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.	U-20147

COMMENTS BY MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB, AND CITIZENS UTILITY BOARD OF MICHIGAN ON DTE ELECTRIC COMPANY'S 2023 DISTRIBUTION GRID PLAN

March 15, 2024

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Comments by MNSC on
DTE Electric Company 2023 Distribution Grid Plan (DGP)

As invited by the Commission's October 24, 2023, Order in Case No. U-20147, the following comments are submitted by the Michigan Environmental Council, Natural Resources Defense Council, Sierra Club, and Citizens Utility Board of Michigan (collectively, MNSC) on the 2023 Distribution Grid Plan (DGP or 2023 DGP) filed by DTE Electric Company on September 29, 2023.

The 2023 DGP presents a plan to spend $9.9 billion from 2024 through 2028 on the distribution system. The plan provides no summary of actual annual distribution spending in prior years, but compared to 2022 (last available) actual annual distribution spending reported in DTE Electric's last rate case (U-21297), annual capital distribution spending would increase by $745 million from 2022 to 2028, from $1,439,523 to $2,185,000 annually.[1] The DGP provides no assessment of how this spending would impact rates nor customer bills for residential customers, who disproportionately fund distribution spending and already suffer high rates. What residential customers get for this investment is lots of new equipment without an assessment of alternatives, without data-informed cost-benefit analyses, and without any measure or accountability for achieving performance improvements. The 2023 DGP proposes to build a new house instead of fixing the roof. It eschews maintenance and embraces replacement. It focuses on hard infrastructure and conversions to the exclusion of inspections, repairs, distributed resources, non-wires load management options, and innovation.

MNSC supported the development of a distribution planning docket, but the 2023 DGP confirms this forum is not advancing the public interest. So long as distribution planning is structured as an informational proceeding, where the utility decides what information to present and withhold, the outcome is naturally self-serving. MNSC offers suggested regulatory responses; at a minimum, the Commission should express unequivocal non-approval of the 2023 DGP and demand improvements.

I. Distribution system plans were envisioned as an opportunity to improve utility spending and ratepayer outcomes but they are just the latest lopsided utility report in a long line of regulatory efforts to improve electric distribution systems.

The Commission has sought to understand and improve electric utility service quality, reliability, and safety issues for more than 30 years. In Case No. U-21122, which the Commission opened to investigate utility responses to severe storms in 2021, the Commission reviewed its previous work opening investigations and initiating other reliability and service quality improvement efforts, including this distribution planning docket (U-20147) and the following additional dockets:[2]

- U-9916 (1991 investigation)
- U-10908 (1995 review of Consumers and Detroit Edison Co storm response ability)

[1] Case No. U-20147, Ex A-12 Sch B5.4, p. 1.

[2] Case No. U-21122, Order dated August 25, 2021, pp. 3-5.

- U-12269 (2000 investigation into Detroit Edison Co compliance with reliability agreement)
- U-12270 (2000 investigation into reliability improvement methods)
- U-14603 (2005 Consumers and Detroit Edison Co investigation)
- U-15605 (2008 Consumers and Detroit Edison Co investigation)
- U-16462 (2010 Detroit Edison Co investigation)
- U-17542 (2014 Consumers and DTE investigation)
- U-18346 (2017 Consumers and DTE investigation)
- U-20169 (2018 DTE investigation)
- U-20464 (2019 Statewide Energy Assessment (SEA) docket)
- U-20629 (Service Quality and Reliability Standards workgroup)
- U-20630 (Technical Standards for Electric Service workgroup)
- U-20645 (MI Power Grid docket)

The Commission also reviewed past orders approving utility programs intended to improve reliability through vegetation management, including:[3]

- U-17767 (DTE electric rate case, Order dated December 11, 2015)
- U-17735 (Consumers electric rate case, Order dated November 19, 2015)
- U-20162 (DTE electric rate case, Order dated May 2, 2019)
- U-20697 (Consumers electric rate case, Order dated December 17, 2020)

Other dockets the Commission has opened to address reliability and service quality include:

- U-13975 (2003 vegetation management investigation)
- U-16065 (DTE reliability and power quality reporting docket)
- U-16066 (Consumers reliability and power quality reporting docket)
- U-21305 (initiating audit of Consumers and DTE distribution systems)
- U-21400 (MI Power Grid Financial Incentives and Disincentives workgroup)

Meanwhile, the Commission has repeatedly noted the disconnect between its efforts and outcomes:

- "Over the last three decades, the Commission has all-too-regularly launched investigations following major storm events, finding repeated patterns of cyclical negligence of necessary system maintenance, upgrades, and safeguards."[4]

- "Yet, despite investigations spanning over two decades, the average reliability scores for system average interruption frequency index (SAIFI) and system average interruption duration index (SAIDI) scores have not improved. Michigan's weighted SAIFI score including major event days (MEDs) increased by approximately 0.1 outages during the period of 2010-2020, actually worsening average system reliability over that period.

[3] *Id.* at pp. 5-6.

[4] Case No. U-20147, Sept. 8, 2022, Order, pp. 75-76 (citing cases).

Michigan's weighted SAIDI score including MEDs, has remained the same over this same period."[5]

- "[T]he Commission is concerned that not enough progress has been made in the last year to harden the 4.8 kV system or to increase measures that ensure the safety of the public and utility workers who encounter the electrical distribution system. The Commission finds that simply commencing another examination of the response of the utilities to increasingly predictable extreme weather conditions is no longer the reasonable and prudent course of action. . . . Additional measures are necessary."[6]

The disconnect persists. The objectives for this docket – safety, reliability and resiliency, cost effectiveness and affordability, and accessibility[7] – have not been achieved despite countless hours spent creating, reviewing, and commenting on distribution plans. With respect to safety – "the Commission's top priority"[8] – and reliability, the Commission noted in September 2022 that there had been "multiple fatalities within the month of August [2022] resulting from contact with downed wires as well as frequent and sustained outages stemming from storm events" and that these were "not new issues nor is progress in addressing them sufficient."[9] The Commission observed:

> [A] core focus of distribution planning is on reliability, and current approaches to distribution planning, the Commission finds, are insufficient to address issues impacting the reliability of utility service to customers—whether current issues or those forecasted for the future. **Put bluntly, Michigan's distribution reliability is inadequate, and current plans for improvements are insufficient**.[10]

Eighteen months later, reliability remains inadequate and current plans for improvements, including DTE's 2023 DGP, remain insufficient.

The Commission also found it "clear that Michigan utility distribution grids are not as well positioned as necessary for the growth of EVs and other DERs."[11] With respect to cost effectiveness and affordability, the Commission has stated from the inception of this docket that it expects "up-front analyses to ensure investment strategies are reasonable and prudent, alternatives are thoroughly considered, and longer-term operational savings from new investments can flow through to customers, thereby keeping rates affordable."[12] It envisioned "[a]

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[5] Case No. U-21305, Oct. 5, 2022, Order, p. 3.

[6] *Id.* at p. 4.

[7] Case Nos. U-17990 and U-18014, Oct. 11, 2017, Order, pp. 10-12 (footnote omitted).

[8] Case No. U-20147, Order dated September 8, 2022, p. 67.

[9] *Id.*

[10] *Id.* (emphasis added).

[11] *Id.*

[12] Case Nos. U-17990 and U-18014, Order dated October 11, 2017, p. 12.

data-driven, value-based approach, as when to repair versus when to replace aging equipment" and that "the ability to integrate new technologies in an optimal manner and provide planning tools and information to encourage efficient siting and operations of customer resources, such as DG [distributed generation] or energy storage, may also help displace or defer costly grid improvements, rather than exacerbate loading conditions and cause additional grid upgrades."[13] The current distribution planning process has not achieved the intended results in these areas.

While the Commission determined that the current distribution planning process remained the appropriate forum in which to consider utility distribution spending plans as of September 2022, it recognized that "several important changes . . . [were] necessary to deliver improved results."[14] This most recent round of planning – and this DGP in particular, with its unjustified $9.9 billion spending plan – demonstrates that even with the changes the Commission adopted 18 months ago – inclusion of hosting capacity analysis (HCA) maps, better forecasted metrics and benchmarking, reliability metrics with MEDs, and development of appropriate DER-related metrics[15] – the process has run its course and it is time for a new approach.

To ensure real transparency and obtain truly useful insight "into utilities' plans for the future . . . when making reasonableness and prudency determinations regarding cost recovery requests in general rate cases,"[16] distribution planning must take place in rate or other contested case proceedings. Only in contested case proceedings can utility assertions be vetted and validated or countered. This informational distribution planning docket lacks regulatory teeth, such as spending approval or disapproval.

The Commission is not powerless to improve Michigan's distribution planning process. As discussed in the final section below, the Commission may request that the Legislature provide systemic fixes. The Commission may also improve the informational docket by, for example, imposing longer planning horizons, requiring the utility to consider alternatives and provide data-informed cost-benefit analyses (including the data informing the cost-benefit analyses), and rejecting deferral of opportunities to proactively address climate and technology advances. At a minimum, the Commission must expressly not approve the 2023 DGP and direct DTE Electric to support with credible evidence in contested rate proceedings all plans and programs it decides to pursue.

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[13] *Id.*

[14] Case No. U-20147, Order dated September 8, 2022, p. 66.

[15] *Id.* at pp. 67-70.

[16] *Id.*

II. DTE Electric's latest Distribution Grid Plan (DGP) offers insights into its plans for increasing excessive capital spending without presenting credible strategies to achieve reliability benefits for ratepayers.

