August 22, 2025

Ms. Lisa Felice
Michigan Public Service Commission
7109 W. Saginaw Hwy.
Lansing, MI 48909

Via E-File

RE: MPSC Case No. U-21860

Dear Ms. Felice:

Attached please find the enclosed documents for filing:

- Direct Testimony and Exhibits of Douglas B. Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Citizens Utility Board of Michigan (CUB-12 through CUB-18); and
- Proof of Service.

Thank you for your assistance in this matter. If you have any questions, please feel free to contact me.

Sincerely,

Digitally signed by Holly Hillyer
Date: 2025.08.22 12:00:44 -04'00'

Holly L. Hillyer
holly@tropospherelegal.com

CC: Parties to Case No. U-21860

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.	U-21860

DIRECT TESTIMONY OF DOUGLAS B. JESTER

ON BEHALF OF

MICHIGAN ENVIRONMENTAL COUNCIL, NATURAL RESOURCES DEFENSE COUNCIL, AND CITIZENS UTILITY BOARD OF MICHIGAN

August 22, 2025

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I. INTRODUCTION & QUALIFICATIONS

Q. Please state for the record your name, position, and business address.

A. My name is Douglas B. Jester. I am Managing Partner of 5 Lakes Energy, a Michigan limited liability corporation, located at PO Box 869, Northport, Michigan 49670.

Q. On whose behalf is this testimony being offered?

A. I am testifying on behalf of the Michigan Environmental Council ("MEC"), Natural Resources Defense Council ("NRDC"), and Citizens Utility Board of Michigan ("CUB"), collectively identified as "MNC."

Q. Please summarize your experience in the field of utility regulation.

A. I have worked for more than 30 years in utility industry regulation and related fields. My work experience is summarized in my resume, provided as Exhibit CUB-12.

Q. Have you testified before this Commission or as an expert in any other proceedings?

A. I have previously testified before the Michigan Public Service Commission ("Commission") in the following cases:

- Case U-17473 (Consumers Energy Company Plant Retirement Securitization);
- Case U-17096-R (Indiana Michigan 2013 PSCR Reconciliation);
- Case U-17301 (Consumers Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17302 (DTE Energy Renewable Energy Plan 2013 Biennial Review);
- Case U-17317 (Consumers Energy 2014 PSCR Plan);
- Case U-17319 (DTE Electric 2014 PSCR Plan);
- Case U-17671-R (UPPCO 2015 PSCR Reconciliation);

- Case U-17674 (WEPCO 2015 PSCR Plan);
- Case U-17674-R (WEPCO 2015 PSCR Reconciliation);
- Case U-17679 (Indiana-Michigan 2015 PSCR Plan);
- Case U-17688 (Consumers Energy Cost of Service and Rate Design);
- Case U-17689 (DTE Electric Cost of Service and Rate Design);
- Case U-17698 (Indiana-Michigan Cost of Service and Rate Design);
- Case U-17735 (Consumers Energy General Rates);
- Case U-17752 (Consumers Energy Community Solar);
- Case U-17762 (DTE Electric Energy Optimization Plan);
- Case U-17767 (DTE General Rates);
- Case U-17792 (Consumers Energy Renewable Energy Plan Revision);
- Case U-17895 (UPPCO General Rates);
- Case U-17911 (UPPCO 2016 PSCR Plan);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-17990 (Consumers Energy General Rates);
- Case U-18014 (DTE General Rates);
- Case U-18089 (Alpena Power PURPA Avoided Costs);
- Case U-18090 (Consumers Energy PURPA Avoided Costs);
- Case U-17911-R (UPPCO 2016 PSCR Reconciliation);
- Case U-18091 (DTE PURPA Avoided Costs);
- Case U-18092 (Indiana Michigan Power Company PURPA Avoided Costs);
- Case U-18093 (Northern States Power PURPA Avoided Costs);
- Case U-18094 (Upper Peninsula Power Company PURPA Avoided Costs);

- Case U-18095 (Wisconsin Public Service Company PURPA Avoided Costs);
- Case U-18096 (Wisconsin Electric Power Company PURPA Avoided Costs);
- Case U-18224 (UMERC Certificate of Necessity);
- Case U-18232 (DTE Renewable Energy Plan);
- Case U-18255 (DTE Electric General Rates);
- Case U-18322 (Consumers Energy General Rates);
- Case U-18406 (UPPCO 2018 PSCR Plan);
- Case U-18408 (UMERC 2018 PSCR Plan);
- Case U-18419 (DTE Certificate of Necessity);
- Case U-20072 (UPPCO 2017 PSCR Reconciliation);
- Case U-20111 (UPPCO Tax Cuts and Jobs Act of 2017 Adjustment);
- Case U-20134 (Consumers Energy General Rates);
- Case U-20150 (UPPCO Revenue Decoupling Mechanism Complaint);
- Case U-20162 (DTE General Rates);
- Case U-20165 (Consumers Energy Integrated Resource Plan);
- Case U-20229 (UPPCO 2019 PSCR Plan Case);
- Case U-20276 (UPPCO General Rates);
- Case U-20350 (UPPCO Integrated Resource Plan);
- Case U-20359 (I&M 2019 General Rate Case);
- Case U-20471 (DTE Integrated Resource Plan);
- Case U-20479 (SEMCO 2019 General Rate Case);
- Case U-20561 (DTE 2019 General Rate Case);
- Case U-20591 (Indian Michigan Power Company IRP);

- Case U-20642 (DTE Gas 2020 General Rate Case);
- Case U-20649 (Consumers Electric Voluntary Green Pricing);
- Case U-20650 (Consumers Gas 2020 General Rate Case);
- Case U-20697 (Consumers Electric 2020 General Rate Case);
- Case U-20713 (DTE 2020 Voluntary Green Pricing);
- Case U-20836 (DTE Electric 2022 General Rate Case);
- Case U-20874 (Alpena Power 2022-23 EWR Plan Case);
- Case U-20875 (Consumers Energy 2022-23 EWR Plan Case);
- Case U-20876 (DTE Electric 2022-23 EWR Plan Case);
- Case U-20877 (Indiana Michigan 2022-23 EWR Plan Case);
- Case U-20878 (NSP 2022-23 EWR Plan Case);
- Case U-20879 (UPPCO 2022-23 EWR Plan Case);
- Case U-20880 (UMERC 2022-23 EWR Plan Case);
- Case U-20881 (DTE Gas 2022-23 EWR Plan Case);
- Case U-20882 (MGU Gas 2022-23 EWR Plan Case);
- Case U-20883 (SEMCO Gas 2022-23 EWR Plan Case);
- Case U-20889 (Consumers Karn Retirement Securitization);
- Case U-20963 (Consumers Energy Electric Rate Case);
- Case U-21015 (DTE Securitization Case);
- Case U-21048 (Consumers Energy 2022 PSCR Plan);
- Case U-21081 (UMERC 2021 IRP);
- Case U-21090 (Consumers Energy 2021 IRP);
- Case U-21189 (Indiana Michigan 2022 IRP);

- Case U-21193 (DTE Electric 2022 IRP);
- Case U-21224 (Consumers Energy 2022 Electric Rate Case);
- Case U-21297 (DTE Electric 2023 Rate Case);
- Case U-21377 (IM Renewable Acquisition);
- Case U-21389 (Consumers Energy 2023 Electric Rate Case);
- Case U-21540 (MGU 2024 Gas Rate Case);
- Case U-21555 (UPPCO 2024 Rate Case);
- Case U-21534 (DTE 2024 Electric Rate Case);
- Case U-21585 (Consumers 2024 Electric Rate Case);
- Case U-21654 (EWR Alternative Compliance Plan);
- Case U-21662 (DTE 2024 Renewable Energy Plan Case);
- Case U-21816 (Consumers Energy 2024 Renewable Energy Plan Case);
- Case U-21859 (Consumers Energy Data Center Tariff Case); and
- Case U-21813 (UMERC 2025 Renewable Energy Plan Case).

Additionally, I have testified as an expert witness before the Public Utilities Commission of Nevada in Case No. 16-07001 concerning the 2017-2036 integrated resource plan of NV Energy; and before the Missouri Public Service Commission in Case Nos. ER-2016-0179, ER-2016-0285, and ET-2016-0246 concerning residential rate design and electric vehicle ("EV") policy, revenue requirements, cost of service, and rate design. I testified before the Kentucky Public Service Commission in Case No. 2016-00370 concerning municipal street lighting rates and technologies. I testified before the Massachusetts Department of Public Utilities in Case Nos. DPU 17-05 and DPU 17-13 concerning EV charging infrastructure program design and cost recovery. Before the Rhode Island Public Utilities

Commission, in case 4780, I testified concerning Advanced Metering Infrastructure and EV charging infrastructure. Before the Delaware Public Service Commission, I testified regarding EV charging infrastructure in case 17-1094. I testified before the Georgia Public Service Commission in Case No. 4822 concerning PURPA avoided cost. I testified before the Colorado Public Utilities Commission in Case Nos. 20A-0204E and 20A-195E concerning cost recovery for EV charging infrastructure. I also testified before the Minnesota Public Utilities Commission in Case No. 22-432 regarding EV charging rate design. I testified before the Public Service Commission of Wisconsin in Certificate of Public Convenience and Necessity cases 6630-CE-316 and 6630-CE-317.

I have also testified as an expert witness on behalf of the State of Michigan before the Federal Energy Regulatory Commission ("FERC") in cases relating to the relicensing of hydro-electric generation and have participated in state and federal court cases on behalf of the State of Michigan concerning electricity generation matters, which were settled before trial. I have also filed affidavits in support of filings by the Attorney General of Michigan in docket no. EL25-90-000 and in support of a request for reconsideration and appeal of a Federal Power Act Section 202c Order by the Secretary of Energy.

Q. Are you sponsoring any exhibits?

A. Yes, I am sponsoring the following exhibits:

Exhibit CUB-12: Resume of Douglas B. Jester

Exhibit CUB-13: Attachment AGDE-2.43-02 S&P 2025 DTE Electric

Exhibit CUB-14: Attachment AGDE-2.43-01 Moody's 2025 Combined

Exhibit CUB-15: Attachment AGDE-2.43-03 Fitch 2025 DTE Electric

Exhibit CUB-16: Change in MERC Coal Delivery Volumes

Exhibit CUB-17: Change in MERC Fuel Handling Historical O&M

Exhibit CUB-18: Authorized vs Actual MERC Fuel Handling O&M Expenses

II. SUMMARY

Q. What topics are you addressing in your testimony?

A. My testimony will address the following topics regarding DTE Electric Company's (hereafter "DTEE" or "the Company") Application and supporting testimony in this case:

- Response to DTEE's arguments regarding under-recovery of capital expenditures;
- Response to DTEE's arguments regarding constant dollar averaging to project future test year costs;
- Response to DTEE's proposed MERC operations and maintenance costs;
- My recommendation to securitize the net book value of assets retired before end of life as a result of distribution system conversions;
- My recommendation to defer and securitize distribution system surge costs;
- My recommendation that the Commission direct DTEE towards future use of seasonal distribution rates.

Q. Which DTEE witnesses' testimony do you discuss in your testimony?

A. I am addressing aspects of the testimony of DTEE witnesses Ambrose, Burgdorf, Cejas Goyanes, Davis, Guillaumin, Ludlow, Lyons, Milo, Nelson, Sheilendranath, Stowe, Turner, and Willis.

Q. What disallowances are you recommending?

A. I recommend disallowance of $1.7 million in expenses for MERC Fuel Handling.

III. UNDER-RECOVERY OF CAPITAL EXPENDITURES

Q. What does DTEE argue in this case regarding the under-recovery of capital expenditures?

A. Although a number of DTEE witnesses undertake to document what they view as erroneous disallowances from past cases,[1] leading to DTEE spending in excess of what was allowed in those previous cases, the Company's overall perspective on this topic is presented by DTEE witness A. Sheilendranath. Witness Sheilendranath argues that disallowances induce regulatory lag and asymmetry risks with effects on business, financial, and regulatory risks and further argues that these have implications to credit ratings, capital outlays, and cost of capital.[2] In short, DTEE is making a specific effort to "work the ref" and persuade the Commission to moderate or eliminate its recent practice of disallowing certain expenditures proposed by DTEE.

Q. Does DTEE operate in a high regulatory risk environment?

A. No, DTEE does not operate in a high regulatory risk environment. Rather, Michigan's electric utilities benefit from multiple regulatory mechanisms that enable timely cost recovery and reduce cash flow uncertainty. The permitted use of a forward-looking 12-month test year, the timely resolution of general rate cases within 10 months, full pass-through of fuel costs, continued authorization of investment recovery mechanisms, and

[1] See the Direct Testimonies of S. B. Ambrose, W. H. Ludlow, M. E. Guillaumin, and J. C. Davis.

[2] Direct Testimony of A. Sheilendranath, AS-3:2-10.

allowing financing interest cost recovery on certain construction work in progress ("CWIP") projects all reduce uncertainty in cost recovery.

The three prominent credit rating agencies, S&P Global[3], Moody's[4], and Fitch[5], provide a similar assessment and categorize Michigan as having a generally supportive regulatory environment. Only 20% of the peer companies in Witness Nelson's proxy group operate in a regulatory environment that is rated as being more constructive than Michigan's Average/1 by S&P's Regulatory Research Associates.[6] Also, Fitch, in its most recent DTEE assessment following the January 2025 rate order, noted that concerns related to the utility's large capex needs to meet its grid reliability and clean energy goals are mitigated by the Michigan Public Service Commission's constructive ratemaking policies.[7]

Q. Can potential future disallowances of capital expenditures expose DTEE investors to additional regulatory risk?

A. Not necessarily. Disallowances due to insufficient evidence of reasonableness and prudence, ill-timed spending, or poor planning do not increase regulatory risk. Rather, these point to managerial risks in project design and execution, and such disallowances protect investors by imposing the kind of capital discipline that competitive markets normally evoke. They can improve the durability of the rate base and earnings quality, in turn, making the company more attractive to long-term investors. This same discipline

[3] Ex CUB-13, Attachment AGDE-2.43-02 S&P 2025 DTE Electric.

[4] Ex CUB-14, Attachment AGDE-2.43-01 Moody's 2025 Combined.

