. In a rate case, DTE must provide full details in support of capacity increases, including details of capacity constraints and load, DG/DS, and electric vehicle forecasts and assumptions on a circuit-specific basis. As DTE indicates it will prepare in the future (but which DTE did not prepare for this iteration of its Plan), 8760 profiles of forecasted loads, DG/DS, and electric vehicle charging based on historical actuals should be provided. Constraint assessments should reflect emergency equipment ratings and switching plans.

Of particular concern is the proposed multi-billion dollar, multi-decade effort to replace the 4.8 kV circuits and substations which comprise the bulk of DTE's distribution grid. Only a fraction of the ultimate costs of such an effort are included in DTE's current Plan. This issue involves more than an investment proposal which can be addressed in the relatively limited context of rate case discovery, or in the 60-day comment period available in the current distribution planning process. A system-wide overhaul is an existential issue which concerns the future of electricity in Michigan and DTE's role in it. It is inappropriate to propose any such investments in the absence of a thorough examination of all sides of the issue by DTE, Staff, stakeholders, the Commission, and the Michigan Office of Climate and Energy. This issue is so large, and so critical to Michigan's energy future, that it cannot be decided by DTE on its own.

III. CONCLUSION

DTE's Plan presents a number of deeply concerning proposals without adequate support or justification. Without sufficient details the Plan includes warnings of "potential problems" based on ill-defined scenarios as justifications for investments. Further, the billions of dollars in proposed reliability investments do not comport with standard industry practices, have not been proven cost-effective through research or the use of pilots, and associated reliability improvement targets are insufficiently aggressive. Similarly, proposals to increase grid capacity are not supported by details indicating near-term need.

In light of these shortcomings, any request for cost recovery regarding these proposals should include the following.

1. Detailed technical explanations of the problems caused by DG/DS and EVs. The alternatives DTE considered for addressing demonstrable technical problems should be processed through a true least cost, best fit analysis. Tangible benefits -- in terms of increases in DG/DS hosting capacity (MW) and increases in the count of electric vehicles accommodated (assuming normalized charging profiles) relative to baselines -- should be specified for each proposed solution.

2. All investments proposed to improve reliability and weather resilience must be piloted, with clear documentation of cost-effectiveness relative to tree trimming and other standard industry practices.

3. All investments DTE proposes to meet capacity needs must be backed by circuit-specific forecasts and constraint details. The forecasts should be in 8760 format and incorporate normalized DG/DS production and electric vehicle charging profiles. Alternatives to capital investment must be evaluated from economic and technical perspectives, with full details available for review. To the extent system-wide upgrades costing billions of dollars over decades are being contemplated, DTE should involve all stakeholders in thinking through the issues from different perspectives, and incorporating strategies and alternative approaches for each perspective, and completing research as necessary, before commencing such a massive effort.

APPENDIX A

Questions ABATE Submitted to DTE Regarding its August 1, 2021 Distribution Grid Plan

Executive Summary

1. Refer to page 3 which states, "In areas where grid hardening work is complete . . . our customers are seeing a 50-70% improvement in reliability." Provide, in MS Excel format:

    a. A list of circuits in which grid hardening work is complete.

    b. For each of the circuits listed in response to subpart (a), provide a list of new equipment installed (meaning, equipment installations not constituting a replacement of existing equipment), the dates completed for each new installation, and the "all in" capital cost of each new installation.

    c. For each of the circuits listed in response to subpart (a), provide a list of existing equipment replaced with new equipment, the dates completed for each replacement, and the capital cost of each new replacement.

    d. For each of the circuits listed in response to subpart (a), provide the dates over which tree trimming was completed, and the O&M cost (and capital cost if any) of the tree trimming.

    e. For each of the circuits listed in response to subpart (a), provide SAIDI and SAIFI with and without major event days by year from 2016 through 2020.

    f. For each of the circuits listed in response to subpart (a), provide actual outage reports, including field notes and cause type by year from 2016 through 2020.

    g. Provide the dates of every major event day DTE declared using the IEEE definition from 2016 through 2020.

2. Refer to the page 3 statement "Modernizing infrastructure will also make the grid more resilient to the increasingly severe weather that is impacting Michigan . . . ."

    a. Provide a count of major event days by year from 2013 through 2020 DTE used to calculate SAIDI and SAIFI data to the U.S. Energy Information Administration on Form 861.

    b. Provide a count of major event days by year from 2013 through 2020 resulting from a loss of supply.

    c. Provide the calculations of SAIDI and SAIFI by year, with and without major event days, and with and without loss of supply, DTE completed to report reliability information on U.S. Energy Information Administration Form 861 from 2013 through 2020.

3. Refer to page 4 which states "The past smart/advanced meter infrastructure (AMI) project is an essential component of a modernized grid, and one that DTEE has already invested in."
    a. Quantify the economic benefits to customers the AMI project delivered in 2020 relative to the status quo (meaning, before smart meters) by benefit type, for example 1) meter reading cost reductions; 2) service disconnect/reconnect cost reductions; 3) customer efficiency improvements; 4) grid efficiency improvements; 5) revenue assurance improvements; 6) reliability improvements; and any others.
    b. Provide, in MS Excel format, all workpapers, calculations, assumptions, estimates, and other support for each of the economic benefits quantified in response to subpart (a).
    c. Provide any and all post-deployment assessments DTE has completed to estimate the economic benefits delivered to customers by the AMI deployment.