A. The DGP proposes significant spending increases.

The DGP proposes to increase total (capital plus operations and maintenance (O&M)) distribution spending over the 5-year period from $7.017 billion in the 2021 DGP (2021-2025) to over $9.278 billion in the 2023 DGP (2021-2025).[17]

Exhibit 11.0.1 Projected Distribution Grid Plan Investments

		$ Millions					
Category		2024	2025	2026	2027	2028	5-Year Total
Capital Investments ($ Millions)							
Base Capital	Emergent Replacements (Reactive Trouble and Storm Capital)	$415	$399	$368	$348	$345	$1,877
Base Capital	Customer Connections, Relocations and Others	$282	$295	$314	$334	$355	$1,580
Strategic Capital Programs (details in Exhibit 11.0.2)		$906	$995	$1,134	$1,302	$1,485	$5,821
Total Capital Investments		**$1,603**	**$1,689**	**$1,816**	**$1,985**	**$2,185**	**$9,278**
Maintenance Programs ($ Millions)							
Tree Trimming		$123	$140	$101	$103	$106	$573
Preventive Maintenance		$10	$10	$10	$10	$10	$50

As shown above, "Strategic Capital Programs" are the largest driver of capital spending for the distribution system from 2024 to 2028. Overall for the 5-year period, for capital distribution programs, the programs with the largest planned spending are the following:[18]

[17] Compare 2021 DGP, p. 110, Exhibit 6.1 to 2023 DGP p. 161.

[18] 2023 DGP, pp. 162-63.

Program	2024-2028 Projected Spending (in millions)
Grid Automation	$1,192
4.8 kV Conversion & Consolidation	$919
Pole & Pole Top Maintenance & Modernization	$773
City of Detroit Infrastructure	$579
Subtransmission Redesign & Rebuild	$524
System Loading	$381
Frequent Outage (CEMI) including Circuit Renewal	$128
Grid Management	$125
8.3 kV Conversion & Consolidation	$114
System Cable Replacement	$102

B. The DGP presents no forward- or backward-looking programmatic or spending context.

The 2023 DGP provides limited window into specific planned spending beyond 2028). The DGP asserts the need for the 4.8 kV Conversion program is likely to continue and increase beyond 2028, noting that complete conversion is estimated at $20-25 billion in 2023 dollars.[19] The DGP proposes to ramp up the 4.8 kV conversion program to $320 million annually and maintain the program at that annual spending level from 2029-2040.[20] Otherwise, the DGP is largely silent about post-2028 plans. The DGP provides no context for the reader to discern the full scope of the proposed projects.

The potential scope of program is not information unknown to the Company. For example, in its last rate case, MNSC uncovered evidence the Company projected spending $1.651 billion for the Pole & Pole Top Maintenance & Modernization (PTMM) program.[21] There is no information in the 2023 DGP about PTMM spending beyond the $773 million proposed for 2024-2028.[22]

There is value in presenting in distribution plan strategies extending over longer horizons:

> Because "[u]sing a planning horizon beyond five years can help ensure near-term investments will provide long-term ratepayer value and will be adaptive to emerging energy technologies that may alter the way energy is produced, delivered, and used in the future," the Commission "directs DTE Electric, Consumers, and I&M to continue to develop detailed distribution plans over a five-year period, but also include in the plan their vision and high-level investment strategies 10 and 15 years out. This approach is consistent with the planning horizons used in IRPs."[23]

[19] 2023 DGP, p. 119.

[20] 2023 DGP, p. 121.

[21] Case No. U-21297, Ex MEC-89, p. 2, Item 17; see also MNSC Initial Brief, p. 58.

[22] 2023 DGP, p. 70.

[23] Case No. U-20147, Sept. 11, 2019, Order, pp. 4-5.

The 2023 DGP includes no comprehensive discussion of the Company's strategies beyond 2028. It notes increasing electrification and Distributed Generation/Distributed Storage (DG/DS) through 2037[24] but does not discuss "high-level investment strategies" more than 5 years out, let alone 10-15 years or longer out.

Not only does the 2023 DGP fail to provide complete spending projections, but it also fails to provide necessary historic spending context. The 2023 DGP fails to identify past actual spending by category (*e.g.*, Strategic Capital Programs) or program areas (*e.g.*, PTMM). Although in its rate case filings, the Company provides a look-back of actual spending for preceding years, the DGP provides no historic context. This would be helpful information to include in a comprehensive distribution plan because it would provide perspective on the relative increase over time for programmatic spending. Historic spending combined with historic outage (before and after investment) data would provide useful and verifiable data to inform programmatic cost/benefit analyses. This is data the Company maintains already. It would be available in a rate case. Providing in the DGP information about how much ratepayers spent on pole or equipment replacement and how the equipment or line segment performed before and after the investment would help assess the reasonableness of increasing investments and the credibility of projected reliability benefits.

C. <u>The 2023 DGP provides no explanation of projected reliability benefits.</u>

The 2023 DGP provides a quick review of historic system reliability performance, which confirms DTE Electric has been consistently and comfortably within the 4th Quartile (worst) measured as system-wide all-weather performance (SAIDI All Weather).[25] Outage frequency (SAIFI) is less bad than outage duration (CAIDI) for DTE Electric in all-weather conditions.[26] In other words, DTE Electric customers suffer unreliability driven by outage *duration* more than *frequency*.

The DGP includes virtually no projection of reliability benefits associated with the proposed capital investments. Overall, the DGP projects 64% improvement in SAIDI All Weather by 2029 and 27% improvement in SAIFI All Weather but provides no projection of outage duration (CAIDI) improvements.[27] The DGP asserts without support or explanation that DTE's All-Weather SAIDI will achieve second-quartile level and SAIFI will achieve first-quartile performance by 2029.[28] It does not explain why the quartiles are static under all weather conditions, which is inconsistent with historic quartiles.

It is difficult to reconcile the improvement projections with DTE's recent performance:[29]

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[24] 2023 DGP, pp. 22-25, 33-34.

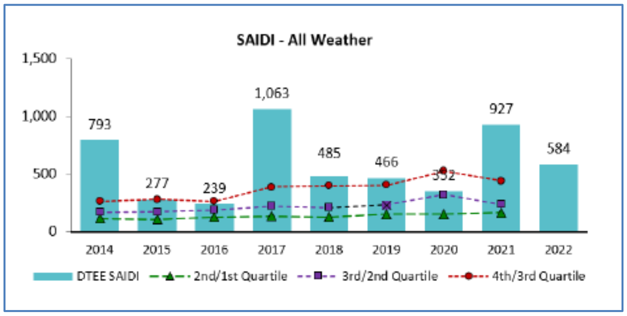
[25] 2023 DGP, p. 39; Appendix A.3, A.4.

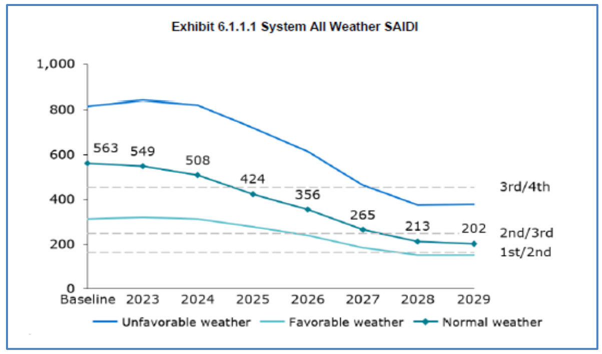
[26] 2023 DGP, pp. 39-40.

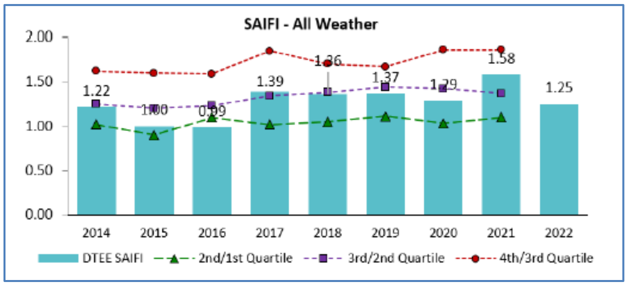
[27] 2023 DGP, pp. 56-57.

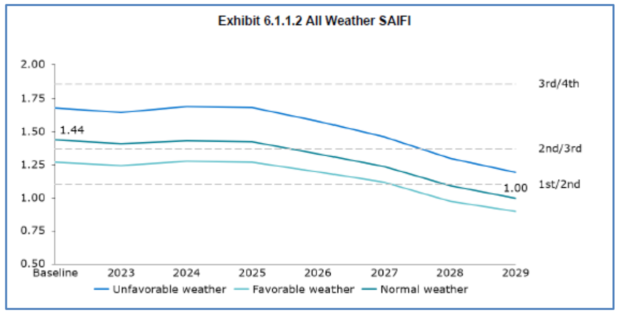
[28] 2023 DGP, p. 56.

[29] 2023 DGP, pp. 39 (historic), 57 (projected).









These graphs raise questions. First, there is insufficient explanation for the three depicted weather conditions (unfavorable, favorable, normal) – only a single uninformative footnote.[30] There is no information about weather conditions in historic years – was 2022 a normal, favorable, or unfavorable weather year? Second, there is no explanation for the starting point for the projections; the "Baseline" for each the SAIDI and SAIFI projections graphs (Exhibits 6.1.1.1 and 6.1.1.2) start at a different point than 2022 SAIDI and SAIFI. Third, there is no graph projecting outage duration (CAIDI), but DTE Electric must have that data as it is in input to develop SAIDI. Why doesn't the DGP include any outage duration projections? Are outages projected to remain uncomfortably long? Fourth, the SAIDI and SAIFI projects are inconsistent: SAIDI seems to get worse in 2023 then better after 2024 in "unfavorable weather" but SAIFI seems to improve in 2023 then get worst after 2024 during "unfavorable weather." In sum, the DGP makes no effort to explain its minimal performance projections.

The Company claims its reliability projections are based on a "new reliability model and methodology" that "uses a circuit-level reliability projection to model investment impacts and to generate system level projection."[31] The DGP references "more details on the methodology" for its reliability projections, together with non-MED metrics, in Appendix A Exhibit A-3.[32] But that reference provides no details about the projection methodology at all, only historic SAIFI/SAIFI/CAIDI Ex-MEDs.[33] The DGP provides no information about model inputs, how many

[30] 2023 DGP, p. 56, n. 29.

