DTE Electric Company
One Energy Plaza, 1635 WCB
Detroit, MI 48226-1279

DTE

John A. Janiszewski
(313) 235-7309
john.janiszewski@dteenergy.com

August 3, 2026

Lisa Felice
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Lansing, MI 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 electronic filing in the above-referenced matter is DTE Electric Company's Reply Brief (Public). Also attached is the Proof of Service.

Very truly yours,

John A. Janiszewski

Digitally signed by John A. Janiszewski
Date: 2026.08.03 16:51:30 -04'00'

John A. Janiszewski

JAJ/cdm
Enclosures

cc: Service List

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 related relief.	))))	Case No. U-22058

<u>**DTE ELECTRIC COMPANY'S**</u>

<u>***PUBLIC***</u>

<u>**REPLY BRIEF**</u>

Dated: August 3, 2026

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I. INTRODUCTION

DTE Electric Company ("DTE Electric" or the "Company") respectfully submits this Reply Brief in support of the Michigan Public Service Commission's ("MPSC" or the "Commission") approval of the Company's Primary Supply Agreement ("PSA") and Clean Capacity Accelerator Agreement ("CCAA") (collectively, the "Special Contracts") with Google LLC (the "Customer"), as well as two related accounting authorizations.[1] Nothing in the parties' initial briefs undermines the central conclusion established by the record that the Special Contracts are lawful, reasonable, and prudent, and should be approved.

As DTE Electric's Initial Brief demonstrated, the Company and the Customer structured the Special Contracts to hold other customers harmless. The record confirms that the costs of serving the Customer are not shifted to other customers, that the Special Contracts strengthen the Company's ability to serve a new, large-load customer without adverse impact to the existing customer base, and that the Special Contracts are projected to produce an estimated benefit to DTE Electric's other customers of approximately $1.7 billion. Section 5.1.3 of the PSA ("Affordability Backstop") provides a further, independent assurance that, should the Commission ever determine that the aggregate costs of serving the Customer exceed the aggregate benefits, that shortfall is borne by the Customer. Staff and intervenors' initial briefs offer no basis to disturb these findings; at most, they propose contract modifications, conditions of approval, or other requests for relief that are unnecessary, unsupported, or directed at issues reserved for other proceedings.

Initial briefs were filed on July 20, 2026 by DTE Electric; Michigan Public Service Commission Staff ("Staff"); the Michigan Attorney General ("AG"); the Association of

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[1] Approval is sought for two accounting authorizations related to the CCAA: (1) the CCAA Regulatory Liability, and (2) the Zonal Resource Credit ("ZRC") financial adder. *See* Sections V.B.3 and V.B.4.

Businesses Advocating Tariff Equity ("ABATE"); the Great Lakes Renewable Energy Association ("GLREA"); the Michigan Environmental Council, Natural Resources Defense Council, and Sierra Club (collectively, "MNS"); and the Michigan Energy Innovation Business Council, the Institute for Energy Innovation, and Advanced Energy United, together with the Clean Energy Organizations (collectively, "MEICEO").

The parties' initial briefs include a range of recommendations — from proposed modifications to the minimum billing demand, termination payment, and collateral terms, to conditions on procurement of CCAA resources, to arguments concerning cost allocation, rate design, and grid reliability. As demonstrated in the Company's Initial Brief and further below, these recommendations should be rejected. Most are properly reserved for future rate cases, the upcoming Integrated Resource Plan ("IRP"), or other case types and are not before the Commission for decision in this proceeding; others are unsupported by the record or would impose unnecessary conditions on the Special Contracts that already protect other customers.

This Reply Brief responds to the initial briefs of Staff and intervenors in the order in which the issues are presented in the Company's Initial Brief, and addresses issues not otherwise preemptively covered in the Company's Initial Brief in the "Other Issues" section below. DTE Electric relies on the content of its Application, testimony, exhibits, and Initial Brief, and incorporates same as if fully restated herein. DTE Electric cannot respond — other than by noting this general objection — to the extent any party's Initial Brief does not articulate or explain a position.[2] The Company's decision not to separately address every argument, position, or

[2] There is similarly no requirement for the Commission to attempt to unravel and consider such matters. Courts have repeatedly recognized, for example: "It is not sufficient for a party 'simply to announce a position or assert a claim of error and then leave it up to this Court to discover and rationalize the basis for his claims, or unravel and elaborate for him his arguments, and then search for authority to sustain or reject his position.'" *Wilson v Taylor*, 457 Mich 232, 243; 577 NW2d 100 (1998), quoting *Mitcham v Detroit*, 355 Mich 182, 203; 94 NW2d 388 (1959). *See also*, *Gross v*

recommendation advanced by any party, whether in the Company's Initial Brief or in this Reply Brief, should not be construed as agreement with, or acquiescence to, that argument, position, or recommendation.[3] Further, some recommendations are beyond the scope of this proceeding and are properly the subject of other cases or proceedings; DTE Electric reserves all rights to address those issues in the appropriate forum and on appeal.

II. HISTORY OF PROCEEDINGS

DTE Electric's Initial Brief, pp. 2-4, addressed this matter. There appears to be no disagreement.

III. JURISDICTION AND STANDARD OF REVIEW

DTE Electric's Initial Brief, pp. 4–10, set forth the jurisdictional and evidentiary framework applicable to this special contract proceeding. No party expressly disputes that the Commission has jurisdiction under 1909 PA 106, MCL 460.51 *et seq*., and 1939 PA 3, MCL 460.1 *et seq*. (including MCL 460.6 and 460.10), or that the VGP Special Contract arises under MCL 460.1061 — the primary authorities the Company identified. Disagreements therefore focus on the scope of this special contract proceeding, the Commission's remedial authority, and the content of the governing standard — all of which the Company addressed in its Initial Brief. These disagreements fall into five categories, addressed in turn below.

First, it should be emphasized that the Commission's recent large-load orders inform the governing standard here, but they arise from materially different proceedings. Case No. U-21859

General Motors Corp, 448 Mich 147, 161-62, n 8; 528 NW2d 707 (1995) ("Failure to properly brief an issue on appeal constitutes abandonment of the question"); *Isagholian v Transmerica*, 208 Mich App 9, 14; 527 NW2d 13 (1994).

[3] For example, but without limitation, some suggestions are beyond the scope of this case, but might be the subject of other case(s) or proceeding(s). DTE Electric reserves all rights to address issues elsewhere and/or on appeal.

concerned a different utility's generally applicable Rate GPD tariff provisions for future qualifying large-load customers. It did not involve DTE Electric, Rate D11, or the Customer-specific Special Contracts presented before the Commission in this proceeding. Case No. U-21859 Order dated November 6, 2025 ("November 6 Order") therefore informs the common customer-protection principle that costs caused by serving a large-load customer should not be shifted to other customers, but the particular tariff terms adopted for that different utility do not automatically govern DTE Electric's separately negotiated Special Contracts. *See* November 6 Order, pp. 103-104, 116-118.

Case No. U-21990 provides the more directly applicable procedural framework because it involved DTE Electric special contracts for a specific large-load customer. The Commission approved those contracts even though it recognized that the application did not mirror every aspect of the November 6 Order, while separately directing DTE Electric to propose a generally applicable large-load tariff aligned with the Commission's U-21859 findings. Case No. U-21990 Order dated December 18, 2025, pp. 37-45 ("December 18 Order"). On rehearing, the Commission made the distinction express: DTE Electric's generally applicable tariff would serve the purpose of setting prospective standards, while special contract applications filed in the interim would be considered on a case-by-case basis. Case No. U-21990 Order dated March 27, 2026, p. 25 ("March 27 Order"). Case No. U-22058 is such a case-specific proceeding. The Commission must therefore evaluate the particular PSA and CCAA on this contested record and as an integrated contractual package, rather than require them to replicate every term of a different utility's generally applicable tariff.

- *An Affirmative Net Benefit Is Not a Legal Prerequisite to Special Contract Approval*

MEICEO urges that the Commission "require an affirmative affordability benefit to other customers rather than just a showing of no cost-shifting." MEICEO Initial Brief, pp. 13-14. As set forth in DTE Electric's Initial Brief, pp. 7-8, 105-107, the common customer-protection principle reflected in the Commission's recent large-load orders is that the customer must fully pay the costs to serve it and not shift costs to, or be cross-subsidized by, other customers. December 18 Order, pp. 32-33, 40-43; November 6 Order, pp. 103-104, 116-117.

Neither order makes a guaranteed affirmative net benefit an independent legal prerequisite to approval. The hold harmless inquiry asks whether costs caused by serving the Customer will be shifted to other customers. The broader public interest inquiry permits the Commission to consider expected affordability, resources, reliability, clean energy, and other record-supported benefits, but it does not convert a projected benefit into a contractual guarantee.

The Special Contracts satisfy both inquiries and, as the Company's Initial Brief demonstrated, the record projects a substantial affirmative benefit in addition to protecting other customers against an aggregate cost shortfall. The record establishes a projected net customer benefit of approximately $1.7 billion that Staff independently replicated and that remained positive under every sensitivity presented by Staff and intervenors in the record. DTE Electric's Initial Brief, pp. 105-106, 113-114; (Isakson, 3T 857-858, 863). That the Special Contracts produce an affirmative benefit does not, however, convert an affirmative benefit into a legal precondition or guaranteed contractual outcome.

The Commission should decline MEICEO's invitation to convert a favorable projected customer benefit result into a new, mandatory legal precondition that appears nowhere in statute or Commission order. The record demonstrates that the Special Contracts affirmatively serve the public interest through the inclusion of contract terms that establish additional protections for the

Company’s other customers beyond those that are currently included in the Company’s Rate Book, the Customer's contribution to fixed system costs, the Customer-funded deployment of up to 1,600 MW of renewable energy and up to 480 MW of energy storage, and the advancement of Michigan's clean-energy objectives under 2023 PA 235, MCL 460.1001 *et seq*. DTE Electric's Initial Brief, pp. 1–2, 73–80.

Those features support the Commission’s public interest determination on this record; they are not independently guaranteed outcomes or a universal checklist for every special contract Indeed, the December 18 Order that MEICEO invokes described the DTE Electric special contracts in Case No. U-21990 as presenting an “opportunity for a benefit” and as a means of “potentially obtaining” the estimated benefit in that matter, while separately conditioning approval on protection against cost shifting and reserving future ratemaking. December 18 Order, pp. 32-39. That language treats the projected benefit as relevant evidence supporting the public interest, not as a guaranteed minimum benefit the customer must underwrite. MEICEO's argument inverts that framing.

MEICEO's error is primarily one of over-expansion. MEICEO’s Initial Brief, pp. 12–14, recasts the Commission's acknowledged discretion to evaluate the public interest as an obligation to maximize it — and then uses that reframing to advance distinct and unbounded conditions: a mandatory affirmative benefit, a requirement that the Company pursue the “most cost-effective” or “most beneficial alternatives,” and open-ended, ongoing conditioning of the Special Contracts. But the Commission's discretion, however broad, is bounded by statute; it “is a creature of the Legislature possessing only express authority granted to it by statute, and it has no common-law or inherent powers.” DTE Electric's Initial Brief, p. 5, citing *Union Carbide Corp v Pub Serv*

Comm, 431 Mich 135, 148-149; 428 NW2d 322 (1988); *Consumers Power Co v Pub Serv Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999).

Contrary to MEICEO’s proposed application of the public interest evaluation, that inquiry does not confer roving authority to impose whatever terms an intervenor prefers, to guarantee an affirmative net benefit, or to conduct the resource-portfolio optimization that the Legislature reserved to the IRP process under MCL 460.6t. DTE Electric's Initial Brief, pp. 127–131.

To the extent MEICEO's Initial Brief, pp. 13-14, proposes that a public interest standard would require not only a net affirmative benefit but also a showing that the Special Contracts are the “most beneficial alternatives,” that requirement is not the governing standard for special contract approval under MCL 460.6a. MEICEO’s related request that the Commission require the Company to “consider or utilize the most beneficial alternatives” for serving the Customer merely repackages MEICEO witness Kenworthy’s proposed “most cost-effective approach” standard. MEICEO Initial Brief, pp. 13-14; (Kenworthy, 3T 688-689). DTE Electric’s Initial Brief explained why that standard is legally and procedurally misplaced, and the Company incorporates that discussion rather than repeating it. DTE Electric Initial Brief, pp. 127-131. Special Contract review does not require the Commission to determine that the negotiated arrangements represent the single least-cost or most beneficial portfolio among hypothetical alternatives.

For the above reasons, MEICEO’s proposed standard should be rejected and the Commission should perform its public interest evaluation consistently with the case-specific framework established in Case No. U-21990: expected affirmative benefits may support approval, but the operative customer-protection requirement is that costs caused by the Customer not be shifted to other customers.

- *The Ex Parte Threshold Under MCL 460.6a(3) Is Not the Governing Merits Standard*

ABATE conflates the MCL 460.6a(3) *ex parte* threshold with the substantive standard governing this special contract proceeding, which is being conducted as a contested case. ABATE contends that, to obtain approval of the Special Contracts, "DTE must demonstrate that its provision of service to Google . . . is reasonable and prudent," and that the Company "has not demonstrated that the contracts are in the public interest and will not increase the cost of service to DTE's other customers," citing the Company's Application at page 1, n 1. ABATE Initial Brief, pp. 2–3.

ABATE combines two distinct propositions. The Company must establish that the Special Contracts are lawful, reasonable, prudent, and in the public interest and that other customers are protected from cost shifting. But the quoted "will not increase the cost of service to the Company's customers" language has a separate procedural source: the statutory predicate for *ex parte* treatment under MCL 460.6a(3), which authorizes approval "without notice or hearing" when the relief requested "will not result in an increase in the cost of service to [the utility's] customers." As the Company explained in its Initial Brief, it noted this *ex parte* threshold as a preliminary matter and expressly preserved, but did not rely upon, its right to *ex parte* treatment — electing instead to proceed as a contested case. DTE Electric Initial Brief, p. 5, citing Application ¶ 16.

ABATE cannot convert a threshold the Company declined to invoke into a freestanding, heightened evidentiary burden. The controlling standard in this contested proceeding is whether the Special Contracts are lawful, reasonable, prudent, and in the public interest, proved by a preponderance of the evidence. DTE Electric Initial Brief, pp. 7–10.

The Commission has applied the public interest inquiry in the large-load context with particular attention to whether costs caused by serving the large-load customer will be shifted to other customers. DTE Electric Initial Brief, pp. 105-107; November 6 Order, pp. 103-104, 116-

118; December 18 Order, pp. 32-34, 40-43. But the orders did so in different settings. Case No. U-21859 established generally applicable tariff terms for Consumers Energy; U-21990 evaluated DTE Electric's customer-specific special contracts and established that subsequent DTE applications filed before approval of its generally applicable tariff would receive case-by-case review. March 27 Order, p. 25

The Company does not dispute this hold-harmless standard, and its Initial Brief recognizes it. DTE Electric Initial Brief, pp. 15, 105–107. The Company's correction is therefore not a retreat from the no-cost-shift principle. The point is that that ABATE mislabels the MCL 460.6a(3) *ex parte* predicate as the merits standard and, in doing so, misreads a threshold observation in the Company's Application as an admission or an independent burden. It is neither.

The distinction has substantive consequences. As DTE Electric's Initial Brief, p. 7, n 3, recognized, although Case No. U-21990 was decided on an *ex parte* basis, the procedural distinction between this contested case proceeding and Case No. U-21990 does not diminish the relevance of the Commission's substantive customer-protection and public interest analysis. Thus, the Commission precedent and analytical framework for approving special contracts discussed in DTE Electric's Initial Brief, pp. 7-8, do not depend exclusively on Case No. U-21990's *ex parte* posture and may inform the Commission's decision where, as here, those findings are supported by a contested record.

At the same time, Case No. U-21990 should not be treated as establishing mandatory terms for every later DTE Electric special contract. The Commission expressly preserved interim case-by-case review pending establishment of the Company's generally applicable tariff. March 27 Order, p. 25. The pertinent question is therefore whether the Special Contracts, viewed as an integrated package and based on this evidentiary record, satisfy the governing hold harmless and public interest requirements. The Special Contracts answer that question through an aggregate customer-protection framework rather than a guarantee that every individual year or cost category will independently produce a benefit. Section 5.1.3 of the PSA ("Affordability Backstop") compares the applicable aggregate costs caused by serving the Customer with aggregate Customer-derived benefits and requires Customer action if the Commission determines that the aggregate assessment shows a shortfall. DTE Electric Initial Brief, pp. 40-42, 106.

Measured correctly, the record establishes — by a preponderance of the evidence, and as independently audited and replicated by Staff — that the Special Contracts protect other customers from an aggregate cost shortfall and project a net customer benefit of approximately $1.7 billion, with the Affordability Backstop requiring the Customer to comply with any Commission ruling or order addressing a Commission-determined aggregate shortfall. DTE Electric Initial Brief, pp. 105–106, 113–114; (Isakson, 3T 857–858, 863).

ABATE's reframing of the standard therefore neither heightens the Company's burden nor alters the conclusion: the Special Contracts satisfy the governing standard.

- *The Commission Lacks Authority to Rewrite the Contracting Parties' Negotiated Bargain*

Third, MEICEO contends the Commission possesses "broad authority to impose conditions on the contracts," including authority to compel an affirmative benefit, mandate "most beneficial alternatives" resources, and require ongoing conditions. MEICEO Initial Brief, pp. 12–14. The AG, ABATE, MNS, and Staff advance the same premise in various arguments (e.g., asking the Commission to "direct DTE to require" a 90% MBD and a 100% full-term termination payment (AG Initial Brief, pp. 2–3, 5-14), to "condition" approval on rewriting the Affordability Backstop, collateral provisions, and establishment of a separate rate class (ABATE Initial Brief, pp. 7–14), and to convert the CCAA's negotiated "up to" quantities into mandatory floors (MNS Initial Brief, pp. 21–23).

As the Company explained in its Initial Brief, the Commission's authority in this proceeding is defined and bounded by statute; it "is a creature of the Legislature possessing only express authority granted to it by statute, and it has no common-law or inherent powers." DTE Electric Initial Brief, p. 6, quoting *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-149; 428 NW2d 322 (1988); *see also Consumers Power Co v Pub Serv Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999). The Company's Initial Brief established that the Commission's role is "to approve, or to decline to approve, the PSA and CCAA as presented," and that the Commission "possesses no statutory authority to reform, rewrite, or nullify the contracting parties' negotiated bargain, or to compel the Company and the Customer to accept terms to which they did not agree." DTE Electric Initial Brief, p. 6. Where the Commission concludes a special contract should not be approved as presented, "its remedy is to decline approval — not to rewrite the contract or order it modified or rescinded." *Id*. at 6-7. The intervenors here ask the Commission to impose a bargain the contracting parties never struck (i.e., a higher MBD, larger termination payment, uncapped collateral, mandatory deployment floors, a new rate class, and extended ZRC/Demand Response ("DR") obligations). Such relief exceeds the Commission's authority. MEICEO's reliance on the Commission's "plenary" ratemaking jurisdiction (MEICEO Initial Brief, p. 11) conflates the power to regulate rates with a power to author private commercial terms and render management decisions incident to ownership but the latter do not exist. *Union Carbide*, at 148-149. Nor does the Company's voluntary acceptance of certain reporting obligations enlarge that authority — as DTE Electric's Initial Brief, p. 6, made clear, "it reflects the Company's acquiescence, not a Commission power to rewrite the Special Contracts over the contracting parties' objection."

- *Cost Allocation, Class Formation, and Rate Design Are Reserved for the Applicable Ratemaking Proceedings*

Fourth, ABATE asks the Commission to place the Customer in its own rate class in this docket (ABATE Initial Brief, pp. 11-12); MNS urges "direct assignment" of incremental costs to the Customer and characterizes that approach as preferable to the aggregate assessment established by Section 5.1.3 of the PSA (MNS Initial Brief, pp. 14-18); and GLREA asks the Commission to consider a "scarcity cost" fee and a separate rate class (GLREA Initial Brief, pp. 13-17).[4]

As the Company explained in Section V.C of its Initial Brief, the scope of cost-related questions properly before the Commission is defined by the Commission's own framework: approval of these Special Contracts "does not guarantee any particular ratemaking treatment," and no cost allocation or cost recovery methods are approved as a result of such an order; ratemaking "may still take place in the appropriate forum wherein all parties may contest the ratemaking proposals." DTE Electric Initial Brief, pp. 87-88, quoting December 18 Order, pp. 37-38. That reservation is consistent with the Commission's interim case-specific review of DTE Electric special contracts pending establishment of its generally applicable large-load tariff. The Commission may determine whether this PSA and CCAA adequately protect other customers without using this docket to establish prospective class formation, allocation, or rate-design.

The Michigan Court of Appeals has confirmed that "merely approving and implementing a special contract is not sufficient, in and of itself, to cause any rate or cost of service increase to occur," and that any future rate or cost-of-service effects are properly addressed in a subsequent rate case. DTE Electric Initial Brief, p. 5, 88, quoting *Attorney General v Pub Serv Comm*, 227

[4] GLREA witness Richter had proposed consideration of a separate data center rate class in testimony (Richter, 3T 609), while GLREA's Initial Brief, pp. 15-16, newly requests that the Commission include language in this case's order concerning future consideration and recovery of asserted direct and indirect data center costs. See Section V.D.3 for further discussion on GLREA's new request for relief.

Mich App 148, 154-155 (1997), *appeal den*, 459 Mich 910 (1998). The Commission likewise explained in the December 18 Order, pp. 29-30, that a special contract matter cannot be treated as a single-issue rate case because rate design and cost allocation must be evaluated holistically.

Staff agrees that "[c]ost allocation issues associated with the Customer are more appropriately addressed in the Company's general rate cases." DTE Electric Initial Brief, p. 88; (Isakson, 3T 864). Staff further testified that the costs reflected in Exhibit A-19 are not allocated among customer classes and that allocation will be addressed as those costs become known and are included in future general rate cases. (Isakson, 3T 864-866). The Company agrees that the IRP may identify resource-planning changes caused by serving the Customer's load, but the IRP does not allocate costs, collect revenues, create customer classes, or design rates. Those functions belong in the applicable ratemaking proceeding. (Willis, 3T 419-421).

As the Company's Initial Brief demonstrated, creating a new rate class is a quintessential rate-design determination for a general rate case. DTE Electric Initial Brief, p. 89-94; (Willis, 3T 420-421, 426-427). The Commission has required comparative cost-allocation and rate-design studies addressing traditional ratemaking, class formation, alternative allocators, and direct-assignment scenarios. December 18 Order, pp. 38-40. Requiring those alternatives to be studied does not select one methodology, establish a preference for direct assignment, or determine how any methodology will apply to this Customer. Nor does identification of a cost as being caused by serving the Customer automatically result in separate assignment of that cost to the Customer. Under PSA Section 5.1.3, Customer-caused costs are included in the aggregate assessment together with Customer-derived benefits. If the Commission determines that the aggregate assessment shows a shortfall, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs caused by its service. If the assessment remains positive, Section

5.1.3 does not provide for separately assigning an individual cost merely because it was identified as being caused by serving the Customer.

The Commission should therefore approve the Special Contracts without creating a new class, endorsing direct assignment, signaling approval of a scarcity fee, or prescribing the future implementation of PSA Section 5.1.3. Those matters should be addressed in the proceedings containing the relevant costs, revenues, billing determinants, and ratemaking evidence.