4. Refer to DTE's description of the new ADMS on page 4. Multiple components/prerequisites for ADMS are mentioned, including GMS, EMS, NMS, OMS, and DMS. For each of these components/prerequisites, provide:
    a. The degree of completion, in percent (100%, 90%, 0%, etc.) as of December 31, 2020, along with a description of how the completion percentage is measured, and the estimated date for 100% completion;
    b. The degree to which the component is providing expected functionality, in percent, as of December 31, 2020, along with a description of how the functionality percentage is measured; and the estimated date for 100% functionality;
    c. The degree to which the component is providing anticipated value to the ratepayer, in percent, as of December 31, 2020, along with a description of how anticipated value to the ratepayer is measured; and the estimated date for 100% ratepayer value delivery.

5. Refer to DTE's description of the new ADMS on page 4, which states "The remaining ADMS applications are planned for launch in 2022."

a. Describe each of these "remaining applications", each's role in the ADMS, an estimate of when each will be implemented to 100% functionality, and the cost to implement each.

b. Provide any and all research, industry publications, whitepapers, or other evidence that the benefits to ratepayers of ADMS is worth the cost of ADMS (capital and ongoing O&M) to ratepayers.

c. Provide the estimated useful life DTE will use/is using for ADMS and each of its component applications.

d. Estimate the year by which DTE estimates it will have to replace ADMS and each of its component applications. Provide any ADMS/component replacement plans DTE has developed.

e. Indicate where in the benefit-cost analysis details provided in response to other ABATE data requests the ADMS/component replacement costs have been considered/included/incorporated.

6. Refer to DTE's description of the new ADMS on page 4 generally. ABATE is aware of a whitepaper by the U.S. Department of Energy's Office of Electric Delivery and Energy Reliability, "Voices of Experience: Insights into Advanced Distribution Management Systems" (February, 2015). The whitepaper describes a litany of issues that other utilities have experienced in attempts to implement ADMS.

   a. Describe any actions DTE has taken to address the issues described in this whitepaper.

   b. Describe any distribution capital or O&M budget estimate adjustments DTE has made to address the issues described in this whitepaper.

   c. The AACE describes categories for cost estimates of varying certainties, from Level 1 (highly accurate, 50-100% of project defined) to level 5 (not at all accurate, 0-2% of project defined). Provide the AACE cost estimate category which best describes the level of accuracy in ADMS cost estimates included in DTE's current DGP.

7. Refer to DTE's description of new substations and conversions of circuit miles to higher voltage levels on page 5. Provide:

   a. A list of all new substations to which DTEE "started the planning for and are in the early phases of construction", or that have been completed since 2018.

   b. For each substation listed in response to subpart (a), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, which describes how construction of each new substation was justified.

c. A list of all projects for "conversion of circuit miles to higher voltage levels" to which DTEE "started the planning for and are in the early phases of construction" or that have been completed since 2018.

d. For "conversion of circuit miles to higher voltage levels" projects listed in response to subpart (c), provide all business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, other documentation, which describes how each "conversion of circuit miles to higher voltage levels" was justified.

e. All business cases, worksheets, workbooks, models, cost-benefit analyses, or any other calculations, presentations, requests, standards, load forecasts, DER forecasts, or other documentation which justifies the added 700 MW of capacity.

8. Refer to page 9, which states "Almost all stakeholders told DTE that this transition to a modernized grid must be done, and it must be done equitably". Describe in detail how DTEE understands the meaning of the word "equity" when used by i) customers; ii) community leaders; and iii) intervenors in DGP engagement activities described in pages 10-19.

Stakeholder Engagement

9. Provide any "willingness to pay" market research DTE has conducted which indicates the level of rate increase customers of various classes (residential, commercial, industrial) would be willing to accept for various levels of reliability improvement. If DTE has not conducted such research, please explain why not.

10. Provide any "willingness to pay" market research DTE has conducted which indicates the level of rate increase customers of various classes (residential, commercial, industrial) would be willing to accept for various levels of resilience improvement. If DTE has not conducted such research, please explain why not.

11. Refer to page 13 which states "Across both customer groups, even among those who were enthusiastic about a grid overhaul, it wasn't until they were made aware of the risks associated with not modernizing the grid that customers ultimately saw enough value in grid modernization that they would be willing to pay more to modernize and ensure continued reliability."

a. Provide the materials presented in engagement activities which "made (customers) aware of the risks associated with not modernizing the grid".

b. Explain how customers described the "value in grid modernization" in engagement activities once the materials provided in response to subpart (a) were presented.

12. Refer to page 17 which states "Additionally, it was considered that without a modern electric grid, Michigan is at risk of being passed over for investments and economic growth."

    a. Provide any evidence of which DTE is aware which indicates that businesses have avoided making investments in the DTE service area over concerns regarding DTE service reliability. If DTE has no such evidence, please so state.

    b. Provide any research DTE has conducted which evaluates the region-wide and/or state-wide economic impact of the incremental rate increases associated with the accelerated investment contemplated by Plan. If DTE has not conducted such research, please explain why not.

