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July 20, 2026

Ms. Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Hwy., 3rd Floor
Lansing, Michigan 48917

RE: ***In the matter of the application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief.***
MPSC Case No. U-22058

Dear Ms. Felice:

Attached for filing in the above-referenced matter is MPSC Staff's Initial Brief, together with Proof of Service.

Subject to the Protective Order issued April 30, 2026, a Confidential version will be filed separately with the Executive Business Section of the MPSC.

Sincerely,

Daniel E. Sonneveldt (P58222)
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Telephone: (517) 284-8140

DES/cars

Attachments

c: Parties of Record

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of
DTE Electric Company for approval of
special contracts and other relief. Case No. U-22058

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MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
INITIAL BRIEF

MICHIGAN PUBLIC SERVICE COMMISSION STAFF

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DATED: July 20, 2026

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I. Introduction

On March 17, 2026, DTE Electric Company (Company or DTE) filed its application in this case seeking the Michigan Public Service Commission's (Commission) expedited approval of the Company's Primary Supply Agreement (PSA) and Clean Capacity Accelerator Agreement (CCAA) (collectively, Special Contracts) with Google LLC (Customer or Google). (DTE Application, p 1.) More specifically, the Company requested that the Commission order the following:

1) Grant the Company's request for review of the Special Contracts on an expedited basis,
2) Determine that the Special Contracts are reasonable and prudent and enter an order approving the Special Contracts as consistent with all applicable law,
3) Authorize the Company to record as income the financial incentives to be paid by Google for the ZRC transfer under the CCAA,
4) Authorize the Company to record regulatory liabilities to Account 254 for the accelerated recovery of costs for storage and renewable energy projects under the CCAA, and
5) Grant the Company such further additional relief as the Commission may deem appropriate. (DTE Application, p 6.)

In support of its application, DTE also filed the direct testimony and exhibits of witnesses Neal Foley, Steven Benyard, Kevin Bilyeu, Shawn Burgdorf, Justin Brooks, and Aaron Willis.

A prehearing was held on April 15, 2026, before ALJ Theresa Staley. At the hearing, intervenor status was recognized and granted to the Attorney General (AG), Natural Resources Defense Council (NRDC); Sierra Club; Michigan Environmental Council (MEC); Great Lakes Renewable Energy Association (GLREA); Institute for Energy Innovation (IEI); Michigan Energy Innovation Business Council (MEIBC); The Ecology Center, The Environmental Law & Policy Center, Union of Concerned Scientists, Vote Solar (collectively, Clean Energy Organizations or CEO); and the Association for Businesses Advocating Tariff Equity (ABATE). At the conclusion of the prehearing, a scheduling memorandum was issued that scheduled cross examination on June 30 and July 1, with Initial Briefs due July 20, 2026.

Staff now files this Initial Brief consistent with the deadline established in the April 15, 2026, scheduling memorandum.

II. Argument

A. Revenue Analysis

1. Staff's analysis does not include rate escalation and represents a lower-bound for the Customer's impact on revenue.

Staff audited the billing determinants and rates used by the Company to calculate the annual revenue generated by the Customer. Staff found the base sales benefit and cost assumptions made by the Company to be an adequate starting point for Staff's initial analysis. Staff found the increase in revenue from using the

Company's most recently approved rates did not have a significant impact on the outcome of the overall net customer benefit. (3 TR 857.)

The Company incorporated a 1.5% escalation in rate revenue throughout the contract term. (3 TR 414.) It is not reasonable to assume increasing revenues from the Customer without considering that those revenues are actually increasing to offset new cost recovery. (3 TR 858.) Staff posited that additional revenue collected from Oracle via base D11 rates may put downward pressure on rates prior to Google taking service, which means that general rate increases may not necessarily be so certain. (*Id.*) Without rate escalation the net benefit using the Company's other assumptions results in a total net benefit of $860.3M (this compares to $1.697B as filed by the Company). (*Id.*)

2. Increased revenue from large load customers may affect customer classes differently.

Staff isolated the revenue impact of Oracle and Google separately by finding the differences between the results of three cost of service studies (COSSs) provided by the Company. (3 TR 859.) An increase in sales means an increase in present revenue which means the Company does not need to collect as much revenue to cover its costs, so the revenue requirement decreases. If the sales and revenue from the Customer were added directly into the COSS from Case U-21534, then all customer classes would receive an overall decrease in revenue requirement enough to completely negate the revenue deficiency resulting from Case U-21534. (3 TR 860.) However, the increased sales of demand and energy may cause more costs to be allocated to the primary class as well, thus muting what would otherwise be a bigger decrease in revenue requirement. (*Id.*)

Furthermore, the reduction in revenue requirement for power supply of $204.1M is offset by a revenue requirement increase for distribution of $2.6M. This analysis does not include any exogenous cost increases for serving the LLCs. (3 TR 860.) Staff found that the predicted increase in revenue resulting from serving the Customer on base rates could affect cost items such as income taxes, which are allocated to power supply and distribution rates. (3 TR 861.) Certain allocators within the COSS depend on sales, revenue, or net income, all of which would be affected by the significant increase caused by serving the Customer. Not all customers will be better off if the Customer's sales and revenue are added to the COSS because of the increase in distribution revenue requirement. Choice customers do not pay for power supply from the Company and thus would not receive the benefit of the downward pressure on rates caused by the Customer. Instead, choice customers would only be affected by the increase in distribution revenue requirement and thus would be the only customer type that would be harmed overall.

The increase in sales from both the Customer and Oracle mean that the cap on choice for the Company will also increase, because it is determined as a percentage of total utility sales. (3 TR 862.) Base rates and revenue requirements may also change if other customers move to or away from full service. Further compounding this issue is the previously established fact that there will be downward pressure on power supply rates, thus potentially making full service more attractive than choice. (3 TR 862-863.) Staff provided an analysis of the impact of choice sales on the revenue sufficiency created by the Customer's additional revenue per the COSS from U-21534. (Exhibit S-3.2.) Staff found that when customers move from full service to choice, the remaining full service primary customers will be better off compared to all other customers. (3 TR 863.)