[5] Ex CUB-15, Attachment AGDE-2.43-03 Fitch 2025 DTE Electric.

[6] U-21860 Exhibit A-14, B 5.8, p. 2.

[7] Ex CUB-15, Attachment AGDE-2.43-03 Fitch 2025 DTE Electric, see p.1.

ensures rates remain just and reasonable for ratepayers, reducing their risk of paying for investments that won't deliver appropriate benefits. Below, I include some examples on how the Commission has applied these principles in previous proceedings.

In U-21297, the Commission disallowed $88.5 million tied to Monroe Units 3 and 4, including $39.8 million for bottom-ash conversion.[8] Given the units' 2028 retirements approved in the company's IRP case, U-21193, large portions of the expenditures were found avoidable, ill-timed, or insufficiently supported. The Commission found that many of these costs were not in line with the cost estimates DTEE provided in U-21193 and adopted the Commission Staff's recommended adjustments. DTEE failed to provide sufficient evidence to support the increased costs it had proposed. The Commission also found the DCS, control room, and ash-removal projects unnecessary so close to retirement.[9] These disallowances applied the predictable standards of cost prudence, evidentiary support, and timing to prevent deployment of capital towards avoidable short-term projects that wouldn't generate durable returns in the future.

In another instance, the Commission rejected DTEE's request to authorize $3.3 million associated with the construction of the Blue Water Energy Center (BWEC) Conference Room Building in U-21534.[10] DTEE said the space was needed during routine and major maintenance when additional support personnel are on-site. But when asked why such a facility was not included in the original site plan (as is typical for power plants), the

[8] Case No. U-21297, Order, December 1, 2023, pp. 19-22.

[9] *Id.*, pp. 14-19.

[10] U-21534, Order, January 23, 2025, pp. 38-40.

Company answered only that it "was not needed at the time."[11] The Commission denied recovery, finding the facility should have been contemplated and included in the original plant design and construction.[12] Such disallowances enforce planning discipline, deterring late-stage scope creep.

Even in instances of unavoidable and prudent costs, disallowances can improve earnings quality if the costs are not incurred in a timely manner or if the actual expenses deviate materially from the estimates. In U-21534, the Commission found that DTE's projections for routine steam generation plant fell short of the actual spending in the first six months of the bridge year by $21.33 million.[13] The Staff contended that the timing of projects is equally important as the total cost in setting reasonable rates. The Commission agreed and did not find DTE's evidence sufficient to burden ratepayers with aspirational spending goals when actual spending is available.[14] The Commission also recognized that DTE's fleet is in transition and that it makes sense to use actual amounts where available, thereby better aligning cost recovery with actual cost expenditures. Given the regular cadence and timely resolution of general rate cases in Michigan, disallowances due to timing issues don't necessarily increase regulatory risk, rather stabilize cash flows around verifiable costs.

Taken together, these examples show that capital expenditure disallowances are not a sign of heightened regulatory risk. Rather, careful assessment of project-level costs through a

[11] *Id.*, p.39.

[12] *Id.*, p. 39.

[13] *Id.*, pp. 40-42.

[14] *Id.*, p. 41.

contested rate case process improves the durability of the rate base and earned returns, anchors recovery to verifiable used-and-useful assets, stabilizes cash flows, and supports healthy credit metrics.

Q. Can persistent disallowances increase regulatory risk?

A. No. Persistent disallowances do not, in themselves, increase regulatory risks. Disallowances stemming from prudence concerns, timing issues, or inadequate documentation, as previously discussed, benefit both ratepayers and investors by promoting accountability and efficiency. Disallowances reflect the utility's failure to support its costs. The Commission can and must exclude those costs when the burden isn't met. Disallowances are a routine, lawful outcome of prudence review, not randomness or bias, which warrants additional risk.

Q. What about instances where DTEE makes the necessary investments despite the disallowances? Can it lead to regulatory lag or asymmetric risk?

A. Making an investment does not automatically guarantee, nor entitle, a utility to cost recovery. Ultimately, the utility must demonstrate that the projections presented to the Commission for approval include good-quality estimates that appropriately reflect project costs and timing. This is particularly critical when utilizing a 12-month forward test year, where ratepayers have no recourse to recover any overpaid dollars.

In U-21534, the Staff recommended disallowances for several projects that were otherwise necessary and prudent because underspending in the bridge year showed a pattern of either

inflated projections, missed project schedules, or unsubstantiated cost reductions.[15] As the Staff emphasized,

> [c]ouple that with the fact that the Company chooses to and does not have to use a projected test year, the benefit of doing so should reasonably come with a higher burden of proof for the Company to ensure it is accurately forecasting project expenses.[16]

I agree. When the utility's evidence falls short in a projected test year, it is appropriate to disallow the unsupported amounts then and allow recovery later only upon demonstration of prudence, need, and accurate timing, so that the ratepayers are not compelled to pay higher bills reflecting inflated estimates or mistimed expenditures. This isn't regulatory lag. Regulatory lag refers to the temporal delay between when a utility incurs *prudent* costs and when those costs are reflected in rates, typically due to the time required for a rate case. By contrast, as previously illustrated, such disallowances of unsupported amounts reflect a substantive determination of cost prudence. When cost estimates are included in rates and the Company fails to spend on its projected schedule but nonetheless earns through rates as though the investments were made as projected, DTEE does not complain of regulatory lag. Nor should it complain of regulatory lag when approved cost estimates understate or assume later expenditures than actually occur. Allowing inflated estimates or ill-timed costs in rates can significantly increase the asymmetric risk for ratepayers who have no recourse to claw back overpayments. The Commission's statutory ratemaking process aims to appropriately allocate those risks between investors and ratepayers.

[15] U-21534, Order, January 23, 2025, p. 43.

[16] *Id.*, p. 47.

Q. If disallowances could increase DTEE's risk, would it mean that DTEE should be allowed to earn a rate of return that is set above its market-determined cost of capital?

A. No. The typical prudence and substantiative regulatory review is already priced in the market-determined cost of capital. Also, mitigating disallowances due to estimate quality, timing, and insufficient evidence are largely within management's control. The Commission clearly lays out its reasoning for disallowance in every rate case, and DTEE has ample opportunity to improve its estimates. It is not an additional risk demanding a premium on equity. On the contrary, as previously discussed, improvement in estimate quality and project execution can improve rate base durability and earnings quality, ultimately lowering, not raising, the utility's risk profile. The authorized return should match the Company's market cost of capital for a utility of comparable risk.

Q. What do you recommend?

A. I recommend the Commission reject DTEE's claim that disallowances increase regulatory risk and its unfounded suggestion that it is entitled to recovery of projected costs without meeting the required standards of evidence. If DTEE decides to proceed with any disallowed expenditures, it has the opportunity to seek cost recovery in a future rate case, subject to the standards of prudence review. While this can create some asymmetric risk for investors, it is not higher than the asymmetric risk borne by the ratepayers, who have no recourse to recover rates based on inaccurate estimates. The Commission must balance these risks appropriately.

I also recommend the Commission not include an additional premium for DTEE's cost of capital beyond the market-determined cost of capital, which already compensates for the typical regulatory review of costs.

IV. CONSTANT DOLLAR AVERAGING

Q. What is constant dollar averaging?

A. Constant dollar averaging converts historical "nominal" dollars to "real" dollars in a single constant-year base using an inflation index and then averages those real costs to arrive at a historical cost estimate. The resulting average is then escalated to the projected test-year dollars. In this case, DTEE is converting 2019–2023 costs to 2023 dollars, averaging them to arrive at the 2023 historical test period estimate, and escalating the average to the test year. See Figure 1 below for an illustrative comparison of projecting O&M costs utilizing historical averages with and without constant dollar averaging. DTEE witness T. S. Lyons posits that, in the absence of constant dollar averaging, DTEE loses purchasing power over time due to inflation and that the Company will be unable to purchase in the future the

same volume of goods and services as in the past.[17]

Line/Column No.		(a)	(b)	(c = 1+a2)	(d = 1+a3)	(e = 1+a4)	(f = 1+a5)	(g)	
		Historical inflation	**Reported O&M**	**Esc. 19-20**	**Esc. 20-21**	**Esc. 21-22**	**Esc. 22-23**	**Adjusted O&M (in 2023 constant dollars)**	
1	2019		$ 100.00	1.033	1.043	1.050	1.025	$ 115.85	g1 = b1*c1*d1*e1*f1
2	2020	3.25%	$ 105.00	1.033	1.043	1.050		$ 118.67	g2 = b2*c2*d2*e2
3	2021	4.25%	$ 94.00	1.033	1.043			$ 101.18	g3 = b3*c3*d3
4	2022	5.00%	$ 82.00	1.033				$ 84.67	g4 = b4*c4
5	2023	2.50%	$ 120.00					$ 120.00	g5 = b5
6	**Historical 5-yr average**		**$ 501.00**					**$ 540.36**	
				Projected estimates					
		Inflation rates	**Based on simple average of reported O&M**					**Based on constant dollar averaging O&M**	
7	2024	3.40%	$ 518.03					$ 558.73	b/g 7 = b/g 6 *(1+a7)
8	2025	3.00%	$ 533.58					$ 575.50	b/g 8 = b/g 7 *(1+a8)
9	2026	3.10%	$ 550.12					$ 593.34	b/g 9 = b/g 8 *(1+a9)

Figure 1: Illustrating constant dollar averaging calculations

Q. For what cost categories is DTEE utilizing constant dollar averaging?

A. In this case, DTEE is utilizing constant dollar averaging to arrive at projected year cost estimates for Distribution Operations.[18] Specifically, DTEE is applying constant dollar averaging to distribution costs related to Restoration Expenses and Distribution Base Capital programs.

Q. Does nominal dollar averaging lose purchasing power over time due to inflation?

A. Not in a cumulative sense. Nominal cost averaging over a few years during which there is inflation and then nominal cost averaging in the next rate case over a similar number of later years will produce a higher cost average, by the amount of inflation, adjusted for

[17] Direct testimony of Timothy S. Lyons, TSL-5, 6:9.

[18] *Id.*, TSL-5, 4:5.

productivity gains, than actually occurred. Witness Lyons does not assert such a cumulative effect, but it could be read into his testimony.

Q: Do you agree with Witness Lyons' claim that the upward trend in Distribution Operations labor rates justifies constant dollar averaging?

A. No. Witness Lyons claims that there has been an upward trend in Distribution Operations contract labor rates over the past several years.[19] However, this does not account for any changes in labor productivity over that period. The Commission should expect continuous improvement in labor productivity, as occurs in the rest of the economy. Further, as shown in the testimony of my colleague Richard Bunch, DTEE has in fact achieved reduced staffing that largely offsets internal labor compensation rates per employee. The Commission and DTEE should expect similar performance from DTEE's contract labor. Constant dollar averaging fails to account for productivity improvements.

Q. Is constant dollar averaging an appropriate methodology for estimating storm-related O&M expenses?

A. No, it is not. Witness Lyons in his testimony provided the example of PECO, an electric delivery investor-owned utility ("IOU") serving 1.7 million customers in Pennsylvania, which has previously used 5-year constant-dollar averaging to determine a "normal" baseline for storm damage expenses.[20] However, in its most recent case, PECO pointed to persistent gaps between the authorized amounts and actual storm expenses and proposed an alternative proposal employing a deferred accounting authorization. Ultimately, PECO

[19] *Id.*, TSL-15:13 through TSL-16:1.

[20] *Id.*, TSL-9, PECO (PA).

withdrew the proposal and reached a settlement to recover up to $22.8 million for storm damage costs *actually* incurred in January 2024, subject to reasonableness and prudence review, in the Company's next rate case.[21]

Between 2016 and 2023, the percentage difference between PECO authorized rates for storm-damage-related expenses and actual amounts spent ranged from -18.5% to 411.1%, with an average of 83.6%.[22] Over these eight years, ratepayers overpaid PECO by $15 million, which is 4.2% more than the actual costs.[23]

Specifically, PECO witness Michael J. Trzaska testified that,

> In the last decade, PECO has experienced material variances between the level of storm damage expense recovered through its base rates and the level of those expenses actually incurred due to the increasing volatility in frequency, severity, and duration of weather events that are outside the Company's control. Due to the volatility in weather events from year-to-year, actual storm damage expense can be notably lower or higher than the amounts reflected in PECO's base rates.[24]

Instead, PECO proposed creating a Storm Reserve Account, a deferred accounting authorization, where the "normal" storm damage expense included in the rate base for recovery would be tallied against actual storm costs to arrive at a regulatory asset or liability. This would be amortized over two years.[25] Pennsylvania's Office of Consumer Advocate countered that ratepayers cannot control rate case frequency and would be

[21] Pennsylvania PUC, Docket No. R-2024-3046931, Opinion and Order, p. 41.

[22] Calculated from values in Pennsylvania PUC, Docket No. R-2024-3046931, Volume II OF VI**,** Direct Testimony of Michael J. Trzaska, p. 75, Table 1, available at https://www.puc.pa.gov/pcdocs/1822416.pdf.

[23] *Id.*, p. 74, 12:16.

[24] *Id.*, p. 71, 6:16.

[25] *Id.*, p. 73, 3:16.

unilaterally dependent on the utility's filing schedule to recover any refunds they are owed.[26]

DTEE proposed a similar mechanism, its Storm Restoration and Cost Recovery Mechanism (SRCSM), in U-21534, with 50% cost sharing between ratepayers and DTE, on a similar hypothesis that the current approach of recovering storm restoration costs as an O&M expense does not address the uncertainty and variability of those expenses in any given year.[27] It has proposed similar mechanisms in previous cases as well. However, the Commission has consistently rejected DTEE's proposal. The Commission explained that with the general trend towards more frequent and severe storms, it seeks stronger cost control and improved performance in storm restoration – neither of which DTEE has demonstrated[28]. The proposed SRCSM didn't offer improved cost control compared to the current mechanism, where DTEE retains 100% of the savings or costs, rather than the proposed 50%.[29] Furthermore, the Staff found that it was unclear what the company was spending on storm restoration expenses and what DTEE even defined as a storm restoration expense,[30] a fundamental and routine expense for a large electric utility!