13. Refer to pages 10-19, which describes customer, community leader, and intervenor engagement. Indicate whether and how the revenue requirement impact of DTE's DGP were estimated and communicated.in the workshops. If DTE did communicate revenue requirement impact estimates, provide materials related to rate impacts DTE presented as part of stakeholder engagement activities. If DTE did not communicate revenue requirement impact estimates, explain how DTE responded to participant inquiries regarding the likely size of revenue requirement impacts associated with its DGP.

14. Refer to Section 2.2.1 on pages 20-21 which describes DTE's proposed methodology for ensuring the reliability of service in geographies in which environmental justice is low is just as good as the reliability of DTE service overall.

    a. Explain how DTE would make a "SAIFI by census tract" chart such as the one illustrated by Exhibit 2.2.1.1. Would DTE use AMI data, GIS data, a combination, or something else, to make such a chart?

    b. Explain how DTE would correlate census tract maps to circuit maps. For example, assume a circuit serving a highly impacted census tract exhibits poor performance on a minority of the circuit and excellent performance on the majority of the circuit. Describe how DTE's proposed methodology to incorporate energy justice would address such a situation.

c. Explain why DTE's current approach to identifying circuits exhibiting poor reliability performance, for example using SAIFI and CEMI metrics, and addressing the root causes of poor performance on circuits identified (known as a worst performing feeder program at most utilities) isn't adequate to securing good energy justice outcomes in an economically-appropriate manner. Provide any analyses DTE has completed which indicates the proposed approach to securing good energy justice outcomes is less costly than industry-standard approaches such as worst-performing feeder.

d. Explain how the approach described could change DTE's grid investment levels and geographic focus. For example, assume that a sparsely populated rural area is designated as highly impacted, and also has relatively worse SAIFI performance. ABATE understands it is typical for rural areas to have worse SAIFI performance than urban areas (due in large part to greater switching options in urban areas). ABATE also understands that it is more costly to improve the SAIFI of sparsely populated areas than to improve the SAIFI of densely populated areas (due in large part to the higher cost of constructing longer back ties). Could DTE use the methodology described to justify investments which are uneconomic on their merits? (In the example instance, "uneconomic" would result from too few customers benefitting from reliability improvements relative to the size of the investment required to improve reliability.) Describe any parts of DTE's proposed approach to energy justice designed to avoid uneconomic investments of the type apparent in the example provided.

Grid Modernization Process

15. Refer to page 25 which states "This will require DTEE to address new and complex issues such as two-way power flow, intermittent generation, and DER aggregation and integration." Provide a list of all customer complaints, power quality issues, safety issues, or service outages that have occurred on the DTE system caused by:

    a. Two-way power flow;

    b. Intermittent generation;

    c. DER aggregation;

    d. DER integration.

16. Refer again to the statement on page 25, "This will require DTEE to address new and complex issues such as two-way power flow, intermittent generation, and DER aggregation and integration." Describe all technical power quality issues, safety issues, or technical reliability issues that have occurred on the DTE system caused by:

a. Two-way power flow;

b. Intermittent generation;

c. DER aggregation;

d. DER integration.

Benefit-Cost Analysis

17. Refer to Exhibit 5.1.6 on page 86, which lists the top 50 strategic capital project or program. For each:

    a. Provide the calculation details for the benefit-cost score, including all workpapers, assumptions, estimates, and other details, in MS Excel format with no hidden or protected cells, no pasted values, and all formulae available for ABATE review.

    b. Provide the calculation details for the economic benefits of each program used to calculate its benefit-cost score, including all workpapers, assumptions, estimates, and other details, in MS Excel format with no hidden or protected cells, no pasted values, and all formulae available for ABATE review.

    c. Provide the calculation details for the economic costs of each program used to calculate its benefit-cost score, including all workpapers, assumptions, estimates, and other details, in MS Excel format with no hidden or protected cells, no pasted values, and all formulae available for ABATE review.

18. Refer to Exhibit 5.3.1 on page 90, which indicates a baseline SAIDI of approximately 440 including major event days, falling to 199 with the investment and rising to 487 without the investment. Provide the calculation details behind:

    a. The baseline;

    b. The fall to 199 with the investment;

    c. The increase to 487 without the investment.

19. Refer to Exhibit 5.3.2 on page 90, which indicates a baseline SAIFI of approximately 1.3 including major event days, falling to 1.06 with the investment and rising to 1.477 without the investment. Provide the calculation details behind:

    a. The baseline;

    b. The fall to 1.06 with the investment;

    c. The increase to 1.477 without the investment.

20. Refer to Exhibit 5.3.3 on page 91, which indicates a baseline SAIDI of approximately 170 without major event days, falling to 118 with the investment and rising to 176 without the investment. Provide the calculation details behind:

    a. The baseline;

    b. The fall to 118 with the investment;

    c. The increase to 176 without the investment.