[31] 2023 DGP, pp. 27-58.

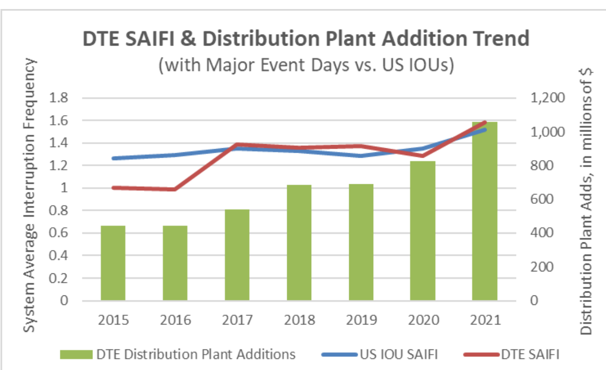
[32] 2023 DGP, p. 58.

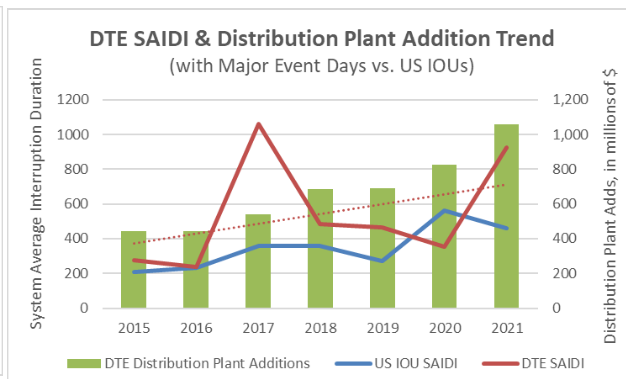
[33] 2023 DGP, p. 206.

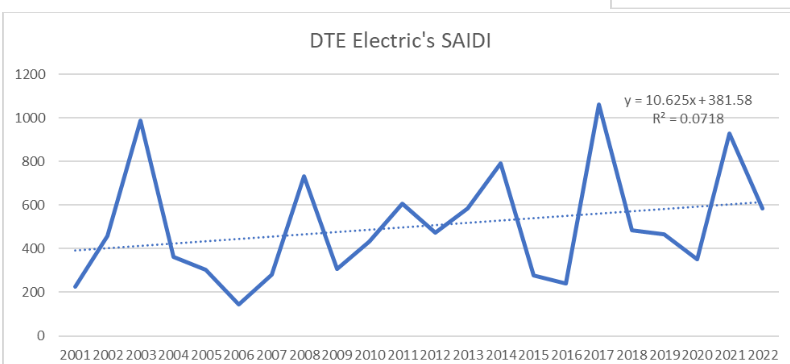
circuits are input, whether the model takes “before and after” metrics associated with particular projects, how inputs are entered, and more. For example, when a circuit is “hardened,” the project includes trimming first, then (potentially) arc wire removal, then equipment replacement. Each part produces different benefits. Does the model recognize those differences?

The DGP is particularly unhelpful for providing no discussion about the particular programs and investments driving projected reliability benefits. There is simply no way for readers to evaluate whether and what parts of the $9.9 billion investment plan are projected to produce reliability benefits, and at what cost. Would the projections look similar if only vegetation management were modeled? What is the reliability benefit of conversion, separate and apart from line trimming? What reliability benefits are pole replacements expected to produce? What are the reliability benefits of conversion and hardening? The DGP does not answer these fundamental questions, providing no way to assess investment programmatic or project benefits nor cost-effectiveness.

MNSC presented evidence in DTE Electric’s last rate case showing that, despite substantial recent *increases* in distribution capital spending – particularly “strategic” capital spending, distribution system performance has been consistently worsening:[34]







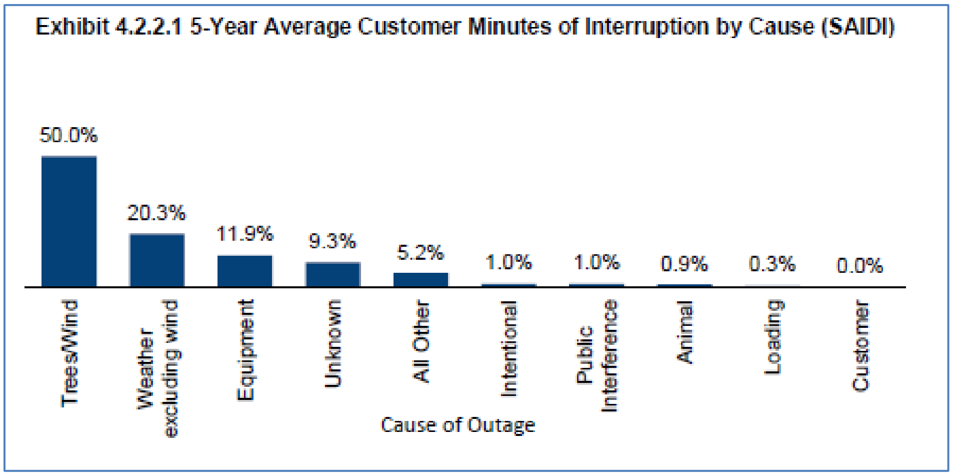
Spending more on capital replacements is demonstratively not improving performance. The 2023 DGP was an opportunity for DTE Electric to present a plan that showed strategic planning leading to cost-effective reliability improvements for residential ratepayers, but it failed to do so. In short, DTE provides no basis to assess whether its DGP investment plan is a credible and cost-effective

[34] Case No. U-21297, MNSC Initial Brief, pp. 18-21.

strategy to improve reliability. It makes no real effort to demonstrate how its investment plan would produce the projected all-weather SAIDI and SAIFI benefits, let alone other reliability metrics like repeated outages and long outages. Notwithstanding the assertions in the 2023 DGP, historic data indicates the Company is unlikely to achieve cost-effective reliability improvements through continued and increasing capital investments in hard infrastructure.

D. Increasing tree trimming is the most significant contributor to reliability benefits.

The DGP blames aging equipment and weather for its reliability challenges.[35] Reflecting this, the DGP spending plan describes equipment age and proposes substantial investments driven by equipment age. But the inescapable reality is that trees are the primary cause of outages:[36]



The DGP lumps tree and wind outages together, but information available in other documents confirms trees are substantially more likely to cause outages than wind:[37]

	Forced Interruptions by Cause				
	Percent of Customers Interrupted				
Conditions	Trees	Equipment	Ice	Wind	All Other
Catastrophic Storms	53.6%	3.7%	0.0%	36.0%	6.7%
Small Storms	43.8%	16.0%	0.1%	27.8%	12.3%
Non-Storm	34.1%	37.6%	0.1%	3.7%	24.5%
All Conditions	39.3%	27.7%	0.1%	13.8%	19.1%

[35] 2023 DGP, p. 6 ("increasingly severe weather and aging infrastructure present challenges to reliability"); p. 10 ("Aging infrastructure and worsening weather patterns have diminished the performance of DTEE's distribution grid, resulting in more frequent outages for our customers.")

[36] 2023 DGP, p. 13 ("Historically, two-thirds of the time customers spend without power is due to falling trees and limbs."); p. 40 (graph).

[37] Case No. U-16065, April 3, 2023, Report, p. 6.

DTE Electric understands that vegetation management is critical to improving reliability. Even so, the 2023 DGP provides no details about outage causes associated particular equipment or programs. To improve reliability cost-effectively, DTE should be addressing the root cause of its outages, which is principally tree encroachments.

Moreover, because DTE has increased its tree trimming program through the ETTP starting in 2016, which aims to reclaim right of ways, address hazard vegetation, and improve trim specifications, it would be prudent to fully evaluate and even improve the program before investing billions of dollars on hard infrastructure justified by promises of improved reliability improvements.

E. The DGP focuses excessively on replacing old and non-standard equipment.

After identifying aging infrastructure and worsening weather as the causes of DTE Electric's poor grid performance, it is unsurprising that the 2023 DGP focuses excessively on equipment replacement and rebuilding as the focus of investments.[38] The DGP discusses at length the age of particular equipment and asserts much of it is "at, or near, the end of useful life."[39] The DGP provides no definition of "end of useful life" – that may be an accounting term (end of depreciation cycle) or equipment rating or something else. What the DGP does not provide is data or detail to suggest that old equipment fails more often than less old equipment – *e.g.*, 60-year-old poles fail more than 40-year-old poles. DTE Electric (alone) maintains such data but fails to provide or summarize it in the DGP, perhaps suggesting the data does not support its narrative.

And even if old equipment is more prone to failure (though there is no evidence of that in the DGP), that begs multiple additional questions. Is failure foreseeable with robust inspections, including technology-driven inspections (like line fault detection software and drone inspections)? When is preemptive replacement (based on age rather than evidence of imminent failure) cost effective for ratepayers? Is technology and other investments (planned, implemented, or available) to mitigate or avoid outages from old equipment, like reclosures and fault detection?

Replacing equipment because it is old or non-standard is insufficient justification for substantial capital improvements. The Company has data showing inspection results, replacement and repair costs, outage frequency and duration, outage causation, and more, that would support an assessment whether to maintain or replace vintage or non-standard equipment. Non-standard lines and equipment might be more costly to repair than standard lines (that is not shown in the DGP), but that also begs follow-up questions: how much more costly, do they fail more, are weaknesses detectable with inspections or technology and at what cost, and so on. An older Lincoln Town Car might cost more to maintain than a new Cadillac CTS but that is not enough to assess whether it should be replaced.

[38] *See, e.g.,* 2023 DGP, pp. 10-11.

[39] *Id.* at p. 10.

It is insufficient to justify large capital investments on the basis they replace old or non-standard equipment absent inspection data, system condition data, outage data, and cost-benefit analyses informed by equipment- and component-specific data, and other supporting information.