The base sales benefit represents one part of the broader affordability benefit described by the Company. The other components are the impact on PSCR, other O&M costs, cost of a new proxy combined cycle gas turbine, cost of carbon capture and storage for that turbine, and the benefit of adding storage resources ahead of schedule. (3 TR 411; Exhibit A-19.)

3. Staff's scenario analysis showed the impact of minimum bills, termination payments, and collateral.

Staff provided an analysis of minimum bills, termination payment, and collateral as detailed in the PSA. Staff Exhibit S-3.3 compares estimated minimum bill revenue to the termination fee and collateral obligation and also includes two possible scenarios. Staff's analysis isolated transmission costs by year from the overall PSCR benefit calculated by the Company. If the Customer only pays minimum bills then it will not pay energy charges and thus not create the total PSCR benefit, but the Company would still face costs from the transmission provider. (3 TR 874.)

When evaluating the scenario where the customer only pays its minimum bill, Staff assumed that future production resources would not be necessary so the analysis does not include the costs of the proxy production plant, the carbon capture system, nor the benefits of the storage pull-ahead. (3 TR 874-875.) Staff found that under its assumptions, the minimum bill revenue is sufficient to cover the estimated non-production costs to serve the customer. (3 TR 875.) The total cumulative non-production costs in fact equals the total cumulative minimum bill revenue under the proposed PSA. Staff did not include distribution costs because the Company estimated that distribution investment needed to serve the customer will range from $29.1M to $44.3M and the Customer is obligated to pay up to $50M toward that cost. (3 TR 450.) Staff's analysis highlights that the largest cost drivers for serving the customer will be production-related, specifically the proxy CCGT and CCS. (3 TR 875-876.) The scenario where the Customer continues to pay its minimum bill obligation without ever taking actual service is unlikely, but it helps highlight how minimum bills will pay for O&M and transmission expenses. (3 TR 876.) The collateral amount is less than the termination payment for the first five years of the contract, meaning the customer could be undercollateralized at the beginning of the contract. However, the Commission already found that the Company will be responsible for any shortfall if collateral is not sufficient to recoup costs. (3 TR 877.)

The AG argued that "under the Minimum Monthly Charge calculation the Company does not get to recover 100% of the demand costs billable to the Customer, but only 80% of the total costs." (3 TR 473.) This is not an accurate description of the costs imposed by nor the minimum revenues to be collected from the Customer. The minimum monthly bill in the PSA sets the floor at 80% of the Customer's demand *revenue*, not 80% of total costs. Other customers on Rate D11 also face a minimum bill, but it is set to 65% of their highest summer on-peak demand. The rates a customer pays are designed to recover costs allocated to its class, not directly assigned to the individual customer, so it cannot be said that paying a minimum bill of 80% of peak demand is only paying for 80% of the customer's individual costs.

Staff also evaluated a possible worst-case scenario of serving the Customer: where the customer completes its load ramp schedule, the Company builds the new proxy production resources, and then the Customer only pays its minimum bills thereafter. (3 TR 877-878.) Staff's analysis found that this scenario would produce a total net cost to the Company of [redacted]. 3 TR 878. Staff notes that the Company may still recoup some revenue by selling excess capacity or energy from the proxy production resources, but the fact remains that without revenue from the Customer beyond minimum bills the proxy production costs are the biggest downside risk of serving the Customer. Regarding collateral, Staff found that [redacted]

[redacted] (*Id.*) This means the Company could face significant risk from the Customer being uncollateralized, but the affordability backstop may prevent the Company from facing that risk should the Commission find that the Company may not pass on stranded costs to its other customers.

As previously explained, the Commission has already cautioned the Company that other customers would not be responsible for any unrecovered costs associated with serving the Customer. (3 TR 879.) Staff again recommends that the Commission make the same finding in the instant case.

B. Contract Terms

1. The CIAC provision of the Company's pending tariff amendment for a Large Load Provision should also apply to the Customer.

The specific terms of the PSA are similar to those found in the Company's proposed Large Load Provision tariff as found in the currently on-going Case U-22061. (3 TR 868.) The main differences between the contracts in the instant case and the proposed tariff in U-22061 are a contract term of 20 years instead of the minimum 15 per the proposed tariff, contribution in aid of construction allowance (CIAC), the collateral amount, and the terms of the CCAA. (3 TR 869.)

The proposed tariff in Case U-22061 provides a CIAC allowance equal to two years of distribution revenue, with the customer paying for all connection costs above that allowance. Staff calculated that using the proposed tariff method would result in a CIAC allowance of approximately $30M. (3 TR 869.) Under the line extension agreement of the PSA the Customer agrees to pay up to $50M toward infrastructure upgrades needed to serve the Customer. (3 TR 450-451.) The Company intends to include any remaining connection costs via base rates as it would for any other new business. (3 TR 451.)

Staff recommended that if and when the tariff in Case U-22061 is approved, that the CIAC allowance from that tariff be applied to the Customer as well. Specifically, any infrastructure costs beyond the initial $50M plus $30M (the two years of distribution revenue) should be paid for by the Customer. Any infrastructure costs that exceed $50M by less than 2 years of distribution revenue should be included for recovery in future rate cases. (*Id.*)

The Company disagreed with Staff's recommendation to apply the CIAC provision of the proposed tariff from U-22061 to the Customer. (3 TR 423.) The Company argues that the Customer already agreed to pay for its own substation and enough to cover the estimated cost of distribution. (*Id.*) If the Company's cost estimates hold then the issue of applying the CIAC provision from the proposed tariff will be moot. The Company explained that the PSA was signed a few days before the tariff case was filed, and that an order is expected in the instant case prior to a final order approving the tariff. (3 TR 423-424.) The Company claims that imposing the CIAC provision of the pending tariff amounts to retroactive tariff application that would open current and future customers to financial liability and thus Staff's recommendation should be rejected. (3 TR 424.)