21. Refer to Exhibit 5.3.4 on page 92, which indicates a baseline SAIFI of approximately 0.95 without major event days, falling to 0.885 with the investment, and rising to 1.024 without the investment. Provide the calculation details behind:

    a. The baseline;

    b. The fall to 0.885 with the investment

    c. The increase to 1.024 without the investment

22. Refer to Exhibit 5.3.5 on page 93, which indicates a baseline of $371 million in emergent capital spend, falling to $353 million with the investment and rising to $420 million without the investment. Provide the calculation details behind:

    a. The baseline, differentiating between weather-related emergent capital and emergent capital related to equipment failure;

    b. The fall to $353 million with the investment, differentiating between weather-related emergent capital and emergent capital related to equipment failure;

    c. The increase to $420 million without the investment, differentiating between weather-related emergent capital and emergent capital related to equipment failure.

23. Refer to page 94, which states, regarding the economic benefits of reliability improvements, "Over the next five years, the expected benefits the investments will deliver are calculated to be between $9.8 billion and $13.2 billion."

    a. Provide, in MS Excel format, the calculation details behind these estimates for each type of benefit by year from 2021 through 2055.

    b. From the calculation details provided in response to subpart (a), provide, in MS Excel format, a breakdown of benefits from each primary DGP spending category, including i) Emergent Replacements; ii) Customer

Connections/Relocations and Others; iii) Strategic Capital Programs; iv) tree trimming; and v) preventative maintenance.

c. Provide each and every ICE calculator input used in these estimates, or each and every ICE calculator input for outputs utilized in the reliability components of calculation details provided in response to subpart (a).

DGP Investment Summary

24. Refer to Exhibit 6.1 on page 98, which indicates capital investment and maintenance program spending for the Plan by year from 2021 through 2025. For each of the five line items, provide capital spending by year from 2016 through 2020.

   a. Emergent Replacements

   b. Customer Connections/Relocations and Others

   c. Strategic Capital Programs

   d. Tree Trimming

   e. Preventative Maintenance

25. Refer again to Exhibit 6.1 on page 98. Provide project and program detail by year from 2021 through 2025 using the "Top 50" list from Exhibit 5.1.6 on page 86, plus any and all additional projects and programs necessary, to tie out to each of five line items listed on Exhibit 6.1.

   a. Emergent Replacements

   b. Customer Connections/Relocations and Others

   c. Strategic Capital Programs

   d. Tree Trimming

   e. Preventative Maintenance

26. Refer again to Exhibit 6.1 on page 98. Using assumptions based on DTE's most recently completed rate case, estimate the revenue requirements of the Plan by year from 2021 through 2055. Provide all worksheets, assumptions, calculations, and other details used to complete this response in MS Excel format with no hidden or protected cells, no pasted values, and all formulae intact and available for ABATE review.

27. Refer to Exhibit 6.2 on pages 99-101. These projects appear to amount to only about $3.6 billion of the $6.8 billion capital plan provided in Exhibit 6.1 on page 98. Provide, in MS Excel format, the capital details of all projects and programs by year from 2021 through 2025 such that the totals tie to the totals by year provided in Exhibit 6.1 by category:

    a. Emergent Replacements

    b. Customer Connections/Relocations and Others

    c. Strategic Capital Programs

Distribution System Overview

28. Refer to the Distribution System Overview generally. Provide:

    a. The name of each service center, and a definition of the geographies served by each

    b. The name of each dispatch center (and/or service centers which include a dispatch center), and a definition of the geographies and/or a list of circuits managed by each.

    c. The number of outage response personnel (i.e., Lineman, etc.) at each service center, and the average response time for these crews.

    d. The number of construction/repair personnel available to repair or replace damaged or failed equipment at each service center, and the average response time for these crews.

    e. Describe all systems presently used by DTE dispatchers, the availability of each system by dispatch center, and the scope or smallest granularity (geographic or device) of each system, including GIS, OMS, DMS, NMS, EMS, SCADA, DERMS, etc.

    f. Describe the availability of each of the systems listed in response to subpart (g), such as 1) terminals in dispatch centers; 2) terminals in service centers; 3) mobile laptops carried by field crews; 4) any other means through which access is available.

29. Refer to the Distribution System Overview generally. Provide a count of customers by class (Industrial/Large Commercial, Small Commercial, and Residential) as of December 31, 2020.

.

30. Refer to the Distribution System Overview generally. Provide, in MS Excel format, a list of substations by name and/or identifying number. For each substation, provide:
    a. The high-side and low-side voltages of each, along with a designation of whether or not the substation is equipped with SCADA;
    b. The number of power transformer units at each, along with an identifier and age for each power transformer as of December 31, 2020;
    c. The normal and emergency capacity ratings of each power transformer unit listed in response to subpart (b);
    d. The peak load by year for each power transformer listed in response to subpart (b) by year from 2016 through 2020;
    e. The results of any "point-to-point" SCADA accuracy tests performed from 2016 through 2020 (for substations equipped with SCADA as listed in response to subpart (a).