F. The Grid Prioritization Model (GPM) remains a mysterious self-serving tool to justify massive capital investment without demonstrating cost-effectiveness.

DTE relies on its Global Prioritization Model (GPM) to support prioritization among projects and investments, particularly strategic distribution capital expenditures.[40] MNSC conceptually supports modelling to help evaluate and score projects competing for limited resources. Such modeling should be designed to identify and demonstrate that particular investments provide the opportunity to deliver measurable benefits for ratepayers commensurate with dollars invested – particularly for non-emergent rebuilds, replacements, and upgrades. Effective distribution planning should incorporate the results from a transparent and credible model using project-specific reliability, conditions, cost, and other data.

Unfortunately, the GPM is not such a model. MNSC explored the GPM model at length through the discovery process in DTE Electric's last rate case and learned the model is opaque – inputs are secret and outputs appear arbitrary.[41] Here are some highlights of GPM flaws:

- GPM scoring appears highly subjective and varies widely among projects and programs. As explained in the rate case, GPM inputs are developed by unidentified non-witness "subject matter experts." DTE refused to produce the analyses that generate project (or programmatic) scores.
- GPM scoring is based on inexplicable secret weighting. Project scores varied wildly without explanation – scores for the same project changed year over year, and the scale of project scores ranged orders of magnitude within the same iteration. For example, 4.8kV Hardening scored 2,271 in "O&M Cost Avoidance" in the rate case iteration of the GPM but the same program on the same factor scored 569 in the previous 2021 DGP iteration of the GPM.[42] Another example is that the Company explained the highest possible score for each dimension is 100 but several projects received scores in the thousands in some dimensions.
- The GPM ranks projects against each other but does not attempt to identify cost-effective projects. The GPM produces the subjective benefits scores and divides those by project costs to rank projects relative to each other. The GPM does not select projects worth pursuing (from a ratepayer cost-benefit or other basis), it ranks projects. But the ranking appears irrelevant – DTE treats all ranked projects as worth pursuing, whatever their score on the Top 50 list. DTE has never produced any list of "excluded" projects – it produces the Top 50 list each time it runs the GPM, then pursues all the projects on the list.

[40] 2023 DGP, pp. 165-66.

[41] Case No. U-21297, MNSC Initial Brief, pp. 23-31.

[42] Case No. U-21297, MNSC Initial Brief, p. 46 (comparing Ex MEC-89 row 3 and Ex MEC-90 row 6).

Comparing projects to each other provides no useful information about whether any particular project should be undertaken.

- Relatedly, comparing programs to projects (and to other programs) provides no useful information about how much of a program should be undertaken in a given time period. The GPM also doesn't determine how much spending to dedicate to projects. For example, the Pole Top program could be cost-effective for certain high-ranking circuits, or the program may be limited by a spending cap after reaching a point of diminishing benefits, but the GPM instead treated it as a monolithic $1.651 billion capital investment project.[43]

Since the last rate case, the DGP asserts the GPM was "enhanced" – it now includes additional "impact dimensions" and a "simplified" scoring process.[44] These changes are irrelevant to the 2023 DGP because the DGP does not provide *any* scores for any of the "Top 50 Strategic Capital Programs" identified in the DGP:[45]

Appendix F Top 50 Strategic Capital Programs and Projects Based on GPM

Rank	Capital Program/Project
1	Pole and Pole Top Hardware (PTMM)
2	4.8 kV Circuit Automation
3	Automation: 13.2kV Circuit Distribution
4	CODI: Charlotte Network Upgrade
5	4.8 kV CC: ISO Conversion Program
6	Substation Risk: Apache
7	4.8 kV Hardening
8	4.8 kV CC: Buckler Circuit Conversion
9	4.8kV CC: Barber Substation and Circuit Conversion
10	CODI: Garfield Network Upgrade
11	Subtransmission Redesign & Rebuild: Bernard
12	Subtransmission Redesign & Rebuild: Trunk 4217
13	Subtransmission Redesign & Rebuild: Tie 6907
14	Subtransmission Redesign & Rebuild: TIE6147
15	Subtransmission Redesign & Rebuild: Boyne
16	Substation Risk: Chestnut
17	4.8 kV CC: Hawthorne Relief and Circuit Conversion

[43] Case No. U-21297, MNSC Initial Brief, p. 58 (citing Ex MEC-89 p 2 Item 17).

[44] 2023 DGP, p. 166.

[45] 2023 DGP, p. 258, Appendix F (excerpt).

The GPM provides a list of 50 possible purchases and ranks them from #1 through #50, which only says what order DTE wants to buy them in but it says nothing about whether to buy the first one, or the first three, or the first five, etc. Nor does it say how many of the purchases ratepayers can afford. Nor does it say which purchases will have more value than cost. Nor does it say whether to buy all of them over two years, or five years, or ten years.

There is likely some risk-informed cost-benefit analytical model that could be used to assist the utility, regulator, and stakeholders in identifying reasonable and prudent strategic distribution system investment. It would need to be objective and transparent, meaning inputs and outputs are accurate, specific, shared, and understandable. The GPM is not that model.

G. The DGP lacks rate impact analysis and accountability mechanisms to ensure ratepayers receive the acclaimed reliability benefits of the spending plans.

The DGP includes no discussion about rate impacts associated with its anticipated increase in distribution spending between 2024 and 2028. The disproportionate allocation of distribution costs to residential ratepayers means this spending would particularly impact residential bills. The DGP presents an anemic discussion of ratepayer reliability benefits and presents no data to support its conclusory SAIDI reduction projections. It ignores less costly alternatives to achieve similar or more reliability benefits, including vegetation management improvements and innovations, technological advances to detect and prevent outages, and robust inspections with targeted improvements. It makes little attempt to plan for an integrated approach to address reliability together with forecasted load growth and distributed resources. It is a plan to spend on the distribution system, not a plan to cost-effectively address historic and foreseeable distribution system challenges.

The 2023 DGP also provides insufficient information to ensure accountability for the minimal proffered performance benefits. The Commission recognizes that traditional ratemaking incentivizes utilities to build infrastructure without encouraging innovation and operating efficiency.[46] Performance-based ratemaking (PBR) offers the potential to adapt regulatory ratemaking to changing conditions, meet policy goals, extend time between rate cases, and remove disincentives for non-capital solutions. The Commission has been grappling with how to advance PBR for years, most recently in the workgroup docket in Case No. U-21400.

At risk of simplifying an inherently complex issue, PBR offers the opportunity for regulators to tie rates that customers pay to utility performance, including reliability performance. A necessary ingredient is transparent, accurate data across uniform metrics. The Commission initially focused

[46] See Michigan PSC, Report on the Study of Performance-Based Reglation, April 20, 2018, available at https://www.michigan.gov/mpsc/commission/workgroups/2016-energy-legislation/performance-based-regulation-report.

on SAIDI, SAIFI, CAIDI with and excluding MEDs, CEMI, downed wire response, and other metrics in U-21400.[47]

The 2023 DGP lacks even basic information to assess historic distribution performance across these metrics, let alone reasonable reliability projections that may serve as a foundation to inform or develop performance targets. The DGP describes what PBR is and recites from several Commission orders regarding PBR, but the DGP concludes by noting its participation in the "Financial Incentives and Disincentives" workgroup.[48] The 2023 DGP is one more lost opportunity to propose meaningful accountability for distribution system investments. Even if DTE implemented the $9.9 billion spending plan as presented in the 2023 DGP, the plan provides ratepayers with no assurance that reliability will measurably improve and no consequence if it does not measurably improve.

H. DGP spending and programs must still be evaluated in the rate case.

DTE will be required to demonstrate the reasonableness and prudence of all proposed distribution investments in a rate case proceeding, which allows intervenors to test, validate, and undermine their asserted reasonableness and prudence. At this point, the only docket permitting intervenors to evaluate spending proposals contained in the 2023 DGP is a subsequent rate case proceeding.

Rate cases may be too short and are already very complex, but they are formal contested proceedings and result in spending approvals and disapprovals. Rate cases appear no more streamlined because of having the utilities file distribution plans in this informational planning and comment docket. To support planned test-year investments, DTE has historically offered the same and more information in rate case testimony and exhibits than is in the distribution plan. DTE relies on filed DGPs to support spending strategies.[49] To the extent the Company relies on untested and non-approved discussions, models, and proposals outlined in the DGP, the DGP adds more complexity to the rate case, not less.

That is not to say distribution planning dockets are inherently useless; they are not. There may be components of distribution system investment planning that would benefit from stand-alone planning considerations, and there may be examples of distribution planning docket procedures that have the effect of reducing the complexity of rate cases. The DGP should provide the supporting details, alternatives assessments, and cost-benefit analysis to support planned investments so they can be reviewed in a less time-constrained manner than the rate case. But that is not the recent experience with DTE Electric's DGPs.

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[47] See Case No. U-21400, April 24, 2023, Order, p. 12. SAIDI means "system average interruption duration index"; SAIFI means "system average interruption frequency index"; CAIDI means "customer average interruption duration index"; CEMI means "customers experiencing multiple interruptions"; MED means "major event days."

[48] 2023 DPG, pp. 176-78.

[49] *See, e.g.,* Case No. U-21297, Ex A-23 Sch M7.

The point is that the present planning docket – and DTE's latest DGP – is not achieving what the Commission has set out to achieve in this docket, nor is it benefiting the rate case proceedings that precede spending approval or disapproval. The Commission should consider alternative procedures that may result in better distribution system planning outcomes for ratepayers and the Commission.

III. The DGP presents a series of expensive programs unsupported by historic cost and reliability data and without accountability metrics nor integration of foreseeable challenges.

This section identifies some of the many flaws in specific distribution investment programs and plans outlined in the 2023 DGP. It does not attempt to identify all the flaws in the programs discussed below, nor does it attempt to identify all flawed programs. It also does not try to identify programs and opportunities that are entirely absent from the DGP but belong there. The program discussions below illustrate the data gaps and dubious assertions that would benefit from the attributes of a contested case – *i.e.*, discovery, testimony under oath, cross examination, legal briefing, fact-finder consideration of the evidence and arguments, assessment of ratepayer impacts, and ultimately approval or disapproval by the regulator.