Staff appreciates the Customer's commitment in its line extension agreement to pay up to $50M toward distribution costs. Staff's recommendation, if approved, would only apply if the Commission also approves the CIAC provision of the tariff, and not if the Commission rejects that part of the proposed tariff. Furthermore, the tariff case was filed *4 days* after the instant case. Approval of the special contracts in the instant case therefore are to serve the customer on different terms and conditions compared to the current Rate D11 tariff, which the Company is also proposing to alter. Staff asserts that it is not reasonable to request special terms via contracts and also change the standard terms from which the contracts are an alternative. Essentially the Company is requesting different rules for the Customer but also requesting to change those rules. Staff argues that it is reasonable for the Customer to be subject to the CIAC provision of the proposed tariff in Case U-22061 because the Customer has not yet begun to be served by the Company.

2. The PSA and the Consumers tariff diverge on the issue of collateral amount.

The Commission approved a large load customer provision to include in the Company's primary class tariff in Case U-21859. (3 TR 855.) The termination payment described in the PSA matches the exit fee approved in the Consumers case because both are equal to remaining minimum monthly bills for the duration of the contract term. (3 TR 869-870.) Under the Consumers tariff the default collateral amount is equal to half of the exit fee (i.e. termination fee in the PSA's parlance).

[redacted]

[redacted]

3. The Company must bear the risk of allowing collateral by parent company guarantee.

The method of providing collateral also differs between the PSA and the Consumers tariff. Under the Consumers tariff the collateral amount may only be provided via a letter of credit or cash, but Consumers may impose a different collateral amount or form subject to approval by the Commission. (3 TR 871.) The PSA allows the customer to provide collateral via a letter of credit, a parent company guarantee, or a combination of the two, with the letter of credit being required depending on the parent company's credit rating. (3 TR 870-871.)

The Commission previously found in its conditional approval of the Company's special contract with Oracle, Case U-21990, that:

> "In addition, in the event of a failure to pay the [minimum billing demand] under the PSA, or in the event of a termination, default, or other event whereby DTE Electric is required to draw on the letter of credit or parental guaranty, if the company determines that the specified collateral is not sufficient to cover the full amount of the remaining financial exposure associated with the [special contracts] (minus the value to customers), the Commission specifically cautions DTE Electric that any unrecovered costs shall not be borne by ratepayers and that DTE Electric bears responsibility for any remaining liability. All risk associated with the sufficiency of the collateral shall be borne by DTE 22 Electric." *In Re* December 18, 2025 Order in MPSC Case No. U-21990, p 41.

In short, the Commission cautioned the Company that setting collateral conditions, such as allowing a parent company guarantee, would not alleviate the Company from the risk that the Customer fails to fully provide its collateral obligation. The Company agreed to this condition for approval of the contracts in U-21990. (3 TR 872.) Staff recommends that the Commission make the same finding in the instant case and require the Company to expressly agree to any other conditions set by the Commission for approval of the Special Contracts. Similarly, the Commission found in Case U-21990 that approval was conditioned "on the requirement that, at the very least, all current and future costs caused by the Customer shall be covered by the Customer or by DTE Electric and not existing customers." *In Re DTE Electric Company for Approval of Special Contracts*, MPSC Case No. U-21990, December 18, 2025, Order, p 33. ABATE agreed with Staff. (3 TR 545.) This statement working in tandem with the affordability backstop should prevent adverse outcomes for existing customers. (3 TR 872.)

The Company also agreed with Staff and ABATE and stated "the Company acknowledges that it bears the risk of collateral insufficiency for costs that the Commission ultimately determines in excess of revenues received under the PSA, CCAA, and other related agreements." (3 TR 135.)

4. The AG's recommendation regarding minimum billing demand is unsupported.

The AG recommended setting the minimum billing demand at 90% instead of the 80% per the PSA. (3 TR 473.) The AG reasoned that because the Company assumed a 90% load factor when estimating the Customer's revenue impact that the same percentage should be used as minimum billing demand. Load factor is the ratio of average demand to maximum demand, whereas minimum demand is just the assumed peak demand used for billing. The Company had to choose a load factor in order to estimate the energy used by the Customer (i.e. how to convert MW to MWh for monthly energy use). Staff disputes the rationale for the AG's recommended 90% minimum billing demand because the assumed load factor and minimum billing demand are not related. Staff's analysis found that minimum billing demand of 80% is sufficient to cover the non-production costs. (3 TR 875.) For this reason the Commission should not approve the AG's recommendation on the basis that a 90% load factor was used to determine energy sales.

The Company also disagreed with the AG's minimum billing demand recommendation. (3 TR 136.) The Company argued that the Commission already established that 80% minimum billing demand is appropriate in Cases U-21859 and U-21990. (*Id.*)

C. Future Proceedings

1. Cost Allocation, including whether or not to create a new customer class, should be determined in future rate cases.

Staff identified several avenues by which the impact of the Customer's sales and revenues may affect the COSS and thus eventually base rates. Those impacts are not set in stone. The instant case is concerned with the appropriateness of the special contracts, and approval or disapproval in the instant case will not affect cost allocation or rate design until the Customer's load is expected to appear during the test year of a general rate case. (3 TR 864.) While it may be tempting to predetermine how service to the Customer will affect the rates paid by all other customers, that is a question for a general rate case where marginal costs for serving the Customer can also be evaluated. (*Id.*) The Commission previously found that "approval of the special contracts, in and of itself, does not approve or require future approval of subsidization by existing customers, or cost recovery of stranded costs from existing customers." *In re DTE Electric Company for Approval of Special Contracts*, MPSC Case No. U-21990, December 18, 2025, Order, p 33. As Staff has shown there will likely be an aggregate positive impact on rates by serving the Customer, but how that impact lands among the various customer classes is yet to be determined. For example, the other cost and benefit components integrated into the overall affordability benefit are still projections and have not yet been allocated among customer classes. (3 TR 865.)

The Company, GLREA, MNS, MEI-CEO all agreed that cost allocation issues are appropriate to consider in rate cases but not the instant case. (3 TR 419-420, 609, 619, 675.)