31. Refer to the Distribution System Overview generally. Provide, in MS Excel format, a list of circuits by name and/or identifying number. For each circuit, provide:
    a. The identity of the associated substation;
    b. The voltage and available capacity of each circuit (MW/KW);
    c. The energy distributed by each circuit by year from 2016 through 2020 (in MWh or GWh);
    d. The peak loading on each circuit by year from 2016 through 2020 and the dates recorded;
    e. The minimum load for each circuit by year from 2016 through 2020 and the dates recorded;
    f. For each circuit, the total capacity of DER;
    g. For each circuit, the percent of circuit load that is supplied by DER at peak load;
    h. For each circuit, the percent of circuit load that is supplied by DER at minimum load;
    i. The forecasted peak load for each circuit by year from 2021 through 2025;
    j. For each circuit, the number and capabilities of remote units, (Station Breakers, Reclosers, sectionalizers, fused cutouts, Trip-Saver devices, switches, regulators, capacitors, others) as of December 31, 2020;
    k. The forecasted increase in DER capacity by year from 2021 through 2025;

l. The number of customers served by each circuit by customer class as of December 31, 2020 (Industrial/Large Commercial; Small Commercial; Residential).

32. Refer to the list of circuits provided in response to data request 31. For each circuit, provide, in MS Excel format:

    a. A report of outages by cause type, by year from 2016 through 2020, with system-wide totals of outages by cause type;
    b. SAIDI, SAIFI, CAIDI, and MAIFI by year from 2016 through 2020;
    c. The length of the longest-duration outage from 2016 through 2020, and the number of customers impacted by the duration indicated;
    d. A count of outages used to calculate SAIFI by year from 2016 through 2020;
    e. A count of customers experiencing 3 or more sustained (SAIFI) outages by year from 2016 through 2020 (as might be identified through a worst performing feeder analysis);
    f. A count of outages caused by reverse power flow from DERs, or any other DER-related outage;
    g. A count of voltage violations or other power quality issues caused by DERs DTE took action to correct;
    h. For all outages with cause type “equipment failure” as provided in response to subpart (a), provide the type of equipment that failed.

33. Refer to the Distribution System Overview generally.

    a. Describe any and all equipment testing and formal inspection programs DTE administers routinely, such as tests of power transformers, circuit breakers, relays, wood poles, etc. Include in each description the types of equipment tested/inspected, the nature of the tests/inspections conducted, and the frequency of the tests/inspections (meaning, years between tests/inspections).
    b. For each type of equipment test/inspection described in response to subpart (a), provide a count of tests/inspections completed by year from 2016 through 2020.
    c. For each count of tests/inspections completed by year by equipment type provided in response to subpart (b), provide the count of each equipment type which failed its tests/inspections by year from 2016 through 2020.

d. For each count of tests/inspections completed by year by equipment type provided in response to subpart (b), provide a random sample of 3 failed tests/inspections.

e. For each count of tests/inspections completed by year by equipment type provided in response to subpart (b), provide a random sample of 3 passing tests/inspections.

34. Refer to the Distribution System Overview generally.

a. Describe in detail DTE's outage management process, including 1) how service centers and/or dispatch centers are notified of potential outages, and how their extent is estimated; 2) how outages are investigated and scoped; 3) how available switching is performed; 4) how restoration times are estimated and reported to customers; 5) how repairs are completed; 6) how outages/causes/durations are recorded; and 7) any other important steps in the outage management process. In the description, please include any use of remote monitoring (AMI, line sensors, recloser lock-outs, etc.) in the outage management process.

b. For each step in the outage management process DTE described in response to subpart (a), provide the average duration of each step system-wide over the last few years based on actual DTE experience.

c. Estimate any average reduction in any outage management process step duration provided in response to subpart (b) resulting from the use of remote monitoring described in subpart (a).

35. Refer to Exhibit 7.2.3.3, "5-year Outage Events by Cause". Refer specifically to the outages identified as "equipment".

a. Describe the types of outages encompassed within outage type "equipment".

b. Provide the guide DTE field personnel use to determine which cause code should be assigned to an outage. (In ABATE's experience, such guides include a list of cause codes, with descriptions of the characteristics of an outage which qualify that outage to be assigned each particular cause code.)

c. Identify any outage cause codes associated with the cause type "equipment" which may include damage caused by wind, lightning, and other weather.

d. Identify any outage case codes associated with the cause type "equipment" which may include damage caused by third parties (for example, vehicle accidents, digging, mylar balloon contact, construction accidents, etc.)

e. Provide a random sample of 50 field outage reports (the actual outage reports prepared by field personnel, including field notes) for outages occurring in 2019 and 2020 with "equipment" cause codes.

Asset Health Assessment

36. Refer to Exhibit 8.1 on page 147 and the Asset Health Assessment chapter generally.

    a. Confirm that the source of the data in the "Life Expectancy" column is asset book life used for depreciation purposes. If this cannot be confirmed, please explain.

    b. Confirm that the equipment currently in operation for the number of years at the high end of the range in the "DTE Electric Age Range (years)" column is operating safely and reliably. If this cannot be confirmed, please explain.

    c. Explain the difference between asset book life ("Life Expectancy") and asset operating life ("DTE Electric Age Range").

    d. Describe how DTE determines "Life Expectancy" and how DTE determines "DTE Electric Age Range" for various types of equipment.

    e. ABATE is aware that standard industry practice is to operate certain assets (power transformers, circuit breakers, relays, and wood poles) until they fail a test/inspection, at which time the asset is replaced, while standard industry practice for all other distribution assets is "run to failure". ABATE is also aware of the standard industry practice of performing root cause analysis of outages on worst performing feeders to identify and address recurring issues. Provide all worksheets, assumptions, calculations, analyses, and other details which indicate that prospective replacements based on age as described in Chapter 8 provides economic benefits to customers in excess of the incremental cost to customers relative to these standard industry practices.