Given PECO's and DTEE's admissions of significant year-to-year variation in actual storm costs compared to estimated projections, constant dollar averaging is not a suitable method for producing reliable estimates of storm recovery O&M expenses. Witness Lyons' claim

[26] Pennsylvania PUC, Docket No. R-2024-3046931, Opinion and Order, p. 41.

[27] U-21534, Order, January 23, 2025, p. 305.

[28] *Id.*, p.312.

[29] *Id.*

[30] *Id.*

that absent constant dollar averaging, DTEE won't be able to perform the same level of work as before does not apply here because the amount of work varies significantly from one year to another. Additionally, historical evidence for PECO shows that in the long term, inflated cost projections have cost ratepayers $15 million. The current Michigan framework provides no safeguard for ratepayers to recover similarly overestimated costs. It is also unreasonable to allow DTEE to inflation-adjust historical spending that the Company has not clearly identified. This is particularly relevant in the context of DTEE's already poor storm restoration performance.

Further, DTEE can reduce storm-related costs by improving tree-trimming and by grid hardening, which DTEE proposes to do at a cost to customers in this case. Continued pressure on DTEE to reduce storm-related costs is warranted. Therefore, I recommend that the Commission disallow DTEE's proposed constant dollar averaging for storm restoration expenses and allow cost projections based on a simple historical average. This mechanism will balance the utility's need for cost recovery with ratepayers' interests in improved storm performance and cost control.

Q. Is constant dollar averaging a widely accepted practice in the utility industry to estimate non-fuel materials, supplies, and other labor costs?

A. No, it is not. Witness Lyons included the example of UE-435, where the Oregon PUC reviewed the application of constant dollar averaging to Portland General Electric's (PGE's) non-fuel Materials and Supplies.[31] Witness Lyons incorrectly claims that the

[31]Lyons Direct, TSL-10, Table 1, Portland General Electric (OR).

Oregon PUC accepted the constant dollar methodology in its final order.[32] A further review of the order shows that the Oregon PUC adopts its Staff's recommendation. Specifically, the Staff states in its initial briefing,

> Staff recommends use of a three-year historical average value based on the last three years of actual data, escalated by the All-Urban Consumer Price Index, to calculate the Company's non-fuel materials and supplies balance for the test year.[33]

And, the Oregon PUC's final order states,

> We adopt the Staff's proposed adjustment using an average monthly balance for the years 2021-2023 and escalating that average balance using the All-Urban CPI index for 2024. We find that the use of a three-year average, adjusted for inflation, strikes the right balance between ensuring a reasonable test year balance based on the company's historic balance and capturing any trend of increases. It also avoids incenting the company to over-stockpile materials and supplies.[34]

The Oregon PUC Staff stated that the utility earns a return on these materials and has an incentive to build up inventory, irrespective of inflationary pressures.[35] The Oregon PUC also categorically denied all PGE expense growth beyond the last full year of actual, demonstrated expenses, plus inflation, except in the case of non-fuel materials and supplies.[36] Specifically, it stated,

> We are committed to continued use of a future test year, but we intend to implement this constructive regulatory policy in a manner that incents PGE

[32] *Id.*, TSL-10, 2:6.

[33] Oregon PUC, Docket UE 435, Staff Opening Brief, p. 18, 9:11, available at https://edocs.puc.state.or.us/efdocs/HBC/ue435hbc332459025.pdf.

[34] Oregon PUC, Docket UE 435, Final Order, 24-454, p.24, available at https://apps.puc.state.or.us/orders/2024ords/24-454.pdf.

[35] Oregon PUC, Docket UE 435, Staff Opening Brief, p.19, 5:6.

[36] Oregon PUC, Docket UE 435, Final Order, 24-454, p.2.

> to control costs and gives Staff and intervenors a reasonable opportunity to review and discipline PGE's expenses.[37]

This is critical; in a high-inflationary environment, utility regulation must mimic the role of market competition and ensure utilities are managing their cost pressure efficiently rather than simply passing it through to customers.

The Commission has previously accepted constant dollar averaging for projecting DTEE's Restoration Expenses, including storm-related and non-storm-related restoration. However, as shown in the previous question and the instance of the Oregon PUC, there is weak support for the efficacy and acceptance of the method for projecting O&M expenses. Instead, allowing utilities to pass through all costs to ratepayers in a high-inflationary environment takes away the incentive to implement cost controls. It is essential to balance utilities' need for enough recovery to maintain financial health and quality service provision with the potential for over-recovery and need to maintain affordability for ratepayers.

I recommend that the Commission reject DTEE's proposal to recover Non-storm Restoration Expense based on constant dollar averaging and instead direct DTEE to use average historical costs and apply a forward inflation escalation to determine projected test-year estimates. Any future inflation escalation should include productivity offsets to ensure any efficiency gains are passed on to ratepayers. I refer to my colleague Richard Bunch's testimony on DTEE's inflation escalator and his recommendation for the years 2024 through 2026.

[37] *Id.*, p. 2.

Q. What about distribution capital additions? Is constant dollar averaging a widely accepted practice in the utility industry for such expenditures?

A. There have been cases where regulators have accepted constant dollar averaging for certain capital additions. However, many of these are in the context of performance-based ratemaking, adjusting rates subject to a revenue cap, allowing for inflation adjustments while accounting for productivity offsets, and including consumer dividends. Two out of the three examples shared by Witness Lyons for capital additions use performance-based ratemaking.[38]

Given DTE's poor reliability and steadily increasing Distribution Operations capital spending, I recommend that the Commission establish a contested case process for Distributed Grid Planning and implement a performance-based ratemaking approach for DTE's Distribution Capital, including its Base Capital programs, with spending subject to approval in the contested Distribution Grid Plans. This would align cost recovery with proven improvements in distribution infrastructure, enhance transparency, and create incentives for efficient capital deployment. In the alternative, I recommend that constant dollar averaging not be allowed for Distribution Operations capital spending in this case.

V. MERC COSTS

Q. What is MERC?

A. MERC is the Midwest Energy Resources Company. It is a wholly owned subsidiary of DTEE, providing coal transportation services to DTEE and third-party customers through

[38] Lyons Direct, TSL-10, Table 1, National Grid (MA) and Atco Electric (Alberta).

a terminal in Superior, WI.[39] In this case, DTEE Witness Milo proposed $0.42 million in capital expenditure for MERC in the projected bridge period ending December 2025 and no capital expenditure in the projected test year.[40] He also proposed $1.70 million in O&M expense for MERC Fuel Handling in the projected test year.[41]

Q. Is MERC projected to cease operations in 2026?

A. Yes, MERC is projected to cease operations at the end of June 2026. This follows the Commission's Order in Case No. U-21193 approving a fuel conversion from coal to natural gas at Belle River Power Plant, the primary plant to which MERC delivers coal through its transshipment services.[42]

Q. How have MERC's coal delivery volumes changed over time?

A. MERC's coal delivery volumes have declined annually by 8% from 2019-2024.[43] DTEE forecasts them to drop by another 13% in 2025 before finally tapering off in 2026.

Q. Given the decline in coal delivery volumes, is it reasonable to apply inflation escalation to MERC-related fuel-handling costs?

A. No. An inflation escalator is intended to preserve purchasing power for a constant level of service. MERC is scheduled to cease operations in June 2026, and coal-delivery volumes are already in steep decline. DTEE is not projecting to provide the same level of service over the period, and thus any inflation adjustments are inappropriate.

[39] Direct Testimony of David C. Milo, DCM-7, 6:11.

[40] *Id.* DCM-11, 9:13

[41] *Id.* DCM-16, 9:11

[42] *Id.* DCM-8, 18:23

[43] Ex CUB-16, MERC Transshipment Volumes.

Q. How have MERC's Fuel Handling O&M historical expenses changed in response to these declining volumes over time?

A. Between 2019 and 2024, MERC Fuel Handling O&M expenses have declined at a compounded annual rate of 2.9%.[44] While this is lower than the commensurate annual decline in coal volumes, it still doesn't warrant DTE's proposed increase in MERC Fuel Handling O&M for bridge years. As previously discussed, inflation adjustment is not appropriate for this category, and the declining costs trends with declining volumes confirm that.

Q. How have MERC's Fuel Handling O&M authorized rates compared with these expenses?

A. Across three recent cases with historical data available (U-20561, U-20836, U-21297), the Commission authorized DTEE to recover $11.54 million in MERC Fuel Handling O&M expenses from ratepayers.[45] The actual expenditure across the test periods for these rate cases totaled $10.23 million, costing $1.3 million to ratepayers. As shown in (Ex. CUB-18), this difference is not driven by a one-off variance but indicates a consistent overestimation of O&M expenses for MERC Fuel Handling by DTEE.

[44] Ex CUB-17, MERC Fuel Handling Historical O&M.

[45] Ex CUB-18, MERC Fuel Handling Authorized vs Actual O&M.

Q. What about the almost $2 million reduction of the expected O&M for MERC Fuel Handling in column (j), line 9, of Exhibit A-13, Schedule C5.2, proposed by DTEE?

A. This reduction reflects the scheduled closure of MERC's transshipment business in June 2026, not adjustments for historical underspending.[46]

Q. What is your recommendation?

A. Given DTEE's historical underspending on MERC's Fuel Handling O&M expenses and the inappropriate application of inflation adjustment to a declining cost, I recommend the Commission disallow $1.7 million in expenses for MERC Fuel Handling. DTEE has already recovered sufficient amounts in prior years to cover any minimal O&M expenses required to operate the facility safely, reliably, and in an environmentally compliant manner until its closure.

VI. SECURITIZATION OF DISTRIBUTION SYSTEM STRANDED ASSETS

Q. What distribution system conversions does DTEE include in this case?

A. DTEE witness R. M. Stowe describes several distribution system conversion programs that are ongoing at DTEE with expenditures that are included in this case. These include:

- 4.8 kV Conversion Program[47]
- 4.8 kV ISO Conversion Program[48]
- City of Detroit Infrastructure (CODI) Conversion Program[49]

[46] Milo Direct, DCM-16, 17:22.

[47] Direct testimony of R. M. Stowe, RMS-21:4 through RMS-42:12.

[48] *Id.*, RMS-42:14 through RMS-48:4.

[49] *Id.*, RMS-48:6 through RMS-68:12.

- 8.3kV Pontiac Conversion Program[50]

Q. What stranded assets result from a distribution system conversion?

A. As described by DTEE witness R. M Stowe, the 4.8kV conversion program typically involves decommissioning 4.8kV substations and associated subtransmission infrastructure.[51] It may also include replacing any 4.8kV-only transformers and protection devices.

As described by DTEE witness R. M. Stowe, the 4.8 kV ISO conversion program includes ISO down transformers.[52]

As described by DTEE witness R. M. Stowe, the CODI program includes decommissioning substations, converting networks and circuits, and decommissioning the existing 4.8 kV underground distribution system and the 24kV sub-transmission system[53] converting network.

As described by DTEE witness R. M. Stowe, the 8.3kV Pontiac conversion program similarly includes decommissioning at least substation equipment, fuses, and line transformers.

In each case, the decommissioning of equipment will include retirement units that are not yet fully depreciated. Those retirement units should properly be treated as stranded assets and securitized.

[50] *Id.*, RMS-69:1 through RMS-74.

[51] *Id.*, RMS-23:1-2.

[52] *Id.*, RMS-44:24.

[53] *Id.*, RMS-49:16-23.

Q. Are there other causes of stranded assets than conversions?

A. Yes, assets might also be stranded by replacements to meet new Company standards.

Q. Why should stranded assets from distribution system conversions and other activities be securitized?

A. These are assets that have remaining life at the time of system conversion but will be withdrawn from service. As with power plants that have been retired before being fully depreciated, these assets should be considered for securitization so as to remove them from DTEE's rate base, finance their remaining value at lower cost, and thereby lower costs to DTEE's customers. These customers are paying for the replacement assets at the beginning of their depreciation when their contribution to rate base is high, so their continuing payments for the retired assets are an undue burden.

Q. What do you recommend that the Commission order on this matter?

A. I recommend that the Commission order DTEE to remove the net book value at retirement of all assets taken out of service in conjunction with distribution system conversions going forward starting in the test year, as well as the current net book value of those remaining in rate base from previous conversions, placing them in a deferred asset account. The Commission should further order DTEE to request securitization.

VII. SECURITIZATION OF DISTRIBUTION SYSTEM SURGE SPENDING

Q. DTEE has been and in this case proposes increasing expenditures on its distribution system. Should any of this spending be considered to be a surge in spending rather than a permanent increase in spending levels?

A. Yes. There are two reasons to consider a significant portion of the increased distribution spending in recent cases and in this case to be a surge. First, a considerable portion of this spending increase is to catch up on deferred maintenance investments. Second, a portion of this spending is to repair damage that resulted from inadequate preventive maintenance, especially inadequate tree trimming.

Q. Please explain why a significant portion of the increased spending is to catch up on deferred maintenance investments.

A. The Liberty Audit identified a number of types of distribution system assets that should be inspected more frequently

Preventive maintenance can reduce aging and extend the expected life of some assets, such as wooden poles. But for many distribution system assets such as line transformers and conductors, most utilities replace failing or failed equipment. Setting aside the benefits of preventive maintenance, the failure rates of distribution system components are not much affected by periodic inspection and maintenance programs. Rather, the main value of an inspection is to identify incipient failures and replace equipment prior to it fully failing and causing an outage.

In steady-state programs, the probability that an incipient failure will be found and the device replaced or repaired before full failure and an outage is approximately[54] proportional to the ratio of the length of the period of failure incipiency to the period between inspections. So, a doubling of the frequency of inspections (or halving of the period between inspections), up to the point when the period between inspections approximates the duration of incipient failure, will in steady state approximately double the number of incipient failures that are detected and addressed. But each of these replacements or repairs during incipient failure avoids a replacement or repair upon failure. In steady state, the number of repairs or replacements per is not greatly changed by more frequent inspections. However, when the period between inspections is shortened, there will be a period of approximately the length of the new inspection cycle when additional replacements or repairs are performed because the more frequent inspections observe more incipient failures that would otherwise have been replaced or repaired later upon full failure. Thus, as with DTEE's tree-trimming surge, a shortened period between inspections will produce a surge.