- *The Related Agreements Are Not Before the Commission for Approval or Modification*

Fifth, the Rider 12 DR Agreement and the Line Extension Agreement ("LEA"), including the Company's CIAC policy, are not before the Commission for decision and fall outside the scope of this proceeding. Staff would apply the CIAC provision from the pending Case No. U-22061 large-load tariff case to the Customer for costs beyond the $50 million LEA commitment (Staff Initial Brief, pp. 8-10); and ABATE and MNS would rewrite or extend the Rider 12 DR Agreement and LEA beyond their negotiated May 31, 2033 end date (ABATE Initial Brief, pp. 9-11; MNS Initial Brief, pp. 16-117) As the Company set forth in its Initial Brief, the relief requested in this proceeding is limited to approval of the PSA and CCAA and two related accounting authorizations; the Rider 12 DR Agreement and the LEA are standard contracts the Company is not asking the Commission to approve, and the Company is not proposing to change its current CIAC policy. DTE Electric Initial Brief, pp. 7-8, 94-98; (Foley, 3T 90; Benyard, 3T 451). Because Rider 12 is an existing, Commission-approved provision of the Company's Rate Book, the Customer's election does not constitute a "special contract" requiring approval and does not alter, change, or amend any rate or rate schedule within the meaning of MCL 460.6a(1). DTE Electric Initial Brief, pp. 7-8. To the extent any party seeks to modify, extend, or condition those agreements, such matters are outside the scope of this special contract proceeding and must be raised in an appropriate tariff or general rate case proceeding. DTE Electric Initial Brief, pp. 8, 95-96. Staff's proposal is doubly improper because it would apply, retroactively, a CIAC standard from a proceeding the Commission has not yet decided. As the Company's Initial Brief emphasized, tariffs operate prospectively, and it would not be appropriate to retroactively apply tariffs to prior contracts or requests. DTE Electric Initial Brief, pp.101-102; (Willis, 3T 423-424). Whatever CIAC standard the Commission ultimately adopts in Case No. U-22061 should be applied prospectively in that docket. *Id*.

- *The Commission Should Apply the Established Legal Standards Without Rewriting the Special Contracts*

In sum, the governing inquiry is whether the Special Contracts are lawful, reasonable, prudent, in the public interest, and structured so that the costs caused by serving the Customer are not shifted to other customers. The *ex parte* threshold in MCL 460.6a(3) does not create a different or heightened merits standard in this contested proceeding, and neither the applicable statutes nor the Commission's prior orders require a guaranteed affirmative net benefit or proof that the Special Contracts embody an intervenor's preferred or "most beneficial alternatives" resource portfolio. The Company has nevertheless exceeded the governing hold-harmless and public interest requirements: the record demonstrates a substantial projected benefit to other customers, and Section 5.1.3 of the PSA requires Customer action if the Commission determines that the aggregate costs of serving the Customer exceed aggregate Customer-derived benefits. DTE Electric Initial Brief, pp. 7-10, 39-43; (Isakson, 3T 857-858, 863).

The Commission should therefore evaluate the Special Contracts as presented and approve them upon finding that they satisfy the governing standard. The Commission should refrain from using its public interest inquiry to reform the contracting parties' negotiated bargain, impose commercial terms to which they did not agree, convert the projected customer benefit into a guaranteed payment obligation, prescribe cost allocation or rate design reserved for general rate cases, direct resource-selection outcomes reserved for the IRP, modify Related Agreements that are not submitted for approval, or retroactively apply provisions of a tariff that remains pending in another proceeding.[5] Staff and intervenors remain free to advocate appropriate resource-planning, tariff, cost-allocation, and rate-design positions in the proceedings established to decide those matters on developed records. Their proposals concerning those separate issues, however, provide no basis to reject or condition the Special Contracts in this case-specific proceeding.

IV. OVERVIEW OF THE SPECIAL CONTRACTS AND RELATED AGREEMENTS

DTE Electric's Initial Brief, pp. 10-14, addressed this matter. The essential nature, structure, and terms of the Special Contracts are not genuinely in dispute. No party contests that the PSA provides service on the Company's cost-based Rate D11, supplemented by the enhanced, customer-protective terms detailed in Company Witness Foley's Table 1 (Foley, 3T 89); that the CCAA obligates the Customer to pay the full cost of the energy storage and renewable energy resources and to provide 300 MW of ZRCs at no cost; or that the PSA commits the Customer to a 20-year term, an 80% minimum billing demand, a termination payment, and credit and collateral requirements that standard Rate D11 does not require. DTE Electric Initial Brief, pp. 10-15. GLREA, for its part, expressly acknowledges "the adequacy of provisions set forth in the PSA and CCAA." (Richter, 3T 580-582). Hence, the parties' disagreements go not to what the Special Contracts are, but to the calibration of discrete terms or issues outside the scope of this proceeding, which the Company addresses in the corresponding sections below.

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[5] *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-149; 428 NW2d 322 (1988); *Consumers Power Co v Pub Serv Comm*, 460 Mich 148, 155; 596 NW2d 126 (1999); *Attorney General v Pub Serv Comm*, 227 Mich App 148, 154-155; 575 NW2d 302 (1997).

V. THE SPECIAL CONTRACTS ARE REASONABLE AND PRUDENT AND IN THE PUBLIC INTEREST.

DTE Electric’s Initial Brief, pp. 15-102, set forth why the Special Contracts are reasonable, prudent, and in the public interest, and the Company relies on and incorporates that showing here. As established in Section III above, the governing standard is whether the negotiated Special Contracts are lawful, reasonable, prudent, in the public interest, and free of cost-shifting — not whether an intervenor can posit a desired alternative term. Measured against the applicable standard, the parties' arguments do not contest the essential structure of the Special Contracts, but instead seek to rewrite discrete, negotiated terms or impose conditions the Commission lacks authority to compel. The Company responds below to the Staff and intervenor arguments applicable to each subject matter, following the same organization as its Initial Brief. Consistent with Section III, and except where expressly stated, the Company's responses are directed at the merits and do not concede that the Commission possesses authority to reform the parties' negotiated bargain.

A. Primary Supply Agreement

As DTE Electric's Initial Brief explained, the PSA is at its foundation an agreement for the Customer to take service on the Company's existing, cost-based Rate D11 — including all applicable surcharges — supplemented by a series of additional terms that Rate D11 does not otherwise require and that operate to the benefit of the Company's other customers. DTE Electric Initial Brief, pp. 15-16. Company Witness Foley's Table 1 confirms that each material deviation from standard Rate D11 — the 20-year term, the restrictions on rate switching, the 80% minimum billing demand, the load-ramp and contract-capacity protections, the termination payment, the Affordability Backstop, the self-directed EWR commitment, and the robust credit and collateral requirements — makes the PSA more protective of other customers than standard Rate D11 in every respect in which the two differ. DTE Electric Initial Brief, pp. 13-15; (Foley, 3T 89). Notably, no Staff or intervenor witness contested the 20-year term, the pricing and rate-switching restrictions, or the essential structure of the PSA; the disputes that remain go to the calibration of discrete terms — principally the minimum billing demand ("MBD"), the termination payment, and the collateral and Affordability Backstop provisions — and, in each instance, would require the Commission either to reform a negotiated commercial term it lacks authority to rewrite or to resolve in this proceeding a matter reserved for a future rate case or the Company's upcoming IRP. The Company responds to each such argument in the corresponding subsection below.

1. 20-Year Contract Duration

DTE Electric's Initial Brief, p. 16, addressed this matter. There appears to be no disagreement. The record thus presents the 20-year commitment as an uncontested, customer-protective feature of the Special Contracts.

2. Pricing and Restrictions on Rate Switching

DTE Electric's Initial Brief, pp. 17-18, addressed this matter. No Staff or intervenor witness challenged the reasonableness of the PSA's cost-based D11 pricing or its rate-switching restrictions, and the record thus presents these as uncontested, customer-protective features of the Special Contracts. To the extent certain parties raise arguments concerning cost allocation, rate design, or the creation of a separate rate class for the Customer, those arguments do not contest the PSA's pricing or rate-switching terms and are addressed in Section V.C below.

3. Minimum Billing Demand (80%)

DTE Electric's Initial Brief, pp. 18-23, demonstrated that the PSA's 80% minimum billing demand ("MBD") is reasonable, prudent, aligned with Commission precedent, and protective of the Company's other customers. Only the AG seeks to disturb the negotiated 80% MBD, recommending that the Commission reject it and impose a figure "no lower than 90%." AG Initial Brief, pp. 6-10; (Coppola, 3T 468, 472-473). The AG's recommendation should be rejected. Notably, it is not merely inconsistent with Commission precedent and unsupported by the record — it is affirmatively opposed by Staff.

DTE Electric's Initial Brief, pp. 19-21, addressed why AG witness Coppola's should be rejected, and the Company relies on and incorporates those arguments here, including the AG's conflation of two distinct concepts (i.e., MBD and load factor), the 80% MBD's alignment with Commission precedent in the November 6 Order and December 18 Order, the unlawful nature of the AG's requested contract modification under *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-149; 428 NW2d 322 (1988), and the affirmative refutation of the AG's cost-shifting concern in the record (Isakson, 3T 875). The Company does not repeat those arguments herein and instead responds to matters the AG raised for the first time in their initial briefs.

Staff opposes the AG's 90% MBD recommendation. Staff Initial Brief, pp. 12-13. As Staff explained, the AG's recommendation "regarding minimum billing demand is unsupported" because "the assumed load factor and minimum billing demand are not related." *Id*. Staff's analysis confirmed that an 80% MBD "is sufficient to cover the non-production costs" of serving the Customer, and Staff therefore recommended that "the Commission should not approve the AG's recommendation on the basis that a 90% load factor was used to determine energy sales." Staff Initial Brief, p. 13.

- *The AG's Reliance on Case No. U-21859 Does Not Establish that the 80% MBD is Inadequate*

The AG's Initial Brief adds two arguments that AG witness Coppola did not advance (AG Initial Brief, pp. 6-9) and therefore warrant a direct reply here. First, the AG argues that the Company improperly treats the 80% MBD approved in Case Nos. U-21859 and U-21990 as an automatic "benchmark" while ignoring the case-specific showing U-21859 contemplates, such that the Company purportedly failed to meet its burden of proof. AG Initial Brief, pp. 7-9.

The Company does not dispute that the Commission must evaluate whether the Special Contracts protect other customers from costs caused by serving the Customer. Nor does the Company contend that Commission approval of an 80% MBD in another proceeding automatically establishes that the MBD is sufficient here. The relevant question is whether the PSA and CCAA, evaluated together and on this record, provide adequate customer protection.

Notably, Case No. U-21859 contemplated that the required case-specific showing be made through an *ex parte* filing. November 6 Order, p. 116 ("prior to each large load customer taking service under this tariff, Consumers must make an *ex parte* filing with the Commission that clearly demonstrates compliance with the tariff requirements and that costs caused by the interconnecting large load customer … are not being paid for by other customers"). Here, DTE Electric did not proceed *ex parte*; it made its showing through a full contested case, with discovery, cross-examination, and intervenor testimony — a process that exceeds what the November 6 Order requires.

The AG's reliance on Case No. U-21859 is particularly misplaced because she advanced the very same position there — that these case-by-case approvals should proceed as contested cases rather than *ex parte* — and the Commission twice rejected it. On rehearing, the AG "reiterate[d] her recommendation that any case-by-case approval-process for new large customers occur as a contested case." Case No. U-21859 Order dated February 19, 2026, pp. 6-7, 11 ("February 19 Order"). The Commission was "not persuaded that the process followed in Case No. U-21990 somehow undermines the findings in the November 6 order," found that the AG "failed to demonstrate her claims of error . . . with respect to the Commission's findings on future required *ex parte* filings," and denied the AG's petition for rehearing. February 19 Order, pp. 16-19. The AG cannot now wield Case No. U-21859 to demand a heightened evidentiary showing that the November 6 Order and February 19 Order do not require and that the Commission declined to impose when the AG requested it.

In any event, the Company made the case-specific showing required in this proceeding. The showing does not rest on the 80% MBD in isolation. The Customer will take service under cost-based Rate D11 and pay applicable surcharges; the MBD establishes a revenue floor; the termination payment protects against early exit; the Customer pays the revenue requirements of the CCAA resources; the collateral provisions support its payment obligations; and Section 5.1.3 of the PSA requires Customer action if the Commission determines that the aggregate costs of serving the Customer exceed Customer-derived benefits. Staff's independent downside analysis provides additional confirmation: under Staff's modeled minimum-bill scenario, minimum-bill revenues cover the estimated non-production costs in every analyzed year, with the lowest annual coverage identified as 116.64% in 2035. Staff Initial Brief, p. 13; (Isakson, 3T 875).

Moreover, as the Company's Initial Brief explained, "[n]othing in this brief asks the Commission to treat Case No. U-21990 as compelling automatic approval; rather, the Company demonstrates that the record here independently satisfies, by a preponderance of the evidence, the same standards" the Commission applied in that case.[6] DTE Electric Initial Brief, pp. 8-9. That approach is consistent with the Commission's case-by-case framework in the March 27 Order, p. 25. Case No. U-21990 does not compel approval here, and Case No. U-21859 does not compel mechanical adoption of the different utility's tariff terms. As described in Section III, the Commission must instead determine whether the Special Contracts, viewed as an integrated package, satisfy the governing hold harmless and public interest requirements on this record.

The AG's assertion that the Company "failed its burden" thus does not withstand the record. The Company presented a Customer-specific showing addressing the expected resources, revenues, costs, and contractual protections, and Staff independently confirmed the adequacy of the minimum-bill revenue in its modeled downside scenario. The AG's preference for a 90% MBD does not establish that the negotiated 80% MBD, considered together with the remaining protections in the Special Contracts, is inadequate.[7]

- *Out-of-State Tariffs Do Not Support Replacing the Negotiated 80% MBD*

Second, the AG cites out-of-state authority for the first time in her initial brief — a 90% MBD said to have been approved by the Kentucky Public Service Commission[8] and a "Very Large Customer" tariff that the AG represents "appears to include" a 100% MBD term approved by the Wisconsin Public Service Commission. AG Initial Brief, pp. 6-7. Neither citation appears in

[6] The same logic generally applies to the Commission's guidance in the November 6 Order insofar as the November 6 Order states that an "application for approval of any special contract shall also include a showing that the full costs of serving the large load customer are paid for by that customer." November 6 Order, pp. 116-117. Importantly, however, Case No. U-21859 was a large load tariff case for a different utility and while its customer-protection principle is relevant, its particular tariff terms do not automatically govern DTE Electric's Special Contracts. *See* Case No. U-22061 for the Company's pending large load tariff proceeding.

[7] To the extent the AG recasts this argument as a burden-of-proof failure premised on allegedly omitted transmission cost categories (AG Initial Brief, pp. 8-9), that contention concerns the treatment of incremental transmission costs in the aggregate cost-and-benefit assessment, not the reasonableness of the MBD floor, and is addressed in Section VI.

[8] The AG's citation to the Kentucky order includes a hyperlink (AG Initial Brief, p. 6, n.18) that does not resolve. The Company has nonetheless located and reviewed the order — Electronic Tariff Filing of Kentucky Power Company to Revise its Industrial General Service Tariff, Case No. 2024-00305 (Ky. PSC Mar. 18, 2025).

witness Coppola's testimony, and neither supports departing from Commission precedent. The AG offers no analysis reconciling those out-of-state tariff cases — which reflect different rate designs, different customer profiles, and different collateral and termination frameworks — with Commission precedent or the customer-protective package negotiated by DTE Electric and the Customer here.

With respect to the Kentucky PSC order, the AG cites the 90% MBD but omits contextual facts that undercut the AG's position more than support it. The Kentucky order approved a generic Industrial General Service tariff, decided without a hearing — contrary to the AG's own Case No. U-21859 argument that demands contested, case-by-case evaluations of specific negotiated contracts. Electronic Tariff Filing of Kentucky Power Company, Case No. 2024-00305, pp. 2-3 (Ky. PSC Mar. 18, 2025). More fundamentally, the 90% MBD the AG highlights was one term in an integrated package that included *an exit payment of only five years* of minimum billing. *Id*. at 3-4. DTE Electric's PSA, by contrast, secures a termination payment of *at least 15 years* of Minimum Monthly Charges ("MMCs") — *three times the Kentucky protection* — along with an affordability backstop, customer-funded renewable and storage resources, and a 300 MW ZRC transfer, *none of which the Kentucky tariff appears to include*. The AG should not be heard when lifting a single term from another jurisdiction's integrated package while ignoring the surrounding terms of the Special Contracts that make the 80% MBD reasonable and prudent here.

The Wisconsin order fares no better, as the AG mischaracterizes what it approved. The "100 percent" figure the AG invokes is not an MBD on bundled service comparable to the PSA's MBD; it is a distinct service charge minimum billing demand directed at a unique cost-recovery timing concern that has no bearing on the PSA's demand floor on cost-based Rate D11 service. Application of Wisconsin Electric Power Co., Docket 6630-TE-113, Finding ¶ 11 and pp. 26-27

(Wis. PSC May 21, 2026). And in any event, the Wisconsin Commission expressly held that "[t]he Commission's determinations in this matter are based on the specific facts presented in this application and are not precedential." *Id*., Conclusion of Law ¶ 6, p. 10. The Wisconsin order the AG invokes thus disclaims the very precedential weight the AG would give it.

What controls is that the Michigan Commission has twice set an 80% MBD in Case Nos. U-21859 and U-21990. November 6 Order, p. 109; December 18 Order, p. 33; DTE Electric Initial Brief, pp. 19-21. Two out-of-state decisions — one a generic tariff approved without a hearing and paired with weaker exit protection, the other a non-precedential charge under a different statutory regime not based on bundled service comparable to the PSA's MBD — provide no basis to override Commission precedent or to rewrite the contracting parties' negotiated term.

- *The 80% MBD Should Be Approved as Filed*

In sum, the 80% MBD is reasonable and prudent, is directly aligned with the Commission's decisions in Case Nos. U-21859 and U-21990, is confirmed by Staff's own analysis, and cannot lawfully be rewritten in this proceeding. The Commission should approve it as filed and reject the AG's recommendation to increase it to 90%. DTE Electric Initial Brief, pp. 22-23.

4. Termination Payment

DTE Electric's Initial Brief, pp. 23-31, demonstrated that the PSA's termination payment is reasonable, prudent, aligned with Commission precedent, and confirmed by Staff to cover the non-production costs of serving the Customer. Two parties seek to challenge the PSA's termination payment: the AG recommends recalculating the termination payment using a 100% MBD over the full 20-year contract term (AG Initial Brief, pp. 10-15; Coppola, 3T 473-474), and ABATE recommends conditioning approval on making the Affordability Backstop modifiable so the termination payment can be adjusted at termination (ABATE Initial Brief, pp. 7-8; Dauphinais, 3T 541-543). Both intervenor recommendations should be rejected.

DTE Electric's Initial Brief, pp. 24-31, addressed and refuted both intervenor recommendations, and the Company relies on and incorporates those arguments here — including that the AG's premise of "no further obligation after 17 years" overlooks the Section 7.3(3) tail (Foley, 3T 136); that the 80% MBD basis for the termination payment is consistent with Commission precedent in the November 6 Order and December 18 Order while the AG's 100% full-term structure is not; that Staff independently confirmed the termination payment covers the non-production costs of serving the Customer (Isakson, 3T 875); that the CCAA's separate, self-adjusting termination payment already addresses ABATE's modification concern (Foley, 3T 138); and that both parties' proposals seek relief the Commission lacks authority to grant under *Union Carbide*, at 148-149. The Company does not repeat those arguments herein and instead responds to the matters the intervenors raised for the first time in their initial briefs.

- *The AG's "Industry-Wide Overcapacity" Theory Lacks a Reliable Evidentiary Foundation*

The AG's Initial Brief, pp. 14-15, presses an "industry-wide overcapacity" theory in support of her termination payment recommendation that rests on an evidentiary foundation its own witness disclaimed. The AG argues that a 100% full-term termination payment is needed to guard against a scenario in which AI demand fails to materialize, hyperscale projects are cancelled, and DTE Electric cannot find a replacement customer. AG Initial Brief, pp. 14-15, citing (Coppola, 3T 481). The sole support AG witness Coppola offered for this theory is comprised of two articles — Exhibit AG-2, a "Data Center Boom" article published on Programs.com, and Exhibit AG-3, an article published by the Institute for Energy Economics and Financial Analysis

("IEEFA"). The Company's discovery exposed, and AG witness Coppola confirmed, that this foundation cannot bear the weight the AG places on it.

With respect to Exhibit AG-2, witness Coppola confirmed that he did not author or contribute to the article, did not independently verify any of its data, methodology, projections, or quoted statements, and relied on "the entire article" without identifying any specific statistic supporting his overcapacity conclusion. Exhibit A-23 (AG Response to DEAG-2.1). The publisher is a website whose stated data sources are the U.S. Department of Education, the Bureau of Labor Statistics, and university program catalogs — sources oriented to comparing academic programs, not forecasting energy-infrastructure markets. *Id*. Critically, the article itself is a data-center growth piece, as it reports that demand is "predicted to nearly triple by 2030," that nearly $7 trillion will be invested in data centers, and that the sector will grow at a 14% compound annual rate. Exhibit AG-2, pp. 1, 4-5. An article documenting a demand boom does not support the AG's contrary premise of a demand collapse. With respect to Exhibit AG-3, witness Coppola likewise confirmed that he did not author or contribute to it, did not independently verify its data, methodology, or projections, and again relied on "the entire article" with no pin citation. Exhibit A-24 (AG Response to DEAG-2.2). By its own description, IEEFA is an organization whose "mission is to accelerate the transition to a diverse, sustainable and profitable energy economy" — a disclosed advocacy position. *Id*.

The AG's affirmative recommendation to rewrite a negotiated, substantial termination payment must rest on more than two unverified articles that the sponsoring witness admits he neither prepared nor checked and from which he identifies no specific supporting figure. Exhibits A-23 and A-24. Expert testimony is "substantial" only where the witness has "an informed and rational basis" for the opinion. DTE Electric Initial Brief, p. 10, citing *Great Lakes Steel v Pub*

Serv Comm, 130 Mich App 470, 481; 334 NW2d 321 (1983). The AG's overcapacity theory does not meet that standard, and in any event provides no basis to inflate a term the Commission lacks authority to rewrite. The record-based protections the Company's Initial Brief identified — a termination payment securing at least 15 years of MMCs, confirmed by Staff to cover the non-production costs of serving the Customer, plus the Affordability Backstop — already address the AG's concern. DTE Electric Initial Brief, pp. 27-30; (Isakson, 3T 875).

- *The AG Identifies No Particular Decommissioning Obligation or Cost Omitted from the Termination Payment*

The AG faults the termination payment for not separately accounting for the hypothetical cost of "decommissioning assets constructed to interconnect the customer," relying on Company Witness Foley's testimony that the termination payment "is based on the minimum monthly charges that the Customer would owe … [and] is not tied to specific investments." AG Initial Brief, p. 12, quoting (Foley, 3T 203). The AG offers that decommissioning example as part of a broader contention that the Company has not demonstrated how the 80% MBD-based termination payment accounts for all Customer-caused costs. Company Witness Foley's quoted testimony describes the termination payment's design, and it is not an admission of inadequacy nor does it establish that an identifiable decommissioning cost has been omitted. As the Company's Initial Brief explained, the termination payment is deliberately a minimum-bill-based measure — the same MBD-keyed structure the Commission approved in both Case Nos. U-21859 and U-21990 — precisely because a formula tied to the MBD provides a transparent, administrable floor rather than an itemized reconciliation of every hypothetical future cost. DTE Electric Initial Brief, pp. 25-26; (Foley, 3T 136). Staff independently confirmed that the resulting termination payment covers the modeled non-production costs of serving the Customer over the contract term. DTE Electric Initial Brief, pp. 24-29; Staff Initial Brief, pp. 5-6; (Isakson, 3T 874-875).

The AG identifies no record evidence that interconnection assets would in fact be stranded on other customers upon an early exit. More fundamentally, the AG does not identify which asset allegedly would be decommissioned, who would own it, what contractual or regulatory obligation would require its removal, or what cost DTE Electric or its other customers allegedly would incur. The record distinguishes among three different components of the interconnection: the Customer will construct and own its on-site substations; DTE Electric will construct distribution facilities connecting those substations to the transmission system; and the transmission provider will construct facilities outside DTE Electric's ownership, control, and cost responsibility. (Benyard, 3T 449-450). The AG's undifferentiated reference to "assets constructed to interconnect the customer" does not address those separate ownership and cost-responsibility arrangements.