Infrastructure Resilience and Hardening (9)

37. Refer to page 210, which states "Projects and programs in this pillar include replacement of aging infrastructure, primarily due to asset health assessments or inspections, and upgrades to circuits in areas of poor reliability. The investments in this pillar will provide a reduction in reactive costs, as the 4.8kV Hardening and PTMM programs are two of the three highest ranked programs for emergent cost reduction (Tree Trimming, as described in Section 10, is also among the top programs for reducing emergent costs). The projects and programs are targeted specifically at equipment with known issues or in areas with known poor reliability and will help drive performance to second quartile within the next five years."

    a. Provide all worksheets, assumptions, calculations, and other details which indicate that replacing "current overhead equipment with equipment designed to our latest standard" provides dollar value to customers in excess of the cost of replacements.

b. Provide any documentation which indicate a requirement to bring equipment up to current standards, when the equipment is presently operating safely and reliably.

c. Provide detailed descriptions of DTE's Automatic Pole Top Switch and SCADA Pole Top Device programs.

d. Provide i) the number of Automatic Pole Top Switches installed by year from 2016 through 2020; ii) the operating sequence and system protection coordination schemes used; iii) the average cost per installation.

e. Provide all worksheets, assumptions, calculations, and other details which indicate that installing Automatic Pole Top Switches provide dollar value to customer in excess of the cost to customers of the installations.

f. Estimate the average number of fault isolations per year that DTE expects per device per year.

g. Provide an estimate of the economic value to customers per average fault isolated.

h. Describe any routine, periodic distribution circuit inspections DTE performs, including the frequency and character of such inspections.

i. Provide detailed descriptions of DTE's 4.8kV hardening and PTMM programs.

j. Provide all worksheets, assumptions, calculations, and other details which indicate that the 4.8kV hardening and PTMM programs provide dollar value to rate payers in excess of the cost of implementation.

k. Describe any worst performing feeder or similar program DTE maintains to identify and improve the reliability of feeders with poor reliability.

Infrastructure Redesign and Modernization (11)

38. Refer to DGP Section 11.3, "4.8kV Conversion" generally.

a. Provide the age of the oldest 4kV power transformer presently in service on the DTEE system

b. Provide the age upon replacement of all 4kV power transformers ever replaced as of December 31, 2020.

c. Describe each of the methods DTEE uses to "harden" a 4kV circuit, and provide the average cost of each.

d. Describe each of the methods DTEE uses to "harden" a 4kV substation, and provide the average cost of each.

e. Provide all business cases, benefit-cost analyses, worksheets, workbooks, models, or any other calculations, presentations, capital requests, or other documentation which indicates that 4kV conversions, other than 4kV conversions completed to accommodate growing load in violation of capacity ratings, delivers value in dollars to customers in excess of the costs to customers (revenue requirements) associated with 4kV conversions (other than to accommodate growing loads).

Technology and Automation (12)

39. Refer to Exhibit 12.1 on page 349. For each Project listed, provide all business cases, benefit-cost analyses, worksheets, workbooks, financial models, or any other presentations, capital requests, or other documentation which indicate that the economic benefits of each project to rate payers are greater than the costs to rate payers (also known as revenue requirements).

40. Refer to Exhibit 12.3.2 on page 369, which indicates telecommunications network costs of $73 million from 2021 through 2025, with a full telecommunications network buildout continuing beyond 2025.

    a. Provide a complete description of the full telecommunications network buildout DTE has planned.

    b. Provide an estimate of the total cost of the full telecommunications network buildout described in response to subpart (a).

    c. Provide DTE's historical telecommunications network O&M spending by year from 2016 through 2020.

    d. Provide DTE's projected telecommunications network O&M spending by year from 2021 through 2025.

    e. ABATE is aware of AT&T's FirstNet, Verizon's CAT M-1, and similar network services available from third parties designed specifically for first-responders and other mission-critical endeavors. ABATE is aware of the "bandwidth slicing" technologies which allow dedicated bandwidth to be reserved for potential customers like DTE in this "Internet of things" era. Provide any analyses DTE has completed which compares the cost of building and operating its own telecommunication network to the cost of network services rental from third party providers.

Base Capital (13)

41. Refer to Exhibit 13.1.1 on page 432.

a. Provide the spending on emergent replacement or other comparable or previously similar programs by year from 2016 through 2020.

b. Describe in detail the processes that DTE uses to identify specific types of equipment for replacement under this program, including age, estimated end-of-life/asset condition modeling based on equipment type populations, or others.

42. Refer to Exhibit 13.1.2.2 on page 436 and the statement "Another driver for increased emergent capital spend has been the increase in asset failures and replacements due to system aging, deterioration, and other factors like tree damage". Provide the capital spending details of this Exhibit by year by each of the following causes:

a. Equipment failure;

b. Asset age/condition/deterioration;

c. Tree-related damage; and

d. Others (please specify).