With more frequent inspections, a larger share of incipient failures will be repaired before full failure and an outage, which is the main benefit of the more frequent inspections. Repairs or replacements during an incipient failure will happen sooner than if the repair or replacement is done only upon full failure. Thus, more frequent inspections to repair or replace equipment with incipient failures will shorten the expected service life of the

[54] If the period of incipient failure was deterministic and constant, this would not be an approximation. The more heterogenous the period of incipient failure, the more necessary it would be to use a more sophisticated formulation of the probability of replacement or repair before full failure, but even in that case, my qualitative characterization of such programs is broadly valid.

equipment by the difference in time between inspection-based replacement of equipment with an incipient failure and when that equipment would have fully failed. Statistically, that difference will be half the average duration of an incipient failure. So, there will be a modest increase in baseline frequency or repair or replacement once a surge is complete. But the utility costs of individual repairs or replacements will likely be less when they are done to correct an incipient failure discovered through inspections than when done in response to outages. The balance of mildly increased repair or replacement frequency and lower cost per repair or replacement event may result in a modest increase or decrease of baseline spending levels, but historic spending levels adjusted for inflation are a reasonable estimate of the post-surge spending levels.

In general, shifts in inspection standards that lengthen the period that inspections would consider to be incipient failure would have similar effects to those I described above for increased inspection frequency.

Changes in distribution system component standards that increase the expected life of components have somewhat different effects on maintenance and repair costs, producing a cost surge as better but more expensive components are infused into the distribution system in replacement of the previous technology, but then providing reduced frequency of repair or replacement after the improved components are in place. Complete replacement of the incumbent technology with the new technology will take the full life cycle of the incumbent technology components, but reduced frequency of repair or replacement due to the new technology will gradually take effect. The period of surge spending associated with such a process depends on the relative effects of increased component cost and decreased repair

frequency and require a different calculation of the surge period. But if the technology change is cost-effective, there will be a period of spending above historical spending levels, followed by a permanent reduction of spending to a level below the historical baseline.

We can therefore reasonably approximate surge spending as the amount in excess of historic spending levels including those done to repair outages caused by the class of component in question, and expect a return to historic spending levels after the surge.

Q. Please explain why a portion of increased spending is to repair damage that resulted from inadequate preventive maintenance?

A. Some well-executed utility maintenance programs serve to prevent damage that then requires repair or replacement of distribution system components. Sometimes, the preventive maintenance is performed directly on the component whose failure rate is reduced. A good example of this is that preservative can be reapplied to wooden poles showing early signs of decay or of depleted preservatives. It is reasonable to assume that some portion of DTEE pole defects is due to historic low inspection frequency and consequent low application of preventive maintenance practices.

But sometimes, the damage is avoided by maintenance or repair of something else. A good example of this is tree trimming. Trees do cause immediate outages, and reducing those outages has been the primary focus of the DTEE's tree trimming surge. However, tree contact causes shorts that can damage nearby electrical equipment. Tree and limb fall creates tension in conductors that can crack pole top insulators. Conductor breaks due to tree damage are typically repaired by splicing conductor at the break point, but splices are weaker than complete conductor and are therefore more susceptible to future line breaks.

It is therefore reasonable to assume that some portion of DTEE's distribution system equipment has been damaged and will have shorter life and higher failure rates as a result of DTEE's historic tree-trimming deficiencies.

Thus, the current baseline and surging spending on DTEE's distribution system are at least partly attributable to deficient historical preventive maintenance, especially in tree trimming.

Q. How should the Commission determine the amounts of surge spending?

A. There are options. Various engineering studies might be done to approximate it, but those would be complex and subject to significant parameter uncertainty, therefore argument. A simpler and likely more reliable approach is to use historical baseline spending on each distribution asset category as though it is the non-surge spending level, consider all spending above that level to be surge spending for several years, then consider spending levels thereafter to be baseline (non-surge) spending. The period during which extra spending is considered surge spending should be based on, and perhaps a bit longer than, the inspection cycle during which DTEE is deemed to be catching up on repair or replacement of distribution system assets.

Q. Why should surge spending on the distribution system be securitized?

A. The Commission previously authorized DTEE's surge in tree-trimming to be deferred and securitized. The logic of that action and this proposal are similar. Much of the distribution surge spending is needed because DTEE spent inadequately on maintenance and inspections in the past; current customers cannot fairly be asked to pay those costs that were not paid by past customers. Current customers will not see major benefits from the

surge spending, which will largely benefit future customers (and perhaps their future selves). Securitization of a surge of operations and maintenance costs reallocates revenue requirements onto the future customers that are the main beneficiaries of the surge spending.

DTEE's past failures to adequately maintain the distribution system, and particularly to spend adequately on current expenses like operations and maintenance, should not enrich current shareholders by inordinately increasing rate base to catch up. Securitization of capital expenditures places surge investments outside DTEE rate base.

Finally, and most importantly, the cost of financing the surge expenditures through securitization bonds will be considerably less than DTEE's authorized weighted cost of capital, helping to mitigate, though not eliminating, the rate impacts of the surge.

Q. What do you recommend the Commission do in this case?

A. First, I recommend the Commission direct DTEE to record as regulatory assets the distribution system maintenance and replacement spending identifiable as catch-up spending or above maintenance baseline. My colleague Richard Bunch and Attorney General, MEC, and NRDC ("MNAG") witnesses Dennis Stephens and Paul Alvarez identify some of the relevant programs and provide estimates of those amounts.

Second, I recommend the Commission order DTEE to propose in its next rate case the baseline spending and surge spending in each distribution system program as well as the duration or criteria for ending surge spending and considering subsequent spending to be normal utility activity.

Third, I recommend the Commission order DTEE to periodically propose securitization of deferred surge spending, as amounts accumulate that warrant the transaction costs. The Commission's previous use of $100 million related to tree trimming is a good point of reference.

VIII. RATE DESIGN

Q. What did DTEE propose in this case regarding rate design?

A. DTEE's rate design proposals are presented and supported by witnesses Aaron Willis (for residential rate schedules) and Anthony Turner (for commercial and industrial rate schedules). For the most part, DTEE does not innovate from the rate design used in the last case.

Aside from changes in the per-unit billing rates attendant on proposed changes in cost responsibility, the principal topic that they address is the treatment of retail capacity charges. Due to a large increase in revenue responsibility attributed to production capacity, as provided by MCL 460.6w(3)(b), in the present case due to reconciliation of past capacity charges proposed by DTEE witness Burgdorf[55], the portion of production costs attributed to capacity costs in this case is quite large. This would have highly distorted the ratio of demand charges to energy charges in the larger customer rate schedules, so witness Turner allocates a potion of capacity revenue responsibility to energy charges in order to preserve a tolerable ratio between demand and energy revenues in those classes.

[55] Direct Testimony of Shawn D. Burgdorf, SDB-12:7-25.

Q. Do you find the continued current approach to rate design satisfactory?

A. No, I continue to be dissatisfied with DTEE's approach to rate design, largely on the grounds that it provides improper price signals to customers and in doing so also creates significant intra-class cross-subsidies. In this case, I propose that the Commission direct DTEE to present seasonal volumetric distribution rates in its next rate case

Q. Why do you recommend that the Commission adopt seasonal volumetric distribution rates?

A. DTEE currently applies a uniform volumetric distribution charge throughout the year. However, distribution system utilization is higher in summer such that any capacity limitations requiring distribution system investments are in summer and increases in winter demand would generally not require distribution system investments. My colleague Graham Woolley testifies about the seasonality of distribution system capacity and demand and the resulting capacity utilization. He shows that DTEE distribution system capacity utilization is distinctly seasonal with a regime of higher utilization from approximately mid-May until the beginning of October.[56] A shift to seasonal distribution rates would have at least four salutary effects.

First, it would more accurately bill customers for their cost of service, with customers that have relatively high summer share of electricity usage paying more than under the current rate design and customers with relatively high winter share of electricity usage paying less. Amongst residential customers, low-income customers and occupants of multi-family

[56] See Exhibit CUB-24, Transformer Network Eff Cap Utilization w Current Load.

dwellings tend to have lower air conditioning usage and higher incidence of electric heat, so seasonal distribution rates would make rate design more equitable.

Second, it would help to repair an unfairness in current rate design. As described by DTEE witness Cejas Goyanes, distribution system costs are allocated in the Company's COSS based on customer count, demand, and special studies of metering costs.[57] Demand is used to allocate costs of "poles, wires, conduit, substations, transformers, and other equipment that comprise the distribution system."[58] The demand metrics used in the COSS are all based on summer peaks. Some distribution costs are assigned to monthly service charges, but most distribution system costs assigned to residential customers are then assigned uniformly as a rate per kWh.[59] Unfairness arises in this approach in that customers that have electric heat have significantly greater kWh sales than customers that use fossil-fueled heat but have similar summer peak demand, As a result, the customers with electric heat overpay their cost of service because they pay a kWh rate based on the average ratio of annual kWh consumption to summer demand peak. A higher summer rate and lower winter rate would partially mitigate this unfairness. Absent a distinct difference in seasonal distribution rates, a separate heating rate would be needed to rectify this unfairness.

Third, seasonal distribution rates that are higher in summer will incent customers to adopt energy efficiency measures that reduce summer load, thereby avoiding utility costs. In particular, this would include air conditioning, building envelope improvements that

[57] Direct Testimony of R. Cejas Goyanes, RCG-17:21 through RCG-19:20.

[58] *Id.*, RCG-18:2-4.

[59] Direct Testimony of A. Willis, AW-12:1-13.

reduce cooling loads, smart thermostats that reduce cooling demand in unoccupied space during daytime, measures that reduce solar gain, and measures that produce interior heat.

Fourth, seasonal distribution rates that are lower in summer may enable customers to adopt electric heat by making it less costly to operate. As Graham Woolley shows in his testimony, there is considerable opportunity to increase the use of heat pump space heating before distribution system capacity usage would peak in winter. Electrification of residential heat has multiple benefits including public health benefits from reducing local emissions from fossil fuel combustion, reducing greenhouse gas emissions, and economic benefits from reducing fuel imports from outside of Michigan.

Q. If the Commission were persuaded to adopt seasonal residential distribution rates, how should those rates be determined?

A. As I noted above, DTEE uses demand-based allocators in its COSS for the costs of "poles, wires, conduit, substations, transformers, and other equipment that comprise the distribution system."[60] If DTEE were to allocate those costs to summer distribution rates, because that is when demand peaks occur, the resulting rate design would have very low winter volumetric rates and very high summer volumetric rates. But, contrary to the use of a demand allocator in the COSS, several of these cost categories are not materially driven by demand. Poles, wires, and conduit are needed to deliver power at all times but relatively little incremental cost is drive by peak demand. Substations, transformers, and some other equipment is sized based on demand. I therefore recommend that costs of poles, wires, and

[60] Cejas Goyanes Direct, RCG-18:2-4.

conduit be allocated to energy throughout the year but that costs of substations, transformers, and related equipment be allocated to summer energy.

IX. RECOMMENDATIONS

Q. Please summarize your conclusions and recommendations to the Commission.

A. I recommend that the Commission:

1. Disregard DTEE's arguments that disallowances create risks for DTEE;
2. Continue to use historical cost averaging rather than constant dollar averaging to project DTEE's distribution system costs;
3. Disallow $1.7 million operations and maintenance costs for MERC.
4. Direct DTEE to propose securitization of the net book value of any assets removed from service as a result of distribution system conversion projects.
5. Direct DTEE to defer and subsequently propose securitization of distribution system investments and expenses that are being incurred to catch up on distribution system maintenance using spending above historical baseline as the guide to determining surge spending, and to propose criteria for ending this practice as the surge is completed.
6. Direct DTEE to propose seasonal distribution rates in its next rate case.

Q. Does that complete your testimony?

A. Yes, it does.

Douglas B. Jester

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Professional experience

January 2011 – present 5 Lakes Energy

Managing Partner

Co-owner of a consulting firm working to advance the clean energy economy in Michigan and beyond. Consulting engagements with foundations, startups, and large mature businesses have included work on public policy, business strategy, market development, technology collaboration, project finance, and export development concerning energy efficiency, smart grid, renewable generation, electric vehicle infrastructure, and utility regulation and rate design. Policy director for renewable energy ballot initiative and Michigan energy legislation advocacy. Supported startup of the Energy Innovation Business Council, a trade association of clean energy businesses. Developed integrated resource planning models for use in ten states' compliance with the Clean Power Plan. Expert witness in more than 70 electric utility regulation cases in Michigan and approximately 15 cases in other states.

February 2010 - December 2010 Michigan Department of Energy, Labor and Economic Growth

Senior Energy Policy Advisor

Advisor to the Chief Energy Officer of the State of Michigan with primary focus on institutionalizing energy efficiency and renewable energy strategies and policies and developing clean energy businesses in Michigan. Provided several policy analyses concerning utility regulation, grid-integrated storage, performance contracting, feed-in tariffs, and low-income energy efficiency and assistance. Participated in Pluggable Electric Vehicle Task Force, Smart Grid Collaborative, Michigan Prosperity Initiative, and Green Partnership Team. Managed development of social-media-based community for energy practitioners. Organized conference on Biomass Waste to Energy.

August 2008 - February 2010 Rose International

Business Development Consultant - Smart Grid

- Employed by Verizon Business' exclusive external staffing agency for the purpose of providing business and solution development consultation services to Verizon Business in the areas of Smart Grid services and transportation management services.

December 2007 - March 2010 Efficient Printers Inc

President/Co-Owner

- Co-founder and co-owner with Keith Carlson of a corporation formed for the purpose of acquiring J A Thomas Company, a sole proprietorship owned by Keith Carlson. Recognized as Sacramento County (California) 2008 Supplier of the Year and Washoe County (Nevada) Association for Retarded Citizens 2008 Employer of the Year. Business operations discontinued by asset sale to focus on associated printing software services of IT Services Corporation.

August 2007 - 2015 IT Services Corporation

President/Owner

- Founder, co-owner, and President of a startup business intended to provide advanced IT consulting services and to acquire or develop managed services in selected niches, currently focused on developing e-commerce solutions for commercial printing with software-as-a-service.