A. Tree Trimming (DGP pp 58-64)

The 2023 DGP proposes to reduce spending on tree trimming between 2024 and 2028:[50]

Maintenance Programs ($ Millions)						
Tree Trimming	$123	$140	$101	$103	$106	$573
Preventive Maintenance	$10	$10	$10	$10	$10	$50

The DGP addresses the success of the Company's tree trimming surge (ETTP) to improve system reliability. The ETTP began in 2016 and continues through 2025, when DTE aims to achieve a 5-year trim cycle.[51]

Line clearing is likely the most cost-effective opportunity to improve distribution reliability and avoid unnecessary outages and restoration costs in terms of dollars spent and outages avoided – more so than most capital investments. In the last rate case, DTE projected its trim surge and other line maintenance investments would drive $60.7 million in O&M and capital savings in 2026,[52] which likely underestimates the full extent of savings and avoided costs.[53] The Commission has been asking DTE in the last several rate cases to better analyze the opportunity

[50] 2023 DGP, p. 161.

[51] 2023 DGP, pp. 58, 256.

[52] Case No. U-21297, Exhibit A-22 Sch L-1.

[53] Case No. U-21297, MNSC Initial Brief, pp. 106-109; PFD, pp. 509-510.

for productivity gains (cost reductions) resulting from the ETTP, which DTE has so-far eschewed.[54] Like its rate case filings, an analysis of productivity benefits is also absent from the DGP, which would have been an ideal docket to present such an analysis.

The DGP acknowledges opportunity to improve line clearing with technology, optimizing trim cycles for particular circuits, and incorporating Light Detection and Ranging (LiDAR) data.[55] Yet the DGP inexplicably punts any effort to incorporate such opportunities: "After the surge is complete, DTEE will be able to implement is risk-based model…."[56] In the last rate case, the Commission adopted Staff's recommendation that DTE Electric analyze more aggressive trimming in particular zones, but the DGP incorporates no such analysis.[57] The DGP fails to address in any meaningful way these opportunities to improve and tailor its tree trimming approach to provide additional outage reductions. Further consideration of line-specific outage-inducing optimization will undoubtedly support shorter trim cycles for at least segments of some lines, with additional reliability benefits and productivity gains. Such opportunities are likely to prove more cost-effective to reduce outages, relative to costly capital investments with low or no projected reliability benefits.

The Company has long-acknowledged significant reliability problems associated with trees along overhead service lines, which are predominantly in older neighborhoods because post-1970s construction requires burying lines.[58] The 2021 DGP presented a plan to underground service lines, but that approach to improve reliability along service lines is excessively costly and disfavored.[59] Instead, MNSC and Staff proposed the Company analyze and develop cost-effective approaches to address the significant problem of reliability associated with trees along residential service lines, which the Company agreed to pursue in U-21297.[60] Nevertheless, the 2023 DGP does not even acknowledge, let alone propose solutions, to address vegetation management along service lines. Instead, it vaguely asserts a commitment "to continuing to mature its capability in Undergrounding the over infrastructure and lower the cost" to relocate "significant portions" of the system underground.[61] This is another example of leap-frogging over cost-effective opportunities and instead landing on the most costly solutions (*i.e.*, capital replacements). The absence of targeted trimming along service drops in the DGP renders its proposed Tree Trimming program insufficient.

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[54] Case No. U-21297, Order, pp. 198-202.

[55] 2023 DGP, p. 62.

[56] 2023 DGP, p. 62.

[57] Case No. U-21297, Order, p. 353.

[58] 2023 DGP, p. 123.

[59] Case No. U-21297, MNSC Initial Brief, pp. 151-156 (outlining history).

[60] Case No. U-21297, MNSC Initial Brief, pp. 151-59; PFD, pp. 849-52; Order, pp. 352-53.

[61] 2023 DGP, p. 123.

At bottom, the 2023 DGP fails to present a robust analysis of practical and technological opportunities to further improve forestry management and provide additional reliability benefits to ratepayers at reasonable costs together with measurable savings in restoration and other outage-related costs.

B. Pole and Pole-Top Maintenance and Modernization Program (PTMM) (DGP pp 66-69)

The 2023 DGP proposes massive investment in the Pole and Pole-Top Maintenance and "Modernization" Program (PTMM):[62]

Exhibit 11.0.2 Projected Distribution Grid Plan Investments (Sorted by Reference Section Number)

Programs	$ Millions						Reference Section #
	2024	2025	2026	2027	2028	5-Year Total	
Infrastructure Resilience & Hardening							
Pole and Pole Top Maintenance and Modernization	$121	$121	$151	$192	$188	$773	8.1

As noted above, this is the third costliest investment in the 2023 DGP. The DGP support for this massive investment is woefully inadequate, particularly given the significant criticism of the massive proposed PTMM ramp-up in the last several rate cases.

This program was formerly called the Pole and Pole Top Maintenance program, but the Company updated its underlying pole specifications and added "Modernization" to the title in 2019. This is essentially a program to trim if needed, inspect, and maintain poles and pole top equipment. When the Company identifies degraded poles, it reinforces or replaces them; when it identifies broken or obsolete equipment, it is replaced. In 2019, the Company changed its specifications to require stronger poles, to test poles earlier, and to replace damaged equipment with modern equipment. The program also looks for old and non-standard equipment and replaces it with "modern" equipment. It appears PTMM inspections look for non-standard equipment as opposed to failing or impaired equipment. DTE proposed but the Commission rejected significant PTMM spending increases in U-20836 (capping PTMM spending at $33.444 million) and U-21297 (capping PTMM spending at $63.45 million).[63] Actual spending in 2021 and 2022 was $31.647 million and $70.224 million respectively.[64]

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62 2023 DGP, p. 161.

63 Case No. U-20836, Nov. 18, 2022, Order, pp. 96, 100; Case No. U-21297, Dec. 1, 2023, Order, pp. 94-96.

64 Case No. 21297, Ex A-12 Sch B5.4 p. 8 line 13.

MNSC opposed the planned PTMM spending increases because DTE Electric did not justify them. The proffered Company rationales – enhanced specifications, shortening inspection cycles, more rigorous physical inspections, persistent backlogs – have repeatedly failed under scrutiny.[65] For example, the "new" specifications have been in place since 2019; the number of poles and pole-tops remediated was consistent with prior, less-costly years. The apparent explanation for the increased PTMM is not related to inspections but instead the result of the Company's shift away from inspection and reinforcement instead to replacement (*i.e.*, replacing more and remediating fewer poles). Pole reinforcement is a cost-effective option to lengthen pole-life, and the shift away from reinforcement to replacement is likely cost *in*effective.

The DGP offers no new insights – it reiterates the narrative from DTE's rate cases, which has been repeatedly debunked and rejected. The DGP does not even pretend this program will produce reliability benefits for ratepayers. It makes no effort to correlate the vintage equipment it replaces (*e.g.*, cross arms, cutouts) with vulnerability in storms or other reliability issues. The Company has years-worth of data documenting before-and-after outages, work, and costs along lines that have been upgraded under the PTMM program – outage frequency, duration, and cause; last trim date; costs for replacement, service restoration, inspection, and line preparation (trim), and much more detailed line-specific data.

The DGP should justify both the overall PTMM investment and justify line prioritization. The DGP should also provide detailed line-specific data – historic performance and costs and projected costs and benefits – for each line segment proposed for investment in the 5-year period. The DGP should identify how it is achieving efficiencies with load growth and electrification-driven projects. And the DGP should provide an accountability mechanism – a look-back on past line-specific investments to assess what they actually cost, what they actually did, and what the investment actually achieved. The DGP does none of these things.

C. 4.8kV Hardening (DGP pp 70-26)

The 2023 DGP proposes to phase out the 4.8kV Hardening program investment:[66]

2021 Actual	2022 Actual	2023 Projected	2024 Planned	2025 Planned	2026 Planned	2027 Planned	2028 Planned
$65 million	$151 million	$80.million	$80 million	$95 million	$54 million	-	-

It seems the Company is shifting direction from hardening to conversion, discussed further below.

The DGP justifies the program on the basis of arc wire removal and reliability benefits. As MNSC has repeatedly pointed out in rate cases seeking spending approval for hardening, arc wire removal is post-hoc rationalization for Hardening, and Hardening is not a cost-effective way to

[65] Case No. U-20836, Nov. 18, 2022, Order, pp. 96, 100; Case No. U-21297, Dec. 1, 2023, Order, pp. 94-96.Case No. U-21297, MNSC Initial Brief, pp. 54-57; PFD, pp. 524-52.

[66] 2023 DGP, p. 162; Case No. U-21297, Ex A-12, Sch B5.4, p. 8 line 12.

remove DPLD arc wire.[67] If arc wire removal is critical, it may be achieved at a lower cost than Hardening:[68]

Exhibit 8.2.2.1 4.8KV Hardening Alternatives

Program	Avg. Cost per Mile	Wire Down Reduction	SAIFI Reduction	SAIDI Reduction
Arc Wire Only	$191k	-13%	-22%	-36%
4.8kV Hardening	$353k	-26%	-44%	-72%
Pre-Conversion	$1.7M	-90%	-85%	-85%
Conversion	$2.7M	-90%	-85%	-85%
Microgrids	$14.6M	-90%	-95%	-95%

As for claimed reliability benefits from Hardening, the Company has replicated the graphs shown in the DPG (Exhibits 8.2.1.3 to 8.2.1.5) over and over, in U-20836, U-21297, and the technical conference, but these before-and-after images fail to identify what benefits are associated with the cost-effective trimming aspect of Hardening versus resulting from costly equipment replacements. The Company has repeatedly failed to provide that information, including in the DGP. As such, the benefits of Hardening remain unproven.