Appendix II – Historical Storm Events

43. On June 10, 2020, DTEE reports a storm event starting at 13:00 impacting 182,824 customers.

a. Provide the "customers restored by hour" detail and chart for this storm from 13:00 on June 10, 2020 through the restoration of the last customer.

b. Provide the cost detail of the $31.1 million cost of this storm, quantifying employee labor regular time, employee labor overtime, contractor labor, labor paid to utilities offering mutual aid, capital cost of equipment replaced, and other significant cost types included in the $31.1 million figure. Of the cost detail provided, quantify the amounts provided which constitute "emergent capital" per DTE's use of the term in the DGP.

c. Provide a list of capital items replaced as a result of this storm, including conductor/cable, poles, conduit, transformers, fuses, switches, sectionalizing devices, etc. etc. etc. Provide the capital costs of each, including both equipment capital and capitalized labor costs listed in response to subpart (b), "emergent capital".

d. Provide a list of repair actions taken during this storm, including feet of cable restrung, transformers re-hung, crossarms fortified, and similar, which comprises the labor costs listed in response to subpart (b) which were not capitalized.

e. Of the list of capital items replaced or repaired provided in responses to subparts (c) and (d), identify those which would not have likely needed to be replaced or repaired if DTE had completed the investments it proposes in its DGP in advance of the storm. For each capital item DTE estimates would not have likely needed to be replaced or repaired, identify which proposed DGP investment would have avoided the replacement or repair, and explain how the proposed DGP investment would have avoided the replacement or repair.

Appendix VIII -- DTEE Grid Modernization Study 2021-2035

43. Refer to the DTEE Grid Modernization Study generally.

    a. Provide a copy of any DTE policies currently in effect regarding distribution planning and/or distribution capacity planning.

    b. Describe DTE's distribution planning and/or distribution capacity planning processes currently being utilized. Be sure to include in this description how DTE i) forecasts loads by circuit; ii) forecasts DER capacity by circuit; iii) identifies forecasted capacity limitations; iv) develops potential capacity limitation solutions; v) evaluates potential capacity limitation solutions; vi) selects from available capacity limitation solutions; vii) prioritizes capacity solutions for implementation.

    c. Explain why DTE's current distribution planning and/or distribution capacity planning processes can't simply incorporate new grid technologies on an as needed basis, and why exceptional grid modernization plans and investments are required outside of these current processes.

44. Refer to the statement on Plan page 26 which states "The team worked with the consultant to assess the current state of the distribution system. Both the current and near-term strategic distribution system investment plans were also reviewed." Refer also to the consultant's five near-term recommendations on Appendix VIII page 59.

    a. Describe DTE's plans, if any, to follow through on each of the five recommendations. For any recommendations DTE has decided not to pursue, please explain why DTE made that decision.

    b. Describe any progress DTE has made on any of the five recommendations. Provide materials which document progress on any of the five recommendations to date.

c. Identify any components of the DGP which were informed by the five near-term recommendations, and describe the nature of the contribution of the five near-term recommendations.

45. Refer to Appendix VIII section 3.1 regarding the electrification scenario.

a. Provide support for the assumption that 53.7% of AC Level 1 and 2 charging will be on peak by 2035 (Table D on page 16).

b. Provide a version of Figure 5 on page 18 which breaks out the overloads by the Key Drivers of electrification from Table D on page 16: i) AC level 1 & 2 charging; ii) DC Level 1 chargers; iii) DC Level 2 chargers; and iv) heat pumps.

c. From the data provided in response to subpart (b), provide the MW at peak from each of the Key Drivers of electrification from Table D on page 16: i) AC level 1 & 2 charging; ii) DC Level 1 chargers; iii) DC Level 2 chargers; and iv) heat pumps.

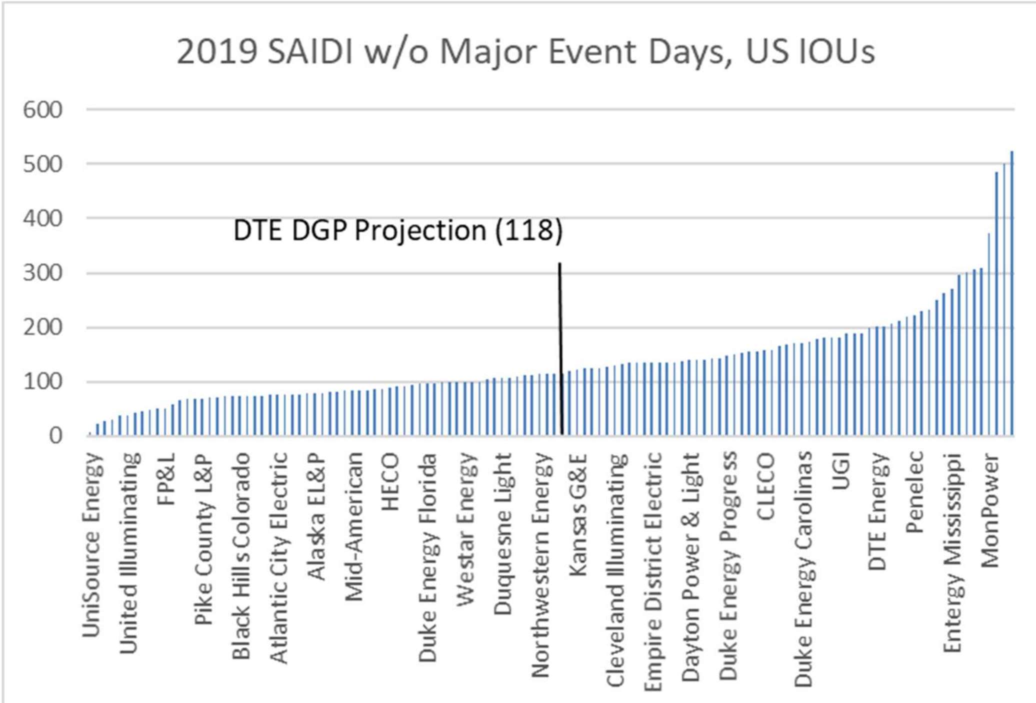
d. Given the Key Uncertainties described in 3.1.1 on page 16, and given customers' expressed lack of interest in purchasing electric vehicles as described on Plan page 11, explain why DTE did not insist that a range of electrification scenarios, along with probabilities for points along the range, be developed for consideration in development of the DGP.