2004 – August 2007 Automated License Systems

Chief Technology Officer

- Member of four-person executive team and member of board of directors of a privately-held corporation specializing in automated systems for the sale of hunting and fishing licenses, park campground reservations, and in automated background check systems. Executive responsible for project management, network and data center operations, software and product development. Brought company through mezzanine financing and sold it to Active Networks.

2000 - 2004 WorldCom/MCI

Director, Government Application Solutions

- Executive responsible in various combinations for line of business sales, state and local government product marketing, project management, network and data center operations, software and product development, and contact center operations for specialized government process outsourcing business. Principal lines of business were vehicle emissions testing, firearm background checks, automated hunting and fishing license systems, automated appointment scheduling, and managed application hosting services. Also responsible for managing order entry, tracking, and service support systems for numerous large federal telecommunications contracts such as the US Post Office, Federal Aviation Administration, and Navy-Marine Corps Intranet.
- Increased annual line-of-business revenue from $64 million to $93 million, improved EBITDA from approximately 2% to 27%, and retained all customers, in context of corporate scandal and bankruptcy.
- Repeatedly evaluated in top 10% of company executive management on annual performance evaluations.

1999-2000 Compuware Corporation

Senior Project Manager

- Senior project manager, on customer site with five project managers and team of approximately 80, to migrate a major dental insurer from a mainframe environment to internet-enabled client-server environment.

1995 - 1999 City of East Lansing, Michigan

Mayor and Councilmember

- Elected chief executive of the City of East Lansing, a sophisticated city of 52,000 residents with a council-manager government employing about 350 staff and with an annual budget of about $47 million. Major accomplishments included incorporation of public asset depreciation into budgets with consequent improvements in public facilities and services, complete rewrite and modernization of city charter, greatly intensified cooperation between the City of East Lansing and the East Lansing Public Schools, significant increases in recreational facilities and services, major revisions to housing code, initiation of revision of the City Master Plan, facilitation of the merger of the Capital Area Transportation Authority and Michigan State University bus systems, initiation of a major downtown redevelopment project, City government efficiency improvements, and numerous other policy initiatives. Member of Michigan Municipal League policy committee on Transportation and Environment and principal writer of league policy on these subjects (still substantially unchanged as of 2022).

1995-1999 Michigan Department of Natural Resources

Chief Information Officer

- Executive responsibility for end-user computing, data center operations, wide area network, local area network, telephony, public safety radio, videoconferencing, application development and support, Y2K readiness for Departments of Natural Resources and Environmental Quality. Directed staff of about 110. Member of MERIT Affiliates Board and of the Great Lakes Commission's Great Lakes Information Network (GLIN) Board.

1990-1995 Michigan Department of Natural Resources

Senior Fisheries Manager

- Responsible for coordinating management of Michigan's Great Lakes fisheries worth about $4 billion per year including fish stocking and sport and commercial fishing regulation decisions, fishery monitoring and research programs, information systems development, market and economic analyses, litigation, legislative analysis and negotiation. University relations. Extensive involvement in regulation of steam electric and hydroelectric power plants.
- Served as agency expert on natural resource damage assessment, for all resources and causes.
- Considerable involvement with Great Lakes Fishery Commission, including:

- Co-chair of Strategic Great Lakes Fishery Management Plan working group
- Member of Lake Erie and Lake St. Clair Committees
- Chair, Council of Lake Committees
- Member, Sea Lamprey Control Advisory Committee
- St Clair and Detroit River Areas of Concern Planning Committees

1989-1990 American Fisheries Society

Editor, North American Journal of Fisheries Management

- Full responsibility for publication of one of the premier academic journals in natural resource management.

1984 - 1989 Michigan Department of Natural Resources

Fisheries Administrator

- Assistant to Chief of Fisheries, responsible for strategic planning, budgets, personnel management, public relations, market and economic analysis, and information systems. Department of Natural Resources representative to Governor's Cabinet Council on Economic Development. Extensive involvement in regulation of steam electric and hydroelectric power plants.

1983-present Michigan State University

Adjunct Instructor

- Irregular lecturer in various undergraduate and graduate fisheries and wildlife courses and informal graduate student research advisor in fisheries and wildlife and in parks and recreation marketing.

1977 – 1984 Michigan Department of Natural Resources

Fisheries Research Biologist

- Simulation modeling & policy analysis of Great Lakes ecosystems. Development of problem-oriented management records system and "epidemiological" approaches to managing inland fisheries.
- Modeling and valuation of impacts of power plants on natural resources and recreation.

Education

1991-1995 Michigan State University

PhD Candidate, Environmental Economics

Coursework completed, dissertation not pursued due to decision to pursue different career direction.

1980-1981 University of British Columbia

Non-degree Program, Institute of Animal Resource Ecology

1974-1977 Virginia Polytechnic Institute & State University

MS Fisheries and Wildlife Sciences

MS Statistics and Operations Research

1971-1974 New Mexico State University

BIS Mathematics, Computer Science, Biology, and Fine Arts

Citizenship and Community Involvement

Youth Soccer Coach, East Lansing Soccer League, 1987-89

Co-organizer, East Lansing Community Unity, 1992-1993

Bailey Community Association Board, 1993-1995

East Lansing Commission on the Environment, 1993-1995

East Lansing Street Lighting Advisory Committee, 1994

Councilmember, City of East Lansing, 1995-1999

Mayor, City of East Lansing, 1995-1997

East Lansing Downtown Development Authority Board Member, 1995-1999

East Lansing Transportation Commission, 1999-2004

East Lansing Non-Profit Housing and Neighborhood Services Corporation Board Member, 2001-2004

Lansing – East Lansing Smart Zone Board of Directors, 2007-2017

Council on Labor and Economic Growth, State of Michigan, by appointment of the Governor, May 2009 – May 2012

East Lansing Downtown Development Authority Board Member and Vice-Chair, 2010 – 2018.

East Lansing Brownfield Authority Board Member and Vice-Chair, 2010 – 2018.

East Lansing Downtown Management Board and Chair, 2010 – 2016

East Lansing City Center Condominium Association Board Member, 2015 – present.

City of East Lansing Advisory Commissioner to the Lansing Board of Water and Light, 2017 – present.

State of Michigan UP Energy Task Force, 2019-present, appointed by Governor Whitmer.

State of Michigan Dam Safety Committee, 2020-2021

State of Michigan Council on Climate Solutions, Energy Production, Transmission, Distribution, and Storage Workgroup Co-Chair, 2021-present.

Board and Executive Committee Member, For Love of Water (FLOW), 2019 - present

S&P Global
Ratings

Research

Tear Sheet:

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

January 31, 2025

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What's new: The Michigan Public Service Commission (MPSC) recently approved a $217 million revenue increase for DTE Electric Co. (DTEE) effective Feb. 6, 2025. The rate case decision maintains the company's authorized return on equity (ROE) at 9.9%, maintains the previously approved equity capitalization structure at 50%, and rejects DTEE's request to raise its authorized ROE to 10.5%. Additionally, the commission also extended the company's investment recovery mechanism (IRM) feature through 2026.

DTE Electric Co.

Michigan

	Rate change (mil. $)	ROE (%)	Rate base (mil. $)
Current Case			
Company request	441.0	10.50	22,063
Authorized	217.4	9.90	21,787
Previous Case			
Company request	583.1	10.25	22,344
Authorized	368.1	9.90	22,151

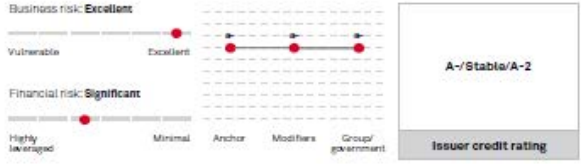
Source: S&P Capital IQ Pro

Why it matters: Although the approved revenue increase is materially lower than DTEE's original rate request of approximately $456 million (later revised to $441 million), it is only modestly below S&P Global Ratings' base case expectation for DTEE's financial performance. The key difference between the company's rate request and the final MPSC decision primarily reflects lower forecasted operating expenses capital spend for forecasted years and lower-than-requested approved ROE, collectively accounting for close to half of DTEE's revised rate request. The commission also approved DTEE's request to extend its IRM through Dec. 31, 2026. The IRM is a cost recovery rider that permits for a timelier recovery of DTEE's electric distribution system investments aimed at improving reliability.

Overall, while the rate case outcome modestly weakens DTEE's funds from operations (FFO) to debt by about 30 basis points beginning in 2025, we expect the company's forecasted FFO to

debt to remain within its financial risk profile category, averaging about 19%-20% over the next two years. Key assumptions to our forecast include capital spending of about $3.8 billion over the next two years, dividends of $800-$900 million, negative cash flow deficit of approximately $1.8 billion in 2025, and steady costs recovery for its investments.

Ratings Score Snapshot



Recent Research

- DTE Energy Co., April 2, 2024

Company Description

DTEE generates and distributes electricity to about 2.3 million residential, commercial, and industrial customers in southeastern Michigan. The electric utility has around 12,000 megawatts of generation capacity.

Outlook

Our stable outlook on DTEE reflects our base-case assumption that the company will generate sufficient cash flow to maintain financial measures that support S&P Global Ratings-adjusted FFO to debt of 19%-20%. The stable outlook also reflects our expectation that parent DTE will focus growth on its lower-risk, regulated utility strategy. We expect the utility businesses will account for about 90% of the consolidated company. We expect DTE's financial measures will generally remain in line with expectations, including FFO to debt of 14%-16%.

Downside scenario

We could lower our rating on DTEE within the next 24 months if we lower our rating on DTE or if DTEE's stand-alone financial measures weaken such that its FFO to debt remains consistently below 15%.

Upside scenario

We could raise our rating on DTEE within the next 24 months if we raise our rating on DTE and DTEE's stand-alone FFO to debt consistently exceeds 21%.

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

Financial Summary

DTE Electric Co.--Financial Summary

Period ending	Dec-31-2018	Dec-31-2019	Dec-31-2020	Dec-31-2021	Dec-31-2022	Dec-31-2023
Reporting period	2018a	2019a	2020a	2021a	2022a	2023a
Display currency (mil.)	$	$	$	$	$	$
Revenues	5,298	5,224	5,506	5,809	6,353	5,729
EBITDA	2,157	2,297	2,507	2,596	2,715	2,715
Funds from operations (FFO)	1,858	1,943	2,165	2,256	2,389	2,282
Interest expense	428	465	490	504	551	623
Cash interest paid	299	309	329	335	359	418
Operating cash flow (OCF)	1,725	1,740	1,909	1,273	1,654	1,534
Capital expenditure	1,982	2,192	2,666	3,008	2,617	3,076
Free operating cash flow (FOCF)	(257)	(453)	(757)	(1,735)	(964)	(1,542)
Discretionary cash flow (DCF)	(718)	(947)	(1,296)	(2,323)	(1,727)	(2,544)
Cash and short-term investments	16	12	16	9	15	15
Gross available cash	16	12	16	9	15	15
Debt	8,219	9,087	9,490	10,115	11,528	12,009
Common equity	6,793	7,195	8,070	8,903	9,695	10,224
Adjusted ratios						
EBITDA margin (%)	40.7	44.0	45.5	44.7	42.7	47.4
Return on capital (%)	8.7	8.2	8.1	8.0	7.6	6.8
EBITDA interest coverage (x)	5.0	4.9	5.1	5.1	4.9	4.4
FFO cash interest coverage (x)	7.2	7.3	7.6	7.7	7.6	6.5
Debt/EBITDA (x)	3.8	4.0	3.8	3.9	4.2	4.4
FFO/debt (%)	22.6	21.4	22.8	22.3	20.7	19.0
OCF/debt (%)	21.0	19.1	20.1	12.6	14.3	12.8
FOCF/debt (%)	(3.1)	(5.0)	(8.0)	(17.2)	(8.4)	(12.8)
DCF/debt (%)	(8.7)	(10.4)	(13.7)	(23.0)	(15.0)	(21.2)

Peer Comparison

DTE Electric Co.--Peer Comparisons

	DTE Electric Co.	CenterPoint Energy Inc.	CMS Energy Corp.	NiSource Inc.	Southwestern Public Service Co.
Foreign currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Negative/A-2
Local currency issuer credit rating	A-/Stable/A-2	BBB+/Negative/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Negative/A-2
Period	Annual	Annual	Annual	Annual	Annual
Period ending	2023-12-31	2023-12-31	2023-12-31	2023-12-31	2023-12-31
Mil.	$	$	$	$	$

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

DTE Electric Co.--Peer Comparisons					
Revenue	5,729	8,523	7,425	5,505	2,152
EBITDA	2,715	3,077	2,498	2,262	902
Funds from operations (FFO)	2,282	2,103	1,854	1,753	670
Interest	623	769	644	576	167
Cash interest paid	418	760	629	499	152
Operating cash flow (OCF)	1,534	3,614	2,309	1,881	842
Capital expenditure	3,076	4,369	2,439	2,590	707
Free operating cash flow (FOCF)	(1,542)	(755)	(130)	(708)	135
Discretionary cash flow (DCF)	(2,544)	(2,065)	(755)	(1,572)	(174)
Cash and short-term investments	15	541	227	2,245	3
Gross available cash	15	541	227	2,245	3
Debt	12,009	18,802	14,610	12,494	3,934
Equity	10,224	9,667	9,018	9,893	3,986
EBITDA margin (%)	47.4	36.1	33.6	41.1	41.9
Return on capital (%)	6.8	6.5	5.8	6.5	6.4
EBITDA interest coverage (x)	4.4	4.0	3.9	3.9	5.4
FFO cash interest coverage (x)	6.5	3.8	3.9	4.5	5.4
Debt/EBITDA (x)	4.4	6.1	5.8	5.5	4.4
FFO/debt (%)	19.0	11.2	12.7	14.0	17.0
OCF/debt (%)	12.8	19.2	15.8	15.1	21.4
FOCF/debt (%)	(12.8)	(4.0)	(0.9)	(5.7)	3.4
DCF/debt (%)	(21.2)	(11.0)	(5.2)	(12.6)	(4.4)

Environmental, Social, And Governance

Environmental factors are a negative consideration in our credit rating analysis of DTEE. The company has exposure to environmental risks compared with peers given its dependence on coal-fired generation and exposure to nuclear generation. Coal-fired generation contributed over 30% of DTEE's net generation portfolio in 2023, a significant carbon footprint relative to its peers. The company is working to reduce its carbon footprint by retiring its coal-fired generation and replacing that capacity with clean energy sources, and the recently approved IRP in Michigan signals a manageable path for the company to address energy-transition risk. Additionally, the company's nuclear generation (approximately 10% of net generation capacity) entail operating and nuclear waste risks and exposes it to potential health and safety risks.