Nor does the AG explain why a hypothetical asset-specific cost would justify replacing the entire termination payment formula with 100% demand charges for the full term. The AG's requested remedy bears no demonstrated relationship to the unidentified cost she invokes. The Commission should evaluate the termination payment on the record evidence of the protection it provides, including Staff's independent coverage analysis, rather than on an unquantified hypothetical that the AG has not tied to any particular facility or obligation.

- *The Absence of a PSCR Component in the Termination Payment Does Not Leave Transmission Costs Uncovered*

The AG next argues that because the MMC used in the termination payment does not include a PSCR surcharge component, the termination payment will not contribute to transmission upgrade costs, and that the Company "presented no evidence" of sufficient coverage without a PSCR contribution. AG Initial Brief, pp. 12-14. The AG connects that point to her broader claim that the termination payment does not account for all Customer-caused costs, including transmission upgrades associated with future generation development, and therefore should be calculated using 100% rather than 80% of demand charges.

This premise misunderstands the function of the termination payment and, more importantly, is refuted in material part by Staff's own analysis (Isakson, 3T 875). The PSA termination payment is a one-time payment owed upon early termination — not an ongoing service charge — and it is not designed to replicate every rate component the Customer pays while taking service. PSA Section 7.3(2); Exhibits A-16 and A-22. While the Customer is taking service, it pays the PSCR surcharge and thereby contributes to the Company's transmission and renewable costs. DTE Electric Initial Brief, pp. 17-18; (Foley, 3T 96-97; Bilyeu, 3T 284). The PSA termination payment addresses the distinct circumstance in which service has ended.

In all events, the AG's "no evidence" assertion is incorrect. Staff's minimum bill scenario analysis expressly isolated transmission costs from the PSCR benefit — modeling precisely the scenario in which the Customer "only pays minimum bills [and] will not pay energy charges and thus not create the total PSCR benefit, but the Company would still face costs from the transmission provider" — and Staff found that "the minimum bill revenue is sufficient to cover the estimated non-production costs to serve the customer." Staff Initial Brief, pp. 5-6; (Isakson, 3T 874-875). Staff retained the transmission costs required for the Customer to begin service, excluded the costs and benefits associated with purchased power through the PSCR, and found that minimum bill revenue covers the resulting non-production cost burden. Staff further explained that, because the termination payment consists of future minimum bill revenue, the termination payment likewise covers those non-production costs over the contract term. (Isakson, 3T 874-875). That independent analysis directly refutes the AG's categorical premise that the absence of a PSCR component necessarily leaves transmission costs uncovered. The minimum bill based formula provides coverage even in Staff's modeled scenario where no energy charges, and therefore no corresponding PSCR benefits, are received.

Staff's minimum bill scenario did not purport to model transmission investments associated with every resource that might later be selected through the IRP. Staff assumed in that scenario that the Customer's reduced usage would eliminate the need for the proxy generating resource, accelerated storage, and purchased power. (Isakson, 3T 874-875). But that limitation does not support the AG's 100% of demand termination payment. The actual resources needed to serve the Customer, and any associated transmission investments, will be identified through future planning processes rather than fixed by the proxy used in this case. As explained in Sections V.A.6 and VI, the Company will include transmission-investment revenue requirements and other Customer-caused transmission-expense effects in the aggregate cost-and-benefit presentations as those costs become known. (Foley, 3T 143-146, 153).

Accordingly, the AG has not demonstrated that excluding an ongoing PSCR surcharge from the one-time termination payment formula creates an uncovered transmission cost category. Staff's independent analysis demonstrates coverage of the transmission and other non-production costs retained in the modeled minimum bill scenario, while future resource-specific costs will depend on resources not yet selected. Neither point supports replacing the negotiated termination payment with the AG's proposed 100% of demand, full term formula.

- *The AG's Prior Shortfall Calculation Was Not a Commission Finding*

The AG further argues that the Company "ignores" her analysis — "referenced by the Commission in Case U-21859" — that an exit fee based on 80% MBD over 15 years "could result in a multi-million dollar shortfall," pointing to the November 6 Order's recitation that a hypothetical 100 MW customer's $359.14 million exit fee "would fail to satisfy estimated costs by more than $85 million." AG Initial Brief, p. 14, citing November 6 Order, p. 69. This argument does not aid the AG; it undermines her.

As an initial matter, the AG mischaracterizes the source. The $359.14 million exit-fee figure and the $85 million shortfall are not Commission findings. The figures appear in the portion of the November 6 Order that summarizes the AG's own position, expressly attributed to her initial brief: "She states that such a customer would have an exit fee of $359.14 million, which would fail to satisfy estimated costs by more than $85 million, even with the low-end and non-comprehensive data that is available here." November 6 Order, pp. 68-69, citing AG's initial brief in Case No. U-21859, p. 18).

That distinction is dispositive. Having recited the AG's shortfall calculation, the Commission in Case No. U-21859 nonetheless established an exit fee for large-load customers keyed to 15 years of an 80% minimum billing demand, and declined to require the 100% full-term structure the AG advocated. November 6 Order, p. 109. The Commission then denied the AG's petition for rehearing challenging its contract term and MBD determinations in Case No. U-21859. February 19 Order, pp. 12-13. In other words, the AG now asks the Commission to credit, in this proceeding, the very shortfall theory the Commission twice declined to adopt in the docket the AG treats as controlling. The AG's recycled shortfall theory should not carry more weight here than it did in Case No. U-21859.

- *The Negotiated Termination Payment Is Consistent with Commission Precedent*

The AG contends that the PSA's termination payment departs from the exit-fee framework the Commission established in Case No. U-21859, which the AG describes as "an exit fee calculation based on the remaining months in the contract term, . . . including any evergreen contract extension." AG Initial Brief, p. 12. While the AG's description of the Case No. U-21859 tariff exit fee appears fair, her conclusion does not follow. The Case No. U-21859 exit fee was adopted for a different utility's generic large-load tariff, with a 15-year minimum contract term. November 6 Order, pp. 108-109. It does not dictate the terms of a separately negotiated 20-year special contract, and it is not the closest precedent for the Special Contracts at issue in this proceeding.

Case No. U-21990 is the more applicable precedent as applied to DTE Electric, in which the Commission approved DTE Electric's special contracts for a large-load data center customer with a termination payment "that starts based on 10 years of MBD and reduces over the term of the contract." DTE Electric Initial Brief, pp. 25-26; (Foley, 3T 136); December 18 Order, p. 33. The PSA's termination payment in this proceeding — which secures at least 15 years of MMCs, plus the additional Section 7.3(3) tail obligation — is therefore consistent with the termination payment the Commission approved for a comparable special contract in Case No. U-21990 and not a departure from Commission precedent. Importantly, Staff reads the Case No. U-21859 framework the same way, describing the PSA's termination payment as "basically an extended version of the exit fee" approved for Consumers, made longer "due to the contract lasting longer than 15 years." Staff Initial Brief, pp. 9-10; (Isakson, 3T 870).

To the extent the AG's real objection is that the PSA measures the termination payment against a 15-year period rather than the full 20-year term, that objection is the same 100% full-term recommendation addressed above, and it fails for the same reasons: the negotiated, MBD-keyed structure is consistent with precedent in Case No. U-21990, is confirmed by Staff to cover the non-production costs of serving the Customer (Isakson, 3T 875), and cannot be rewritten by the Commission. *Union Carbide*, at 148-149.

- *The Kentucky Tariff Cited by the AG Confirms the Strength of the PSA's Exit Protection*

It should also be noted that the Kentucky order the AG holds out as a model in support of her MBD recommendation in Section V.A.3 above, reinforces rather than undermines the reasonableness of the PSA's termination payment. While the AG invokes Kentucky's 90% MBD, the same integrated package paired that figure with an exit payment of only five years of minimum billing. Electronic Tariff Filing of Kentucky Power Company, Case No. 2024-00305, pp. 3-4 (Ky. PSC Mar. 18, 2025). The PSA's termination payment, by contrast, secures at least 15 years of MMCs — three times the exit protection in the very order the AG presents as persuasive. DTE Electric Initial Brief, pp. 25-26. To the extent the AG urges the Commission to look to other jurisdictions, Kentucky confirms that the PSA's termination payment is more protective of other customers, not less.

- *The Commission Has Already Declined to Require Front-End Adjudication of Mitigation*

Finally, the AG suggests that "any potential mitigation of the termination payment" — for instance, if the Company later secures a replacement customer for the released capacity — "could be adjudicated through a contested proceeding before the Commission." AG Initial Brief, p. 15. This suggestion is unnecessary and, in substance, seeks a mechanism the Commission already considered and declined to require. The November 6 Order, pp. 109-110, expressly declined to require the contested adjudication the AG proposes, holding that "Commission review and approval of the mitigation effort is not required, as customers have the option of filing a complaint with the Commission if they believe that mitigation was not adequately pursued." The AG's suggestion that mitigation "be adjudicated through a contested proceeding" is therefore not a novel safeguard offered to the Commission; it is a return to the front-end review mechanism the Commission considered and rejected in favor of an as-applied complaint process. The AG offers no reason to depart from that prior determination here.

- *ABATE's Proposed Post-Termination Modification Mechanism Misunderstands the Structure of the Special Contracts*

ABATE recommends that any approval of the Special Contracts be conditioned on modifying the Affordability Backstop (PSA Section 5.1.3) "to allow an evaluation and modification of the termination payment by the Commission based on the facts and circumstances known or knowable at the time of termination." ABATE Initial Brief, pp. 7-8, 13-14; (Dauphinais, 3T 541-543). DTE Electric's Initial Brief, pp. 29-30, addressed and refuted this recommendation, and the Company relies on and incorporates those arguments here rather than repeating them — including that the PSA termination payment is deliberately keyed to the minimum billing demand, consistent with the Commission's approvals in the November 6 Order and December 18 Order (Foley, 3T 138-139); that the separate CCAA termination payment already "is set equal to the . . . unrecovered revenue requirement" of the deployed projects and thus "automatically adjusts," accomplishing for the CCAA precisely what ABATE seeks (DTE Electric Initial Brief, pp. 63-64; Foley, 3T 124, 138); that the termination payment is not static but is calculated at the time of termination as a function of the then-current, Commission-approved rates and tariffs over which the Commission retains oversight (Foley, 3T 139); and that ABATE's proposed open-ended modification mechanism would prevent the Customer from reasonably assessing its potential liabilities and is not commercially reasonable.

- *The Affordability Backstop and Termination Payment Protect Different Periods*

ABATE's central premise is that the Affordability Backstop "does not extend beyond termination of the PSA," leaving a gap in which aggregate costs could exceed aggregate benefits after the PSA ends. ABATE Initial Brief, p. 7; (Dauphinais, 3T 541-543). That premise mistakes a deliberate feature of the Special Contracts for a defect. By its terms, the Affordability Backstop is a during-term protection: Section 5.1.3 operates "if, at any time during the term of the PSA," the Commission determines that the aggregate costs to serve the Customer exceed the aggregate benefits of the Special Contracts. DTE Electric Initial Brief, pp. 35-36. The Special Contracts do not rely on the Affordability Backstop to address early exit; they rely on the termination payment, which is the instrument crafted for that circumstance. The two mechanisms are complementary and address different periods — the Affordability Backstop protects other customers while service continues, and the termination payment protects them if early termination occurs by securing at least 15 years of MMCs. DTE Electric Initial Brief, pp. 23-31, 35-36. ABATE's proposal to extend the Affordability Backstop past termination would collapse that deliberate division, converting a during-term reimbursement mechanism into an open-ended, post-termination cost-reconciliation proceeding the contracting parties never negotiated.

ABATE's premise also lacks a limiting principle. If the Affordability Backstop had to remain operative after termination to be adequate, the same reasoning would condemn other large-load termination measures the Commission has approved — including the 15-year-MBD exit fee in Case No. U-21859 and the 10-year-MBD termination payment in Case No. U-21990 — neither of which is a perpetual, post-exit cost true-up. DTE Electric Initial Brief, pp. 25-26. The Commission approved those MBD-keyed measures as adequate precisely because they secure a substantial, defined recovery upon exit, not because they reconcile actual costs in perpetuity. ABATE offers no reason for the Commission to apply a more demanding, commercially unreasonable standard here. Indeed, to the extent ABATE suggests the PSA termination payment departs from the U-21859 framework, Staff confirmed the opposite. As Staff explained, "[t]he termination payment described in the PSA matches the exit fee approved in the Consumers case," because both are keyed to the same minimum-billing measure. Staff Initial Brief, p. 10; (Isakson, 3T 869-870). The PSA's MBD-keyed termination payment is thus consistent with, not a departure from, the measure the Commission approved in Case No. U-21859.

- *The PSA's MBD-Keyed Termination Payment Is Determinate, Enforceable, and Collateralizable*

ABATE characterizes the termination payment as "a fixed formula . . . untethered to the actual costs and benefits of serving Google at the time of termination," and contends that Company Witness Foley's testimony that the termination payment is based on the MBD and not on an assessment of specific costs or benefits of serving the Customer effectively acknowledges this flaw. ABATE Initial Brief, p. 7; (Foley, 3T 138-139). ABATE's reading inverts Company Witness Foley's testimony. As the Company's Initial Brief explained, Witness Foley described a deliberate design choice the Commission has twice endorsed, not a concession of error. DTE Electric Initial Brief, pp. 25-26, 29. A termination payment keyed to the MBD is not "untethered"; to the contrary, it is tethered to a transparent, administrable measure (the Customer's minimum contribution to system costs) rather than to a speculative reconstruction of "actual costs and benefits" at an unknown future exit date.

The feature ABATE calls a flaw is what makes the termination payment enforceable and collateralizable. An MBD-keyed measure yields a determinate amount the Customer can be held to and the Company can secure; ABATE's "actual costs and benefits at the time of termination" measure would yield an amount no one could know in advance, could not be reliably collateralized, and would require a contested cost-reconstruction at the moment of exit — when the Company most needs certainty of recovery. DTE Electric Initial Brief, pp. 30-31; (Foley, 3T 139). ABATE thus identifies not a defect but the very feature that protects other customers, and provides no basis to rewrite a negotiated term the Commission lacks authority to reform. *Union Carbide*, at 148-149.

- *The CCAA Already Provides the Cost-Based, Self-Adjusting Protection ABATE Seeks*

To the extent ABATE's premise is that a cost-based, self-adjusting termination measure is missing, that argument is answered by the structure of the Special Contracts themselves and was addressed in the Company's Initial Brief. As explained therein, the CCAA termination payment "is set equal to the unrecovered portion of each project's costs (i.e., revenue requirement) over its respective depreciable life" and therefore "automatically adjusts to account for the costs of those projects" — the self-adjusting design ABATE says is absent. DTE Electric Initial Brief, pp. 63-64; (Foley, 3T 124, 138). That the contracting parties built such a measure into the CCAA, where project-specific revenue requirements make it appropriate, while keying the PSA termination payment to the MBD for cost-based Rate D11 service, confirms that the PSA measure reflects a thoughtful and prudent choice rather than an oversight.

- *ABATE's Proposed Exit Reconciliation Would Be Open-Ended and Commercially Unworkable*

In its Relief Requested, ABATE elaborates that a modifiable backstop must give "full consideration to both the reasonably projected forward-looking benefits at that time and any sunk costs incurred by DTE." ABATE Initial Brief, pp. 13-14. This formulation, which ABATE's testimony did not articulate, confirms the impracticality of its proposal. It would require the Commission, upon an early exit, to (i) reconstruct all "sunk costs" DTE Electric incurred to serve the Customer, (ii) forecast the "reasonably projected forward-looking benefits" of assets remaining on the system after the Customer departs, and (iii) net the two to set a bespoke termination figure — a full cost-of-service and resource-valuation exercise conducted in the least suitable posture, after service has ended and the Customer's incentive to litigate every input is at its peak. Neither Case Nos. U-21859 nor U-21990 contemplated such an exercise, and both adopted determinate, MBD-keyed measures precisely to avoid it. DTE Electric Initial Brief, pp. 25-26. ABATE's "forward-looking benefits" input also cuts against its own position. Any assets that remain useful after the Customer's exit continue to benefit other customers and are properly accounted for through the Company's resource planning and rate cases — not through a one-time termination reconciliation. Crediting those forward-looking benefits at termination, as ABATE proposes, would pull into a single exit calculation value that the ratemaking process already delivers to other customers over time. The negotiated MBD-keyed termination payment, which Staff independently confirmed covers the non-production costs of serving the Customer, Staff Initial Brief, p. 6; (Isakson, 3T 875), is the far more reasonable and administrable measure.

- *The Negotiated Termination Payment Should Be Approved as Filed*

In sum, ABATE's recommendation to make the Affordability Backstop modifiable and effective after termination rests on a misunderstanding of the contractual provision's during-term function, mischaracterizes a deliberate and twice-approved design choice as a "flaw," and would replace a determinate, enforceable, MBD-keyed termination payment with an open-ended cost-reconstruction proceeding conducted at an unfavorable time. The concern ABATE raises about post-exit project costs is already resolved by the CCAA's self-adjusting termination payment and the CCAA Regulatory Liability, and the concern about residual risk is resolved by the Company's acceptance of collateral-insufficiency risk. The Commission should therefore reject ABATE's proposed condition and approve the negotiated termination payment as filed.

5. Credit and Collateral Requirements

DTE Electric's Initial Brief, pp. 31-35, demonstrated that the PSA's credit and collateral requirements — a Parent Guaranty ("PG") that escalates to a Letter of Credit ("LoC") if the parent's credit rating falls below a defined threshold — are reasonable, prudent, consistent with the

Commission's approvals in the November 6 Order and December 18 Order. Moreover, the Company confirmed that it bears the risk of any collateral insufficiency. DTE Electric Initial Brief, pp. 32-33; (Foley, 3T 134-135). The AG recommends that the Commission reject any limitation on the Special Contract PG and LoC terms — that is, that the Commission order uncapped collateral. AG Initial Brief, pp. 16-19; (Coppola, 3T 475, 480, 909-915). ABATE separately contends that the Company's commitment to bear unrecovered costs is not contractually binding. ABATE Initial Brief, p. 9; (Dauphinais, 3T 543-545). Both intervenor arguments should be rejected. GLREA asks the Commission to state in its order that any payment deficiency caused by Customer default will not be recoverable from other customers. GLREA Initial Brief, pp. 3-4; (Richter, 3T 585).

DTE Electric's Initial Brief, pp. 33-35, addressed the core of the intervenors' recommendations, and the Company relies on and incorporates those arguments here — including that the premise that other customers are "at risk to absorb any shortfall" is incorrect because the Company has accepted that the risk of collateral insufficiency falls on the Company (Foley, 3T 134-135); that the PG-plus-conditional-LoC structure is consistent with Commission precedent while the AG's "full payment of total obligations" alternative is not (Foley, 3T 106-107); that the structure escalates automatically to a LoC precisely when a decline in the parent's creditworthiness would increase risk (Foley, 3T 106); that Staff independently opined the PSA's collateral form and amount are permissible under the Case No. U-21859 framework (Isakson, 3T 871); and that both intervenor arguments seek relief the Commission lacks authority to grant under *Union Carbide*, at 148-149. The Company replies further below to address the arguments the AG and ABATE set forth in their Initial Briefs.

The concern animating the intervenors' recommendations is that a shortfall between the collateral posted and the Customer's obligations could fall on other customers. The record, however, forecloses that concern. As Company Witness Foley confirmed in rebuttal, DTE Electric "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." (Foley, 3T 134-135); DTE Electric Initial Brief, p. 33. Staff agreed this is the correct outcome and confirmed the Company accepted it, noting that the Commission cautioned in the December 18 Order, p. 41, that "any unrecovered costs shall not be borne by ratepayers and that DTE Electric bears responsibility for any remaining liability." Staff Initial Brief, pp. 11-12; (Simpson, 3T 844; Isakson, 3T 871, 879). AG witness Coppola made the same recommendation. (Coppola, 3T 469). And GLREA, too, expressly "appreciate[s] the Company's acknowledgement" of collateral-insufficiency risk, quoting Company Witness Foley's rebuttal directly, but asks that "a direct Commission statement in the order" be added to "provide other customers more legal protection than the Company's acknowledgement alone." GLREA Initial Brief, pp. 3-4; (Richter, 3T 585). This can be addressed by the Commission memorializing it as a condition of its approval order as it did in the December 18 Order, pp. 40-41.

- *The Difference Between Collateral and Potential Exposure Does Not Create a Cost Shift*

The AG's principal new argument is that the confidential parent-guaranty caps are lower than the potential termination-payment exposure [redacted]

[redacted] That gap does not support uncapped collateral, for two primary reasons.

First, the gap is precisely what the Company's acceptance of collateral-insufficiency risk resolves. If, in the circumstances the AG hypothesizes, the posted collateral proved insufficient to cover the Customer's remaining obligations, the shortfall would fall on the Company, not other customers. (Foley, 3T 134-135). The existence of a gap between a guaranty cap and a peak potential exposure is therefore not a cost-shifting risk to other customers; it is a risk the Company has assumed.

Second, the guaranty structure is deliberately calibrated to the Company's declining exposure over the contract term. As Company Witness Foley explained with respect to the CCAA, the guaranty “declines over time to track the declining termination payment, because a larger guaranty becomes superfluous as the Customer pays down the projects' revenue requirement,” and the guaranty “escalates automatically” — converting to a LoC — if the parent's credit rating falls below the defined threshold. (Foley, 3T 125); DTE Electric Initial Brief, pp. 63-64. The AG's proposal to require a static guaranty equal to the peak potential obligation for the entire term would impose a commercially unreasonable requirement untethered from the Company's actual, declining risk. DTE Electric Initial Brief, p. 64.

The AG argues that the Company’s commitment set forth in Company Witness Foley’s rebuttal does not “sufficiently mitigate the risk of cost-shifting” because the Company “has not presented any evidence . . . as to how it could absorb any portion or particular amount of credit risk,” pointing to a discovery response stating that the “speculative and undefined downstream financial consequences” of a hypothetical shortfall are “outside the record of this proceeding.” AG Initial Brief, pp. 18-19, citing Exhibit AG-8, p. 13. This argument misunderstands the nature of the commitment. The Company's acceptance that it — not other customers — bears any collateral shortfall is a binding allocation of risk, consistent with the December 18 Order's condition; it does not depend on the Company first proving its financial capacity to absorb a hypothetical future shortfall. The dispositive point for this proceeding is that the shortfall will not be borne by other customers. *See* December 18 Order, p. 41. How the Company would absorb a speculative future shortfall of unknown magnitude, arising years from now under unknown conditions, is not a question this special contract proceeding must resolve — and the Company's discovery response correctly stated so. The AG's demand for "evidence" of the Company's absorptive capacity would convert a forward-looking risk allocation into a present-day financial-capacity trial removed from any actual controversy.

The AG argues that "[r]elying solely on a utility credit backstop has also historically presented a risk that a utility might nonetheless eventually seek ratepayer coverage," referring to the Midland Nuclear Power Plant matter, in which the Commission permitted Consumers Power Company to seek a "financial stabilization" rate increase. AG Initial Brief, p. 19, citing *Attorney General v Pub Serv Comm*, 189 Mich App 138 (1991). However, that example is inapposite. Midland involved the extraordinary circumstance of a stalled and converted nuclear construction project that threatened the utility's solvency; the "financial stabilization" mechanism arose from that unique financing crisis, not from a special contract collateral commitment. Nothing in Midland addresses, much less undermines, a Commission-imposed condition that "any unrecovered costs shall not be borne by ratepayers." December 18 Order, p. 41. To the contrary, the AG's concern that a utility "might eventually seek ratepayer coverage" is answered by that very condition: the Company has accepted, and the Commission may condition its approval upon, the requirement that unrecovered collateral costs not be shifted to other customers.