Staff recommended that the Commission continue to require the Company to submit 6 COSSs as part of its rate case applications that would include scenarios with a new customer class, direct assignment of costs, and using different production allocators among others. (3 TR 865.) Staff recommended that the direct assignment required by the sixth COSS should be made to each large load customer individually. (3 TR 865-866.) Further, Staff recommended that the Company provide all data necessary to recreate those six COSS proposals as well as track any cost data that may be directly attributable to the Customer. (3 TR 868.)

The Company claimed that Staff recommended that the Company provide the six COSSs annually and disagreed because it would be burdensome and those studies were already provided in the Company's current on-going rate case. (3 TR 420-421.) Staff did not recommend that the COSSs be provided annually, but rather recommended that the Commission require the Company to provide those COSSs in its next general rate case just as the Commission ordered in U-21990 (with costs directly assigned to individual large load customers separately). Staff agrees with the Company that the discussion and evaluation of the six studies in the current rate case should be resolved before determining appropriate next steps. (3 TR 421.) Staff does not recommend that the studies in the current rate case be updated for the Customer.

Staff discussed the process by which a new customer class may be created for large load customers and how it differs from simply creating a new rate within the existing primary class. Specifically, Staff explained that customers within any one class all pay the same distribution rates (depending on voltage level for primary customers.) So, for example, if a new large load customer rate was created and remained in the primary class, then costs attributable to those large load customers would still be integrated into all other primary rates, thus leaving the new customers unmeaningfully separate. Creating a new class for large load customers may also create issues because the Customer will build and own its own substation and pay up to $50M toward distribution investment needed for its service. This could lead to distribution charges for large load customers becoming effectively zero and greatly reduce the Customer's contribution to embedded distribution costs. (3 TR 867-868.)

Staff did not recommend that a new customer class be created in the instant case for the same reasons that cost allocation should be treated in general rate cases.

2. Determining Customer-specific costs in an IRP will be valuable to support future determinations of cost responsibility.

The actual production resources needed to serve the Company's customers, including the Customer, will be determined in future integrated resource plan (IRP) cases. The Commission should consider how to eventually assign production costs to the Customer, or to the Customers' rate class if it is separated, so that any marginal cost of new capacity resources will not be passed on to other customers unfairly. The Commission may be able to identify costs specific enough to the Customer to be able to use in future rate cases in case Staff's worst-case scenario comes to be. The Commission could determine, using data from the IRP, what an adjustment to future revenue requirements would be in the event that the Customer or any other large load customer leaves service before the end of their special contract. (3 TR 880.) Staff notes that costs are not recovered via rates as part of IRP cases, but the determination or at least calculation of customer-specific costs in an IRP would be valuable to support future determinations if necessary.

The Commission may revisit the instant case if it finds that the assumptions made regarding revenue or costs differ materially when they become known in the future. Approval of the special contracts is therefore conditional. Specifically, the Commission has already found in Case U-21990 that it "retains jurisdiction of this matter and reserves the authority to reopen this case at any time and/or issue an order to show cause if DTE Electric's claimed affordability benefit fails to materialize or vanishes or costs associated with serving the Customer are expected to fall upon existing customers." *In Re DTE Electric Company for Approval of Special Contracts,* MPSC Case No. U-21990, December 18, 2025, Order, p 43. Staff recommends that the Commission make the same finding in the instant case. Staff further recommended that the collateral amount and termination payment should be re-examined within three years of the load ramp completion date. (3 TR 881.) A periodic review of the affordability benefit should be made in future rate cases and require the Company to confirm that the special contracts are contingent on the Customer's rate revenue and special contracts will cover the cost to serve the customer including generation, transmission, distribution, and other costs.

MEI-CEO argued similarly to Staff that the costs and revenues assumed in the instant case should be revisited and evaluated once those costs and revenues are known. (3 TR 696.) Though, MEI-CEO argues that the cadence of regular IRP proceedings are a natural fit for reexamining the assumptions made in the instant case. (*Id.*)

The Company intends to report aggregate cost and benefit in future rate case and PSCR proceedings. (3 TR 143.) This reporting may include revenue requirements for projects deployed under the CCAA, resources identified in IRPs caused by the Customer's load, increased fuel and purchased power costs, transmission revenue requirements, and avoided costs. As part of this reporting an evaluation should also be made regarding collateral and termination payments per Staff's recommendation to re-examine those items within three years of a Customer's completed load ramp and may occur in one of the types of proceedings described by the Company (e.g. general rate cases).

The Company disagreed with Staff's recommendation that the Commission use IRP proceedings to determine costs attributable to the Customer or other large load customers. (3 TR 420.) The Company argued that Staff was correct in noting that costs are not allocated nor is revenue collected in IRPs, and therefore any exploration of cost allocation or cost assignment should only be addressed in rate cases. (*Id.*)

D. Other Issues

1. The Customer should be made aware of the requirements and implications of the legislation related to EWR goals.

According to the Company the Customer is committing to participate and comply with the self-directed EWR plan requirements as set forth in MCL 460.1093.

(3 TR 103.) Staff recommended the Commission direct the Company to work with the Customer to establish an EWR plan in coordination with the stipulations in Case No. U-21627. (3 TR 890.) Staff also recommended the Commission order the Company to cooperate with the Customer to make it aware of Section 93 (9) of the Act, which states: "…[t]he report shall provide sufficient information for the provider and the commission to monitor progress toward the goals in the self-directed plan and to develop reliable estimates of the energy savings that are being achieved from self-directed plans." Staff will be conducting audits and reviewing subsequent reports as they do with all other EWR plans. (3 TR 891.) Staff also discussed recommending the Company discuss with the Customer that there is a financial penalty for not meeting the goals with newly implemented EWR measures annually, and that self-direct plans must be multi-year in duration. (3 TR 891.)

It is requested that the Commission Order the Company to communicate the requirements of Case No. U-21627, Section 93 (9) of the Act, and expectations of self-directing an EWR plan to the Customer. (3 TR 891.)