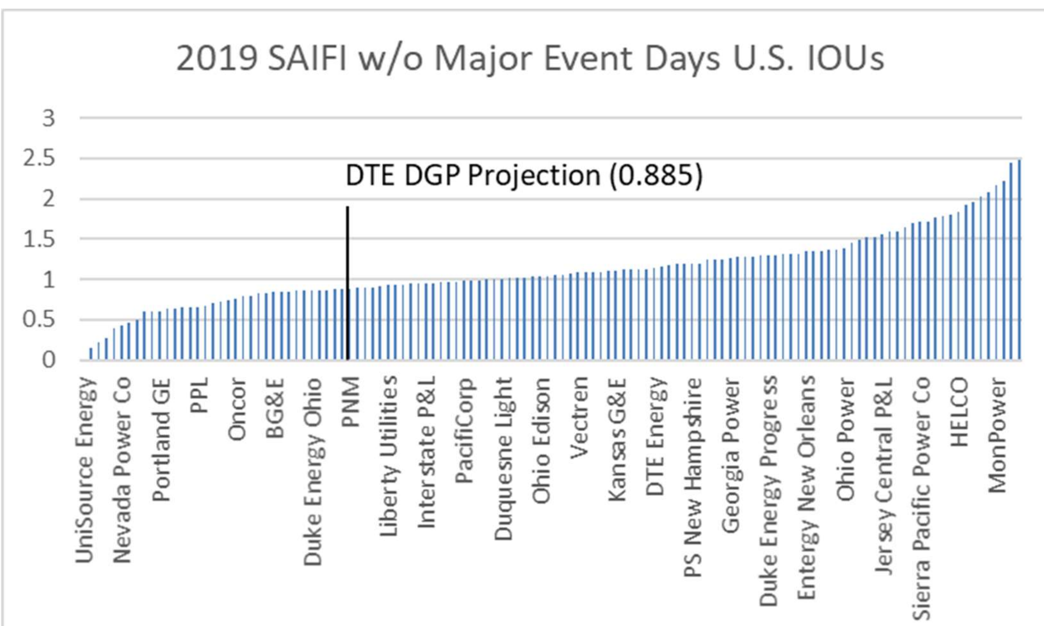
46. Refer to Table F on Appendix VIII page 22.

a. Table F indicates that over 12% of DTE's peak will be offset by distributed energy resources (DG/DS scenario) by 2035. Provide any analysis DTE or its consultant completed which compares DG/DS scenario 8760 generation profiles to the 8760 load profiles of the electrification scenario as a potential reduction in the overload estimates from electrification presented in Figure 5 on page 18.

b. Given the Key Uncertainties described in 3.3.1 on page 22, explain why DTE did not insist that a range of DG/DS scenarios, along with probabilities for points along the range, be developed for consideration in development of the DGP.

APPENDIX B


2019 SAIDI w/o Major Event Days, US IOUs
600
500
400
300
200
100
0
DTE DGP Projection (118)
UniSource Energy
United Illuminating
FP&L
Pike County L&P
Black Hills Colorado
Atlantic City Electric
Alaska EL&P
Mid-American
HECO
Duke Energy Florida
Westar Energy
Duquesne Light
Northwestern Energy
Kansas G&E
Cleveland Illuminating
Empire District Electric
Dayton Power & Light
Duke Energy Progress
CLECO
Duke Energy Carolinas
UGI
DTE Energy
Penelec
Entergy Mississippi
MonPower


2019 SAIFI w/o Major Event Days U.S. IOUs
3
2.5
2
1.5
1
0.5
0
DTE DGP Projection (0.885)
UniSource Energy
Nevada Power Co
Portland GE
PPL
Oncor
BG&E
Duke Energy Ohio
PNM
Liberty Utilities
Interstate P&L
PacifiCorp
Duquesne Light
Ohio Edison
Vectren
Kansas G&E
DTE Energy
PS New Hampshire
Georgia Power
Duke Energy Progress
Entergy New Orleans
Ohio Power
Jersey Central P&L
Sierra Pacific Power Co
HELCO
MonPower