- *The Company's Rebuttal Provides the Express Commitment ABATE Claims Is Missing*

ABATE contends that the Company's collateral-insufficiency position is not a contractually binding requirement, and that DTE Electric reserved the right to seek recovery from other customers, citing the Company's response to Staff discovery (STDE-8.2), which included the statement "if at a later date the Commission determines such costs to be reasonable and prudent and appropriately attributable to utility service provided to customers generally, the Company may seek recovery at that time." ABATE Initial Brief, p. 9, quoting Exhibit AB-1, p. 26. ABATE's reliance on that language is misplaced.

DTE Electric's collateral insufficiency commitment was made express in Company Witness Foley's rebuttal (3T 134-135). Company Witness Foley testified that "in the highly unlikely event of a Customer bankruptcy or other circumstance in which recovery from the Customer, its parent guarantor, and letters of credit is not sufficient, DTE Electric's position is that it would not seek to recover from other customers costs that are ultimately determined by the Commission, pursuant to Section 5.1.3 of the PSA, to be in excess of the combined revenues payable to the Company under the PSA and Related Agreements," and that "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." (Foley, 3T 134-135). The discovery response ABATE cites essentially notes the same benefit cost analysis without expressly citing the Affordability Backstop. If the costs are properly attributable to the Customer under the Affordability Backstop analysis, the Company will not seek recovery of them. If they are not attributable to the Customer, they will not be included in the revenue-cost calculation. At all times, the Company has stated that it bears the risk of any insufficiency of collateral for unrecovered costs attributable to the Customer. The Company's firm collateral-insufficiency commitment is further confirmed by its conduct in the Case No. U-21990 docket itself. As Company Witness Foley testified, the Company "accepted the Commission's conditions through its January 15, 2026 letter" in Case No. U-21990 — including the condition that "all risk associated with the sufficiency of the collateral shall be borne by DTE Electric." (Foley, 3T 134); December 18 Order, p. 41. Here too, the commitment can be made binding by the Commission memorializing it as a condition of its approval order, exactly as the Commission did in the December 18 Order, pp. 40-41.

- *Staff's Review of the Confidential Terms Does Not Support Uncapped Collateral*

It bears reemphasis that Staff reviewed the same confidential collateral terms the AG relies upon and did not recommend uncapped collateral or a rewriting of the guaranty structure. [redacted] Staff Confidential Initial Brief, pp. 10-11; (Isakson, 3T 870-871). That the neutral party, having examined the confidential terms, declined to join the AG's recommendation further confirms that the negotiated structure adequately protects other customers.

- *The Negotiated Credit and Collateral Structure Should Be Approved*

In conclusion, the credit and collateral requirements are reasonable and prudent, escalate automatically upon any decline in the parent's creditworthiness, are calibrated to the Company's declining exposure, and are consistent with the structures the Commission approved in Case Nos. U-21990 and U-21859. The Company has accepted and does not oppose the Commission memorializing that the risk of any collateral insufficiency falls on the Company consistent with the December 18 Order. That acceptance fully resolves the concern underlying the collateral recommendations of the AG, ABATE, and GLREA alike, without rewriting the negotiated guaranty caps. The Commission should approve the credit and collateral requirements as filed, memorialize the collateral-risk condition consistent with Case No. U-21990 if it finds a statement useful, and reject the AG's recommendation for uncapped collateral.

6. Affordability Backstop (PSA Section 5.1.3)

DTE Electric's Initial Brief, pp. 35-48, demonstrated that the Affordability Backstop in PSA Section 5.1.3 is reasonable, prudent, consistent with the November 6 Order and December 18 Order, and protective of other customers because it requires the Customer to reimburse any Commission-determined shortfall between the costs to serve the Customer and the benefits under the Special Contracts, measured in the aggregate over the life of the Special Contracts. Staff and intervenors cover a variety of issues regarding the Affordability Backstop. Staff and GLREA generally treat the Affordability Backstop as an operative customer protection and do not attack the mechanism.[9] MEICEO contends it must be evaluated on a rate-case cadence and can be triggered before year 20 of the Special Contracts (MEICEO Initial Brief, pp. 23-25). MNS contends it is “fundamentally flawed” and urges direct assignment of resources instead (MNS Initial Brief, pp. 14-19). The AG asks the Commission to make DTE Electric an affirmative backstop for residual costs during and after the agreements (AG Initial Brief, Section III.G). And ABATE contends the Affordability Backstop must be modifiable and effective after termination

[9] Staff identifies the Affordability Backstop as the protection that addresses the very worst-case scenario Staff modeled, observing that even in a scenario producing a net cost to the Company, "the affordability backstop may prevent the Company from facing that risk." Staff Initial Brief, pp. 7-8; (Isakson, 3T 878-879). That Staff relies on the Affordability Backstop as the answer to its own worst-case scenario is strong confirmation that the mechanism protects other customers.

(ABATE Initial Brief, pp. 7-8) — an argument addressed in Section V.A.4 above. The Company responds to each remaining argument below.

DTE Electric's Initial Brief, pp. 35-48, addressed several of these challenges, and the Company relies on and incorporates those arguments here rather than repeating them — including that the Affordability Backstop operates at the aggregate level, comparing the aggregate costs of serving the Customer to the aggregate revenues and avoided costs over the life of the Special Contracts (Foley, 3T 103, 246); that a single-year snapshot of costs and benefits misstates the negotiated economics, because the Special Contracts are structured so that net benefits in most years offset modeled net costs in the interim years; that the negotiated Affordability Backstop satisfies the November 6 Order’s directive that a special contract filing demonstrate that the costs caused by serving the large-load customer will not be shifted to other customers because Section 5.1.3 of the PSA requires Customer action if the Commission determines that aggregate costs of serving the Customer exceed Customer-derived aggregate benefits; and that a quarterly reporting cadence is unwarranted because an annual reporting framework, together with the regular cadence of rate, PSCR, and IRP proceedings, already supplies the necessary information (Foley, 3T 151-154). The Company replies further below to address the arguments set forth in the parties’ Initial Briefs.

- *The Commission May Act During the Contract Term*

MEICEO's principal argument is that DTE Electric reads the Affordability Backstop as authorizing only a single reconciliation at the end of the 20-year term, and that this reading conflicts with the plain language of Section 5.1.3, which provides that “[i]f, at any time during the Term,” the Commission determines that the costs to serve the Customer exceed the benefits, the Customer must comply. MEICEO Initial Brief, p. 24. MEICEO therefore asks the Commission to clarify that the Affordability Backstop can be triggered prior to the end of the 20-year contract duration and to evaluate the no-cost-shift requirement on the same cadence as the Company's rate cases. *Id*., pp. 23-25. MEICEO's argument rests on a false premise, because it conflates two distinct questions: when the Commission may act under the Affordability Backstop, and how costs and benefits are measured when it does.

On the first question of *when* the Commission may act, the Company agrees that, by its plain terms, the Affordability Backstop may be triggered "at any time during the Term" of the PSA under Section 5.1.3. The Company has never contended that the Commission is powerless to act before the twentieth year, or that the Affordability Backstop lies dormant until a single end-of-term reconciliation. To the contrary, the Company will present the aggregate costs and benefits of serving the Customer in its general rate cases and PSCR proceedings throughout the contract term, precisely so that the Commission can act under Section 5.1.3 if the record warrants. (Foley, 3T 143-144, 153). Indeed, MEICEO itself acknowledges that "any benefits will be passed through to other ratepayers via the Company's PSCR and rate cases" and that "[c]osts will be passed through in the same manner." MEICEO Initial Brief, p. 24. To the extent MEICEO seeks a clarification that the Commission retains authority to invoke the Affordability Backstop during the contract term, the Company does not oppose it, because it reflects the plain language of Section 5.1.3 and the Commission's retained jurisdiction.

- *Interim Review Does Not Convert the Aggregate Standard into an Annual True-Up*

On the second question of *how* costs and benefits are measured, however, MEICEO is incorrect, and its asserted conflict with the PSA's plain language disappears. The Company's testimony that the no-cost-shift requirement is measured "over the life of the special contracts" and "not an annual retroactive reconciliation" (Foley, 3T 147; Exhibit MEICEO-38, p. 17) refers to the standard of measurement, not to a bar on interim Commission action. There is no tension between the two: Section 5.1.3 authorizes the Commission to act "at any time during the Term," and the standard it applies when it does is whether, in the aggregate, the costs to serve the Customer exceed the combined benefits. The measurement of costs and benefits is aggregate because the negotiated Special Contracts were deliberately structured in that manner. Pursuant to this proper measurement, net benefits in the vast majority of years offset the modeled net costs in the interim years — here, the approximately $172 million in modeled net costs during 2035-2038 that MEICEO isolates. MEICEO Initial Brief, pp. 23-24; (Kenworthy, 3T 679). As the Company's Initial Brief demonstrated, that interim-year pattern reflects the timing of the proxy resource, not a structural cost shift, and the aggregate benefit remains substantial and positive. DTE Electric Initial Brief, pp. 39-41. Measuring the Affordability Backstop year-by-year would recharacterize a modeled interim-year cost as a cost shift, contrary to the Special Contracts aggregate design and the Commission's aggregate framing in the December 18 Order, pp. 40-41.

- *MNS' Preference for Direct Assignment Does Not Establish a Defect in the Affordability Backstop*

MNS contends that the Affordability Backstop is "untested and unclear," and asks the Commission to displace the Affordability Backstop in favor "direct assignment of the incremental costs of serving Google," which MNS characterizes as administratively preferable to the Affordability Backstop. MNS Initial Brief, pp. 14-19. MNS advances three specific arguments in support of that contention. *Id.*, pp. 14-16. None establishes a defect in the negotiated Affordability Backstop.

Under PSA Section 5.1.3, costs determined to be caused by serving the Customer are included in the aggregate assessment together with the applicable Customer-derived benefits. If the Commission determines that the aggregate assessment shows a shortfall, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs associated with its service. The PSA does not prescribe the means by which the Customer must satisfy that Commission-determined shortfall. If the aggregate assessment remains positive, Section 5.1.3 does not provide for separately assigning an individual cost to the Customer merely because that cost was identified as being caused by serving it. DTE Electric Initial Brief, pp. 36-43, 116-119; (Foley, 3T 103-105, 143-144, 244-246). MNS' preference for separately assigning particular costs thus provides no basis to reject or condition the Special Contracts, and the Company responds to each of MNS' three criticisms in turn.

First, MNS' contention that the Affordability Backstop "relies on the same faulty assumptions" as the $1.7 billion benefit conflates the mechanism with its inputs. MNS argues that the Affordability Backstop "appears to improperly include the 'Avoided Costs' of 250 MW of renewable energy projects" and "does not include costs associated with using banked RECs paid for by other customers." MNS Initial Brief, pp. 14-15. These are challenges to particular inputs — the treatment of avoided costs and banked RECs — not to the adequacy of the mechanism, and they fail to undermine the Affordability Backstop for two primary reasons. As a threshold matter, whether avoided costs are properly credited and whether banked-REC costs must be attributed to the Customer go to the magnitude of the projected net customer benefit, and the Company addresses those disputes in Section VI. More fundamentally, the Affordability Backstop does not depend on the precision of any particular input at the time of approval. Its implementation entails a forward-looking, aggregated presentation: whatever costs and benefits the Commission ultimately determines — including any adjustment to the treatment of avoided costs or banked RECs the Commission may adopt — are captured in the application of Section 5.1.3. DTE Electric Initial Brief, pp. 39-43. MNS' input criticisms thus do not show the mechanism is flawed; if anything, they confirm why an aggregated presentation reviewed by the Commission in contested general rate cases and PSCR proceedings — rather than a fixed, once-and-for-all determination in this docket — is the appropriate customer protection. And MNS' specific RPS concern is answered by the Affordability Backstop's own scope, as Company Witness Foley testified that the analysis will include "[t]he revenue requirement of renewable energy projects deployed to meet the Company's Renewable Portfolio Standard (RPS) obligations not covered by the CCAA." (Foley, 3T 143-144). To the extent MNS contends that RPS-compliance costs caused by the Customer's non-VGP load may not be considered, Section 5.1.3 of the PSA includes the revenue requirement of RPS resources not covered by the CCAA among the aggregate costs evaluated under the Affordability Backstop. (Foley, 3T 143-144). Whether such costs arise, in what amount, and whether the aggregate assessment produces a shortfall are matters for future presentations, not a defect in the mechanism itself.

Second, that the Affordability Backstop is a newly negotiated mechanism whose presentation format is not yet finalized does not make it unreasonable or unclear. MNS argues that the Affordability Backstop is defective because Company Witness Foley "acknowledged that DTE has not previously employed the affordability backstop concept, has not executed it in practice, and has not developed the form of how it will be presented in future proceedings," leaving it "unclear what will be included in the affordability backstop analysis." MNS Initial Brief, pp. 15-16. Novelty is not a defect. Every special contract protection is, in some measure, tailored to the transaction. The relevant question is whether the mechanism protects other customers, and the Affordability Backstop does just that by obligating the Customer to reimburse any Commission-determined aggregate shortfall and operating in conjunction with the 80% MBD floor, termination payment, and collateral package. DTE Electric Initial Brief, pp. 35-37.

Nor does the absence of a finalized presentation format make the scope of the aggregate assessment unclear. Company Witness Foley enumerated the categories of aggregate costs and benefits the presentation in support of the Affordability Backstop will include — among them the revenue requirement of CCAA storage and renewable projects, the revenue requirement of RPS renewable projects not covered by the CCAA, the revenue requirement of other resources identified in the IRP as caused by the Customer's load, increased fuel and purchased-power costs, the revenue requirement of transmission investments, and avoided costs realized through the contracts. (Foley, 3T 143-144). That the precise presentation format will be refined for implementation in future general rate cases and PSCR proceedings is not a flaw; it reflects that the Affordability Backstop is applied in those contested proceedings, where Staff, intervenors, and the Commission will be able to review and test the inputs — the ordinary and adequate safeguard against the transparency concern MNS raises. MNS' suggestion that the Company "will seek to hinder or foreclose" review (MNS Initial Brief, p. 15) is merely speculation, and it is belied by the Company's commitment to present aggregate costs and benefits in precisely those open, contested forums. (Foley, 3T 143-144, 153).

MNS also emphasizes that, during cross-examination, Company Witness Foley referred questions concerning the calculation of incremental RPS-compliance costs to Company Witness Bilyeu, while Company Witness Bilyeu clarified that he was not the witness sponsoring the Affordability Backstop. MNS Initial Brief, pp. 15-17; (Foley Cross, 3T 241; Bilyeu Cross, 3T 349). That exchange reflects the witnesses' different subject matters, not an omission of RPS-compliance costs from PSA Section 5.1.3. Company Witness Foley identified the revenue requirement of renewable projects deployed to meet RPS obligations and not covered by the CCAA as a category included among the aggregate costs evaluated under the Affordability

Backstop. (Foley, 3T 143-144). Company Witness Bilyeu, in turn, explained why calculating any incremental RPS cost is necessarily fact-dependent: the analysis must determine what caused the REC deficiency and whether the circumstances are attributable to the Customer's load or instead reflect broader market or industry conditions. (Bilyeu Cross, 3T 349). The record therefore identifies both the governing treatment and the factual inquiry. It does not establish that every possible future RPS-compliance calculation must be fixed before the relevant resource need, REC position, and causal circumstances are known. Further, Company Witness Bilyeu's observation that calculating incremental RPS-compliance costs "depends on the circumstances" (Bilyeu Cross, 3T 349) does not show the backstop is "unwieldy"; it reflects the unremarkable fact that cost causation is fact-dependent — which is precisely why the analysis is performed on a developed record in future proceedings rather than fixed prematurely here.

Third, MNS' objection to the treatment of distribution costs above the LEA's $50 million threshold is a matter for the LEA and rate cases, and in any event those costs are captured by the Affordability Backstop. MNS argues that "even for costs that there is little dispute can be attributed to Google," DTE Electric will add distribution costs above the $50 million LEA threshold "to the rate base to be paid for by all customers," and that the Customer should instead pay all electric infrastructure costs required to connect the Facility without any cap. MNS Initial Brief, p. 16; (Woods, 3T 628). This objection is misplaced on two levels. First, the $50 million cap is a term of the LEA — a Related Agreement that, as the Company explains in Section V.D.2 below, the Company is not asking the Commission to approve in this proceeding. DTE Electric Initial Brief, pp. 94-102. Second, and in any event, MNS' premise that these distribution costs escape attribution to the Customer is incorrect. Company Witness Foley testified that distribution costs associated with serving the Customer will be included in the aggregate Affordability

Backstop analysis. (Foley Cross, 3T 251-252). Those distribution costs therefore are not excluded from the aggregate assessment. If the Commission determines that the aggregate costs of serving the Customer, including any qualifying distribution costs, exceed the applicable Customer-derived benefits, Section 5.1.3 requires the Customer to comply with the Commission's ruling or order addressing the shortfall. MNS witness Woods' recommendation that the Customer pay all interconnection costs "without any cap" is thus, at bottom, a proposal to impermissibly alter the LEA's negotiated cost-recovery terms that provides no basis to find the Affordability Backstop inadequate or to reject the Special Contracts.

MNS' three criticisms reduce to disputes over particular inputs, a complaint that the future presentation format is not yet finalized, and a request to replace the LEA's negotiated cost treatment with an uncapped payment obligation. None establishes that PSA Section 5.1.3 is unclear or ineffective. The provision requires Customer-caused costs to be evaluated as part of the aggregate assessment and requires Customer action if the Commission determines that the assessment shows a shortfall. MNS' preference for separately assigning particular costs does not provide a basis to reject or condition the Special Contracts. The Commission should therefore reject MNS' recommendation to condition or withhold approval on this basis.

- *The AG's Requested Company Backstop Is Largely Duplicative and Improperly Open-Ended*

The AG requests the Commission to require that "if at any time during the term of the PSA, CCAA, or other agreements with the Customer or after the expiration of those agreements, costs related to the Customer exceed any benefits, or there are no longer any offsetting benefits, the Company and not the other customers should be responsible for such costs." AG Initial Brief, pp. 29-30. The AG's recommendation rests on a premise the record does not support, and it is in substantial part already satisfied.

First, during the contract term, the premise that residual costs would fall on other customers is incorrect. The Affordability Backstop places any Commission-determined shortfall between the aggregate costs to serve the Customer and the benefits of the Special Contracts — not on DTE Electric or other customers. DTE Electric Initial Brief, pp. 35-37. The AG's recommendation thus addresses a risk the Affordability Backstop already allocates to the Customer in the first instance.

Second, to the extent the Customer is ultimately unable to pay and the collateral proves insufficient, the Company has already accepted that the residual risk falls on the Company, not other customers, as explained in Section V.A.5 above. (Foley, 3T 134-135). Thus, costs the Customer cannot pay do not fall on other customers, because the Customer bears them under the backstop and the Company bears any collateral insufficiency.

Third, insofar as the AG's recommendation reaches costs arising "after the expiration of those agreements," it is both unnecessary and improper. It is the same post-term overreach the Company addresses in response to ABATE in Section V.A.4. The Affordability Backstop is a during-term protection, and the termination payment governs the consequences of exit; neither mechanism was designed to impose an open-ended, post-expiration cost guarantee on the Company. Any question concerning the recovery of costs after the Special Contracts expire would be a matter for a future rate case, on a future record, not a condition properly imposed in this special contract proceeding. DTE Electric Initial Brief, pp. 86-94. Moreover, the AG's formulation — that DTE Electric must be responsible whenever "there are no longer any offsetting benefits" — would convert the governing no-cost-shift standard into an open-ended requirement that the Company guarantee an affirmative benefit in perpetuity. As explained in Section III above, that is not the standard the Commission has articulated for large-load special contracts, and the Commission should decline to adopt it here.

- *Challenges to the Estimated $1.7 Billion Customer Benefit Involve Valuation, Not the Affordability Backstop's Adequacy*

Several intervenor arguments nominally aimed at the Affordability Backstop are in substance challenges to the size of the projected $1.7 billion benefit — including MNS' avoided-cost and banked-REC critiques (MNS Initial Brief, pp. 7-15), the AG's observation that the benefit rests on assumptions that "will likely vary from actual costs" (Coppola, 3T 486), and ABATE's contention that the projection "is not sufficient to show DTE's other customers would not ultimately see higher costs" (Dauphinais, 3T 541). As the Company's Initial Brief explained, these do not undermine the Affordability Backstop, which protects other customers regardless of the ultimate magnitude of the benefit realized. DTE Electric Initial Brief, pp. 39-41. Because they go to magnitude of the customer benefit, the Company addresses them in Section VI.

- *The Aggregate Cost-Benefit Presentation Will Include Network Upgrade Revenue Requirements and the Customer's Load-Related Transmission-Expense Effects*

The AG and MEICEO seek additional tracking and reporting of transmission costs associated with serving the Customer, and MNS adopts those recommendations as proposed conditions on the Affordability Backstop. AG Initial Brief, pp. 21-24; MEICEO Initial Brief, pp. 21-24; MNS Initial Brief, pp. 17-18, 30-31. The intervenors' shared concern is that the aggregate cost-and-benefit presentation accounts both for transmission investments required to serve the Facility and for the effects of the Customer's load on the transmission expenses allocated to DTE Electric under the applicable MISO schedules. The Company agrees with that objective, and the record demonstrates that both components have been identified and will be included using the best information available. DTE Electric Initial Brief, pp. 43-45; (Foley, 3T 143-146, 153; Burgdorf, 3T 396-398).

The two components should not be conflated. First, serving the Customer requires transmission investments whose costs affect DTE Electric's transmission expense. The current analysis assumes approximately $308 million in ITC network-upgrade capital costs, which will be reflected through Schedule 9. In the 2029 comparison, approximately $49.2 million of the approximately $91 million increase in transmission expense is associated with those estimated network-upgrade costs. Second, the Customer's load increases the Company's peak demand and energy usage, thereby affecting DTE Electric's responsibility under the applicable transmission schedules. Approximately $41.8 million of the modeled 2029 increase is associated with the Customer's load affecting the Company's total load, including approximately $4.2 million under Schedule 9 after removal of the network-upgrade component and additional amounts under Schedules 1, 10, 10-FERC, 26, and 26-A. (Burgdorf, 3T 396-398).

This record answers the concern raised by MEICEO witness Kenworthy that the analysis did not distinguish how much of the approximately $91 million increase in modeled 2029 transmission expense reflected the ITC network-upgrade component recovered through Schedule 9 and how much reflected other transmission-expense changes associated with the Customer's load. MEICEO Initial Brief, pp. 15-17, 21-24; (Kenworthy, 3T 683-684; Burgdorf, 3T 396-398). Company Witness Burgdorf provided a schedule-by-schedule comparison and explained that each schedule is calculated by applying the forecasted rate to the relevant demand or energy billing determinant. DTE Electric Initial Brief, pp. 126-128; (Burgdorf, 3T 396-398). MEICEO witness Kenworthy ultimately acknowledged that the issue was not that the base-rate and PSCR transmission components were absent; his concern was whether they fit together without a gap or overlap. (Kenworthy, 3T 683). Company Witness Burgdorf's rebuttal supplied the requested breakout by identifying the network upgrade and Customer-load components of the modeled transmission-expense increase. (Burgdorf, 3T 396-398).

The Company also agrees that future aggregate cost-benefit presentations should use updated transmission cost information. Company Witness Foley testified that the Company will include the revenue requirement of transmission investments among the costs presented in future general rate cases and PSCR proceedings. (Foley, 3T 143-144, 153). For network upgrades, the Company can use the actual or then-current project capital costs publicly available through ITC's Attachment O filings to MISO to estimate the associated revenue requirement. For transmission expense resulting from the Customer's demand and energy contribution, the Company can use the applicable MISO schedule rates and billing determinants to model the Customer-related effect. (Foley, 3T 144-146, 249-250); Exhibit AG-8, p. 20. Those calculations permit the Commission and the parties to evaluate both components against the Customer-derived benefits in the aggregate presentation.