As it did in the rate cases, the 2023 DGP fails also to consider Hardening cost-effectiveness. The DGP identifies how many miles have been Hardened but not how much ratepayers have invested in this program. There is no assessment of outage causes along the Hardened lines. There are no details on trim history along Hardened lines, nor how much trimming alone would have cost and achieved.

The DGP is an opportunity to assess programs in detail – looking backwards and projecting forwards the problems, costs, and benefits of the capital investment – but it fails to do so.

D. System Equipment Replacement (DGP pp 77-81)

The 2023 DGP proposes to invest $365 million in asset replacement over the next five years.[69] Because the DGP separates this program into 10 discrete subprograms in the Investment Plan,

[67] Case No. U-20836, Sept. 19, 2022, PFD, pp. 190-93; Case No. U-21297, Oct. 5, 2023, PFD, pp. 235-42.

[68] 2023 DGP, p. 75.

[69] 2023 DGP, p. 77. However,

they evade the “top 10” list of costliest programs noted above. Here is the spending plan for the 10 System Equipment Replacement subprograms:[70]

Exhibit 11.0.2 Projected Distribution Grid Plan Investments (Sorted by Reference Section Number)

Programs	$ Millions						Reference Section #
	2024	2025	2026	2027	2028	5-Year Total	
Infrastructure Resilience & Hardening							
SCADA Pole Top Device	$2	$2	$2	$3	$5	$14	8.3.1
Steel Pole Highway Crossings	$3	$5	$5	$5	$5	$25	8.3.1
System Cable Replacement	$21	$20	$20	$20	$20	$102	8.3.2
Underground Residential Distribution (URD) Cable	$15	$15	$15	$15	$15	$75	8.3.2
Subtransmission Disconnect Switches	$3	$3	$3	$3	$3	$15	8.3.3
Circuit Switchers	$2	$2	$2	$2	$2	$10	8.3.3
Circuit Breakers	$14	$15	$15	$15	$15	$74	8.3.3
Substation Regulators	$1	$1	$1	$1	$1	$4	8.3.3
Batteries & Chargers	$3	$3	$3	$3	$3	$15	8.3.3

The DGP includes almost no detail on these programs. There is no detail on historic spending, cost-effectiveness, or achievements. There is no detail on prioritization, projected benefits, or the ultimate scope of the program (how many more years beyond 2028 does the Company propose to keep replacing old equipment). This is a program that stands on what it does: replacing old equipment with new equipment.

[70] 2023 DGP, p. 162.

The 2023 DGP cross-references Section 8 of the 202**1** DGP, Asset Health Assessment.[71] The 202**1** DGP confirms what one might suspect: these are programs driven entirely by asset *age* not asset *health*. Here is what the 202**1** DGP says under Asset Health Assessment:[72]

Exhibit 8.1 Asset Age Summary

Section	Asset	DTE Electric Average Age (Years)	DTE Electric Age Range (Years)	Life Expectancy (Years)
8.1	Substation Power Transformers	43	0 – 96	40 – 45
8.2	Network Banks	64 (structures) 46 (transformers)	0 – 85+	20 - 30 (transformers)
8.3	Circuit Breakers	42	0 – 85	30 – 40
8.4	Subtransmission Disconnect Switches	Not Available	0 - 85	Not available
8.5	Circuit Switchers	18	0 – 35	Not available
8.6	Relays	32	0 – 60+	15 – 50
8.7	Switchgear	37	0 – 67	40
8.8	Poles and Pole Top Hardware	46	0 – 90+	40 – 50
8.9	Small Wire (i.e., #4, #6, and #8)	70+	Not Available	Varies based on field conditions
8.10	Fuse Cutouts	19	0 – 50+	40
8.11	Three-phase Reclosers	9	0 – 31	20
8.12	SCADA (Supervisory Control and Data Acquisition) Pole Top Switches	14	0 – 38	20
8.13	40 kV Automatic Pole Top Switches	36	0 – 50+	40
8.14	Overhead Capacitors	Not Available	Oldest: 25+	20
8.15	Overhead Regulators	Not Available	Oldest: 25+	20
8.16	System Cable	45	0 – 100+	20 – 40
8.17	Underground Residential Distribution (URD) Cable	25	0 – 60+	40
8.18	Manholes	78	0 – 100+	Varies based on construction and field conditions
8.19	Vaults	Not Available	Not Available	Varies based on construction and field conditions
8.20	Advanced Metering Infrastructure (AMI meters)	6.5	0 – 10	20

[71] 2023 DGP, p. 77.

[72] 2021 DGP, p. 160 of 568, Exhibit 8.1.

The 2021 DGP asserts that equipment is old, and equipment fails, but it fails to show that older equipment fails more or that outages last longer or otherwise. There is no documented assessment of *health* in the "Asset Health Assessment."

MNSC opposed the Company's replacement approach for old equipment in U-21297.[73] Equipment replacement should be driven by some indication that replacement is necessary because failure is imminent, and replacement should be supported by risk-informed benefit cost analyses to determine whether incremental benefits are worth incremental costs. While testing underground cable is not economically feasible, many utilities take a "three strikes" policy as an indicator of need for replacement. The Company's approach is premature replacement of equipment that is operating safely and reliably. In U-21297, MNSC witness Stephens considered Company data for circuits replaced in 2020, together with interruption (customers and customer minutes) 2 years before and 2 years after replacements. The data showed both customers and customer minutes increased in the years after underground cable replacements on those circuits. This analysis, while imperfect given DTE's data that lacks usability and explanations, nonetheless suggests the programs are not cost effective.

The DGP should provide detailed programmatic benefit cost analysis to support the program overall. It should also include detailed cost-benefit analysis to support the projects proposed for inclusion in the 5-year window, to ensure the program is projected to deliver benefits exceeding costs – and to enable look-back accountability for projected benefits. The Company has been undertaking aged-based replacements for some years, it (alone) has circuit-specific data showing actual costs and benefits. The Company has been replacing old cable for years, and the Company maintains all kinds of outage data – causation, duration, customer, and more. Yet the DGP includes no data showing cable failures based on cable type, length or number of outages associated with cable outages before nor after replacements. The DGP may have identified demonstrable or measurable safety benefits to employees or customers from breaker and other equipment replacements. It may have identified historic outages caused by breaker failures or improved reliability resulting from replaced breakers. It may identify actual historic reactive expenditures due to equipment failures, potentially supporting avoided costs resulting from the program. It may have identified the number of replaced breakers that enabled SCADA benefits or demonstrated fault location and event analysis enabled by breaker replacement. It provided none.

The 2023 DGP was an opportunity to justify this age-based asset replacement program but it failed to do so.

E. Short Cycle Maintenance Programs for Poor Reliability Circuits (DGP pp 84-86)

The 2023 DGP discusses two distribution system capital investment programs targeting poor performing circuits – the Customer Excellence (CE) Program and the Frequent Outage Program

[73] U-21297, MNSC Initial Brief, pp. 65-73.

(CEMI).[74] The DGP identifies no spending associated with the CE Program. Here is historic and projected spending under the CEMI program:[75]

2021 Actual	2022 Actual	2023 Projected	2024 Planned	2025 Planned	2026 Planned	2027 Planned	2028 Planned
$15 million	$27 million	$25 million	$48 million	$20 million	$20 million	$20 million	$20 million

The DGP provides minimal detail about these programs, but they appear to be primarily AMI data-driven programs identifying frequent outages that respond with targeted tree trimming. The Company provides no assessment of the cost-effectiveness of its CEMI investment. The program appears less effective than the ETTP in terms of frequent interruption improvements. The DGP indicates the number of outage events improve 27.3 % one year following ETTP-trimming, while SAIFI for CE & CEMI-treated lines improve 21.7% one year following pre-storm treatment.[76]

As with so many other capital investments, the DGP fails to provide data-informed cost-benefit analysis to support substantial spending. After years of implementing this program, the Company (alone) has line-specific data showing before-and-after outages, restoration costs, investments (including component costs of the investments – trimming versus equipment replacements), together with other data demonstrating program and line-specific cost effectiveness. Given its experience with the program, the Company might have supported the CEMI investment with projections of reliability benefits. It provides neither the look-back nor the look-ahead.

The DGP fails to justify the CE and CEMI programs. Spending may be better redirected to zonal improvements to the tree trimming program, discussed above.

F. Distribution Load Relief Projects (DGP pp 87-96)

The DGP discusses its plans to invest $381 million for load relief. It mentions the opportunity for non-wires alternatives (NWA) to address foreseeable load challenges.[77] It notes the 2021 DGP included NWA projects but the 2023 DGP provides no update nor any projection of NWA investments in the 2024-2028 period. The 2021 DGP suggested NWA investments would largely phase out before the 2023 DGP period:[78]

[74] 2023 DGP, pp. 84-86.

[75] Case No. U-21297, Ex A-12 Sch B5.4 p. 8, line 14; 2023 DGP, p. 162. While CEMI is identified as a “maintenance” program, the Company identifies CEMI spending as a capital investment.

[76] 2023 DGP, pp. 59, 85.

[77] 2023 DGP, pp. 94-95.

[78] 2021 DGP, p. 402 of 568.