2. The Commission and ALJ should adopt Staffs recommendations regarding emergency load shedding procedures.

In direct testimony, Staff witness Cody S. Matthews recommended that the Commission ensure that the reliability concerns it previously identified in its order in Case No. U-21859 regarding large-load customers are addressed with respect to the special contract at issue in this proceeding. Specifically, Mr. Matthews testified that DTE's proposed amendments to its Emergency Electric Procedures in Case No.

U-22059 would address those concerns if approved, because the proposed provisions would apply to the customer taking service under the instant special contract. (3 TR 822.) Staff witness Matthews further recommends that if the Commission does not approve the proposed amendments in Case No. U-22059, that DTE either amend the special contract to incorporate equivalent reliability protections or amend its emergency procedures in a manner that ensures those protections apply to the customer served under the special contract. (3 TR 822.)

Staff witness Matthews explained that the Commission has previously recognized the reliability implications associated with very large electrical loads. (3 TR 820.) Witness Matthews highlights that in Case No. U-21859, the Commission noted that the substantial increase in load represented by data centers and other large-load customers poses potential risks to system reliability. (3 TR 820.) The Commission subsequently addressed those concerns more directly in Case No. U-21990, involving DTE's special contract with Oracle. In its December 18, 2025 order in case no U-21990, the Commission directed DTE to update its Emergency Electric Procedures to provide that, after public appeals and voluntary load reductions have been exhausted, the large-load customer would be subject to firm load shedding prior to other DTE customers when doing so could prevent the shedding of other customer load and would not compromise system reliability. (3 TR 821.)

Staff witness Matthews also noted that the Commission has not yet approved DTE's proposed amendments in Case No. U-22059. (3 TR 821.) Consequently, absent approval of those amendments, there would be no assurance that the reliability protections contemplated by the Commission in Case No. U-21990 would apply to the customer served under the special contract in this case. Because the proposed amendments are not approved at this time, in order to ensure that the reliability concerns addressed in the Commissions U-21859 order also apply to this special contract, Staff recommends that one of the following options take place if the Commission does not approve DTEs amended emergency procedures in case No. U-22059: (3 TR 822.) DTE can amend the special contract in the instant case to include language to address the Commission's concerns it laid out in its U-21990 order, or DTE amend its emergency procedures language to ensure that any provision in its emergency procedures tariff also apply to this special contract. (3 TR 822.)

3. The ALJ and Commission should deny the requests made by MEIU/CEO regarding changes to the 300 zonal resource credits being transferred to DTE under the proposed contract.

In rebuttal testimony, Staff witness Matthews responded to recommendations made by MEI/CEO witness Laura Sherman regarding the source of the 300 zonal resource credits (ZRCs) that would be transferred to DTE under the Capacity Contribution and Assignment Agreement (CCAA). (3 TR 825.) Specifically, Mr. Matthews addressed witness Sherman's recommendation that a portion of those ZRCs be provided through demand response programs, virtual power plant (VPP) programs, and behind-the-meter battery storage resources. (3 TR 826.)

Witness Matthews testified that Staff does not support imposing requirements on the source of the 300 ZRCs beyond those already contained in the agreements negotiated between the Customer and DTE. (3 TR 825.) Further noting that because the Customer is already providing the ZRCs to the Company at no cost, and MEI/CEO witness Sherman did not demonstrate why additional requirements governing the source of those ZRCs would be necessary or appropriate. (3 TR 826.) Staff therefore recommends that requiring the Customer to satisfy the obligation through specific technologies or program types would unnecessarily constrain the parties without a demonstrated benefit.

Witness Matthews further testified that uncertainties remain regarding the cost and implementation of the programs identified by witness Sherman. (*Id.*) While the ZRCs themselves may be provided to DTE at no cost, demand response programs, VPP programs, and behind-the-meter storage programs all require utility administration, coordination, and operational infrastructure. Staff expressed concern that the costs associated with implementing and operating such programs may exceed the value of the ZRCs being provided, particularly where participant compensation and program administration are not directly tied to prevailing capacity market prices. (*Id.*) As a result, requiring the Customer to support such programs as a condition of providing the ZRCs may not be reasonable.

With respect to behind-the-meter battery storage specifically mentioned by witness Sherman, witness Matthews acknowledged that such resources may ultimately serve as valuable components of a virtual power plant. (*Id.*) However, he explained that substantial practical and operational challenges remain. Among those challenges is the need for a distributed energy resource management system (DERMS) capable of coordinating and controlling battery systems across numerous manufacturers, inverter types, and operating configurations. Staff testified that the costs and operational requirements associated with implementing such a system remain uncertain and could be substantial. (*Id.*)

Witness Matthews also noted that DTE's current interconnection procedures significantly limit the ability of behind-the-meter battery systems to export power onto the electric grid. (*Id.*) Under existing procedures, battery storage systems are generally configured to operate in import-only, export-only, or no-exchange modes. Because export-only operation provides limited value to most customers, Staff expects that the majority of installed battery systems are currently configured in import-only or no-exchange modes, neither of which allows meaningful export to the grid. Consequently, the effective contribution of existing behind-the-meter battery resources toward capacity needs may be substantially less than their installed nameplate capacity. (*Id.*)

For these reasons, witness Matthews testified that if the Commission determines that behind-the-meter storage resources should be used to support the ZRC obligation, the Commission should first require DTE to update its interconnection procedures to allow those resources to export energy to the grid. (*Id.*) Without such changes, the practical ability of behind-the-meter batteries to provide the contemplated capacity benefits may be limited.

Witness Matthews noted that if a solicitation process is ultimately used for procuring the required ZRCs, developers or utilities may have an opportunity to compete to provide those resources. (3 TR 827.) Staff believes such an approach would allow the market to determine the most cost-effective source of capacity rather than prescribing particular technologies or program structures in advance.

Accordingly, Staff recommends that the Commission decline to require that any portion of the 300 ZRCs be sourced from demand response programs, virtual power plants, or behind-the-meter battery storage. Staff further recommends that, if the Commission determines that behind-the-meter storage should be utilized for this purpose, DTE should first be required to modify its interconnection procedures to allow those resources to export power to the grid and meaningfully contribute toward capacity obligations.