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

Rating Component Scores	
Foreign currency issuer credit rating	**A-/Stable/A-2**
Local currency issuer credit rating	**A-/Stable/A-2**
Business risk	**Excellent**
Country risk	Very Low
Industry risk	Very Low
Competitive position	Excellent
Financial risk	**Significant**
Cash flow/leverage	Significant
Anchor	**a-**
Diversification/portfolio effect	Neutral (no impact)
Capital structure	Neutral (no impact)
Financial policy	Neutral (no impact)
Liquidity	Adequate (no impact)
Management and governance	Neutral (no impact)
Comparable rating analysis	Neutral (no impact)
Stand-alone credit profile	**a-**
Group credit profile	**bbb+**
Entity status within group	**Core (no impact on SACP)**

Related Criteria

- Criteria | Corporates | General: Sector-Specific Corporate Methodology, April 4, 2024,
- Criteria | Corporates | General: Methodology: Management And Governance Credit Factors For Corporate Entities, Jan. 7, 2024
- Criteria | Corporates | General: Corporate Methodology, Jan. 7, 2024
- General Criteria: Environmental, Social, And Governance Principles In Credit Ratings, Oct. 10, 2021
- General Criteria: Group Rating Methodology, July 1, 2019
- Criteria | Corporates | General: Corporate Methodology: Ratios And Adjustments, April 1, 2019
- Criteria | Corporates | General: Reflecting Subordination Risk In Corporate Issue Ratings, March 28, 2018
- General Criteria: Rating Government-Related Entities: Methodology And Assumptions, March 25, 2015
- Criteria | Corporates | General: Methodology And Assumptions: Liquidity Descriptors For Global Corporate Issuers, Dec. 16, 2014
- General Criteria: Methodology: Industry Risk, Nov. 19, 2013
- General Criteria: Country Risk Assessment Methodology And Assumptions, Nov. 19, 2013

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

- General Criteria: Principles Of Credit Ratings, Feb. 16, 2011

DTE Electric Co. Rate Case Outcome Modestly Below Base-Case Expectation

MOODY'S
RATINGS

Announcement of Periodic Review: Moody's Ratings announces completion of a periodic review of ratings of DTE Energy Company, DTE Electric Company and DTE Gas Company

11 Mar 2025

New York, March 11, 2025 -- Moody's Ratings (Moody's) has completed a periodic review of the ratings of DTE Energy Company (DTE Energy), DTE Electric Company (DTE Electric), DTE Gas Company (DTE Gas) and other ratings that are associated with these issuers.

The review was conducted through a rating committee held on 7 March 2025 in which we reassessed the appropriateness of the ratings in the context of the relevant principal methodology(ies), and recent developments.

This publication does not announce a credit rating action and is not an indication of whether or not a credit rating action is likely in the near future. Please see the Issuer page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

Key Rating considerations and rationale are summarized below.

DTE Energy Company's credit quality reflects the relatively strong credit profiles of its two primary regulated utilities, DTE Electric Company (DTE Electric, A2 stable) and DTE Gas Company (DTE Gas, A3 stable), and the supportive regulatory framework in Michigan, where both utilities operate. We view DTE as a stable regulated utility holding company with good growth potential, and expect the regulatory environment to remain credit supportive. In 2023 and 2024, DTE's credit metrics sustained an improvement back to historical levels following the weakness exhibited in 2022 primarily driven by a less supportive rate case outcome and delays in the recovery in commodity cost. As a result, its cash flow from operations before changes in working capital (CFO pre-WC) to debt was 17.1% in 2024, excluding securitization debt and the underfunded portion the nuclear decommission trust. We anticipate that the company's credit metrics be lower as a result of elevated capital expenditures and the potential for higher debt. We expect DTE to produce CFO pre-WC to debt around 14% over the next 2-3 years.

DTE Electric Company's credit quality reflects its operating profile as a vertically integrated utility that generates steady and predictable cash flow in a credit supportive Michigan regulatory environment. This is offset by capital investments that will remain elevated in order to maintain operational reliability, and to transform DTE Electric's majority coal-fired generation fleet into a predominantly renewable technologies fleet with some continued use of natural gas fuel and nuclear. Over the next couple of years, we expect DTE Electric to produce CFO pre-WC to debt of between 21% and 23% compared to 20.5% and 21.8% in 2023 and 2024, respectively. We anticipate that DTE Electric's leverage will be sustained at an elevated level to fund its capital investment program. However, the company should maintain a relatively steady credit profile supported by the regulatory mechanisms for cost recovery available in Michigan.

DTE Gas Company's credit assessment incorporates its low business risk profile as a regulated natural gas local distribution company (LDC) and a credit supportive regulatory environment in Michigan. Despite this regulatory environment and frequent rate case filings, the credit profile of DTE Gas declined in 2024 as it continues to undergo a large capital investment program. We expect DTE Gas's cash flow from operations before changes in working capital (CFO pre-WC) to

debt ratio to decline from historical levels driven by these sustained higher capital expenditures and potential delays in the timing of commodity cost recovery. In 2024, DTE Gas's cash flow from operations before changes in working capital (CFO pre-WC) to debt was 18.7%, down from 22.1% in 2022 and 24.1% in 2023. Over the next 2-3 years, the company's leverage is likely to increase in order to partially fund its capital expenditures and to maintain a 50% equity capital structure. However, we expect DTE Gas to also steadily increase its cash flow generation under the constructive Michigan regulatory framework, maintaining an adequate financial profile for its rating.

This document summarizes our view as of the publication date and will not be updated until the next periodic review announcement, which will incorporate material changes in credit circumstances (if any) during the intervening period.

The principal methodology used for this review was Regulated Electric and Gas Utilities published in August 2024. Please see the Rating Methodologies page on https://ratings.moodys.com for a copy of this methodology.

This announcement applies only to EU rated, UK rated, EU endorsed and UK endorsed ratings. Non-EU rated, non-UK rated, non-EU endorsed and non-UK endorsed ratings may be referenced herein to the extent necessary, if they are part of the same organization list.

This publication does not announce a credit rating action. For any credit ratings referenced in this publication, please see the issuer/deal page on https://ratings.moodys.com for the most updated credit rating action information and rating history.

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FitchRatings

Corporates
Electric-Corporate
United States

DTE Electric Company

DTE Electric Company's (DTEE; A–/Stable) ratings reflect Fitch Ratings' expectations of stable credit metrics at the low-risk regulated electric utility with a predominantly constructive regulatory environment in Michigan. Funds from operations (FFO) leverage is projected to remain within the rating sensitivities' range through 2025-2027, despite significant capital expenditure (capex) plans. Fitch Ratings' assessment of parent DTE Energy Company's (DTE; BBB/Stable) group structure allows an up to two-notch differential between the Long-Term Issuer Default Ratings (IDR) of DTE and DTEE.

Key Rating Drivers

Supportive Regulatory Environment: Fitch views the regulatory environment for electric utilities in Michigan as mostly constructive from a credit perspective. The regulatory framework allows full pass-through of fuel costs, forward-looking test years and a timely 10-month review period for general rate case resolution. DTEE's authorized return on equity (ROE) of 9.9% remains above the 2024 industry average of 9.74%.

Increased Regulatory Scrutiny: DTEE has faced increased regulatory scrutiny over storm outages after a regulator-commissioned audit. The audit cited aging distribution equipment and insufficient vegetation management practices as key factors contributing to extended customer outages. In response, DTEE has committed to reducing power outages by 30% and cutting outage time in half by 2029 by increasing investments in distribution and vegetation management. In 2024, customer outage times decreased by 70%, which is a good development as regulators focus on customer reliability.

DTE Electric GRC Order Balanced: Fitch believes that the January 2025 rate order issued is credit supportive, albeit less than expected. The approved $217.4 million revenue requirement increase, representing 49% of the request, down from 63% previously, is based on a 9.9% ROE (unchanged) and a 50% equity ratio (unchanged) on a $21.8 billion rate base. Regulators authorized the continuation of the investment recovery mechanism for $300 million in distribution investments through 2025. The rise in customer bills is approximately $4.61 per month, which is offset by lower fuel costs.

Growing Data Center Demand: DTEE recently signed three non-binding agreements to serve up to 2.1 GW of data center load, which ramps up through 2032. Demand will be met by 1 GW of existing generating capacity, and new generation will be needed in the near term. Longer term, generation needs will be supported by DTEE's 2026 Integrated Resource Plan (IRP). Retail sales growth driven by data center load is projected to increase to 4%-5% in 2028-2032 after being flat in 2024. Michigan has a sale and use tax exemption for data center equipment through 2050.

Elevated Capex Driven by Decarbonization: DTEE plans to invest approximately $24 billion from 2025 through 2029, with $10 billion for clean generation and other projects, $10 billion for distribution infrastructure, and $4 billion for base infrastructure. This is a $4 billion increase compared with the previous plan and reflects greater clean energy and distribution investments. The investments will result in negative free cash flow (FCF) in the intermediate term. Fitch expects the capital program will be funded with internal cash flow, debt and equity.

Upward Capex Revisions Likely: Fitch believes an upward revision in capex is likely, given the increasing focus on reliability and clean energy legislation passed in Michigan in 2023 that targets 100% clean generation by 2040 in MISO. Concerns regarding the large capex plan are mitigated by the Michigan Public Service Commission's constructive ratemaking policies and alignment of planned capex with state policy. The energy legislation provides expanded incentives for energy efficiency and improved economics for PPAs, which are beneficial in Fitch's view.

Ratings

Long-Term IDR	A–
Short-Term IDR	F2
Senior Secured Debt - Long-Term Rating	A+
Outlook	
Long-Term Foreign-Currency IDR	Stable

Click here for the full list of ratings

ESG and Climate

Highest ESG Relevance Scores	
Environmental	3
Social	3
Governance	3
2035 Climate Vulnerability Signal:	53

Applicable Criteria

Sector Navigators – Addendum to the Corporate Rating Criteria (December 2024)
Parent and Subsidiary Linkage Rating Criteria (June 2023)
Corporate Rating Criteria (December 2024)
Corporate Recovery Ratings and Instrument Ratings Criteria (August 2024)
Corporate Hybrids Treatment and Notching Criteria (November 2020)

Related Research

Global Corporates Macro and Sector Forecasts – January 2024 (January 2025)
North American Utilities, Power & Gas Dashboard: 4Q24 (January 2025)
North American Utilities Outlook 2025 (December 2024)
North American Utilities Monitor: 2Q24 (August 2024)

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Decarbonization Path: DTEE is exiting its coal-fired generation by 2032 and replacing it with natural gas and renewables. DTEE's current IRP, which aims for net-zero emissions by 2050, aligns with Michigan's clean energy policy, which has a standard of 80% clean energy by 2035 and 100% by 2040, with a renewable standard of 50% by 2030. By 2027, an additional 1.2 GW of solar and 350 MW of energy storage are planned, with 220 MW of storage under construction. By 2042, an additional 15.4 GW of renewables and 1.8 GW of storage are planned.

Solid Financial Profile: Fitch believes DTEE's credit metrics are consistent with its rating. Debt maturities are manageable, and DTEE is expected to have continued access to capital markets. Fitch-calculated FFO leverage was at 3.9x in 2024, which was 60 basis points stronger than in 2023 and primarily reflects new rates following a constructive GRC outcome in December 2023, along with warmer summer weather and lower storm expense. FFO leverage is expected to average 3.8x through 2025-2027, supported by recent and ongoing rate relief.

Financial Summary

(USD Mil.)	2021	2022	2023	2024
Gross revenue	5,809	6,397	5,804	6,277
EBITDA	2,431	2,567	2,606	2,853
CFO (Fitch-defined)	2,310	1,684	2,269	2,813
Capital intensity (capex/revenue) (%)	51.9	41.1	53.2	57.9
Debt	9,200	10,167	10,755	11,936
FFO leverage (x)	4.2	3.6	4.5	3.9
FFO interest coverage (x)	6.5	7.8	5.6	6.1
EBITDA leverage (x)	3.8	4.0	4.1	4.2

F – Forecast.
Source: Fitch Ratings, Fitch Solutions

Peer Analysis

DTEE compares favorably with regulated single-state peers Consumers Energy Company (Consumers; A-/Stable) and Northern States Power Company Wisconsin (NSP; A-/Stable). All three operate in supportive regulatory environments with favorable recovery mechanisms. DTEE and Consumers operate in Michigan and are similarly sized, while NSP is smaller and based in Wisconsin.

However, Consumers also operates as a gas utility, while DTEE and NSP are both electric utilities. DTEE's financial profile compares favorably with Consumers', but less so with NSP's. Fitch forecasts DTEE'S FFO leverage to average 3.8x through 2025 to 2027, modestly better than 4.1x at Consumers and in line with NSP's average of 3.8x to 4.2x through 2028.

Rating Sensitivities

Factors that Could, Individually or Collectively, Lead to Negative Rating Action/Downgrade

- A notch downgrade at the parent DTE;
- An adverse change in Michigan's regulatory environment;
- Sustained FFO leverage greater than 4.5x.

Factors that Could, Individually or Collectively, Lead to Positive Rating Action/Upgrade

- Sustained FFO leverage of 3.5x or better.

Liquidity and Debt Structure

DTEE had approximately $146 million of available liquidity as of Dec. 31, 2024, consisting of cash and amounts available under revolving credit facilities and letter of credit facilities. DTEE's revolving credit facility expires in October 2029.

Liquidity is provided by an $800 million revolving credit facility at DTEE. DTEE was compliant with a consolidated debt/capitalization ratio of 52% as defined under the credit agreement as of Dec. 31, 2024. Debt maturities remain manageable given the history of successful refinancing, and Fitch expects DTEE to have continued access to the capital markets.