Exhibit 12.7.1 NWA Projects and Other Technology Pilots Investment Summary

Project	2021	2022	2023	2024	2025	2021-2025
NWA Pilot Projects						
Fisher	$0.04 M	$0.8 M	$3.4 M	-	-	$4.2 M
Port Austin	-	$2.0 M	$2.5 M	-	-	$4.5 M
Omega	$3.4 M	$3.5 M	-	-	-	$6.9 M
Veridian	-	$1.8 M	$5.6 M	$0.3 M	$0.3 M	$8.1 M
O'Shea	$1.3 M	-	-	-	-	$1.3 M
Other Technology Pilots						
Mobile Energy Storage	$1.5 M	$0.5 M	$1.5 M	$1.5 M	-	$5.0 M
Small Solar and Storage Test Bed	$0.4 M	$0.4 M	$0.3 M	$0.3 M	$0.3 M	$1.6 M
EV Fast Charging and Charge Management	$0.7 M	$0.8 M	$1.3 M	$0.4 M	$0.4 M	$3.6 M

The 2023 DGP notes challenges and success with the historic NWA projects – including that "EWR and DR programs, with additional marketing and outreach, show higher levels of customer engagement than expected or experienced with less targeted efforts."[79] This bare assertion lacks details, quantification, costs or savings, or anything else. The 2023 DGP concludes by noting a summary of NWA project learnings will be included in the 2025 DGP.[80]

This is another lost opportunity. The 2023 DGP kicks NWA opportunities out at least another two years, increasing the likelihood that load challenges will be resolved with more costly hard infrastructure investments rather than innovative and less-costly non-wires solutions that require years to develop, refine, and roll out effectively.

Notably, the proposed load relief projects also lack detailed support. The projects are listed in Appendix B.1 but the appendix provides little more than a description of the project (*e.g.*, install new substation, replace cable, reconductor lines, decommission retired substation). The Company failed to fully support the programs with details and robust load studies in the rate case,

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[79] 2023 DGP, p. 95.

[80] 2023 DGP, p. 95.

then provided even less supporting detail in the DGP.[81] Ratepayers need the Company to produce evidence justifying the expense and demonstrating the projects are solving real problems and producing measurable benefits. Post-spending reporting of costs and benefits for particular projects would assist with accountability.

G. Subtransmission Redesign and Rebuild Program (DGP pp 96-107)

The 2023 DGP proposes to invest $524 million (about $100 million annually) for subtransmission redesign and rebuilds.[82] The program proposes to bring sections of the subtransmission system

> to updated standards to improve reliability, safety, and efficiency and increase capacity where it's currently constrained or where there is strong customer load growth, as well as increase automatic restoration and truck accessibility.[83]

The 2023 DGP describes 59 individual projects within this program in Appendix B.2. The projects include a wide range of work from substation upgrades to line replacements. The projects appear disjointed – a variety of projects to address a variety of improvements. The DGP indicates some of the 59 projects scored well in the GPM but provides no scoring nor input data.

The DGP asserts the investment will "dramatically improve safety, reliability, operability, and increase capacity".[84] But there is exactly zero data in the DGP that help the reader verify that assertion. There is no detail of outage, safety, or load history for any of the 59 projects or even representative projects. There is no data supporting forecasting overload. There is no indication the Company engaged in a risk-informed cost-benefit analysis to identify and pursue these projects. There is simply the promise of dramatic improvements in return for $100 million of annual capital investments.

In the last rate case, MNSC tried to understand the evidentiary support for the proposed subtransmission system upgrades but the Company generally failed to support the investments.[85] MNSC identified the Company justified upgrades by artificially derating substation capacities (versus nameplate capacity), making subjective assertions of degraded conditions unsubstantiated by reliability assessments, and maintaining unreasonable risk tolerance. The final order largely deferred analysis of specific programs as many continue beyond the test year, but noted concern about inability to obtain supporting documentation for the spending through discovery.[86]

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[81] Case No. U-21297, Oct. 5, 2023, PFD, p. 278; Order, p. 108.

[82] 2023 DGP, p. 162.

[83] 2023 DGP, p. 99.

[84] 2023 DGP, p. 99.

[85] Case No. U-21297, MNSC Initial Brief, pp. 84-87; PFD, pp. 267-275.

[86] Case No. U-21297, Dec. 1, 2023, Order, pp. 104-106.

The 2023 DGP does not illuminate DTE's subtransmission rebuild and redesign spending plan. To the contrary, it continues to rely on the same rationales that were shown in the rate case to be deficient – particularly standards setting unreasonably low tolerance for risk and reliability. The DGP might have redeemed some programs but it instead provides an unsupported spending plan.

H. <u>4.8kV and 8.3kV Conversions (DGP pp 107-123)</u>

The 2025 DGP proposes to ramp up capital investments to convert the 4.8kV system to 13.2 kV substations in the City of Detroit (CODI) and elsewhere, as well as one project to convert a single 8.3kV line to 13.2kV:

	2024	**2025**	**2026**	**2027**	**2028**	**5-year DGP Plan**
4.8kV Conversion and Consolidation	$76 million	$76 million	$195 million	$253 million	$320 million	$919 million
City of Detroit Infrastructure (CODI)	$95 million	$126 million	$148 million	$119 million	$90 million	$579 million
8.3 kV Conversion and Consolidation	$19 million	$31 million	$29 million	$18 million	$18 million	$114 million
Total Conversions	**$190 million**	**$233 million**	**$372 million**	**$390 million**	**$428 million**	**$1,612 million**

According to the 2023 DGP, to completely convert the 4.8kV system would cost an estimated $20 to $25 billion.[87] According to the DGP, conversion is needed because the 4.8kV system poses safety, operation, and reliability challenges due it its age, configuration, and loading.[88] The DTP asserts that 4.8kV equipment "often exceeds industry expected lifespan which can result in increased equipment outages," 4.8kV wire is weaker than current standard wire, and it ungrounded configuration makes it challenging to detect and protect downed wires.[89] While the system is capable of accommodating EV and DER, areas where the system is near capacity face challenges. Thus, conversion promises to provide the following: strengthening the wires; adding capacity; reducing voltage drops; improving detection of downed wires; reducing outage duration; and improving remote monitoring.

MNSC opposed the Company's proposed rapid pace of conversions in the last rate case.[90] MNSC supported a conversion approach that is on a circuit-by-circuit, substation-by-substation basis, using load forecasts relative to substation capacities, but that is not what the 2023 DGP is proposing. The DGP proposes a wholesale conversion of the system without providing circuit-level challenges or forecasting to support conversion. Particular conversions are likely justifiable but the DGP justifies neither the program nor individual conversions. Reliance on the GPM to justify conversion is flawed because the model itself is unverifiable and non-credible, as discussed above, and outputs are unavailable. Moreover, the GPM provides no way to separate the parts of

[87] 2023 DGP, p. 119.

[88] 2023 DGP, p. 107.

[89] 2023 DGP, p. 107.

[90] Case No. U-21297, MNSC Initial Brief, pp. 75-84; PFD, pp. 279-86.

the program that make sense on a cost-benefit and other reasonable bases from the parts that are gold-plated capital spending.

This proposed investment plan for conversions requires far more detail about historic considerations and projected growth and other challenges identified for particular circuits – circuit-specific, data-based, and risk-informed cost-benefit analysis, with transparent post-spending accountability. Until the Company demonstrates effective incorporation of such a framework into its management approach to distribution spending generally and the conversion program in particular, each conversion projects must be justified in a rate case with circuit-specific data and after-the-fact reporting of spending and achievements.

I. Grid Automation (DGP pp 133-144)

The largest component of the 2023 DGP is called "Grid Automation," for which the plan anticipates spending $1.192 billion during the 2024-2028 period.[91] Within the Grid Automation program, there are 11 subcomponents:[92]

Exhibit 10.1.3: Key Investment and Timeline for Grid Automation

Key Investment (in millions)	2024	2025	2026	2027	2028
Grid Automation	$61.6	$162.6	$190.6	$308.6	$469
Grid Automation Telecommunications Program	$16.9	$15.0	$13.8	$12.5	$11.0
CVR/VVO Program	$5.0	$5.0	$5.0	$5.0	$5.0
Capacitor Placement and Control Program	-	$5.6	-	-	-
NWA Projects	$14.5	$1.3	$0.3	-	-
Grid Edge Enablement Program	$5.5	$4.2	$4.2	$3.0	$2.8
Vehicle Electrification Projects	$2.9	$1.0	$0.8	$0.8	$0.5
URD Fault Indicators	$3	$3	$3	$3	$3
New Technology Evaluation Program	$1.2	$1.0	$1.0	$1.0	$1.0
Line Sensors	$0.5	-	-	-	-
Large/Medium Sized DER Monitoring and Control	$0.3	$0.3	$0.3	$0.3	$0.3
Total	**$111.4**	**$199**	**$219**	**$334.2**	**$492.6**

[91] 2023 DGP, p. 163.

[92] 2023 DGP, pp, 136-37.

Within this “Grid Automation” program, the “Grid Automation” subprogram is the largest component – 88% over the 5-year period and 95% of annual spending by 2028. These comments focus on the Grid Automation subprogram.

Per the DGP, Grid Automation (the subprogram) would retrofit the existing 4.8kV and 13.2 kV system (*i.e.*, practically the whole distribution system)[93] to install 10,000 line reclosers and upgrade an unknown number of switching and tie points.[94] The DGP does not identify how many line-miles would be retrofitted nor how many switches would be built and installed nor how many circuits would receive automation to existing ties versus how many circuits would require new ties. There is no break-down of the costs nor spending projection beyond the 5-year period. There is no justification for retrofitting 4.8kV lines, which the DGP proposes to convert. Because reclosures are voltage-specific, the investment in reclosers in lines scheduled for obsolescence is unreasonable and imprudent.

For circuits that have existing ties, which the DGP would propose to automate, the cost-benefit ratio may be positive – i.e., the benefits of automation in terms of reduced outage lengths relative to the cost of automation may be positive. For circuits that do not have existing ties, for which the DGP apparently proposes both to construct and install ties and automate, the cost-benefit ratio is more likely to be negative, considering the potentially high construction cost to build new ties or upgrade existing ties. Thus, circuit-specific benefit-cost analyses are necessary to evaluate the projects.

The DGP also includes no information to evaluate the benefits of automating switching compared to manual switching. How much outage time is saved? How many customers benefit? What is the cost of automation? There is simply no cost-benefit analysis of automation.

The DGP also includes no information on the component cost of switch rebuilding or recloser installation or grounding – the other component costs in this program.