The Company's agreement does not extend to imposing a project-by-project billing regime that does not correspond to how DTE Electric incurs transmission expense. ITC does not bill DTE Electric on a Customer-project-specific basis for ratemaking purposes. Instead, ITC's costs are reflected in charges imposed through the applicable MISO schedules, including Schedule 9. DTE Electric can identify publicly available project capital costs and calculate modeled transmission-expense effects, but it cannot produce project-specific ITC billing traceability or site-specific ITC O&M information that ITC does not separately provide. DTE Electric Initial Brief, pp. 43-45; (Foley, 3T 146, 249-250). The absence of a separate ITC invoice for each Customer-related facility does not mean the associated revenue requirement is excluded from the aggregate assessment; it means the amount must be determined using the best information available and the transmission-cost structure actually applicable to DTE Electric.

A new condition is not necessary to require what the Company has already committed to doing. Section 5.1.3 of the PSA requires the aggregate costs of serving the Customer and Customer-derived aggregate benefits to be presented in the regulatory proceedings applicable to the Company's cost of serving the Customer. The Company has expressly identified transmission-investment revenue requirements as an included cost category and has committed to presenting the aggregate accounting in future general rate cases and PSCR proceedings, both of which are contested proceedings. DTE Electric Initial Brief, pp. 39-45; (Foley, 3T 143-146, 153). The Commission and interested parties can test the available capital cost information, applicable MISO schedule rates, billing determinants, revenue requirement calculations, and Customer-related revenues in those proceedings.

Accordingly, the Commission should recognize the Company's commitment to include both network upgrade revenue requirements and the Customer-load effects under the applicable transmission schedules in the aggregate Affordability Backstop presentation. It should decline, however, to impose the intervenors' recommendations to the extent they require project-specific billing or O&M data that DTE Electric does not receive from ITC or dictate a separate accounting system divorced from the applicable transmission-cost recovery structure.

- *The AG's Regulatory-Liability Proposal Is Unnecessary and Improperly Extends Beyond the Special Contracts Before the Commission*

The AG indicates that she is hopeful that the Company's Affordability Backstop will provide a foundation for ensuring that the Customer will cover its costs and pass benefits to other customers. AG Initial Brief, p. 25. Nevertheless, the AG renews witness Coppola's recommendation that the Commission require DTE Electric to establish a regulatory liability capturing the annual benefits from the Customer and “any other data centers,” for inclusion in future rate cases as a reduction to future base-rate increases or for direct pass-through through a separate customer credit or refund. AG Initial Brief, pp. 24-27; (Coppola, 3T 485-487). The AG accompanies that proposal with a requested annual reconciliation based on actual costs and revenues, including costs and revenues under the CCAA. *Id*.

DTE Electric’s Initial Brief addressed AG witness Coppola’s recommendation as applied to the Customer, and the Company relies on and incorporates that discussion. DTE Electric Initial Brief, pp. 46-48; (Foley, 3T 147-149). As explained there, a separate regulatory liability is unnecessary because benefits arising from service to the Customer flow through existing regulatory mechanisms. Power supply benefits may be reflected through the PSCR factor, while base rate benefits arise when the Customer’s revenues and billing determinants are included in the cost-of-service study and reduce the revenue requirement otherwise borne by other customers. DTE Electric Initial Brief, pp. 46-48; (Foley, 3T 147-149; Willis, 3T 412-418). Staff independently recreated the base sales analysis and confirmed that its result matched Exhibit A-20. (Isakson, 3T 863; Willis, 3T 418).

The AG argues that the Company’s potential deferral of a future rate case filing demonstrates the need for a regulatory liability. According to the AG, absent such a mechanism, incremental data center revenues received during years in which the Company does not file a rate case would not be fully reflected in customer base rates because a later rate case would incorporate only the revenues and benefits included in its projected test year. AG Initial Brief, pp. 26-27. That argument raises issues concerning the timing and ratemaking treatment of future revenues, not the reasonableness of the Special Contracts or the adequacy of the Affordability Backstop. Whether and under what circumstances a regulatory liability should be used to address large-load revenues is a ratemaking question properly considered in a general rate case, where the Commission can evaluate forecasted sales, actual and projected costs, the Company's revenue requirement, test-year treatment, and any proposed accounting mechanism on a complete ratemaking record.

This proceeding does not establish the Company's future revenue requirement, approve a projected test year, determine whether actual large-load sales exceed the sales reflected in base rates, or adjudicate whether any resulting amount constitutes excess margin. The interaction among forecasted sales, actual sales, regulatory lag, future costs, and base-rate treatment cannot properly be determined from this record. The AG's discussion of potentially deferred rate case filings therefore supplies no basis to establish here a separate deferral-and-refund mechanism for revenues that have not yet been received and whose ratemaking treatment will depend on circumstances presented in future proceedings. The AG also does not answer the implementation concern addressed in DTE Electric's Initial Brief. A regulatory liability would be recorded after the relevant revenues and costs arose and would then require disposition through a general rate case or separate accounting proceeding before any balance could be reflected in customer rates. Existing regulatory mechanisms already permit the Commission to address power-supply effects through the PSCR process and base rate revenues and costs through general rate cases. The AG's proposal would add a deferral entry and another adjudicatory step without demonstrating that the Commission's existing ratemaking and accounting tools are inadequate. DTE Electric Initial Brief, pp. 46-48; (Foley, 3T 147-149).

The AG's proposed regulatory liability account also conflicts with the aggregate framework established by Section 5.1.3 of the PSA. The Affordability Backstop does not require annual sequestration or a refund of Customer revenues whenever benefits in a particular year exceed the costs identified for that same year. It requires consideration of aggregate costs and benefits over the life of the contracts in regulatory proceedings concerning the Company's cost of serving the Customer. DTE Electric Initial Brief, pp. 39-48; (Foley, 3T 103-105, 143-149). An automatic annual regulatory liability would separate revenues and benefits arising in one period from costs arising in another, rather than evaluate the integrated Special Contracts over the period relevant to their aggregate costs and benefits.

The AG's proposed regulatory liability account is independently improper insofar as it would apply to "any other data centers" AG Initial Brief, p. 25; (Coppola, 3T 486). This proceeding concerns approval of the PSA and CCAA negotiated with the Customer. It does not present for adjudication the contracts, tariffs, costs, revenues, load characteristics, customer protections, or regulatory treatment applicable to every other existing or future data center customer. Yet the AG asks the Commission to use this Customer-specific special contract proceeding to establish a generally applicable accounting requirement for an undefined class of other customers, including customers whose arrangements are not before the Commission in this docket.

Accordingly, the AG's proposal is unnecessary and exceeds the scope of this Customer-specific proceeding.

- *Staff's Periodic-Review Recommendation Aligns with the Company's Framework*

Staff's principal recommendation regarding ongoing review of the affordability benefit confirms, rather than challenges, the Company's proposed Affordability Backstop framework. Staff recommends that the Commission make the same finding it made in the December 18 Order — retaining jurisdiction to reopen the case "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" — and that "[a] periodic review of the affordability benefit … be made in future rate cases," confirming that the Special Contracts "will cover the cost to serve the customer including generation, transmission, distribution, and other costs." Staff Initial Brief, p. 17; December 18 Order, p. 43; (Isakson, 3T 881).

Staff's recommendation for ongoing review of the affordability benefit aligns with the Company's proposals. As to forum, the Company has committed to present the aggregate costs and benefits of serving the Customer in its future general rate case and PSCR proceedings — precisely the "future rate cases" that Staff identifies. (Foley, 3T 144). As to scope, the cost categories Staff enumerates — generation, transmission, distribution, and other costs — are the same categories the Company committed to include in the Affordability Backstop presentation: the revenue requirement of CCAA and RPS-related renewable and storage resources and of other resources identified in the IRP as caused by the Customer's load (generation); the revenue requirement of transmission investments (transmission); increased fuel and purchased-power costs (other costs); and, as to distribution, any recoverable distribution costs to the extent they exceed the $50 million the Customer funds under the Line Extension Agreement. (Foley, 3T 143-144, 251-252). The Company therefore does not oppose a Commission finding, consistent with the December 18 Order, that it retains jurisdiction to reopen this matter and that the benefit will be reviewed in future rate cases in the form of the Company's presentation of aggregate costs and benefits. Such periodic review governs when and in what forum the aggregate assessment is presented; it does not alter the aggregate, over-the-life measurement standard the Special Contracts embody, and it cannot become a vehicle to reform the negotiated terms. DTE Electric Initial Brief, pp. 30-31.

- *Annual Reporting Is the Appropriate Cadence*

Staff generally supports the Company's overall reporting proposal for the Special Contracts set forth in Company Witness Foley's rebuttal at 3T 151-154. Staff Initial Brief, pp. 26-27. The remaining reporting recommendations fall into two categories, and both are answered by the Company's committed annual reporting framework.

First, MEICEO and GLREA recommend a quarterly reporting cadence modeled on Case No. U-21990. MEICEO Initial Brief, pp. 21-23; GLREA Initial Brief, p. 17. As the Company's Initial Brief explained, a quarterly cadence is unwarranted because the Company's annual report, together with the aggregate cost-and-benefit accounting presented in the regular cadence of general rate cases, PSCR, IRP, and REP proceedings, already supplies the necessary information, and Section 5.1.3 introduces new tracking and reporting requirements beyond what U-21990 involved. DTE Electric Initial Brief, pp. 41-42; (Foley, 3T 151-154).

- *MEICEO's Proposed True-Up and Counterfactual Requirements Are Already Addressed*

Separately, MEICEO contends that approval must be conditioned on a package of "reporting, verification, and true-up procedures," including measurable triggers, a defined true-up remedy, a sunset/reopener tied to the IRP cadence, multi-docket reporting, a maintained "without-customer" counterfactual baseline, and an *ex post* demonstration that the Company pursued the resource opportunities MEICEO witness Sherman identifies. MEICEO Initial Brief, pp. 21-23; (Kenworthy, 3T 697-698). Several of these conditions seek what the Special Contracts and the Company's commitments already provide; the remainder should be rejected.

First, the true-up remedy MEICEO seeks — "a true-up or claw-back to the Customer rather than other ratepayers" — is effectively addressed by the Affordability Backstop itself. Section 5.1.3 obligates the Customer, not other ratepayers, to reimburse any Commission-determined shortfall between the aggregate costs and benefits. (Foley, 3T 103-104). MEICEO thus asks the Commission to impose a remedy the parties already negotiated into the PSA.

Second, the “without-customer counterfactual baseline” MEICEO demands is the with-and-without analysis the Company already committed to perform. As Company Witness Foley explained, the resources “caused by” the Customer's load will be identified by comparing the IRP resource selections in a scenario that includes the Customer's load against a scenario without it. (Foley, 3T 244-245); DTE Electric Initial Brief, pp. 116-119. That is essentially the “without-customer reference case” MEICEO describes. To the extent MEICEO further insists the analysis use “actual resource modeling rather than the placeholder construct,” that objection goes to the proxy resource and the magnitude of the projected benefit, and is addressed in Section VI.

Third, the reporting and reopener components are addressed by the Company's committed annual reporting framework and the Commission retention of jurisdiction. The Company will present the aggregate costs and benefits in future rate cases and PSCR proceedings and will file an annual report on realization of the benefit; and, as discussed above, the Company does not oppose a Commission finding, consistent with the December 18 Order, retaining jurisdiction to reopen this matter. DTE Electric Initial Brief, pp. 41-42, 47-48; Staff Initial Brief, p. 17; (Foley, 3T 151-153); December 18 Order, p. 43.

Fourth, the conditions the Company opposes are the two that would rewrite the contract or the governing standard. To the extent MEICEO asks the Commission to amend Section 5.1.3 to hard-code single-variable “measurable triggers,” the Company's Initial Brief explained why that is both unnecessary and beyond the Commission's authority to compel over the contracting parties' negotiated agreement. DTE Electric Initial Brief, p. 39; *Union Carbide Corp v Pub Serv Comm*, 431 Mich 135, 148-149; 428 NW2d 322 (1988). And to the extent MEICEO would condition any recognized benefit on an "*ex post* demonstration" that the Company pursued MEICEO witness Sherman's preferred resource options, that is the "most cost-effective approach" standard the Company addresses, and rejects, in Section VI: it would graft an IRP-style resource-optimization test onto a special contract proceeding, contrary to the governing standard. DTE Electric Initial Brief, pp. 127-131.

Lastly, to the extent Staff maintains that its recommended combined large-load analysis "is still necessary," the Company relies on and incorporates its Initial Brief's explanation of why each large-load customer must be modeled individually, in sequence, in the IRP. Staff Initial Brief, p. 26; DTE Electric Initial Brief, pp. 44-46; (Foley, 3T 149-150).

- *The Affordability Backstop is Reasonable and Prudent*

In conclusion, the Affordability Backstop is a reasonable and prudent mechanism that requires the Customer to reimburse any Commission-determined aggregate shortfall in costs and benefits. Staff and GLREA treat it as adequate, and Staff supports the Company's reporting proposal. The Commission should therefore approve the PSA as filed.

7. Load Ramp Flexibility

DTE Electric's Initial Brief, pp. 48-50, demonstrated that the PSA's load-ramp flexibility is reasonable and prudent, as it permits the Customer to delay its load ramp by up to 18 months in the aggregate without diminishing the Customer's underlying commitments; it does not permit the Customer to reduce the 1,000 MW contract capacity on which the 80% MBD, termination payment, and collateral obligations are based; and, through the PSA Section 2 adjustment right, it protects the Company's generation and distribution systems and the reliability of service to other customers. (Foley, 3T 88-89, 99-101). Only ABATE challenges these provisions, contending that the Company's "tools to ensure resource adequacy contain shortcomings" and that "any contract approval here should be conditioned on revising these measures." ABATE Initial Brief, pp. 9-10; (Dauphinais, 3T 545-548). Neither of ABATE's arguments warrant a condition on approval of the Special Contracts.

- *ABATE Identifies No Basis to Require a Blanket Commitment to Exercise Section 2.4 of the PSA*

DTE Electric's Initial Brief, pp. 48-50, addressed and refuted ABATE's recommendation that the Company be required to commit "to fully utilize the discretion given to it under Section 2 of the PSA," and the Company relies on and incorporates those arguments here. Section 2.4 establishes a contractual process if the Company is unable, for reasons contemplated in the PSA, to achieve or maintain the Customer Committed Capacity Ramp or maximum load. A blanket commitment to "fully utilize" that process in every instance would be unnecessary and potentially counterproductive because its availability and appropriate exercise depend on the circumstances specified in the PSA and the then-existing facts. ABATE identifies no meaningful content distinguishing the "full" utilization it seeks from the contractual process and discretion that Section 2.4 already provides. (Foley, 3T 140). ABATE's Initial Brief reiterates witness Dauphinais' testimony on this point without offering any new argument, and the recommendation should be declined for the reasons set forth in the Company's Initial Brief. That conclusion does not depend on treating Section 2.4 as a general emergency reliability provision.

ABATE's Initial Brief separately raises a point regarding firm load shedding that does not support any condition on approval of the Special Contracts. ABATE observes that the Company's firm-load-shedding tariff revisions were filed in a separate proceeding, and argues those revisions "should be limited to the circumstances presented by" the special contracts approved in Case No. U-21990. ABATE Initial Brief, pp. 9-10; (Dauphinais, 3T 545-548). This position should be rejected for the below reasons.

There is no genuine dispute that the Customer should be subject to firm load shedding before other customers. ABATE itself concedes that, "given the 1,000 MW size of the Google data center load addition at issue here, . . . subjecting Google to an early load shedding requirement until the resources necessary to serve it are fully online is fully justified in this case." ABATE Initial Brief, p. 10. The Company agrees. As the Company's Initial Brief explained, once the amended Emergency Electric Procedures are approved, the Customer will be subject to them, and those procedures will subject the Customer to firm load shedding before the firm load of other customers is curtailed. DTE Electric Initial Brief, pp. 49-50; (Foley, 3T 140-141). The Customer will therefore be subject to firm load shedding ahead of other customers, which is the protection ABATE says is justified.

Section 2 of the PSA and the Emergency Electric Procedures address different circumstances. Section 2.4 provides a contractual process if the Company is unable, for reasons specified in the PSA, to achieve or maintain the Customer Committed Capacity Ramp or maximum load. It should not be characterized as a general emergency load shedding provision or as a substitute for the Company's Emergency Electric Procedures. DTE Electric Initial Brief, pp. 48-50; (Foley, 3T 101, 140). The emergency treatment of the Customer should instead be determined under the generally applicable Emergency Electric Procedures being addressed in Case No. U-22059.

In conclusion, the PSA's load-ramp flexibility reasonably accommodates the construction of the Facility without diminishing the Customer's commitments; the contract-capacity protections preserve the financial obligations on which other-customer protections depend; and the Emergency Electric Procedures pending approval in a separate docket protects the reliability of service to other customers. The Commission should therefore approve the PSA as filed without expanding Section

2.4 beyond its contractual terms or duplicating the emergency procedures being addressed in the separate tariff proceeding. DTE Electric Initial Brief, pp. 48-50.

8. Energy Waste Reduction

DTE Electric's Initial Brief, pp. 50-52, demonstrated that the PSA's Energy Waste Reduction ("EWR") provision is reasonable, prudent, and in the public interest: the Customer commits to participate in and comply with the self-directed EWR plan requirements of MCL 460.1093; the savings identified in the Customer's self-directed plan count toward the Company's statutory EWR goals; and the Customer will continue to pay a surcharge supporting the Company's low-income EWR programs even if it self-directs. No party opposes the EWR provision, and only Staff addresses it.

Staff does not oppose the Customer's election to self-direct its EWR plan but makes three cooperative recommendations concerning the Company's coordination with the Customer, each of which the Company's Initial Brief already stated it does not oppose because the Company expects to satisfy them in the normal course of business. Staff Initial Brief, pp. 18-19; (Smith, 3T 889-891). Nothing in Staff's Initial Brief alters that consensus, and the Company confirms its acceptance of each recommendation here.

B. Clean Capacity Acceleration Agreement

DTE Electric's Initial Brief, pp. 52-86, demonstrated that the CCAA is reasonable, prudent, and in the public interest. The CCAA enables the Company to deploy up to 480 MW of energy storage and up to 1,600 MW of renewable energy, and to receive 300 MW of ZRCs, with the Customer paying the full cost of every project and providing the ZRCs at no cost — such that no CCAA costs are shifted to the Company's other customers. DTE Electric Initial Brief, pp. 52, 59-

65; (Foley, 3T 88, 107-125). The CCAA holds other customers harmless through layered, mutually reinforcing protections: full-cost recovery from the Customer over each project's depreciable life, annual reconciliation to actual costs, credits capped at market revenues, project-by-project Commission review before construction, the CCAA Regulatory Liability that funds any post-term revenue requirement, a self-adjusting termination payment keyed to unrecovered project costs, and a parent-guaranty-and-letter-of-credit collateral package. DTE Electric Initial Brief, pp. 59-65. Beyond holding other customers harmless, the CCAA affirmatively benefits them and advances Michigan's clean-energy objectives — chiefly by reducing the RECs the Company must otherwise procure while the Customer funds the associated renewable resources. DTE Electric Initial Brief, pp. 73-80.

As with the PSA, the parties do not contest the essential structure of the CCAA; their disagreements go to discrete features — the procurement framework for the VGP renewable resources, the accounting treatment of the ZRC financial adder, the treatment of RECs and the Company's renewable forecast, and the procurement and deployment of CCAA resources — and, in several instances, would require the Commission either to rewrite a negotiated commercial term it lacks authority to reform or to resolve in this proceeding a resource-planning question reserved for the Company's upcoming IRP. The Company responds to the Staff and intervenor arguments applicable to each subject matter in the corresponding subsections below.

1. VGP Special Contract

DTE Electric's Initial Brief, pp. 52-59, demonstrated that the renewable-energy component of the CCAA is a customer-requested VGP Special Contract, pursuant to MCL 460.1061 and the VGP Settlement Agreements in Case Nos. U-20713/U-20851 and U-21172; that the Customer pays the full cost of the renewable resources procured on its behalf under the VGP Special

Contract; that each project returns to the Commission for review and approval before construction; and that the arrangement therefore holds other customers harmless while advancing Michigan's clean-energy objectives. DTE Electric Initial Brief, pp. 52-59; (Bilyeu, 3T 278-279, 296-297; Foley, 3T 110). Only MEICEO, through witness Sherman, challenges the VGP Special Contract, and its principal recommendation — that the Commission impose an ownership split between Company-owned and third-party-owned renewable projects — should be rejected.

DTE Electric's Initial Brief, pp. 54-59, addressed and refuted the core of MEICEO's recommendation, and the Company relies on and incorporates those arguments here rather than repeating them — including that the customer-requested offering, not Rider 17, is the correct Commission-approved vehicle for the Customer's 1,600 MW renewable requirement (Bilyeu, 3T 306); that no ownership split is needed to protect other customers because the Customer bears the full revenue requirement of the resources (Bilyeu, 3T 304); that MEICEO witness Sherman's "capital bias" assertion is unsupported and that the Company's more recent RFP data shows third-party ownership to be the more expensive option (Bilyeu, 3T 307-308); that the Case No. U-21172 settlement's build-transfer provision establishes a procurement process, not a mandatory RFP outcome (Bilyeu, 3T 305-306); and that witness Sherman's reliance on paragraph 7 of the Case No. U-21172 settlement is misplaced because the CCAA's own termination-payment and cost-recovery provisions govern (Bilyeu, 3T 311-312). The Company writes further only to address the aspects of MEICEO's Initial Brief that its Initial Brief did not separately reach.

- *MEICEO's Recast Ownership Target Remains an Impermissible Procurement Mandate*

In testimony, MEICEO witness Sherman recommended a fixed "50% third-party / 50% Company-owned" ownership split. (Sherman, 3T 774). MEICEO's Initial Brief now recasts that recommendation as a request that the Commission require "roughly equivalent amounts of

Company-owned and third-party owned projects." MEICEO Initial Brief, p. 25. This reframing does not change the analysis. Whether styled as a rigid 50/50 quota or a "roughly equivalent" target, MEICEO asks the Commission to impose an ownership structure that appears nowhere in the negotiated VGP Special Contract and to override the Commission-approved procurement framework established in the VGP Settlement Agreements. As set forth in Section III and in the Company's Initial Brief, the Commission lacks statutory authority to rewrite the parties' negotiated agreement by imposing an ownership mandate that does not derive from statute. DTE Electric Initial Brief, pp. 57-58; *Union Carbide*, at 148-149. A less precise ratio is no less a Commission-imposed mandate than a fixed one.

- *Customer-Paid Resources Do Not Require an Ownership Mandate to Protect Other Customers*

Recognizing that the Customer bears the full cost of renewable resources under the VGP Special Contract — and thus that no ownership split is needed to protect other customers from the renewable revenue requirement — MEICEO pivots to argue that DTE Electric's "Customer bears the costs in full" response "ignores that the Commission's evaluation of these Special Contracts involves an evaluation of the public interest," and that the Commission should weigh the "wider benefits of third-party ownership," including promoting competitive renewable markets, lower long-run costs, and faster procurement. MEICEO Initial Brief, pp. 30-31. That argument fails for two primary reasons in addition to positions set forth in the Company's Initial Brief, pp. 54-59.

First, MEICEO's concession is significant: because the Customer bears the full revenue requirement of the VGP resources, an ownership mandate is not needed to hold other customers harmless. (Bilyeu, 3T 304). MEICEO's public-interest theory is therefore not a cost-shifting protection at all; it is a request that the Commission use this special contract proceeding to advance a generalized renewable-market-development policy untethered from the costs of serving the Customer.

Second, as explained in Section III, the Commission's evaluation of the public interest is bounded by statute and does not empower the Commission to rewrite negotiated commercial terms or to impose, as a condition of approving a special contract, an ownership structure that the Legislature has not required and that the parties did not agree to. The “wider benefits of third-party ownership” MEICEO invokes are quintessential resource-procurement and market-structure policy considerations that do not belong in this proceeding in which the question is whether the negotiated Special Contracts are reasonable, prudent, and free of cost-shifting. DTE Electric Initial Brief, pp. 57-58, 127-131. MEICEO's public interest framing thus repeats the over-expansion the Company addresses in Section III, as it would convert the Commission's discretion to evaluate the public interest into authority to mandate a preferred procurement outcome. The Commission should decline that invitation, particularly where the record shows a third-party-ownership mandate would tend to raise the Customer's costs, not lower them. (Bilyeu, 3T 307-308).