ESG Considerations

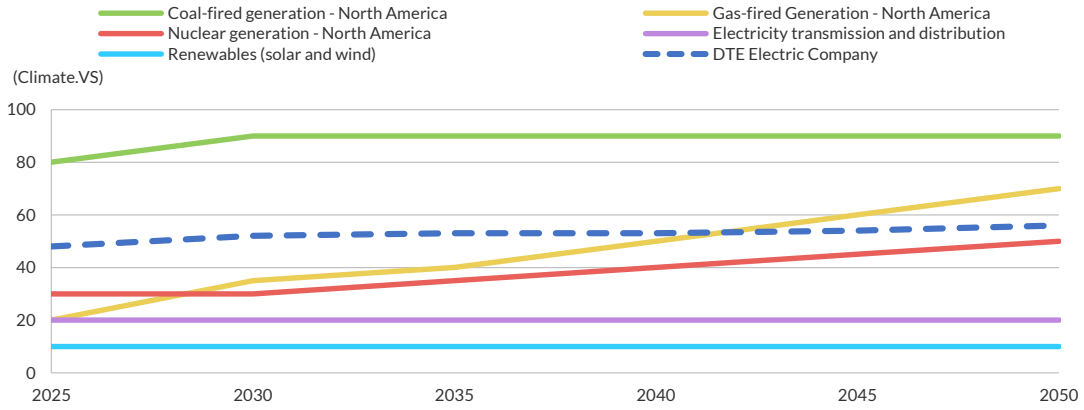
The highest level of ESG credit relevance is a score of '3', unless otherwise disclosed in this section. A score of '3' means ESG issues are credit-neutral or have only a minimal credit impact on the entity, either due to their nature or the way in which they are being managed by the entity. Fitch's ESG Relevance Scores are not inputs in the rating process; they are an observation on the relevance and materiality of ESG factors in the rating decision. For more information on Fitch's ESG Relevance Scores, visit https://www.fitchratings.com/topics/esg/products#esg-relevance-scores.

Climate Vulnerability Considerations

Fitch uses Climate Vulnerability Signals (Climate.VS) as a screening tool to identify sectors and Fitch-rated issuers that are potentially most exposed to credit-relevant climate transition risks and, therefore, require additional consideration of these risks in rating reviews. Climate.VS range from 0 (lowest risk) to 100 (highest risk). For more information on Climate.VS, see Fitch's Corporate Rating Criteria. For more detailed, sector-specific information on how Fitch perceives climate-related transition risks, see Climate Vulnerability Signals for Non-Financial Corporate Sectors.

DTEE's Climate.VS in 2035 is elevated at 53. It reflects DTEE's ownership of its coal and gas generation fleet, partially offset by transmission and distribution operations and nuclear generation. Most of the coal generation will be retired and replaced with renewable resources and the company expects to retire all of its coal generation by 2032. For further information on how Fitch perceives climate-related risks in the utilities sector, see Utilities - Long-Term Climate Vulnerability Signals Update.

Climate.VS Evolution
As of Dec 31, 2024.



Source: Fitch Ratings

Liquidity and Debt Maturities

Cash and Maturities Report

(USD Mil.)	December 31, 2023	December 31, 2024
Total cash and cash equivalents	32	59
Short-term investments	—	—
Less not readily available cash and cash equivalents	17	48
Fitch-defined readily available cash and cash equivalents	**15**	**11**
Availability under committed lines of credit	471	135
Total liquidity	486	146
LTM EBITDA after associates and minorities	2,606	2,853
LTM FCF	-1,822	-1,599

Source: Fitch Ratings, Fitch Solutions, DTE Electric Company

Scheduled Debt Maturities

(USD Mil.)	December 31, 2024
2025	1,016
2026	677
2027	—
2028	575
2029	59
Thereafter	9,609
Total	**11,936**

Source: Fitch Ratings, Fitch Solutions, DTE Electric Company

Key Assumptions

- Constructive regulatory environment in Michigan with ROE for DTEE in line with currently approved returns;
- No material equity issuances;
- Securitization debt is excluded from the FFO leverage calculations;
- Capital structure commensurate with regulatory structure.

Financial Data

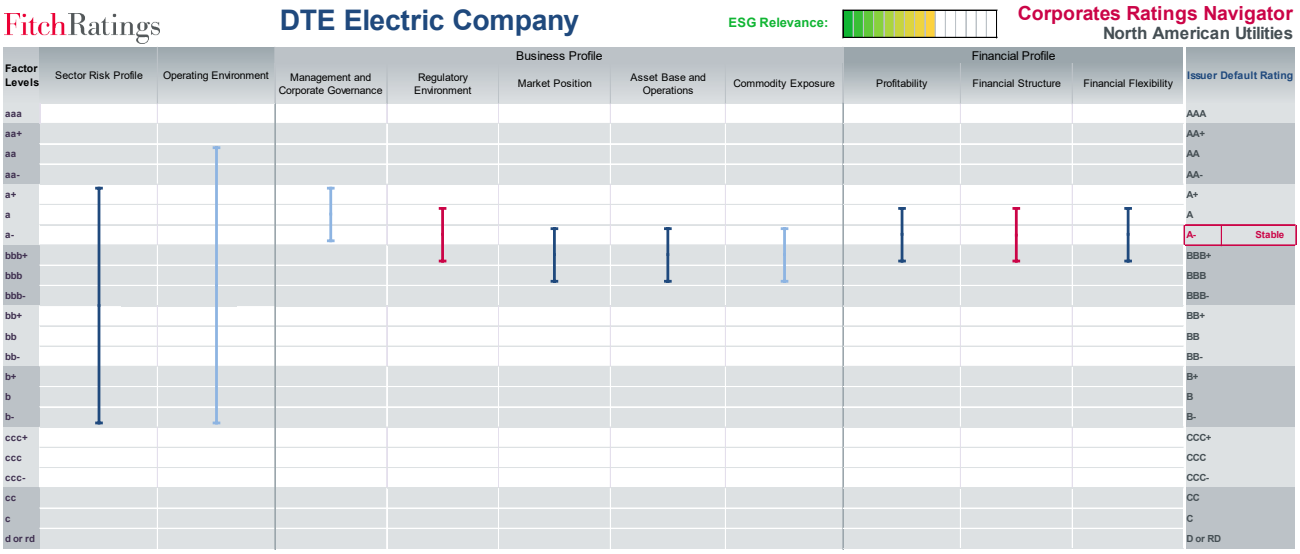
(USD Mil.)	2021	2022	2023	2024
Summary income statement				
Gross revenue	5,809	6,397	5,804	6,277
Revenue growth (%)	5.5	10.1	-9.3	8.2
EBITDA before income from associates	2,431	2,567	2,606	2,853
EBITDA margin (%)	41.8	40.1	44.9	45.5
EBITDA after associates and minorities	2,431	2,567	2,606	2,853
EBIT	1,270	1,327	1,227	1,369
EBIT margin (%)	21.9	20.7	21.1	21.8
Gross interest expense	-346	-381	-444	-529
Pretax income including associate income/loss	970	981	850	1,040
Summary balance sheet				
Readily available cash and equivalents	9	15	15	11
Debt	9,200	10,167	10,755	11,936
Net debt	9,191	10,152	10,740	11,925
Summary cash flow statement				
EBITDA	2,431	2,567	2,606	2,853
Cash interest paid	-332	-361	-424	-501
Cash tax	-5	33	-15	231
Dividends received less dividends paid to minorities (inflow/outflow)	—	—	—	—
Other items before FFO	-252	216	-219	-46
FFO	1,842	2,463	1,968	2,537
FFO margin (%)	31.7	38.5	33.9	40.4
Change in working capital	468	-779	301	276
CFO (Fitch-defined)	2,310	1,684	2,269	2,813
Total non-operating/nonrecurring cash flow	—	—	—	—
Capex	-3,017	-2,626	-3,089	-3,636
Capital intensity (capex/revenue) (%)	51.9	41.1	53.2	57.9
Common dividends	-588	-763	-1,002	-776
FCF	-1,295	-1,705	-1,822	-1,599
FCF margin (%)	-22.3	-26.7	-31.4	-25.5
Net acquisitions and divestitures	—	4	—	—
Other investing and financing cash flow items	-36	-54	-59	-118
Net debt proceeds	769	1,170	1,130	1,110
Net equity proceeds	555	600	759	634
Total change in cash	-7	15	8	27
Calculations for forecast publication				
Capex, dividends, acquisitions and other items before FCF	-3,605	-3,385	-4,091	-4,412
FCF after acquisitions and divestitures	-1,295	-1,701	-1,822	-1,599
FCF margin after net acquisitions (%)	-22.3	-26.6	-31.4	-25.5
Gross Leverage ratios (x)				
FFO leverage	4.2	3.6	4.5	3.9
(CFO-capex)/debt	-7.7	-9.3	-7.6	-6.9
Net Leverage ratios (x)				
FFO net leverage	4.2	3.6	4.5	3.9
(CFO-capex)/net debt	-7.7	-9.3	-7.6	-6.9
Coverage ratios (x)				
FFO interest coverage	6.5	7.8	5.6	6.1
FFO fixed-charge coverage	6.5	7.8	5.6	6.1

CFO – Cash flow from operations
Source: Fitch Ratings, Fitch Solutions

How to Interpret the Forecast Presented

The forecast presented above is based on Fitch Ratings' internally produced, conservative rating case forecast. It does not represent the forecast of the rated issuer. The forecast set out above is only one component used by Fitch Ratings to assign a rating or determine a rating outlook, and the information in the forecast reflects material but not exhaustive elements of Fitch Ratings' rating assumptions for the issuer's financial performance. As such, it cannot be used to establish a rating, and it should not be relied on for that purpose. Fitch Ratings' forecasts are constructed using a proprietary internal forecasting tool, which employs Fitch Ratings' own assumptions on operating and financial performance that may not reflect the assumptions that you would make. Fitch Ratings' own definitions of financial terms such as EBITDA, debt or free cash flow may differ from your own such definitions. Fitch Ratings may be granted access, from time to time, to confidential information on certain elements of the issuer's forward planning. Certain elements of such information may be omitted from this forecast, even where they are included in Fitch Ratings' own internal deliberations, where Fitch Ratings, at its sole discretion, considers the data may be potentially sensitive in a commercial, legal or regulatory context. The forecast (as with the entirety of this report) is produced strictly subject to the disclaimers set out at the end of this report. Fitch Ratings may update the forecast in future reports but assumes no responsibility to do so. Original financial statement data for historical periods is processed by Fitch Solutions on behalf of Fitch Ratings. Key financial adjustments and all financial forecasts credited to Fitch Ratings are generated by rating agency staff.

Ratings Navigator



Bar Chart Legend:	
Vertical Bars = Range of Rating Factor	Bar Arrows = Rating Factor Outlook
Bar Colors = Relative Importance	⇧ Positive
Higher Importance	⇩ Negative
Average Importance	⇳ Evolving
Lower Importance	▭ Stable

FitchRatings

Corporates
Electric-Corporate
United States

FitchRatings

DTE Electric Company

Corporates Ratings Navigator
North American Utilities

Operating Environment

aa+		Economic Environment	aa	Very strong combination of countries where economic value is created and where assets are located.
aa		Financial Access	aa	Very strong combination of issuer specific funding characteristics and of the strength of the relevant local financial market.
		Systemic Governance	aa	Systemic governance (eg rule of law, corruption; government effectiveness) of the issuer's country of incorporation consistent with 'aa'.
b-				
ccc+				

Management and Corporate Governance

aa-		Management Strategy	a	Coherent strategy and good track record in implementation.
a+		Governance Structure	aa	No record of governance failing. Experienced board exercising effective check and balance to management. No ownership concentration.
a		Group Structure	a	Group structure shows some complexity but mitigated by transparent reporting.
a-		Financial Transparency	a	High quality and timely financial reporting.
bbb+				

Regulatory Environment

a+		Degree of Transparency and Predictability	a	Track record of transparent and predictable regulation.
a		Timeliness of Cost Recovery	a	Minimal lag to recover capital and operating costs.
a-		Trend in Authorized ROEs	a	Above-average authorized ROE.
bbb+		Mechanisms Available to Stabilize Cash Flows	bbb	Revenues partially insulated from variability in consumption.
bbb		Mechanisms Supportive of Creditworthiness	bbb	Effective regulatory ring-fencing or minimum creditworthiness requirements.

Market Position

a		Market Structure	a	Well-established market structure with complete transparency in price-setting mechanisms.
a-		Consumption Growth Trend	bbb	Customer and usage growth in line with industry averages.
bbb+		Customer Mix	a	Favorable customer mix.
bbb		Geographic Location	bbb	Beneficial location or reasonable locational diversity.
bbb-		Supply Demand Dynamics	bbb	Moderately favorable outlook for prices/rates.

Asset Base and Operations

a		Diversity of Assets	bbb	Good quality and/or reasonable scale diversified assets.
a-		Operations Reliability and Cost Competitiveness	a	Track record of reliable, low-cost operations.
bbb+		Exposure to Environmental Regulations	bbb	Limited or manageable exposure to environmental regulations.
bbb		Capital and Technological Intensity of Capex	bbb	Moderate reinvestments requirements in established technologies.
bbb-				

Commodity Exposure

a		Ability to Pass Through Changes in Fuel	bbb	Limited exposure to changes in commodity costs.
a-		Underlying Supply Mix	bbb	Low variable costs and moderate flexibility of supply.
bbb+		Hedging Strategy	a	Highly captive supply and customer base.
bbb				
bbb-				

Profitability

a+		Free Cash Flow	bbb	Structurally neutral to negative FCF across the investment cycle.
a		Volatility of Profitability	a	Higher stability and predictability of profits relative to utility peers.
a-				
bbb+				
bbb				

Financial Structure

a+		EBITDA Leverage	bbb	3.75x
a		FFO Leverage	a	3.5x
a-				
bbb+				
bbb				

Financial Flexibility

a+		Financial Discipline	a	Clear commitment to maintain a conservative policy with only modest deviations allowed.
a		Liquidity	bbb	One-year liquidity ratio above 1.25x. Well-spread maturity schedule of debt but funding may be less diversified.
a-		FFO Interest Coverage	a	5.5x
bbb+				
bbb				

How to Read This Page: The left column shows the three-notch band assessment for the overall Factor, illustrated by a bar. The right column breaks down the Factor into Sub-Factors, with a description appropriate for each Sub-Factor and its corresponding category.