4. The ALJ and Commission should deny MEIU witness Sherman's recommendation about directing an ownership split of 50% third-party owned projects and 50% Company-owned projects, including Build-Transfer Agreements (BTAs) and self-build projects.

Staff witness Naomi Simpson's rebuttal testimony opposes MEI/CEO witness Sherman's recommendation that DTE's voluntary green pricing procurement include a predetermined ownership split of 50% third party-owned projects and 50% Company-owned projects. (3 TR 848.) Staff argues that resource selection should be driven by the Competitive Procurement Guidelines and that the most economic projects should be chosen regardless of ownership structure. (3 TR 849.)

Staff contends that establishing a mandatory ownership allocation would effectively create separate procurement tracks, limiting competition among all proposed resources and potentially resulting in higher-cost projects being selected over lower-cost alternatives. (3 TR 849.) While Staff acknowledges that to the extent that a special contract resource is being paid by a specific customer under a voluntary program, Staff does not have the same concerns given that the single customer is aware of these costs and is agreeing to pay them. (3 TR 848.) Staff also must acknowledge the fact that this customer has the ability to cancel the Customer Requested Offer (CRO) special contract which would then allocate these resources to other customers. (3 TR 849.) Because resources procured under the program could ultimately be allocated to all ratepayers if customer demand declines, Staff maintains that no ownership preference should be imposed as this may result in higher costs for customers. (*Id.*) Instead, Staff recommends allowing all projects to compete on equal footing to ensure the lowest-cost portfolio is selected. (*Id.*) Staff further notes that it expects DTE to adhere to the cost assumptions used to justify Company-owned projects and will review and audit those costs in future cost recovery proceedings. (*Id.*)

5. Staff does not contest the Company's proposal to analyze each large load customer separately, however, maintains that Staff's recommended combined analysis is still necessary.

Staff witness Simpson testifies that Staff recommends the Commission again adopt the additional analysis it adopted in the Commission's Order in Case No. U-21990 on December 18, 2025. However, Staff recommends that this analysis be done by analyzing the Company's large load customers in aggregate. (3 TR 837-839.) Company witness Foley testifies that each large load should be analyzed independently because Staff's recommendation conflicts with Section 5.1.3 of the PSA (the affordability backstop) and the Commission's December 2025 order in the Case No. U-21990 directing the Company to analyze that customer independently, enabling the Company to provide an annual report of the "realization of the projected affordability. (3 TR 150.)

Staff takes no issue with the Company's intent to analyze each load separately to identify the individual affordability impact of each of its large load customers. However, Staff still recommends that an analysis that looks at the impact of the Company's large loads in aggregate, as specified in witness Simpson's testimony, also be completed. This will help to illustrate the aggregated affordability impact and assess a future where both loads exist or both loads do not materialize because the impacts may not simply be additive.

6. Staff supports the Company's reporting proposal.

Staff witness Simpson recommended reporting consistent with the Commission's December 2025 order in Case No. U-21990. (3 TR 844.) Company witness notes that several parties recommended reporting at differing intervals. (3 TR 151.) The Company notes that the existence of the PSA, Section 5.1.3, creates an affordability backstop that requires new tracking and reporting requirements and identifies what it believes the report should contain. (3 TR 152-153.) The Company also argues that the reporting requirements identified by both Staff and GLREA to assess the financial state of the Customer are not required because the credit and collateral requirements of the PSA and CCAA rely on publicly available credit ratings. (3 TR 154.) Staff agrees with the Company's recommendations and recommends the Commission direct the Company to report as intended but that any changes in the publicly available credit ratings that would impact the credit and collateral requirements of the PSA and CCAA be noted in its annual report.

7. The Commission should direct the Company to follow the Competitive Procurement Guidelines to the extent practicable.

Staff witness Simpson testified that the Company should prioritize resources necessary to achieve the Company's IRP that serve all customers prior to selecting those for the Company's Large Load Customer under the CCAA so that the Company's Large Load Customer does not end up paying less than other customers for resources of the same technology type contracted at about the same time. (3 TR 840.) Company witness Bilyeu agrees with the general principal that other customers should not subsidize resources for the Large Load Customer under the CCAA. (3 TR 296-298.) The Company also states that Storage will be procured using the Commission's Competitive Procurement Guidelines, but renewable resources acquired for the CCAA will follow a specialized procurement process in accordance with the Commission's April 14, 2021, Order approving the settlement in Case No. U-20713/U-20851 and the Commission's March 14, 2024, Order approving the settlement in Case No. U-21172. (3 TR 161-162; 3 TR 296-298.) The Company specifically references the U-20713/U-20851 Settlement Agreement term 9.1.2 which states:

> The projects associated with customer-requested projects shall utilize a specialized competitive bidding process for all contracts above $100,000 other than a contract with the anchor tenant. The details of the competitive process will be agreed upon with the customer and will incorporate any competitive bidding rules specific to the customer. Competitive bidding for customer-requested projects remains subject to Commission Staff audit.

Although witness Bilyeu did not specifically identify the precise language in the U-21172 Settlement that he was referring to, taking the settlement as a whole, it does reference the *Michigan Public Service Commission's Competitive Procurement Guidelines for Rate Regulated Electric Utilities (Not for Public Utility Regulatory Policies Act ("PURPA")*.

Company witness Bilyeu somewhat misstates Staff's concern. (3 TR 297.)Staff is in agreement that the resources to serve the Company's Large Load Customer should not be subsidized by other ratepayers as the Company states, but Staff's concerns are broader than that. Staff does not believe that resources procured for the Large Load Customers should cost less than similar resources contracted for other customers. Staff's position comports with recent VGP settlements, such as in U-21172. In fact, Staff's position does nothing to preclude the Company from ensuring that the best projects and most cost-effective projects are first assigned to all rate payers and used to fulfill the Company's IRP/REP need.