- *The VGP Special Contract Should Be Approved as Filed*

In sum, the VGP Special Contract is lawful, reasonable, and prudent under MCL 460.1061 and the VGP Settlement Agreements, holds other customers harmless because the Customer bears the full cost of the renewable resources, and remains subject to project-by-project Commission review. MEICEO's ownership-split recommendation — whether framed as a 50/50 quota or “roughly equivalent amounts” — would impermissibly rewrite a negotiated contract term, is unnecessary because the Customer bears the full cost, and rests on a public interest theory that would improperly convert this proceeding into a resource-procurement and market-development policy docket. The Commission should approve the VGP Special Contract as filed and reject MEICEO's recommendations. DTE Electric Initial Brief, pp. 58-59.

2. The CCAA Does Not Shift Costs to Other Customers

DTE Electric's Initial Brief, pp. 59-65, demonstrated that the CCAA holds the Company's other customers harmless through layered, mutually reinforcing protections: (1) the Customer pays the full revenue requirement of every CCAA project over its depreciable life; (2) the Company reconciles those payments to actual costs annually; (3) the credits the Customer receives are capped at the lower of the calculated credit or market revenues, so other customers bear no cost and share any upside through the PSCR; (4) no CCAA project is deployed without Commission review and approval before construction; (5) the CCAA Regulatory Liability funds any revenue requirement extending beyond the 20-year term; and (6) upon a Customer default, a self-adjusting termination payment collects the unrecovered revenue requirement of the deployed projects, backed by a parent guaranty and, as necessary, a letter of credit. DTE Electric Initial Brief, pp. 59-65; (Foley, 3T 107-125). The Company relies on and incorporates that showing herein.

No party contends that the Customer will not pay the full revenue requirement of each CCAA project, that the annual reconciliation is inadequate, that the market revenue credit cap fails to protect other customers, or that project-by-project Commission review is insufficient. The cost-related arguments the parties do raise are directed either at the size of the projected benefit or at discrete features of the Special Contracts addressed elsewhere, and the Company's Initial Brief preemptively addressed each. The Company briefly identifies where each is answered and does not repeat those arguments here.

- *The CCAA Termination Payment Already Provides a Self-Adjusting Recovery Mechanism*

First, to the extent ABATE contends the CCAA termination payment must be made modifiable at termination (ABATE Initial Brief, pp. 7-8), the Company's Initial Brief explained that the CCAA termination payment is self-adjusting — set equal to the unrecovered revenue requirement of each deployed project — and therefore requires no modification mechanism to prevent a cost shift. DTE Electric Initial Brief, pp. 63-64; (Foley, 3T 124, 138). ABATE's Initial Brief adds no new argument, and the recommendation is addressed in more detail in Section V.A.4.

- *The CCAA Collateral Structure Does Not Shift Risk to Other Customers*

Second, to the extent the AG contends the CCAA collateral must be uncapped (AG Initial Brief, pp. 16-19), the Company's Initial Brief explained that the CCAA guaranty is deliberately calibrated to the Company's declining exposure, escalates automatically to a letter of credit if the parent's credit rating falls, and is backed by the Company's acceptance that any collateral shortfall falls on the Company. DTE Electric Initial Brief, pp. 63-64; (Foley, 3T 125, 133-134). The AG's Initial Brief adds no new argument as applied to the CCAA, and the recommendation is addressed in more detail in Section V.A.5.

- *Post-Termination Resource Use Does Not Transfer Unrecovered Costs to Other Customers*

Third, MEICEO witness Sherman contends that, under paragraph 7 of the Case No. U-21172 settlement, the renewable resources supporting the Customer's VGP Special Contract would, upon termination, first be reallocated to other VGP customers and then, if VGP demand is insufficient, to all customers — thereby exposing other customers to the cost of those resources. MEICEO Initial Brief, pp. 25-26; (Sherman, 3T 774). That contention fails because the Case No. U-21172 settlement provision does not override the CCAA's own cost-recovery terms. As Company Witness Bilyeu explained, in the event the CCAA is terminated through the Customer's default, the Customer is obligated to pay a termination payment designed to collect the unrecovered portion of each project's costs over its depreciable life. (Bilyeu, 3T 311). Because the CCAA termination payment recovers the full unrecovered revenue requirement of each deployed project from the Customer, the future allocation of resource capacity to VGP, REP, or CEP needs contemplated in the Case No. U-21172 settlement provision does not mean that other customers would automatically bear unrecovered costs from the Customer's VGP Special Contract. (Bilyeu, 3T 311). To the contrary, if — after the Customer's payment obligations have been satisfied — a renewable resource later provides value for VGP, REP, or CEP purposes, "that does not establish that other customers are subsidizing the Customer;" it means other customers receive a resource whose costs the Customer has already paid. (Bilyeu, 3T 311-312). The Customer's payment obligations under the CCAA — not the ownership form of the resource or its post-termination disposition — are the protection, and those obligations ensure the Customer bears the full cost of every CCAA project whether the agreement runs its term or is terminated on default. (Bilyeu, 3T 312).

- *The CCAA Holds Other Customers Harmless*

Because the Customer pays the full, reconciled cost of every CCAA project, receives credits capped at market revenues, funds any post-term revenue requirement through the CCAA Regulatory Liability, and remains obligated on default to a self-adjusting termination payment secured by declining collateral — and because no party disputes those mechanisms — the CCAA does not shift any costs to other customers. The Commission should approve the CCAA as filed.

3. CCAA Regulatory Liability

DTE Electric's Initial Brief, pp. 65-66, demonstrated that the Commission should authorize the Company to record a regulatory liability to Account 254 to effectuate the CCAA's accelerated cost-recovery mechanism — a core customer-protection feature ensuring that the Customer pays the full revenue requirement of each energy storage and renewable energy project over its entire depreciable life, even where that life extends beyond the 20-year CCAA term. DTE Electric Initial Brief, pp. 65-66; (Foley, 3T 111, 113-114, 127-128).

As the Company's Initial Brief observed, no Staff or intervenor witness opposed the CCAA Regulatory Liability in testimony, and no Staff or intervenor Initial Brief opposes it now. The Commission should therefore grant the requested authorization to record the CCAA Regulatory Liability to Account 254, as set forth in the Company's Request for Relief. DTE Electric Initial Brief, pp. 65-66, 131.

4. ZRC Transfer and Financial Adder

Under the CCAA, the Customer commits to transfer 300 MW of MISO Zone 7 Zonal Resource Credits to the Company at no cost for each MISO planning season from June 1, 2028 through May 31, 2033, and separately agrees to pay the Company a financial adder in connection with that transfer. DTE Electric's Initial Brief, pp. 66-73, demonstrated that both features are reasonable, prudent, and in the public interest: the transfer of 300 MW of capacity at no cost is a direct benefit to the Company's other customers, contributing to the Company's resource adequacy without any associated cost to them; and the financial adder is a negotiated term of the CCAA that the Company appropriately proposes to record as non-refundable income. DTE Electric Initial Brief, pp. 66-67; (Foley, 3T 115-116). Staff and intervenors raise two distinct sets of challenges: Staff, ABATE, MEICEO, and GLREA contend the financial adder should be rejected or, if collected, treated as ordinary revenue offsetting the Company's revenue requirement (Staff Initial Brief, pp. 30-33; ABATE Initial Brief, p. 12; MEICEO Initial Brief, pp. 40-41; GLREA Initial Brief, pp. 4-8); and MEICEO contends the Customer should be permitted to satisfy a portion of its

300 MW ZRC obligation through Company-administered DR and distributed-energy programs (MEICEO Initial Brief, pp. 36-39). Both sets of challenges should be rejected.

DTE Electric's Initial Brief, pp. 67-73, addressed and refuted the core of these arguments, and the Company relies on and incorporates those arguments herein rather than repeating them. As to the financial adder: the absence of a statutory PPA is beside the point because the Company does not seek the accounting treatment under MCL 460.1028, but as a negotiated term of the CCAA (Foley, 3T 155-156); granting the treatment works no harm to other customers because the adder does not offset a cost the Company would otherwise recover from them (Foley, 3T 156); denying the Company a modest negotiated benefit while requiring it to bear the risks of serving the Customer is inequitable (Foley, 3T 156); and the Commission cannot rewrite a negotiated payment term over the parties' agreement under *Union Carbide*, at 148-149. As to MEICEO's DR and distributed-energy proposal: the Company is not involved in the Customer's procurement of the ZRCs and the source of those ZRCs is left to the Customer's discretion (Foley, 3T 165); substituting Company-administered programs for a portion of the obligation would introduce reliability risk to other customers because the Company could not invoke Section 2.4 of the PSA if program enrollment targets were not met (Foley, 3T 166); such programs would disrupt the no-cost nature of the ZRC transfer by introducing program costs that do not exist under the negotiated CCAA (Foley, 3T 166); this special contract proceeding is not the appropriate forum to mandate new Company resource programs, which belong in the IRP (Foley, 3T 166-167); and the Commission cannot rewrite the negotiated 300 MW ZRC obligation. The Company replies further below to address arguments developed in the parties' Initial Briefs.

- *The Financial Adder Is a Negotiated Payment That Does Not Offset a Customer Cost*

Staff, MEICEO, and GLREA each argue that, because the adder is not tied to incremental utility capital at risk, it should be treated as a cost offset that lowers revenue requirements for all ratepayers. MEICEO Initial Brief, pp. 40-41; (Sherman, 3T 810-811); Staff Initial Brief, p. 33; (Simpson, 3T 844); GLREA Initial Brief, p. 8; (Richter, 3T 587). That argument wrongly assumes the adder is a cost of serving the Customer that would otherwise be recovered from other customers. As Company Witness Foley explained, "the financial adder is not offsetting a cost to the Company that it would otherwise recover from its other customers," and other customers "would be held harmless if the Commission were to grant the Company's requested accounting treatment." (Foley, 3T 156). The adder is an incremental payment the Customer agreed to make in addition to the full revenue requirement of the CCAA resources and in addition to transferring 300 MW of ZRCs at no cost. Because other customers bear no cost associated with the adder, treating it as a cost offset would not "hold customers harmless" — it would transfer to other customers the benefit of a payment the Customer negotiated to make to the Company in exchange for the Company's assumption of risk under the Special Contracts.

GLREA argues that the Company "did not cite risk of default as a justification for the ZRC adder in its direct testimony" and that raising it in rebuttal "creates the appearance that this justification was invented after criticisms in testimony." GLREA Initial Brief, pp. 7-8; (Richter, 3T 586-587). GLREA's premises are inaccurate. The Company's direct testimony proposed to record the adder as non-refundable income "like it does with the FCM," expressly grounding the request in the adder's similarity to the Financial Compensation Mechanism. (Foley, 3T 116). And in a discovery response served before any rebuttal, the Company explained that the adder "is intended to account for the opportunity cost of foregoing the development of a company-owned resource or a third-party resource that would receive an FCM, such as a PPA." (Ex. MEICEO-

37). The Company's rebuttal did not manufacture a new justification; it reiterated that same FCM/lost-opportunity rationale and responded to the intervenors' contention that the Company should bear the risks of serving the Customer while forgoing the negotiated benefit that offsets them. (Foley, 3T 154-156). That responsive point is precisely what rebuttal testimony is for, and GLREA's "appears invented" characterization identifies no inconsistency in the Company's position. In any event, the propriety of the accounting treatment does not turn on whether the adder is best described as compensation for a lost opportunity or for assumed risk; it turns on the fact that the adder is a negotiated payment the Customer agreed to make, that its treatment as non-refundable income works no harm to other customers, and that the Commission lacks authority to rewrite that negotiated term. (Foley, 3T 155-156).

GLREA also argues that because the Customer provides ZRCs for only five years (June 2028–May 2033) while the CCAA continues longer, "[i]n the event of an early default, no adder would have been paid yet," so the adder cannot be default-risk compensation. GLREA Initial Brief, p. 8; (Richter, 3T 587). This argument, too, assumes the financial adder's validity depends on a precise proportionality to default risk. It does not. The financial adder is consideration the Customer agreed to pay in connection with the ZRC transfer, and GLREA identifies nothing in the CCAA, the governing statutes, or Commission precedent requiring that a negotiated payment be mathematically calibrated to a single identified risk before it may be recorded as the Company proposes. The timing of the ZRC transfers does not convert a negotiated benefit into a cost borne by other customers, and it supplies no basis to reject or recharacterize the financial adder.

Staff reframes the risk of serving the Customer as a risk to other customers — if the Customer underperforms, the ZRCs do not materialize, or non-CCAA resources cost more than expected — and concludes that the financial adder should therefore benefit all customers. Staff

Initial Brief, pp. 32-33; (Simpson, 3T 844). That argument is answered by the customer-protective architecture the Company has demonstrated throughout, e.g., the 80% MBD, the termination payment, the Affordability Backstop, and the Company's acceptance of collateral-insufficiency risk ensure that the risks Staff identifies are borne by the Customer or the Company, not by other customers. Because other customers are already held harmless, Staff's premise that ratepayers bear an uncompensated risk warranting the financial adder as an offset does not hold. As for Staff's concern that the treatment would create a "bad incentive" to "seek out future large customers . . . willing to pay more than is necessary" (Staff Initial Brief, p. 32), the Company disagrees and, in any event, has accepted that its requested treatment will not serve as precedent for mandating a financial adder from future customers. (Foley, 3T 156-157). Thus, ABATE's non-precedent condition, which the Company accepts and which the Commission may memorialize, fully addresses the precedent concern.

The Commission's authority to determine accounting treatment differs from the substantive basis for the negotiated payment. The Company does not contend that the contracting parties' characterization of an amount conclusively binds the Commission's accounting determination. The relevant question is not whether MCL 460.1028 mandates the adder, but whether the record supports the accounting treatment the Company requests for this negotiated Special Contract payment. Company Witness Foley explained that the adder accounts for the opportunity cost of foregoing development of a Company-owned resource and is similar to an FCM in concept and objective, while expressly disclaiming reliance on MCL 460.1028 as the source of entitlement. (Foley, 3T 155-156). The Customer receives the benefit of satisfying a portion of its capacity responsibility through a Customer-provided ZRC transfer rather than through Company-owned investment, while the Company forgoes the opportunity associated with developing and owning the corresponding capacity resource. The negotiated adder compensates the Company for that foregone opportunity; it is not a reimbursement of a revenue requirement otherwise recoverable from customers.

Moreover, the absence of a statutory mandate for the payment does not establish that the payment should be credited to other customers. MCL 460.1028 governs a statutory FCM; it does not prohibit parties from negotiating economically comparable compensation in a Special Contract or require every voluntary payment to be treated as base-rate revenue. The Company relied on the FCM analogy to explain the adder's economic function, not to claim that MCL 460.1028 compels approval. Nor does Staff identify a Customer-caused cost that other customers bear in exchange for the adder. The Customer provides the 300 ZRCs without resource cost to DTE Electric, and the customer-protection provisions independently address costs and risks associated with service. Treating the adder as an offset to the Company's general revenue requirement would transfer to other customers the economic benefit that the Customer negotiated in connection with the ZRC transfer.

GLREA argues that "[a] special contract is not an opportunity to create entirely new sources of profit for the Company," and that the law already provides the Company's authorized returns. GLREA Initial Brief, pp. 7-8; (Richter, 3T 586-587). But a special contract, by its nature, contains negotiated terms that differ from standard tariff service — that is what makes it a special contract. The financial adder is not a Commission-conferred "new source of profit;" rather, it is a term the Customer voluntarily agreed to pay, and the only question is whether the Company may record a payment the Customer agreed to make as the Company proposes. GLREA identifies no statute or precedent prohibiting that treatment.

To the extent that MEICEO invokes the PFD in Case No. U-21972 to suggest that a negotiated contractual charge is impermissible unless mathematically tied to a discrete, customer-caused cost, that reliance is misplaced. MEICEO Initial Brief, p. 40, n. 7. The ALJ's non-binding, and presently non-adopted, recommendation in Case No. U-21972 addressed the Financial Compensation Mechanism—a statutory incentive created to encourage utility use of PPAs—and rested on the conclusion that the FCM is not a cost caused by participation in a pilot and therefore should not be assigned to participating customers. *See* Case No. U-21972, Proposal for Decision dated July 14, 2026, p. 39. That reasoning is confined to the unique statutory character of the FCM. The CCAA financial adder at issue here is a negotiated contractual term supported by record evidence of the opportunity cost and risk the Company assumes, not a statutory incentive of the sort that the Case No. U-21972 ALJ addressed. That PFD accordingly provides no basis to reject or condition the adder.

- *Company-Administered Programs Are Not a Substitute for the Customer's ZRC Transfer*

MEICEO witness Sherman recommends that the Commission reject what she mischaracterizes as "DTE's unreasonable limitation of Google's options for procuring the ZRCs" and direct the Company to work with the Customer to satisfy a portion of the 300 MW obligation through an expanded Smart Savers DR program and a new, Customer-funded Virtual Power Plant ("VPP") program. MEICEO Initial Brief, pp. 36-38. That framing inverts the record. The CCAA does not limit the Customer's options for procuring ZRCs; to the contrary, "[t]he Company is not involved in the Customer's procurement of ZRCs," and "the source of those ZRCs is at [the Customer's] discretion." (Foley, 3T 165). The Customer remains free to procure the 300 MW of ZRCs from whatever source it chooses. It is MEICEO — not the Company — that seeks to constrain how the Customer's obligation is satisfied, by directing that specific Company-administered programs supply a portion of it. What the Company opposes is not the Customer's freedom to source ZRCs, but being ordered, in this proceeding, to stand up and administer new utility programs to generate ZRCs in the Customer's stead. MEICEO's request is unreasonable and provides no basis to rewrite the CCAA.

MEICEO's Initial Brief contends that Company-administered programs are "consistent with the CCAA's ZRC transfer obligation" because what matters "is that the Company's capacity position is improved by the amount specified — not the specific MISO accounting mechanism." MEICEO Initial Brief, pp. 36; (Sherman, 3T 795). That mischaracterizes the defined product the CCAA requires. The CCAA obligates the Customer to transfer to the Company 300 MW of MISO Zone 7 ZRCs — a specific, MISO-registered capacity product that the Customer procures and conveys to the Company at no cost. As MEICEO's own brief acknowledges, "[t]he expansion or creation of a utility program would include no such transfer since the ZRCs would be generated by the Company and would require entirely different compensation and tracking structures," and "such an approach would not comply with the terms of the CCAA." MEICEO Initial Brief, p. 6, quoting Exhibit MEICEO-38, p. 15. MEICEO witness Sherman's recommendation therefore does not offer an alternative means of satisfying the negotiated ZRC obligation; it proposes to replace that obligation with an altogether different arrangement — Company-generated capacity from Company-run programs — that the CCAA does not contemplate and that would alter the product, the cost allocation, and the risk allocation the contracting parties negotiated.

Finally, MEICEO's public interest, affordability, and "Customer-funded" framing does not cure the serious defects of their proposals. MEICEO argues that a Customer-funded DR expansion and VPP program would deliver near-term grid and affordability that it maintains is consistent with the public interest. MEICEO Initial Brief, pp. 36-37. That framing does not support the relief sought, for three primary reasons. First, as explained in Section III, the Commission's public interest evaluation does not authorize it to use a special contract approval as a vehicle to mandate new, Company-administered ratepayer programs the contracting parties did not negotiate. The desirability of DR and VPP programs in the abstract is not a basis to rewrite the CCAA's negotiated ZRC obligation. Second, even a "Customer-funded" program is not costless to the Company or other customers: it would impose administrative burden on the Company and introduce performance and reliability risk, because if enrollment targets were not met the Company — and ultimately other customers — would bear the shortfall, and the Company could not invoke Section 2.4 of the PSA as it can if the Customer fails to provide the ZRCs. DTE Electric Initial Brief, pp. 70-71; (Foley, 3T 166). Third, the negotiated ZRC transfer already delivers a public interest benefit — 300 MW of firm, MISO-registered capacity at no cost to other customers beginning in 2028 — whereas MEICEO's VPP alternative depends on future regulatory developments, including MISO's implementation of FERC Order 2222, under which distributed-energy aggregations cannot begin registering until 2029 and cannot participate in the MISO market until 2030. (Sherman, 3T 806-807). Substituting a contingent, enrollment-dependent program that cannot supply market-recognized capacity until 2030 for a firm, no-cost transfer beginning in 2028 would reduce, not enhance, the protection other customers receive. To the extent the Company's DR and VPP programs should be expanded, that is a resource-planning question for the Company's IRP, not a condition on approval of these Special Contracts. DTE Electric Initial Brief, pp. 71-72; (Foley, 3T 167).

- *The Commission Should Not Extend the ZRC Transfer Beyond the Negotiated Term*

ABATE witness Dauphinais and MEICEO witness Hotaling recommend that the Commission condition approval of the Special Contracts by modifying the CCAA to require the

Customer to continue transferring 300 MW of ZRCs beyond the negotiated May 31, 2033 end date — to the extent the Company has been unable to bring 550 MW of replacement ZRCs online in MISO Zone 7 — alleging that the sunset of the ZRC transfer (together with the Rider 12 DR commitment) creates a resource adequacy cliff in 2033 and is likely the principal contributor to the Company's projected 677 MW capacity need that year. ABATE Initial Brief, pp. 10-11; MEICEO Initial Brief, pp. 38-39; (Dauphinais, 3T 547-548; Hotaling, 3T 716-718). DTE Electric's Initial Brief, pp. 71-72, addressed and refuted these recommendations, and the Company relies on and incorporates those arguments here — including that the 300 MW ZRC transfer is a voluntary, negotiated Customer obligation the Commission cannot unilaterally extend, and that the recommendation rests on two unverified assumptions: that ZRCs will be available beyond May 31, 2033, and that the Customer is willing to provide them. (Foley, 3T 163). The Company responds below to the additional points developed in the ABATE’s and MEICEO’s Initial Briefs below.

First, ABATE’s and MEICEO’s underlying concern — that the expiration of the Customer's ZRC transfer and Rider 12 DR commitment will leave the Company short of capacity in 2033 — is, by MEICEO’s own characterization, a resource-planning question for the Company's 2026 IRP, not a basis to rewrite the CCAA's negotiated end date in this proceeding. MEICEO concedes that “the IRP is the correct place to identify and select specific resources.” MEICEO Initial Brief, p. 39. The nature of the 2033 capacity need, which resources should fill it, and how related costs and risks compare to alternatives are precisely the questions the IRP will resolve on a developed, system-wide record.

Second, the 677 MW “perfect capacity” figure the intervenors invoke does not establish a cost shift to other customers, because it is a system reliability metric used in the Company’s modeling in this proceeding, which the Company has not attributed to the Customer. The 677 MW of "perfect capacity" is the amount of outage-free capacity that Company Witness Brooks' SERVM analysis identified as necessary to restore the Company's system to a 0.1 loss-of-load-expectation standard in 2033. (Brooks, 3T 439-440; Exhibit A-4). In the context of Company Witness Brooks' SERVM analysis, the 677 MW figure is a measure of the total system's reliability requirement for modeling purposes, not a quantity of resources attributed to or caused solely by the Customer's load. As Company Witness Burgdorf testified, while "the expiration of the ZRC contract and demand response are factored into the 2033 analysis, they do not define the 2033 system reliability requirements," which are "set by the combination of all load and resource changes on the system." (Burgdorf, 3T 399; Exhibit MEICEO-13). The Company has not isolated the extent to which the 2033 reliability need is attributable to the expiration of the ZRC and DR commitments as opposed to other system factors — including native load growth, supply-side resource changes, and the availability of non-firm energy from MISO — explaining that such an inquiry belongs in the holistic, system-wide analysis of the upcoming IRP. (Burgdorf, 3T 399). That the 677 MW "perfect capacity" system need is not specifically associated with or assigned to the CCAA is therefore the Company's own position, consistent with its treatment of resources generally: the Company "does not assign any specific resource to the Customer," and the with-and-without IRP comparison identifies resources associated with the Customer's load "only in the aggregate." (Foley, 3T 244-246).