The DGP asserts the investment in reclosers would improve safety by helping detect wire downs and reliability by enabling remote outage isolation and customer switching.[95] These are measurable objectives, but the DGP provides no measures to support any part of the massive investment. The DGP should provide a look-back on DTE’s recent experience with retrofitting lines with reclosers and switching – including before-upgrades performance; after-upgrades performance; and component costs.

Without information about historic vegetation management along circuits where DTE is proposing to invest in Grid Automation, the DGP fails to demonstrate that there are not more cost-effective approaches to achieve similar reliability benefits. Before investing hundreds of millions of dollars

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[93] 2023 DGP, p. 9, Exhibit 1.2.4 (63 miles out of 41,905 miles – or 13 out of 3,273 circuits – in the low-voltage distribution system are not 4.8 kV or 13.2 kV – *i.e.*, 8.3. kV).

[94] 2023 DGP, p. 134.

[95] 2023 DGP, p. 133.

to retrofit lines with ties and automate them, there should be a comprehensive evaluation of the results of DTE's expanded vegetation management efforts.

There is no information about how lines are prioritized. There are undoubtedly line segments that would benefit measurably from retrofitted reclosures and switch automation but there is no information in the DGP indicating the Company would prioritize those lines. Presumably DTE plans to prioritize worst-performing lines that are not scheduled for conversion for automation, but that is no clear from the DGP. The DGP does not identify how DTE plans to roll out retrofitting grid automation. The DGP says the program is focused on "installation and automation of most of the existing 4.8kv and 13.2kV system to the retrofit specification…."[96] There is no apparent prioritization.

Given the scope of spending for the Grid Automation subprogram, the DGP should include system-wide SAIDI and SAIFI improvement projections, and DTE should provide after-the-fact SAIDI and SAIFI improvements associated with this spending, on an annual basis or in the rate case.

There would be a point of diminishing returns with Grid Automation – a point at which the costs outweigh benefits. But the DGP provides no way to identify that point. The grid plan is supposed to provide the long-view on long-term investments – assessments of the point of diminishing returns are harder to make on the one-year horizon in a rate case.

In sum, while Grid Automation may be justified for particular lines, the 2023 DGP approach to Grid Automation is unjustified. Moreover, the 2023 DGP approach to Grid Automation planning is another example confirming DTE lacks an effective planning framework – an approach to planning for distribution spending that demonstrates integration of programs and goals, risk-informed cost-benefit analysis, with accountability for measurable outcomes transparent to regulators and stakeholders. Until the Company demonstrates such a management approach, all dollars proposed for spending on Grid Automation must be justified in a rate case with circuit-specific data and after-the-fact reporting of spending and achievements.

IV. The Commission should express unequivocal <u>non</u>-approval of the 2023 DGP and exercise its authority to improve Michigan distribution planning.

A. <u>The DGP is flawed.</u>

DTE Electric's 2023 DGP is a distribution spending plan, not a transparent roadmap for how it will cost-effectively improve reliability, plan for load growth and distributed resources, and incorporate technology and innovations. This plan is a lost opportunity to present a reasonable strategic distribution plan.

The DGP spending plan would consume any available headroom left in residential customer rates and leave nothing available to address other distribution-related priorities (*e.g.,* equity,

[96] 2023 DGP, p. 134.

electrification, distributed resources, etc.). It avoids inspections and a conditions-driven approach and instead doubles-down on replacing old equipment because it is old. It kicks community priorities down the road, increasing the likelihood that foreseeable distribution challenges associated with electrification and DER will be resolved with more costly hard infrastructure investments rather than innovative and less-costly non-wires solutions that require time to develop, refine, and roll out effectively.

At bottom, the 2023 DGP achieves what it set out to do – present a plan to spend ratepayer resources replacing old equipment. It asserts this investment will result in a newer system, not necessarily a more reliable system; there is not even lip service to cost-effectiveness. The DGP is loaded with assertions and conclusions that lack support and credibility.

B. The Commission should endorse legislative solutions to improve distribution system planning.

There are systemic problems with Michigan's present approach to distribution planning that may require legislative fixes. All aspects of this DGP – its priorities, forecasts, program and spending proposals, and more – would benefit from the procedural attributes and verification opportunities provided in a contested case proceeding. Moreover, the distribution plan would also benefit from coordination with IRP planning, and the IRP proceedings would likely benefit from more robust distribution plans.[97] The Commission may advance the public interest in improved distribution system planning by articulating clearly the importance of legislative fixes.

C. The Commission should require more robust and credible distribution plans.

Independent of legislative solutions, the Commission is empowered to improve the quality and value of distribution plans. It should direct the utility to present more robust and credible plans. This would include detailed circuit- or line-level performance data (outage causation, duration, customer counts, frequency, restoration time and cost, trim history, and more). It would also include actual detailed historic spending and actual programmatic reliability improvements associated with historic investments. Plans should also articulate how each program – and the components of the program (*e.g.*, trimming versus cross-arm replacement) will achieve the

[97] The Commission has recognized the value of aligning distribution planning with the IRP process. See Case No. U-20147, Sept. 11, 2019, Order, p. 2, noting recommendations from the Michigan Statewide Energy Assessment (SEA) report in Case No. U-20464 to "better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk," update IRP modeling parameters relating to DERs and reliability, and develop a framework "to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans." The Commission has also "recognize[d] that a perfect line up between [distribution planning and IRPs] may not be achievable given the statutory framework of MCL 460.6t and the utility-specific nature of each IRP case." Case No. U-20147, Aug. 20, 2020, Order, pp. 50-51.

claimed benefits and at what cost. A robust data-informed risk-based cost benefit analysis should accompany all spending proposals in the distribution plan.[98]

The Commission should also direct the utility to demonstrate how its plan efficiently coordinates reliability, capacity, and other programs, rather than segmenting reliability priorities while delaying programs to address predicable load growth and technology and innovation priorities.

The Commission should also require the utility to present meaningful performance-based metrics tied to distribution spending to increase the likelihood that ratepayers will in fact receive the benefits touted in the distribution plan.[99] The distribution plan should also include spending and benefits projected over a substantially longer horizon.[100] And the distribution plan should address the rate and customer bill impacts of the plan – particularly for residential customers who shoulder more of the burden of distribution spending.

At bottom, the Commission should ensure the distribution plans are robustly supported and explained so that this planning docket is worthwhile. The 2023 DGP is selectively duplicative of rate case filings without the benefit of additional context and detail. It is an additional proceeding that produces a document outlining all the spending on the horizon without additional perspective to evaluate that spending.

D. <u>The Commission should confirm it is not approving the spending or other parts of this DGP.</u>

The Commission should ensure the investment plan in the 2023 DGP does not become self-serving evidence presented to support future rate case spending and program requests. The Commission should proactively and unequivocally disavow that it has "approved" any spending proposals or other aspects of this (or any prior) DGP. Instead, it should reiterate that DTE Electric is required to support the reasonableness and prudence of all spending proposals in its rate case proceedings – including those described in the DGP.

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[98] The Commission has also recognized the importance of a cost-benefit analysis from the early days of this docket, "direct[ing] the Staff to continue to work with utilities and other stakeholders in continuing to explore the appropriate framework" while reminding utilities that the lack of an agreed-upon framework does not "absolve . . . [them] from justifying their investments, including consideration and quantification of costs and benefits relative to alternatives."U-20147, Aug. 20, 2020, Order, pp. 45-46. In its September 8, 2022, Order, the Commission adopted a recommendation from the Staff that utilities include in future distribution plans "a summary of the full set of alternatives analyzed before determining the selected solution." Case No. U-20147, Sept. 8, 2022, Order, pp.74-75 (quotation omitted).

[99] See Case No. U-20147, Aug. 20, 2020, Order, pp. 46-47.

[100] See Case No. U-20147, Sept. 11, 2019, Order, pp. 4-5.

V. Appendix

A. Michigan Environmental Council (MEC)

Michigan Environmental Council is a statewide environmental organization with 70 member groups and a collective membership of over 200,000 people. Its mission is to champion lasting protections for Michigan's air, our water, and the places we love. MEC's vision is to be a national environmental policy leader where a powerful network of advocates has built a track record of enacting enduring and equitable policies that protect the health of our communities and offer unparalleled stewardship of our land, air, and water in the face of climate change. (environmentalcouncil.org)

B. Natural Resources Defense Council (NRDC)

Natural Resources Defense Council is a nonprofit corporation has more than 3 million members and online activists with the expertise of some 700 scientists, lawyers, and other environmental specialists to confront the climate crisis, protect the planet's wildlife and wild places, and to ensure the rights of all people to clean air, clean water, and healthy communities. NRDC has over 30 years of experience working on state energy policy, including utility regulation and energy efficiency. (nrdc.org)

C. Sierra Club (SC)

Sierra Club is a national, non-profit environmental organization with approximately 150,000 members and supporters in Michigan, 8,757 of whom live, work, and pay electric bills in the Consumers Energy service territory. Founded in 1892, the Club is America's oldest, largest and most influential grassroots environmental organization. Its mission is to: (1) Explore, enjoy, and protect the wild places of the earth; (2) Practice and promote the responsible use of the earth's ecosystems and resources; (3) Educate and enlist humanity to protect and restore the quality of the natural and human environment; and (4) Use all lawful means to carry out these objectives. Sierra Club has many years of experience working on energy and electric generation issues throughout the United States, including in Michigan. (sierraclub.org)

D. Citizens Utility Board of Michigan (CUB)

The Citizens Utility Board of Michigan is a nonpartisan, nonprofit organization whose members are individual residential customers of Michigan's energy utilities. CUB was formed in 2018 to represent the interests of residential energy customers across Michigan. It educates and engages Michigan consumers in support of cost-effective investment in energy efficiency and renewable energy and against unfair rate increase requests. CUB helps to ensure that Michiganders pay the lowest reasonable rate for utility services and also benefit from the environmental implications of investment in clean energy. (cubofmichigan.org)