Ultimately, Staff supports a framework that includes protections for all customers. Staff is unclear if witness Bilyeu is indicating that the Company simply intends to follow the settlement with the listed modifications to the Competitive Procurement Guidelines or if witness Bilyeu believes that these settlement terms allow for negotiation deviating further from the Competitive Procurement guidelines. (3 TR 297-298.) Staff concern is that a drastically different RFP process that significantly deviates from the Competitive Procurement Guidelines may include provisions that result in certain Company owned or build transfer agreement projects being bid into only one RFP process. Staff would support a framework whereby the Company complied with the Competitive Procurement Guidelines as modified by the aforementioned settlement agreements and ensured that ratepayers for resources to fulfill the IRP/REP requirements did not pay a premium as compared to the CCAA. One option could be to use a single solicitation to determine all possible projects available for a given year, select the resources necessary to meet the Company's IRP and REP first, then fill the CCAA with remaining projects, selecting from those remaining projects those that comply with the terms of the settlement agreements, to the extent that there are enough projects in total to meet first, the IRP/REP need and, second, the CCAA. Staff believes that either alternative would allow the Company to also comply with the Competitive Procurement Guidelines as modified by the aforementioned settlement agreements.

8. The Commission should find that following the Competitive Procurement Guidelines, for Special Contracts, to the extent practicable and inclusive of the applicable modifications contained in previous settlement agreements will help to reduce risks to other ratepayers.

Utilizing as much of the Competitive Procurement Guidelines as possible also adds protection ratepayers that resources are competitively bid. The Company argues that, because the Customer is responsible for the full revenue requirement used to serve its VGP enrollment that MEI/CEO witness Sherman's concerns regarding ratepayer risk is not applicable. (3 TR 304.) Staff generally disagrees with the Company's position. If, at any point in the future, the Customer or its parent company is no longer viable, there could be a future whereby these resources are first used to serve other VGP load and absent ample VGP enrollment, would be used to serve the Company's load for all customers. Therefore, these resources are still ultimately backstopped by other ratepayers and protection against risk is an important consideration.

9. The Commission should deny the Company's request to book the financial adder associated with 300 ZRCs as non-refundable income.

The Company has requested to book the financial adder associated with 300 ZRCs as non-refundable income in Company witness Foley's testimony. (3 TR 115-116.) The Company continues to argue for this approval in witness Foley's rebuttal testimony. (3 TR 154-155.) Staff, MEI/CEO, GLREA, and ABATE all agree that the financial adder should not be allowed to be recorded as non-refundable income.

(3 TR 154-157.) Rather it should be either rejected or be treated as ordinary revenue used to offset the Company's future revenue deficiencies.

In its rebuttal, the Company states that, although it recognizes that the acquisition of the ZRCs is not a PPA and therefore not seeking accounting treatment pursuant to MCL 460.1028, that it is a part of the special contract and is similar to the financial compensation mechanism because it is designed to account for the opportunity cost of the Company foregoing the development of a company-owned resource. (3 TR 156.) In addition, the Company states that the various intervenor positions establish an unfair sharing of risks and benefits related to the provisions of service because all argue that the Company should bear the risk of the Customer not fully covering their financial obligations.

Staff disagrees. The Company is expected to invest significantly to build resources that will fulfill the special contract to serve this customer's load, develop resources to achieve the renewable energy plan, and fulfill a resource transition away from its legacy coal generation. It gleans the benefit of return on and of all of those investments. Clearly, the Company has determined that there is a capacity need that exceeds the amount of capacity and energy that the special contract and its existing renewable plan provides, otherwise the 300 ZRC's included in the CCAA special contract would not be necessary. The Company's long-term energy and capacity needs are determined in its IRP filings. Therefore, Company has imposed a stop-gap to cover the capacity need in the near term to allow them to quickly serve this customer while letting the Company's next IRP determines the most reasonable and prudent way to meet the longer-term capacity needs to serve all customers. Allowing the Company to book a financial adder on the ZRC transfer as a non-refundable income for this special customer creates a future incentive for the Company to seek out future large customers that are willing to pay more than is necessary to have their load served. Staff recognizes that the Customer in question is of a size that requires special consideration and the resources that will be developed to fulfill the special contract will do that. The ZRC's are simply a short term stop gap that does not need to be further incentivized.

Staff also disagrees with the notion that the Company is bearing all of the risk and receiving none of the reward. As stated earlier, the Company will glean the return on and of all new resources that are necessary to serve this customer, achieve REP and CEP compliance, and transition away from legacy fossil generation. Staff recognizes that there is a risk, but not necessarily that of the Company's. Rather, Staff views the risk of serving this customer as a risk to other ratepayers if for some reason the Customer does not fulfill its load obligations, or if the ZRC's don't come to fruition as they should at the time of need, or that the resources not covered in the CCAA that are needed to serve this customer's load are more costly than expected. The idea that there is a risk around the ZRC transaction or the ZRC's themselves further support Staff's position that the financial adder should not be recorded as non-refundable income because the risk is to that of other customers, not the Company, and therefore the financial adder should be used for the benefit of <u>all</u> customers. (3 TR 844.)

10. The Commission should only consider the CCAA to be a voluntary green pricing program if the renewable energy credits associated with the enrolled customer load are accounted for in the year that the retail sales are removed from the compliance calculation.

The Company identifies the renewable resources in the CCAA as being voluntary green pricing resources. (3 TR 111.) The Company goes on to explain that the RECs associated with the VGP resources will be transferred to the Customer. (Exhibit S-1.0.) The Company acknowledges that renewable energy credits should not be double counted and that there should be a mechanism to ensure that does not happen but offers no such mechanism and argues that the Company is not responsible for any such tracking to ensure RECs are ultimately retired and not sold. (3 TR 290-291.) The Company argues that REC ownership does not invalidate the underlying renewable nature of the energy produced. (3 TR 291.) Staff agrees in so far as the renewable nature is transferred to the owner of the REC because Staff maintains that a REC is the certified renewable attribute of renewable generation. (3 TR 842.) The renewable energy compliance calculation excludes both distributed generation outflow and voluntary green pricing. Staff finds that this exclusion is appropriate because both of those generation sources are presumed to be renewable and cover the load that is enrolled in the associated tariff. However, this only results in a logical conclusion if the RECs are either retired by the Company on behalf of the customer or transferred to the customer and then retired by the customer in the year that the enrolled load is being excluded from retail sales. Any other treatment results in a mismatch between the amount of load being removed from the compliance calculation and the amount of RECs, and the renewable energy attribute, being retired which is illogical.