Third, and relatedly, the 677 MW "perfect capacity" figure does not represent a cost silently shifted to other customers. It is *distinct* from the 727 MW proxy CCGT with CCS that Company Witness Burgdorf modeled to represent, and to place a cost on, that reliability need in the customer benefit analysis. (Burgdorf, 3T 375). The 727 MW proxy is "a placeholder representing potential future 'perfect capacity' (as defined by Witness Brooks) . . . rather than a determination that the Company will construct or acquire a specific CCGT resource." (Exhibit MEC-44). In the benefit analysis, the Company counted the full revenue requirement of that proxy as a cost in the Customer Datacenter Case. (Burgdorf, 3T 375; Willis, 3T 410; Exhibit A-19). The approximately $1.7 billion projected benefit therefore was not calculated by ignoring the cost of meeting the modeled reliability need. It is the net result after the proxy's full modeled revenue requirement is included as a cost. That treatment does not establish how the costs of any actual resource will be allocated or recovered; it demonstrates only that the customer benefit analysis includes a modeled cost for the identified reliability need.

The treatment of any actual resource(s) selected through the Company's upcoming IRP is a separate matter. The IRP's with-and-without modeling comparison will identify any resources caused by the serving the Customer's incremental load, but it will not assign any individual resource exclusively to the Customer or determine how the resource's revenue requirement will be allocated or recovered. DTE Electric Initial Brief, pp. 36-37; (Foley, 3T 143-144, 244-246). Instead, the revenue requirement of resources identified through that IRP analysis as caused by serving the Customer's incremental load, and not recovered through the CCAA, will be included among the aggregate costs evaluated under Section 5.1.3 of the PSA. (Foley, 3T 143-144). Cost allocation and recovery will be determined in applicable general rate cases on the records developed there.

If the Commission determines that the aggregate costs of serving the Customer exceed Customer-derived aggregate benefits, the Affordability Backstop requires the Customer to comply with the Commission's ruling or order addressing that shortfall. The Affordability Backstop therefore protects other customers without predetermining the resource selection reserved for the

IRP or cost-allocation and rate recovery decisions reserved for future general rate cases. Neither the modeled 677 MW "perfect capacity" need nor the 727 MW proxy used to assign a cost to that need supports compelling the Customer to extend its ZRC transfer beyond the negotiated term. The customer benefit analysis already includes a modeled cost for the reliability need; the IRP will determine the actual resource portfolio; future rate cases will determine the appropriate allocation and recovery of actual resource costs; and the Affordability Backstop will address any Commission-determined aggregate shortfall.

Fourth, ABATE witness Dauphinais' observation that Section 2 of the PSA "will [not] provide any protection" for the modeled 677 MW "perfect capacity" need — because it "is not associated with the CCAA or any agreement between DTE and Google" — does not support requiring the Customer to extend its ZRC transfer. ABATE Initial Brief, pp. 10-11; (Dauphinais, 3T 526). The premise may be correct, but the conclusion does not follow. Namely, Section 2 of the PSA protects other customers by allowing the Company to adjust the Customer's own load ramp or maximum load when the contracted resources to serve that load are unavailable; it is not, and was never designed to be, the mechanism for meeting a system-wide capacity requirement. Its inapplicability to a 2033 system reliability need that the Company has not attributed to the Customer is therefore unremarkable, not a gap — it confirms only that a system reliability requirement is planned for and met through the Company's IRP, as every other component of system resource adequacy is.

Fifth, MEICEO's contention that the Special Contracts improperly "foreclose" lower-cost or lower-risk alternatives — and thereby make a future fossil-fuel buildout "more likely" — is incorrect. MEICEO Initial Brief, p. 39; (Hotaling, 3T 716-717). Nothing in the Special Contracts forecloses the Company from pursuing any resource, including a negotiated extension of the

Customer's ZRC transfer, to meet a 2033 need identified in the IRP. The Special Contracts simply do not compel the Customer, as a condition of approval today, to provide ZRCs beyond the term it agreed to. If the Customer is willing to extend the transfer, nothing prevents the parties from negotiating that extension; the CCAA's negotiated end date does not bar a future agreement. As presented in this proceeding, the CCGT with CCS is strictly a proxy used for modeling to quantify the customer benefit and to represent the 2033 reliability need, not a resource the Company is committed to build. (Burgdorf, 3T 375, 394). The actual 2033 resource selection will be made in the IRP. *Id*. MEICEO's concern — that allowing the ZRC transfer to expire in 2033 will leave a capacity need the Company fills by building new fossil-fuel generation rather than lower-cost or lower-emission alternatives — is therefore a matter for the IRP's resource selection, not a reason to impermissibly rewrite the CCAA.

Sixth, to the extent MEICEO offers, as a fallback, that the Commission direct the Company to perform an IRP modeling run evaluating whether incremental resources are needed above an extended ZRC and DR commitment (MEICEO Initial Brief, p. 39; Hotaling, 3T 715), that recommendation is both misdirected and unnecessary. The modeling scenarios and assumptions a utility must include in its IRP are established by the Commission under MCL 460.6t(1)(f), through a dedicated proceeding that provides for public comment and hearings — the process that produced the currently effective IRP Filing Requirements and Michigan Integrated Resource Planning Parameters in Case No. U-21867. A special contract proceeding is not the proper vehicle for parties to advocate for the Commission to prescribe modified IRP modeling scenarios such as this proposal. That is especially so here, where the scenario MEICEO would have the Company model is premised on an extension of the Customer's ZRC obligation that, as explained above, the Commission lacks authority to compel. In all events, the directive is unnecessary: the Company's

2026 IRP will holistically evaluate resource adequacy and identify the least-cost, reliable means of serving customers on a system-wide basis, including any 2033 capacity need. (Burgdorf, 3T 399).

Finally, to the extent ABATE and MEICEO ask the Commission to modify the CCAA to compel an extension of the Customer's ZRC transfer, they seek relief the Commission cannot lawfully grant. As set forth in Section III, the Commission lacks statutory authority to rewrite the contracting parties' negotiated agreement and compel the Customer to provide capacity for years it did not agree to. *Union Carbide*, at 148-149. Any extension of the Customer's ZRC obligation, if it occurs, must be a matter of negotiation between the Company and the Customer, informed by the resource needs the IRP identifies — not a term the Commission imposes in this proceeding.

- *The ZRC Transfer and Financial Adder Should Be Approved as Filed*

In conclusion, the 300 MW ZRC transfer provides capacity to the Company at no cost — a direct benefit to other customers — and the financial adder is a negotiated CCAA term the Customer agreed to pay over and above the full cost of service. Staff and the intervenors identify no cost to other customers from the requested accounting treatment and no statute or precedent barring it; their position would deny the Company the benefit of a negotiated term while leaving it to bear the risks of serving the Customer. And MEICEO's recommendation to meet a portion of the ZRC obligation through Company-administered programs would imprudently and unlawfully replace a defined, no-cost, firm capacity transfer with contingent utility programs the CCAA does not contemplate, introducing cost, administrative burden, reliability risk, and timing uncertainty. Accordingly, the Commission should approve the ZRC transfer and the requested non-refundable-income treatment for the financial adder as filed, subject to the non-precedent condition the Company has accepted, and should decline MEICEO's recommendation to direct the Company to meet any portion of the ZRC obligation through Company-administered programs. DTE Electric Initial Brief, pp. 72-73.

5. System Benefits and Reduction in RECs Needed in the Forecast

DTE Electric's Initial Brief, pp. 73-75, explained that the Customer's enrollment of 1,600 MW of load in the VGP Special Contract provides system benefits by reducing the amount of the Customer's load included in the Company's RPS requirement and, correspondingly, reducing the incremental renewable resources the Company otherwise would need to acquire for RPS compliance. The Company's analysis projected that the Customer's VGP enrollment, together with the forecasted REC balance, would allow the Company to reduce its compliance-side renewable additions by 200 MW in 2033 and 50 MW in 2034 while maintaining a positive REC balance and meeting its RPS obligations. The Company further explained that the Customer will fully fund the renewable resources developed under the VGP Special Contract while continuing to contribute through the PSCR to renewable-resource costs incurred for the broader system. (Bilyeu, 3T 279-284).

DTE Electric's Initial Brief, pp. 74-80, also addressed the principal challenges raised in Staff and intervenor testimony and relies on those arguments here rather than repeating them. Specifically, the Company explained that: (1) its RPS-compliance analysis appropriately maintained the assumptions used in Case No. U-21662 to provide an apples-to-apples comparison of the incremental effects of the Customer's load and VGP enrollment, and any updated assumptions will be addressed comprehensively in the forthcoming IRP and Amended REP (Bilyeu, 3T 302-304); (2) GLREA's requested warning concerning future RPS compliance is unwarranted because the Customer-funded renewable portfolio will contribute substantially to the Company's renewable portfolio, and the forthcoming IRP and Amended REP will evaluate the effects of large-load customers and identify any additional resources needed to maintain compliance (Bilyeu, 3T 314); and (3) Staff's legitimate concern about double counting does not require DTE Electric itself to retire every REC associated with VGP sales because appropriate REC ownership, transfer, tracking, verification, and reporting ensure that RECs associated with the Customer's VGP participation are not also used by the Company for RPS compliance. (Bilyeu, 3T 290-296, 302-304, 314).

Staff and intervenor Initial Briefs largely repeat those positions. MNS, however, develops additional arguments concerning whether the projected 250 MW reduction in compliance-side renewable additions is attributable to the Customer's VGP enrollment, the role of renewable resources assumed for another large-load customer in the Company's forecasted REC balance, and the use of banked RECs to satisfy the RPS requirement associated with the Customer's non-VGP load. MNS Initial Brief, pp. 7-13. Staff further develops its REC-retirement argument by invoking the separate treatment of VGP load under the REP and Clean Energy Plan compliance calculations and the Commission's December 18, 2025 order in Case No. U-21867. Staff Initial Brief, pp. 33-37. Those additional arguments are addressed below.

- *The Customer's VGP Enrollment Reduces the Increase in the Company's RPS Requirement*

First, MNS' arguments do not negate the reduction in the Company's RPS requirement produced by the Customer's VGP enrollment. MNS emphasizes that 60% of the Customer's load will remain outside the VGP Special Contract and therefore will increase the Company's RPS requirement. MNS Initial Brief, pp. 8-11. MNS further argues that the 1,600 MW VGP portfolio does not supply RECs the Company can use to satisfy the RPS obligation associated with that non-VGP load and therefore only reduces—rather than eliminates—the increase in RECs caused by the Customer's total load. *Id.*; *see also* (Bilyeu, 3T 279, 283, 336). That argument does not contradict the Company's analysis. The Company has not claimed that the Customer's VGP enrollment eliminates every incremental REC associated with the Customer's entire load or provides the Company with RECs that may also be used for non-VGP RPS compliance. Rather, the claimed benefit is that removing 1,600 MW of enrolled VGP sales from the retail-sales component of the RPS calculation reduces the increase in the Company's RPS requirement that otherwise would result if the Customer's entire load were treated as non-VGP sales. (Bilyeu, 3T 279-284). MNS' acknowledgment that the VGP enrollment "only reduces the increase" in the number of RECs the Company needs confirms the existence of the benefit; MNS disputes its size and characterization, not the underlying reduction in the Company's RPS requirement. MNS Initial Brief, p. 8 and n. 35; (Bilyeu, 3T 333).

MNS' argument also improperly treats two different propositions as though they were inconsistent. The Customer's non-VGP load increases the Company's RPS requirement, while the Customer's 1,600 MW VGP enrollment reduces that increase relative to the requirement that would apply if none of the Customer's load were enrolled in VGP. Both may be true. The relevant comparison for identifying the VGP benefit is not whether the Customer's total load produces no incremental RPS obligation, but whether the Company's RPS requirement is lower with the Customer's 1,600 MW VGP enrollment than it would be without that enrollment. The record establishes that it is. (Bilyeu, 3T 279-284).

- *Other Resources in the Forecast Do Not Eliminate the Incremental Effect of VGP Enrollment*

Second, MNS' discussion of the forecasted REC surplus does not establish that the 250 MW reduction is unrelated to the Customer's VGP enrollment. MNS argues that the projected REC surplus reflected in the Company's analysis is attributable principally to renewable resources assumed for Oracle rather than to the Special Contracts at issue here. MNS contends that the annual REC balances in the scenarios it compares already incorporate the Customer's VGP enrollment and that the renewable resources assumed for Oracle—not the Google CCAA—produce the REC surplus that permits the forecasted 200 MW reduction in 2033 and 50 MW reduction in 2034. MNS Initial Brief, pp. 9-11.

MNS' argument conflates the source of the Company's projected REC balance with the incremental effect of the Customer's VGP enrollment on the Company's RPS requirement. The forecast necessarily reflects the Company's broader load and resource assumptions, including other large-load customers and associated renewable builds. But those background assumptions do not eliminate the effect of subtracting the Customer's enrolled VGP sales from the RPS calculation. The Company maintained the assumptions from Case No. U-21662 and other then-current planning information to permit an apples-to-apples comparison of the incremental effects associated with this Customer. (Bilyeu, 3T 302-304). Within that common planning baseline, the Customer's VGP enrollment reduces the RPS requirement, and the resulting compliance analysis showed that the Company could reduce compliance-side renewable additions by 200 MW in 2033 and 50 MW in 2034 while retaining a positive REC balance. Exhibit MEC-22; DTE Electric Initial Brief, pp. 73-75.

The fact that other resources contribute to the projected REC balance does not mean the reduction in the Company's RPS requirement produced by the Customer's VGP enrollment has no value. Nor does it establish that the Company would project the same compliance-side renewable additions if the Customer's 1,600 MW VGP enrollment were removed while all other assumptions remained constant. MNS' argument therefore does not negate the system benefit identified by the Company; at most, it challenges the attribution and magnitude of the associated avoided-cost component in the current customer-benefit estimate. That valuation issue is addressed in Section VI, while this section addresses the distinct regulatory effect of the VGP enrollment on the Company's RPS requirement.

- *Use of the Company's REC Balance Does Not Establish a Customer Subsidy*

Third, the use of the Company's REC balance does not establish that other customers subsidize the Customer. MNS argues that the Company could satisfy part of the RPS obligation associated with the Customer's non-VGP load using banked RECs acquired before the Customer began paying PSCR charges. From that premise, MNS asserts that the Company fails to account for a cost borne by other customers and overstates the system benefit produced by the Special Contracts. MNS Initial Brief, pp. 11-13. MNS separately points to the historical decline in the Company's REC balance and argues that the addition of large-load customers may accelerate that decline.

The existence and use of a REC balance is part of the Company's ongoing, system-wide RPS-compliance planning; it does not establish that any particular banked REC is assigned to the Customer or that the Special Contracts shift a Customer-caused cost to other customers. The Company's RPS analysis evaluates compliance over the planning horizon using the applicable load, VGP-sales, resource, REC-purchase, and REC-balance assumptions. The Customer's non-VGP sales are included in that analysis, while the Customer continues to contribute through PSCR charges toward the Company's renewable resource and power supply costs. DTE Electric Initial Brief, pp. 73-75; (Bilyeu, 3T 283-284).

Moreover, MNS' argument again concerns the magnitude of the projected benefit, not whether the VGP enrollment reduces the Company's RPS requirement. If future compliance planning identifies additional renewable or REC costs caused by serving the Customer, those costs are included in the aggregate costs of serving the Customer under the Affordability Backstop.

(Foley, 3T 143-144). The Commission will therefore evaluate actual costs and benefits in the applicable contested proceedings as the relevant costs, revenues, and avoided costs become known. Nothing in MNS's banked-REC argument supports rejecting or modifying the Special Contracts.

- *GLREA Identifies No Present RPS Compliance Failure Requiring a Warning*

GLREA's renewed concern about the pace of renewable development does not warrant a Commission warning in this proceeding. GLREA continues to request a warning that increased data-center load may make RPS compliance more difficult because of practical limits on the amount of renewable generation the Company can develop and interconnect in a given year. GLREA Initial Brief, pp. 9-10. GLREA points to the renewable development pace discussed in the Company's prior IRP and compares that pace with the additional renewable resources associated with large-load customers.

GLREA's Initial Brief does not materially alter the recommendation the Company already addressed. As explained in DTE Electric's Initial Brief, the Customer will fully fund up to 1,600 MW of renewable resources under the VGP Special Contract, and the Company's forthcoming IRP and Amended REP will evaluate RPS compliance, the effects of large-load customers, development constraints, and any additional resources required to maintain compliance. DTE Electric Initial Brief, pp. 75-76; (Bilyeu, 3T 314). The Company remains committed to satisfying its statutory RPS obligations, and GLREA identifies no present compliance failure requiring a warning in this Special Contract proceeding. (Bilyeu, 3T 314).

One clarification is appropriate. The Customer-funded VGP resources support the Company's overall renewable resource development, but the associated RECs will not also be used by the Company to satisfy its RPS obligation for non-VGP retail sales. The Company's position is not dependent on double counting those attributes; it depends on the reduction in the RPS requirement produced by excluding properly enrolled VGP sales and on the Company's future planning through the IRP and Amended REP. (Bilyeu, 3T 290-296). Thus, GLREA's observation that the Customer receives the renewable attributes associated with the VGP resources does not undermine the Company's RPS-compliance position.

- *REC Transfer and Tracking Prevent Double Counting Without Mandatory Utility Retirement*

Staff's Initial Brief provides no basis to require exclusive utility retirement of the VGP RECs. Staff's Initial Brief continues to argue that the associated RECs must be retired before VGP sales may be removed from the RPS compliance calculation. Staff contends that transferring the renewable attribute to the Customer separates that attribute from the underlying generation and produces a mismatch between the VGP load removed from the RPS calculation and the RECs retired. Staff further argues that the Commission's order in Case No. U-18349 requires RECs to be "properly assigned and retired." Staff Initial Brief, pp. 33-36.

Those arguments were addressed comprehensively in DTE Electric's Initial Brief, pp. 76-80, and Staff's Initial Brief supplies no new record evidence warranting repetition of that response.

- *The Commission-Approved Clean Energy Plan Template Separately Accounts for VGP Energy and RECs, and Any Implementation Issues Belong in the CEP Proceeding*

Staff's Initial Brief raises a specific question concerning alignment of the Company's REP and Clean Energy Plan ("CEP") compliance calculations. Staff observes that properly enrolled VGP sales are removed from the RPS retail-sales calculation, while Staff contends that the CEP calculation does not remove VGP sales in the same manner. Staff further states that the Company plans to use renewable generation associated with the VGP Special Contract resources toward CEP compliance and argues that the Commission has not approved an alternative to REC retirement for aligning the two calculations. Staff therefore asks the Commission to reaffirm, based on the

December 18, 2025 order in Case No. U-21867, that one REC must be retired to demonstrate one megawatt-hour of clean-energy compliance. Staff Initial Brief, pp. 36-37.

Staff's concern emphasizes that the same renewable attribute cannot be used twice. The Company does not contend otherwise. Company Witness Bilyeu explained that the RECs associated with the Customer's VGP participation will be subject to appropriate tracking and verification and will not also be used by DTE Electric for RPS compliance in a manner that produces double counting. He further explained that preventing double counting does not invariably require DTE Electric to own and retire every REC. Depending on the Customer's election under the VGP Special Contract, the associated RECs may be retired by the Company on the Customer's behalf or transferred to the Customer, provided that the same renewable attributes are not also used by DTE Electric for its own compliance claim. (Bilyeu, 3T 295-296).

The proposition that retirement of one REC may demonstrate one megawatt-hour of clean-energy compliance therefore does not establish that DTE Electric must own and retire every REC associated with a VGP customer. Transfer of a REC to the Customer does not itself produce double counting. The relevant protection is that DTE Electric may not also use the transferred REC, or the same associated renewable attribute, to support the Company's own statutory compliance claim. (Bilyeu, 3T 295-296). Staff's cited principle concerns the evidentiary use of a REC when DTE Electric relies on that REC to demonstrate compliance; it does not, on this record, eliminate the REC-disposition flexibility negotiated in the VGP Special Contract.

The MIRECS tracking system provides the practical means of enforcing that distinction. RECs are tracked by their source and disposition, including whether they remain in an account, are transferred to another account holder, or are retired. The transfer of a REC associated with a VGP resource therefore does not occur outside the tracking system or leave DTE Electric free to acquire and use the same renewable attribute without detection. Once the REC is transferred to the Customer, the transfer and subsequent disposition remain traceable through MIRECS, ensuring that DTE Electric could not later acquire or use the same REC for its own compliance claim without that transaction being identifiable in the tracking record. That tracking function directly addresses Staff's concern that the Company could later acquire or use the associated RECs without the transaction being known or reflected in the compliance record.

The ability to trace a REC's generation source and disposition also permits the Company and the Commission to distinguish among: (1) renewable energy generated by the VGP Special Contract resources; (2) the associated RECs transferred to or retired for the Customer; and (3) RECs retained or acquired by DTE Electric and actually available to support the Company's statutory compliance. Staff's double-counting concern therefore does not require mandatory retirement by DTE Electric. It requires accurate tracking and a compliance presentation that does not claim an attribute already transferred to the Customer, which is the protection Company Witness Bilyeu described. (Bilyeu, 3T 295-296).

Staff's double-counting theory should not be extended to treat every subsequent use or transfer of a REC as a second use of the same attribute. The relevant inquiry is whether the same renewable attribute is claimed more than once for the same compliance or environmental purpose. Transfer of a REC through MIRECS preserves, rather than obscures, the chain of title and disposition. The tracking record identifies the generating source, transfer history, current account holder, and ultimate retirement of the REC. Thus, a later transfer or retirement by the Customer does not occur outside the tracking system, and it does not permit DTE Electric to claim that the same REC remained available for the Company's compliance use. (Bilyeu, 3T 295-296).

Staff's proposed immediate-retirement condition would also eliminate a substantive contractual right, not merely establish an accounting safeguard. The VGP Special Contract permits the Customer to receive and control the associated RECs, subject to the requirement that DTE Electric not use the same attributes for its own compliance claim. Requiring immediate retirement would prevent the Customer from holding, transferring, or retiring the RECs in accordance with its own renewable-energy accounting needs. Staff identifies no statutory provision requiring immediate utility-directed retirement whenever VGP sales are excluded from the RPS calculation. DTE Electric Initial Brief, pp 77-78. The Commission should not eliminate that negotiated flexibility where MIRECS provides a traceable record of the generation source and subsequent disposition and the Company disclaims any concurrent use of the transferred attribute.

Staff's argument also does not account for the full CEP reporting framework the Commission approved in Case No. U-21867. The Commission-approved CEP template separately identifies VGP as an energy type measured in megawatt-hours and includes separate lines addressing purchased RECs and RECs reported under MCL 460.1029(4). Case No. U-21867 Order dated December 18, 2025, pp. 48-50 and Appendix A. The approved template thus distinguishes the reporting of VGP energy from the separate accounting of RECs. Staff's reliance on the principle that one retired REC may demonstrate one megawatt-hour of clean-energy compliance does not establish that mandatory retirement by DTE Electric is the exclusive means of reporting VGP energy or preventing duplicate use of the associated renewable attributes.

Staff's Initial Brief nevertheless identifies an implementation issue for the Company's future CEP filing: how the VGP megawatt-hours, disposition of the associated RECs, and resources and attributes supporting the Company's clean energy compliance claim should be displayed under the Commission-approved template. Staff Initial Brief, pp. 36-37. That implementation issue does not require resolution through a condition rewriting the VGP Special Contract. The approved template already provides separate reporting for VGP energy and REC accounting, and future CEP proceedings will permit the Commission to review the Company's application of that framework to the actual generation, sales, and attribute data then available. MIRECS tracking will allow the Company and the Commission to verify the generation source and disposition of the associated RECs when that compliance presentation is reviewed.