Credit-Relevant ESG Derivation

DTE Electric Company has 12 ESG potential rating drivers

- Emissions from operations
- Fuel use to generate energy and serve load
- Impact of waste from operations
- Plants' and networks' exposure to extreme weather
- Product affordability and access
- Quality and safety of products and services; data security

Showing top 6 issues

				Overall ESG
key driver	0	issues	5	
driver	0	issues	4	
potential driver	12	issues	3	
not a rating driver	2	issues	2	
	0	issues	1	

For further details on Credit-Relevant ESG scoring, see page 3.

FitchRatings

Corporates
Electric-Corporate
United States

FitchRatings

DTE Electric Company

Corporates Ratings Navigator
North American Utilities

Credit-Relevant ESG Derivation

DTE Electric Company has 12 ESG potential rating drivers

- DTE Electric Company has exposure to emissions regulatory risk but this has very low impact on the rating.
- DTE Electric Company has exposure to energy productivity risk but this has very low impact on the rating.
- DTE Electric Company has exposure to waste & impact management risk but this has very low impact on the rating.
- DTE Electric Company has exposure to extreme weather events but this has very low impact on the rating.
- DTE Electric Company has exposure to access/affordability risk but this has very low impact on the rating.
- DTE Electric Company has exposure to customer accountability risk but this has very low impact on the rating.

Showing top 6 issues

key driver	0	issues	5	ESG Relevance to Credit Rating
driver	0	issues	4	
potential driver	12	issues	3	
not a rating driver	2	issues	2	
	0	issues	1	

Environmental (E) Relevance Scores

General Issues	E Score	Sector-Specific Issues	Reference
GHG Emissions & Air Quality	3	Emissions from operations	Asset Base and Operations; Commodity Exposure; Regulation; Profitability
Energy Management	3	Fuel use to generate energy and serve load	Asset Base and Operations; Commodity Exposure; Profitability
Water & Wastewater Management	2	Water used by hydro plants or by other generation plants, also effluent management	Asset Base and Operations; Regulation; Profitability
Waste & Hazardous Materials Management; Ecological Impacts	3	Impact of waste from operations	Asset Base and Operations; Regulation; Profitability
Exposure to Environmental Impacts	3	Plants' and networks' exposure to extreme weather	Asset Base and Operations; Regulation; Profitability

E Relevance: 5, 4, 3, 2, 1

Social (S) Relevance Scores

General Issues	S Score	Sector-Specific Issues	Reference
Human Rights, Community Relations, Access & Affordability	3	Product affordability and access	Asset Base and Operations; Regulation; Profitability; Financial Structure
Customer Welfare - Fair Messaging, Privacy & Data Security	3	Quality and safety of products and services; data security	Regulation; Profitability
Labor Relations & Practices	3	Impact of labor negotiations and employee (dis)satisfaction	Asset Base and Operations; Profitability
Employee Wellbeing	2	Worker safety and accident prevention	Profitability; Asset Base and Operations
Exposure to Social Impacts	3	Social resistance to major projects that leads to delays and cost increases	Asset Base and Operations; Profitability

S Relevance: 5, 4, 3, 2, 1

Governance (G) Relevance Scores

General Issues	G Score	Sector-Specific Issues	Reference
Management Strategy	3	Strategy development and implementation	Management and Corporate Governance
Governance Structure	3	Board independence and effectiveness; ownership concentration	Management and Corporate Governance
Group Structure	3	Complexity, transparency and related-party transactions	Management and Corporate Governance
Financial Transparency	3	Quality and timing of financial disclosure	Management and Corporate Governance

G Relevance: 5, 4, 3, 2, 1

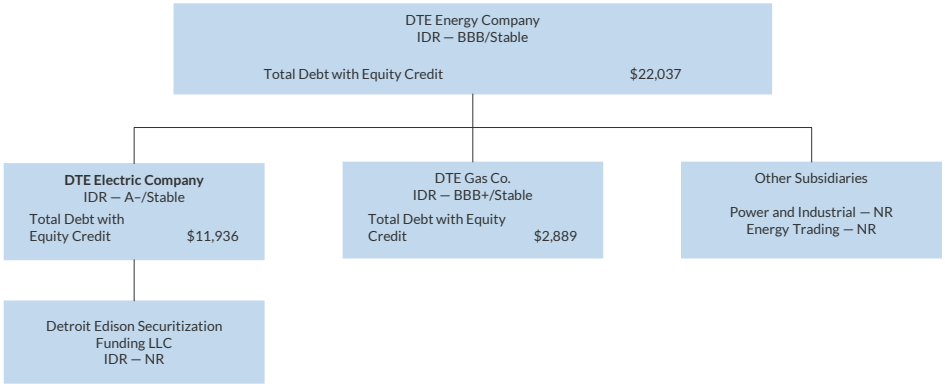
How to Read This Page
ESG relevance scores range from 1 to 5 based on a 15-level color gradation. Red (5) is most relevant to the credit rating and green (1) is least relevant.
The Environmental (E), Social (S) and Governance (G) tables break out the ESG general issues and the sector-specific issues that are most relevant to each industry group. Relevance scores are assigned to each sector-specific issue, signaling the credit-relevance of the sector-specific issues to the issuer's overall credit rating. The Criteria Reference column highlights the factor(s) within which the corresponding ESG issues are captured in Fitch's credit analysis. The vertical color bars are visualizations of the frequency of occurrence of the highest constituent relevance scores. They do not represent an aggregate of the relevance scores or aggregate ESG credit relevance.
The Credit-Relevant ESG Derivation table's far right column is a visualization of the frequency of occurrence of the highest ESG relevance scores across the combined E, S and G categories. The three columns to the left of ESG Relevance to Credit Rating summarize rating relevance and impact to credit from ESG issues. The box on the far left identifies any ESG Relevance Sub-factor issues that are drivers or potential drivers of the issuer's credit rating (corresponding with scores of 3, 4 or 5) and provides a brief explanation for the relevance score. All scores of '4' and '5' are assumed to reflect a negative impact unless indicated with a '+' sign for positive impact.
Classification of ESG issues has been developed from Fitch's sector ratings criteria. The General Issues and Sector-Specific Issues draw on the classification standards published by the United Nations Principles for Responsible Investing (PRI), the Sustainability Accounting Standards Board (SASB), and the World Bank.

CREDIT-RELEVANT ESG SCALE
How relevant are E, S and G issues to the overall credit rating?

5	Highly relevant, a key rating driver that has a significant impact on the rating on an individual basis. Equivalent to "higher" relative importance within Navigator.
4	Relevant to rating, not a key rating driver but has an impact on the rating in combination with other factors. Equivalent to "moderate" relative importance within Navigator.
3	Minimally relevant to rating, either very low impact or actively managed in a way that results in no impact on the entity rating. Equivalent to "lower" relative importance within Navigator.
2	Irrelevant to the entity rating but relevant to the sector.
1	Irrelevant to the entity rating and irrelevant to the sector.

Simplified Group Structure Diagram

Organizational and Debt Structure — DTE Energy Company
($ Mil., as of December 31, 2024)



IDR – Issuer Default Rating. NR – Not rated.
Source: Fitch Ratings, DTE Electric Company.

Peer Financial Summary

Company	Issuer Default Rating	Financial statement date	Gross revenue (USD Mil.)	FFO (USD Mil.)	FFO interest coverage (x)	FFO leverage (x)	EBITDA leverage (x)
DTE Electric Company	A–						
	A–	2024	6,277	2,537	6.1	3.9	4.2
	A–	2023	5,804	1,968	5.6	4.5	4.1
	A–	2022	6,397	2,463	7.8	3.6	4.0
Consumers Energy Company	A–						
	A–	2023	7,127	2,144	6.2	4.2	4.5
	A–	2022	8,116	2,052	8.1	4.4	4.5
	A–	2021	6,987	1,974	8.0	3.9	4.0
Northern States Power Company-Wisconsin	A–						
	A–	2023	1,177	295	6.8	3.7	3.3
	A–	2022	1,201	270	7.4	3.7	3.2
	A–	2021	1,105	254	7.4	3.7	3.4

Source: Fitch Ratings, Fitch Solutions

Fitch Adjusted Financials

(USD Mil., as of December 31, 2024)	Notes and formulas	Standardized values	Fair value and other debt adjustments	Lease treatment	Other adjustments	Adjusted values
Income statement summary						
Revenue		6,277	—	—	—	6,277
EBITDA	(a)	2,927	—	—	-74	2,853
Depreciation and amortization		-1,487	—	—	3	-1,484
EBIT		1,440	—	—	-71	1,369
Balance sheet summary						
Debt	(b)	12,566	91	-8	-713	11,936
Of which other off-balance-sheet debt		—	—	—	—	—
Lease-equivalent debt		—	—	—	—	—
Lease-adjusted debt		12,566	91	-8	-713	11,936
Readily available cash and equivalents	(c)	11	—	—	—	11
Not readily available cash and equivalents		48	—	—	—	48
Cash flow summary						
EBITDA	(a)	2,927	—	—	-74	2,853
Dividends received from associates less dividends paid to minorities	(d)	—	—	—	—	—
Interest paid	(e)	-467	—	—	-34	-501
Interest received	(f)	—	—	—	—	—
Preferred dividends paid	(g)	—	—	—	—	—
Cash tax paid		231	—	—	—	231
Other items before FFO		-151	—	—	105	-46
FFO	(h)	2,540	—	—	-3	2,537
Change in working capital		276	—	—	—	276
CFO	(i)	2,816	—	—	-3	2,813
Non-operating/nonrecurring cash flow		—	—	—	—	—
Capex	(j)	-3,636	—	—	—	-3,636
Common dividends paid		-776	—	—	—	-776
FCF		-1,596	—	—	-3	-1,599
Gross leverage (x)						
FFO leverage	b/(h-e-f-g)	4.2	—	—	—	3.9
(CFO-capex)/debt (%)	(i+j)/b	-6.5	—	—	—	-6.9
Net leverage (x)						
FFO net leverage	(b-c)/(h-e-f-g)	4.2	—	—	—	3.9
(CFO-capex)/net debt (%)	(i+j)/(b-c)	-6.5	—	—	—	-6.9
Coverage (x)						
FFO interest coverage	(h-e-f-g)/(-e-g)	6.4	—	—	—	6.1

CFO – Cash flow from operations
Notes: The standardized items presented above are based on Fitch's taxonomy for the given sector and region.
Reported items may not match the Fitch taxonomy, but they are captured into corresponding lines accordingly.
Debt includes other off-balance-sheet debt.
Source: Fitch Ratings, Fitch Solutions, DTE Electric Company

Parent Subsidiary Linkage Analysis

Key Risk Factors and Notching Approach

Parent	DTE Energy Company
Parent LT IDR	BBB
Subsidiary	DTE Electric Company
Subsidiary LT IDR	A-
Path	Stronger Subsidiary
Legal ring-fencing	Porous
Access and control	Porous
Notching matrix outcome	Consolidated+2
Override applied	No
Notching approach	—

LT IDR – Long-Term Issuer Default Rating
Source: Fitch Ratings

Stronger Subsidiary Notching Matrix

Access and control	Open	Porous	Insulated
With open ring-fencing	Consolidated	Consolidated+1	Consolidated+2[b]
With porous ring-fencing	Consolidated+1	Consolidated+2[b]	Consolidated+2[b]
With insulated ring-fencing	[a]	Standalone	Standalone

[a] It is unlikely that considerations for "insulated" legal ring-fencing would coexist with the conditions outlined under "open" for access and control. It is more likely that other factors relevant to legal ring-fencing or access and control, but not within this table, would move either one, or both, of the individual Linkage Factor Assessments (LFAs) to a "porous" level that would lead to a consolidated+1, consolidated+2 or standalone outcome.
[b] Notching is capped at the subsidiary's Standalone Credit Profile.
Source: Fitch Ratings

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Source: Response to STDE-4.21

MERC Transshipment Volumes (Tons)					
	Year	**DTE Electric Co.**	**External**	**Total**	**Annual change**
Actual	2019	6,765,785	1,054,287	7,820,072	
Actual	2020	4,752,391	717,508	5,469,898	-30.1%
Actual	2021	6,564,373	870,876	7,435,248	35.9%
Actual	2022	5,637,290	1,272,731	6,910,021	-7.1%
Actual	2023	5,121,426	543,113	5,664,539	-18.0%
Actual	2024	4,836,320	331,110	5,167,430	-8.8%
Forecasted	2025	3,944,901	537,000	4,481,901	-13.3%
Forecasted	2026	405,000	125,000	530,000	-88.2%
Compound annual growth rate (2019 - 2024)		**-6.5%**	**-20.7%**	**-8.0%**	

Source: Discovery response to MNSCDE-9.2

Year	MERC Fuel Handling Historical O&M (in $000s)	Annual change
2019	3,836	
2020	3,576	-6.8%
2021	3,293	-7.9%
2022	3,850	16.9%
2023	3,351	-13.0%
2024	3,315	-1.1%
Compound annual growth rate (2019 -2024)	**-2.9%**	

Source: Discovery response to MNSCDE-9.3a, 9.3b, 9.3c

MERC Fuel Handling O&M (in 000s)			
	Approved rates	**Actuals**	**Variance (actual - approved)**
U-20561	4,044	3,482	-562
U-20836	3,886	3,434	-452
U-21297	3,615	3,318	-297
Total	**11,545**	**10,234**	**(1,311)**

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE ELECTRIC COMPANY** for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority	Case No. U-21860

Proof of Service

On the date below, an electronic copy of **Direct Testimony and Exhibits of Douglas B. Jester on behalf of Michigan Environmental Council, Natural Resources Defense Council, and Citizens Utility Board of Michigan (CUB-12 through CUB-18)** was served on the following:

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The statements above are true to the best of my knowledge, information and belief.

Troposphere Legal, PLC
Counsel for MNC

Date: August 22, 2025

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