The Company argues that neither MCL 460.1061 nor the Commission's order require utility retirement. Staff again opines that the load enrolled in Section 61 VGP is expected to be covered by renewable energy in the total of the amount enrolled. (3 TR 290-291.) If the renewable energy has had the renewable attribute separated and removed from it, then it is no longer considered renewable and therefore not compliant with Section 61. If the load enrolled is not covered by renewable energy inclusive of the actual renewable attribute, then the program simply cannot be a voluntary green pricing program that complies with MCL 460.1061. In addition, Staff believes that the Company is misinterpreting the Commission's July 12, 2017, order in U-18349. The Commission clearly indicated that RECs under VGP programs should be properly assigned and retired (emphasis added) and that they are not double counted. (3 TR 841-842.) The Company's proposal includes gaps that essentially violate the Commission's order because, at the point where the load is being removed from compliance but it is not covered by energy that includes the renewable attribute, the associated REC is being double counted or more specifically a single REC is being associated with more than a single MW of generated renewable energy. The Company argues that the transfer simply changes who can claim the renewable energy. (3 TR 291.) Staff further expands on that and finds that the renewable energy can only be claimed to cover the associated load and subsequent retail sales if the RECs are indeed retired in the year they are claimed. (3 TR 842.) Therefore, creating an illogical outcome where the load enrolled and subsequent sales is not truly covered by renewable energy because the attribute has been separated and not retired in the year claimed. Absent the Company's commitment to comply with the Commission's previous direction to assign and retire RECs for VGP enrolled load associated with the CCAA, the Commission should clarify that the CCAA is not a VGP program.

11. The Company's argument that transferred RECs are not available to DTE creates a safeguard should be ignored.

The Company argues that transferred or retired RECs creates a critical safeguard because they cannot be used for RPS compliance and are not available to DTE once transferred to the Customer. (3 TR 292-293.) However, there is no mechanism whereby the RECs transferred to the Customer, if not also retired by the Customer in the year that the load is removed from compliance, could not potentially be sold back to DTE or another Michigan utility at a later date. Therefore, Staff recommends the Commission should find that the claimed safeguard simply doesn't exist.

12. The Company's claims of implications to other large customers should be disregarded.

The Company argues that Staff's position creates unnecessary rigidity and implications for existing large customers, specifically Ford, Stellantis, and the University of Michigan. Staff recommends that the Commission disregard this concern simply because the Company has not shown that these other customers currently engage in this practice. Further, the Company has offered no testimony stating that these other existing customers specifically receive RECs and claim the renewable energy without either the Company or the customers retiring the RECs necessary to cover the renewable energy claimed. Therefore, the Commission should disregard the Company's concerns about implications to other large customers.

13. The Commission should reaffirm VGP RECs must be retired to be counted toward Clean Energy Compliance, consistent with its December 18, 2025, Order in Case No. U-21867 stating that one REC may be retired to meet one megawatt-hour of clean energy compliance.

Staff raises concerns regarding the alignment of the Clean Energy Plan (CEP) with the Company's REP if VGP REC's are not retired. (3 TR 842.) The Company has indicated that it plans to use the RECs generated using the VGP resources developed under the CCAA toward its CEP Compliance. (Exhibit S-1.1.) Company witness Bilyeu states that VGP REC retirement is not the only way to ensure alignment of the REP and CEP and goes on to state that this is a tracking and verification issue rather than a retirement issue. (3 TR 295.) However, the Commission has not approved any other means of aligning the CEP and REP. Staff correctly notes that, although the REP compliance calculation removes VGP from the retail sales, the CEP compliance calculation does not. Therefore, it isn't a tracking issue, the only means to count renewable generation that covers VGP is to retire the REC associated with it because that is the only mechanism that the Commission has approved to date. Therefore, Staff recommends that the

Commission reaffirm its previous finding that one REC can be retired to meet one MWh of Clean Energy which allows for the VGP load to be covered by the retirement of RECs that were generated from VGP resources.

III. Conclusion

For all the reasons presented in Staff's testimony, exhibits, and this initial brief, Staff respectfully requests the ALJ adopt Staff's recommendations into the Proposal for Decision, including:

. • Issues of cost allocation should be addressed in future rate case proceedings.

• Recommend the Commission continue to require the Company to submit the six cost of service studies required in Cases U-21859 and U-21990 in future proceedings.

• Recommend the Commission require the Company to track any costs that may be directly tied to the Customer so that it is possible to determine the effect of directly assigning costs to either the Customer or a potential new large load customer class.

• If a CIAC allowance is approved in Case U-22061, then it should be applied to the Customer for any costs in excess of the line extension agreement.

• Recommending the Commission consider re-opening the instant case if and when potential new power supply costs are approved in the Company's next IRP or within at least 3 years following the Customer's load ramp completion date.

- Recommending the Commission require the Company to submit a letter to the docket accepting all conditions deemed by the Commission as necessary for approval of the special contracts.

Respectfully submitted,

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DATED: July 20, 2026

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the application of DTE ELECTRIC COMPANY for approval of special contracts and for other relief. /	Case No. **U-22058** **(e-file paperless)**

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF EATON)

Cherie A. R. Shea, being first duly sworn, deposes and says that on **July 20, 2026,** she served a true copy of **Michigan Public Service Commission Staff's Initial Brief** upon the parties listed on the attached service list **via email only:**

Cherie A. R. Shea

Subscribed and sworn to before me
this **20th** day of **July, 2026**.

E. M. Fielder-Attia, Notary Public
State of Michigan, County of Jackson
Acting in the County of Eaton
My Commission Expires: 07-09-2031

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