The Company does not ask the Commission in this proceeding to approve the use of a REC transferred to the Customer as support for DTE Electric's own CEP compliance. Nor does approval of the CCAA determine that renewable generation whose attributes have been transferred to the Customer may simultaneously be counted by the Company without an appropriate adjustment or other compliance treatment. The Company likewise does not contend that the same REC or renewable attribute may support both the Customer's renewable energy claim and DTE Electric's statutory compliance claim. Rather, the Commission-approved template, together with MIRECS tracking and verification, permits the VGP megawatt-hours and disposition of the associated RECs to be separately identified without requiring DTE Electric to own and retire every REC associated with a VGP Special Contract. (Bilyeu, 3T 295-296).

The Company's future CEP proceeding is the proper forum to apply the approved reporting framework. That proceeding will permit the Commission to verify the VGP megawatt-hours reported under the template, the MIRECS records showing the generation source and disposition of the associated RECs, the generation and attributes on which the Company relies, and the statutory requirements governing the compliance showing. This Special Contract proceeding does not contain the complete future compliance calculation or the actual generation and attribute data needed to apply the template. It should not be used to prescribe Customer-specific CEP treatment before that information is presented.

Staff identifies no basis in this special contract proceeding to eliminate the Customer's negotiated REC-ownership flexibility preemptively. The Commission-approved CEP template separately identifies VGP generation in megawatt-hours and provides separate REC-accounting lines, while the record establishes that tracking and verification can prevent duplicate use of transferred renewable attributes. Case No. U-21867 Order dated December 18, 2025, pp. 48-50 and Appendix A; (Bilyeu, 3T 295-296). MIRECS supplies the traceable record of the RECs' generation source, transfer, and disposition necessary to verify that the same renewable attribute is not claimed twice. Staff's concern regarding alignment of the REP and CEP calculations therefore does not establish that mandatory retirement by DTE Electric is the only permissible means of preventing duplicate use of renewable attributes.

The Commission should therefore reject Staff's mandatory-utility-retirement condition and preserve the Customer's negotiated REC-disposition flexibility. The future CEP proceeding will provide the appropriate forum for the Commission to review the reported VGP megawatt-hours, the MIRECS records reflecting disposition of the associated RECs, and the resources and attributes used to support DTE Electric's statutory compliance showing. That approach preserves the Customer's contractual rights while ensuring that a REC or renewable attribute transferred to the Customer is not also used by DTE Electric for its own compliance claim.

- *Positions with Respect to the Customer's Renewable Energy Characterization Do Not Affect Approval of the Special Contracts*

MEICEO and MNS address the Company's position that the Customer's 1,600 MW VGP commitment, which is sized to support the 40% of the Customer's load enrolled in the VGP Special Contract, together with the renewable share of DTE Electric's system portfolio as the Company progresses toward the 60% RPS requirement in 2035, would support the Customer's ability to claim 100% renewable energy for the Facility on an annual-matching basis by 2035. (Bilyeu, 3T 279-280). MEICEO's Initial Brief ultimately identifies that position as one that "appear[s] supported by evidence." MEICEO Initial Brief, pp. 2-3. MNS reaches the opposite conclusion, adopting MEICEO witness Shaver's earlier criticism and asking the Commission not to endorse the characterization. MNS Initial Brief, pp. 24-25; (Shaver, 3T 739-746).

Notably, this difference of opinion does not present an issue the Commission must resolve to approve the Special Contracts. As Company Witness Bilyeu explained in rebuttal, his testimony does not ask the Commission to adjudicate the Customer's voluntary sustainability claims or determine the particular form of renewable energy reporting the Customer may use. Rather, the relevant regulatory facts are that the Customer elected to support renewable resources through a VGP Special Contract for 40% of its load and that the associated renewable attributes will be tracked through RECs consistent with the applicable VGP framework. (Bilyeu, 3T 313-314). MEICEO witness Shaver's analysis addresses a different question: the distinction between traditional annual REC-based matching and hourly or physical matching. (Shaver, 3T 739-746). That distinction matters. The Special Contracts do not guarantee that renewable generation will physically supply the Facility during every hour of its operation, and the Company does not seek a Commission finding to that effect. The renewable component of the CCAA instead operates through a customer-requested VGP Special Contract under which the Company may deploy up to 1,600 MW of renewable resources, the Customer pays the associated costs, and the renewable resources are treated as customer-requested VGP resources for RPS purposes. DTE Electric Initial Brief, pp. 52-59; (Foley, 3T 110-111; Bilyeu, 3T 279-296).

MNS instead calculates a 76% renewable energy share by adding the 40% of the Customer’s load enrolled in the VGP Special Contract to 36% of the Customer’s total load, the latter figure representing application of the 60% RPS requirement to the 60% of the Customer’s load that is not enrolled in VGP. MNS Initial Brief, pp. 24-25; (Shaver, 3T 739-742). MNS’ contrary percentage calculation, however, does not rebut the reasonableness of the VGP Special Contract or the system benefits addressed in this section. Regardless of how the Customer characterizes its broader sustainability objective, the Customer’s VGP enrollment reduces the increase in the Company’s RPS requirement relative to the requirement that would apply if the Customer’s entire load were treated as non-VGP sales. The Customer will fund the renewable resources to support its VGP participation while continuing to contribute through the PSCR to the Company’s existing and future renewable-resource costs. DTE Electric Initial Brief, pp. 73-75; (Bilyeu, 3T 279-284, 333, 346).

MNS does not identify any requested approval that depends upon the Commission accepting the disputed terminology. Approval of the Special Contracts does not constitute Commission certification of the Customer’s voluntary sustainability reporting. It approves the contractual obligations actually presented, including the Customer’s VGP enrollment, its responsibility for the costs of the CCAA renewable projects, the treatment and tracking of the associated renewable attributes, and the resulting treatment of properly enrolled VGP sales under the applicable regulatory framework. MNS’ request that the Commission reject the annual renewable energy characterization therefore provides no basis to reject, condition, or modify the Special Contracts.

The Commission should resolve the issue no more broadly than necessary. It may approve the Special Contracts based on their actual terms and regulatory consequences without adjudicating the Customer's voluntary sustainability claim, adopting MNS' competing percentage calculation, or determining whether annual REC-based matching and hourly physical matching should be described in identical terms. MEICEO's Initial Brief confirms that the Company's annual-matching position is supported by record evidence, while Company Witness Bilyeu's rebuttal confirms that the Commission need not decide the Customer's reporting methodology to determine that the VGP Special Contract is reasonable. MEICEO Initial Brief, pp. 2-3; (Bilyeu, 3T 313-314).

- *The VGP System Benefits Should Be Recognized Without Rewriting REC Ownership*

In sum, the Customer's VGP enrollment does not eliminate every increment of the Company's RPS requirement associated with the Customer's total load, and the Company has never claimed otherwise. It does, however, reduce the increase in that requirement relative to treating the Customer's entire load as non-VGP sales. The parties' disputes concerning the precise valuation of the projected 250 MW reduction, the contribution of other resources to the forecasted REC balance, and the use of banked RECs concern the magnitude of the projected benefit and future compliance planning; do not negate the statutory and analytical effect of the Customer's VGP enrollment. The Company's forthcoming IRP and Amended REP will update the relevant resource and REC assumptions, and the Affordability Backstop will capture costs determined to be caused by serving the Customer.

Likewise, Staff's anti-double-counting objective is fully addressed through appropriate REC ownership, tracking, verification, and reporting. Neither Staff's reliance on Case No. U-18349 nor its CEP alignment argument establishes that DTE Electric must itself own and retire every REC associated with the Customer's VGP participation. The Commission should recognize the system benefits produced by the Customer's VGP enrollment, decline GLREA's requested warning, and reject Staff's proposed mandatory-utility-retirement condition.

6. Procurement and Deployment of CCAA Resources

DTE Electric's Initial Brief, pp. 80-86, demonstrated that the CCAA's procurement and deployment provisions are reasonable, prudent, and in the public interest. Three parties challenge those provisions: MNS witness Woods argues the "up to" quantities should be converted to mandatory floors and that the Commission should impose feasibility-study and related conditions; MEICEO witness Hotaling argues the deployment caps should be raised or removed; and Staff witness Simpson argues the Company should prioritize IRP/REP resources over CCAA resources in procurement. MNS Initial Brief, pp. 22-28; MEICEO Initial Brief, pp. 31-33; Staff Initial Brief, pp. 27-30. Each challenge should be rejected.

DTE Electric's Initial Brief, pp. 80-86, preemptively addressed and refuted the core of each challenge, and the Company relies on and incorporates those arguments here rather than repeating them — including that the Company "intends to deploy the full 1,600 MW of renewable energy projects" and "at least 450 MW and up to 480 MW of energy storage," so MNS' "floors" condition is unnecessary (Foley, 3T 158); that the "up to" contractual language reflects the commercial reality that projects are developed in discrete sizes subject to procurement, permitting, and interconnection, and should not be converted into a requirement that forces default or the acceptance of resources outside the negotiated framework (Foley, 3T 159); that MEICEO's proposal to raise or remove the caps misconstrues the CCAA (which deploys up to a nameplate capacity and is not designed to match one customer's needs) and would impose commercially unreasonable uncapped liabilities (Foley, 3T 160); and that Staff's procurement-priority condition is unnecessary because the CCAA's full-cost-recovery and market-revenue-cap mechanics, together with the Commission-approved VGP procurement framework, already prevent subsidization (Bilyeu, 3T 296-298). The Company replies further below to address the parties' Initial Briefs.

- *The CCAA's Negotiated "Up To" Quantities Should Not Be Converted into Mandatory Floors*

MNS request that the Commission require the Company to deploy the full renewable and storage amounts as a mandatory minimum — and its argument that under-deployment would deplete the Company's REC bank — does not warrant conditioning approval. MNS asks the Commission to condition approval of the Special Contracts on a requirement that the Company deploy, and the Customer pay for, the full 1,600 MW of renewable energy and at least 450 MW of energy storage, treating those figures as binding minimums the Company must meet rather than maximums it may not exceed. MNS Initial Brief, pp. 22-23; (Woods, 3T 621, 633-635). As the Company's Initial Brief explained, the Company intends to deploy the full 1,600 MW of renewable energy and at least 450 MW (up to 480 MW) of energy storage, and other customers are protected regardless of the amount deployed because the Affordability Backstop remains in effect and Section 2.4 of the PSA provides a mechanism to address any shortfall in deployment. DTE Electric Initial Brief, pp. 80-82; (Foley, 3T 158-159). The "up to" term set forth in the CCAA is not a device to under-deliver; it reflects the commercial reality that renewable and storage projects are developed in discrete sizes subject to procurement, permitting, and interconnection, such that the portfolio may not configure to exactly 1,600 MW or 480 MW. (Foley, 3T 159).

- *MNS' Proposed Floor Cannot Be Reconciled with the Contractual Maximum*

MNS' Initial Brief indicates that its proposed condition *would not* require the Customer to accept more renewable capacity than the CCAA's 1,600 MW maximum because the Customer would remain responsible only for resources within that limit. MNS Initial Brief, p. 23. But that response does not solve the problem created by MNS' own proposal. If competitively selected projects cannot be configured to total exactly 1,600 MW, a condition requiring deployment of at least 1,600 MW cannot simultaneously preserve 1,600 MW as the maximum amount for which the Customer is responsible. The Company would either have to reject an otherwise reasonable portfolio below the exact target, procure capacity above the contractual maximum without a corresponding Customer payment obligation, or fail a Commission-imposed minimum despite complying with the negotiated CCAA. The contractual "up to" formulation avoids those commercially unreasonable outcomes while preserving the Company's stated intent to deploy the full 1,600 MW. (Foley, 3T 158-159).

- *MNS' Hypothetical REC Consequences Do Not Justify a Mandatory Deployment Condition*

MNS' Initial Brief further argues that, if the Company deploys less than the full 1,600 MW of renewable energy contemplated by the CCAA, the Company would need to retire additional RECs or acquire additional renewable resources outside the CCAA to maintain RPS compliance, potentially reducing the Company's existing REC balance and imposing costs on customers other than the Customer. MNS Initial Brief, pp. 22-23; (Woods, 3T 633-635). That asserted consequence does not justify converting the CCAA's negotiated 1,600 MW maximum into a mandatory minimum, for two primary reasons.

First, it rests on a hypothetical the record does not support. It assumes the Company will deploy less than the full 1,600 MW of renewable energy under the VGP Special Contract, but the Company has testified that it intends to deploy the full amount. (Foley, 3T 158). MNS identifies no record evidence that the Company will fall short; it infers under-deployment solely from the "up to" language, which — as explained above — reflects ordinary project-sizing variability, not an intention to deploy less.

Second, even if a shortfall in VGP Special Contract renewable deployment were to occur, the concern MNS identifies — that other customers would bear incremental REC or renewable-energy costs caused by the Customer's load — is a concern the Affordability Backstop is designed to capture. Any incremental renewable or REC cost attributable to serving the Customer that is not covered by the CCAA is included in the aggregate cost-and-benefit assessment under Section 5.1.3, and if the Commission determines that the costs of serving the Customer exceed the combined revenues, the Customer bears the difference. DTE Electric Initial Brief, pp. 74, 82; (Bilyeu, 3T 284; Foley, 3T 143-144). MNS' REC-bank concern therefore does not establish that any cost would be shifted to other customers, and it provides no basis to convert the negotiated "up to" quantities into a mandatory minimum — relief that, as set forth in Section III, the Commission lacks authority to impose over the parties' negotiated agreement. *Union Carbide*, at 148-149.

- *MNS' Feasibility Recommendations Belong in the IRP and Amended REP*

Next, MNS' Initial Brief recommends that the Commission require the Company to conduct feasibility studies (i.e., land, interconnection, permitting, construction), make specific commitments regarding how the Company will respond if it would deploy less than planned, and amend its RPS-compliance assessment in the forthcoming amended REP. MNS Initial Brief, pp. 25-28; (Woods, 3T 631-632, 639-643). As the Company's Initial Brief explained, these are IRP-style resource-planning and procurement requirements, and MNS witness Woods herself characterized the Company's committed approach — comparing resource needs with and without the Customer's load and selecting an optimized, least-cost portfolio in the upcoming IRP — as "best practice." DTE Electric Initial Brief, pp. 82-84; (Woods, 3T 620, 631). MNS' Initial Brief does not reconcile that internal tension: it asks the Commission to import into this special contract proceeding the detailed resource-planning review that witness Woods agrees belongs in the IRP and Amended REP. The Company already maintains the planning processes, development pipeline, and competitive procurement tools that MNS witness Woods' "best practices" describe, and the detailed review she seeks will occur in the upcoming IRP and Amended REP. DTE Electric Initial Brief, pp. 83-84; (Bilyeu, 3T 299-301).

The Commission should decline to impose MNS' requested conditions in this proceeding. They would require project-development, feasibility, mitigation, and annual resource-planning determinations before the projects are selected through the applicable procurement processes and before those issues are evaluated in the IRP and Amended REP proceedings specifically designed to address them.

- *MEICEO's Accreditation Speculation Does Not Justify Uncapped Deployment Obligations*

MEICEO's Initial Brief sets forth witness Hotaling's recommendation that, because energy-storage accreditation may evolve, the Commission should direct the Company to increase the CCAA deployment caps and add ongoing accreditation reporting. MEICEO Initial Brief, pp. 31-33; (Hotaling, 3T 720-723). MEICEO's Initial Brief adds no argument beyond witness Hotaling's testimony, which the Company's Initial Brief preemptively refuted and which the Company incorporates here: the recommendation misconstrues the CCAA (which authorizes deployment "up to" a nameplate capacity and does not size a single customer's resources to a moving accreditation target, because system resource adequacy is ensured through the IRP); removing the caps would impose commercially unreasonable, uncapped liabilities on the Customer; the accreditation concern is a system resource-adequacy question reserved for the IRP, and tracking individual CCAA resources' accreditation would not reveal what resources are attributable to the Customer's load; and, in all events, the Affordability Backstop protects other customers regardless of how much capacity is ultimately deployed. DTE Electric Initial Brief, pp. 84-85; (Foley, 3T 160-161). To the extent MEICEO also contends that the proxy resource's accreditation assumptions render the Company's benefit or resource-adequacy showing unreliable, that contention goes to the magnitude of the projected benefit and is addressed in Section VI.

- *Staff's Single-Solicitation Proposal Is New and Unsupported by the Evidentiary Record*

Staff's Initial Brief initially restates Staff witness Simpson's recommendation that the Company use the Competitive Procurement Guidelines "as appropriate" and prioritize resources needed to satisfy the Company's IRP and serve all customers before selecting resources for the CCAA, so that the Customer does not pay less for resources of the same technology contracted at approximately the same time. Staff Initial Brief, pp. 27-28; (Simpson, 3T 839-840). The Company's Initial Brief fully addressed that recommendation, including why resources procured for a customer-specific VGP Special Contract cannot reliably be compared with resources procured for general system needs based only on technology type and procurement timing. DTE Electric Initial Brief, pp. 85-86; (Bilyeu, 3T 296-298). Staff's Initial Brief adds no new evidentiary support for the recommendation already addressed.

Staff's Initial Brief, however, goes materially further than witness Simpson's testimony by proposing, for the first time, a new procurement structure under which the Company would conduct a "single solicitation to determine all possible projects available for a given year," select resources needed to satisfy the IRP and Renewable Energy Plan first, and then use the projects remaining after those selections to fulfill the CCAA. Staff Initial Brief, pp. 29-30. Staff witness Simpson did not sponsor that single-solicitation proposal, describe how it would operate, analyze its compatibility with the VGP Settlement Agreements or the CCAA, or present evidence concerning its commercial, timing, pricing, or procurement consequences. (Simpson, 3T 839-

840). Because Staff introduced the proposal only in its Initial Brief, the Company had no opportunity to address it through discovery, rebuttal testimony, or cross-examination.

- *Staff's Single-Solicitation Proposal Would Likely Delay Time-Sensitive Compliance and Special Contract Procurement*

Staff's belated single-solicitation proposal fails to account for the timing consequences of requiring the Company to combine distinct procurement needs into a single solicitation for each year. Staff Initial Brief, pp. 29-30. IRP, REP, and customer-requested VGP Special Contract needs do not necessarily arise at the same time, follow the same approval schedule, require the same commercial terms, or target the same in-service dates. A customer-requested Special Contract need may arise after the Company has already issued or completed a solicitation intended to procure resources for then-identified IRP or REP requirements. Under Staff's proposal, it is unclear whether the Company would be required to reopen the earlier solicitation, attempt to satisfy the later Special Contract from projects solicited for different purposes, or defer the customer-requested procurement until the next annual solicitation. Staff offers no testimony or analysis addressing any of those consequential issues.

The timing concern is not merely theoretical. For example, if the Company issued a compliance solicitation early in a year and a customer-requested Special Contract need arose several months later, a single-solicitation requirement could prevent the Company from promptly initiating the customer-specific procurement. Deferring that procurement until the following year could delay project selection, interconnection, permitting, contracting, and commercial operation. Conversely, delaying an otherwise necessary REP solicitation until every potential Special Contract need for the year is known would slow procurement undertaken to satisfy statutory renewable energy requirements. Staff's proposal thus could impair, rather than improve, the

Company's ability to conduct timely procurement for both regulatory compliance and customer-requested VGP obligations.

These consequences underscore the importance of the differentiated and well-established procurement framework Staff now proposes to replace. Company Witness Bilyeu explained that comparability depends on the procurement framework, project attributes, commercial requirements, eligibility criteria, allocation of risk, and customer-specific obligations, not merely technology type and timing. (Bilyeu, 3T 297-298). The VGP Settlement Agreements likewise recognize that procurement may be tailored to the particular resource purpose or need and establish a specialized competitive-bidding process for customer-requested projects. Case Nos. U-20713/U-20851 Settlement Agreement, ¶¶ 9.1.2, 11.1.1. That flexibility permits the Company to initiate and structure procurement when the relevant need arises, rather than forcing differently timed and differently purposed resource needs into a single annual process.

The Commission should not impose a consequential procurement structure when the record is void of evidence establishing that it is administratively workable, commercially practicable, or compatible with timely RPS compliance and the Customer's VGP Special Contract requirements.

- *The Record Distinguishes Storage Procurement from VGP Special Contract Renewable Procurement*

With respect to the merits of Staff's new proposal, it conflicts with the record evidence distinguishing the procurement frameworks applicable to the two categories of CCAA resources. Company Witness Foley explained that the Company's Competitive Procurement Guidelines and 2022 IRP Settlement discussion in his testimony concerned the CCAA energy-storage portfolio. The CCAA renewable-energy resources, by contrast, are part of a customer-requested VGP Special Contract and will be selected under the VGP Settlement Agreements, with the details of the competitive process agreed upon with the Customer. Company Witness Foley therefore expressly clarified that he did not testify that the VGP Special Contract renewable resources would be procured through the energy-storage RFP or under the 2022 IRP Settlement procurement framework. (Foley, 3T 161-162). Staff's newly introduced single-solicitation proposal disregards that distinction by combining resources procured for general IRP and REP requirements with resources procured under a customer-specific VGP Special Contract.

- *The VGP Settlement Agreements Establish a Specialized Procurement Framework*

Staff's proposal is inconsistent with the VGP Settlement Agreements. Paragraph 9.1.2 of the settlement in Case Nos. U-20713/U-20851 that was approved by the Commission on June 9, 2021, establishes a specialized competitive-bidding process for customer-requested projects, provides that the details of that process will be agreed upon with the customer, permits incorporation of customer-specific competitive-bidding requirements, and subjects the process to Staff audit. The same settlement separately recognizes that bidding processes may be tailored to the particular resource purpose or need. Case Nos. U-20713/U-20851 Settlement Agreement, ¶¶ 9.1.2, 11.1.1. Those provisions contemplate procurement designed around the specific customer-requested project; they do not contemplate placing the Customer's resources at the end of a single system-wide solicitation and limiting the CCAA to whatever projects remain after IRP and REP selections.

Likewise, the settlement in Case No. U-21172 approved by the Commission on July 2, 2024, establishes requirements applicable specifically to resources acquired for Special Contracts. It requires a BTA solicitation addressing capacity needed to fulfill each Special Contract and provides that the Company "shall not be required to issue more than one RFP per Special Contract." Case No. U-21172 Settlement Agreement, ¶¶ 1-2. As Company Witness Bilyeu explained, that settlement establishes a procurement process rather than a guaranteed procurement outcome. (Bilyeu, 3T 304-305). It does not require—and nowhere describes—a single solicitation combining procurement for Special Contracts with procurement for the Company's IRP and REP requirements.

- *Case No. U-21172 Settlement Agreement Selectively Incorporates—not Wholesale Adopts—the Competitive Procurement Guidelines*

Staff emphasizes that, "taking the [Case No. U-21172] settlement as a whole, it does reference" the Competitive Procurement Guidelines. Staff Initial Brief, p. 28. That limited observation is accurate, but it does not support Staff's conclusion. Paragraph 2 of the Case No. U-21172 settlement agreement *does not* incorporate the Competitive Procurement Guidelines wholesale or make them the generally controlling procurement framework for VGP special contracts. Rather, it provides that, in acquiring renewable resources for VGP special contracts, the Company will comply with the Guidelines "as [they] pertain[] to use of an Independent Monitor," and as set forth in paragraph 9 of the U-21193 Settlement Agreement, subject to specified exceptions. Case No. U-21172 Settlement Agreement, ¶ 2. Those exceptions are material: the solicitation is limited to BTAs, and the provisions of the Competitive Procurement Guidelines concerning technology neutrality and PPAs expressly do not apply. *Id*. Thus, the Case No. U-21172 settlement agreement selectively incorporates specified procedural protections from the Competitive Procurement Guidelines into a procurement framework negotiated specifically for VGP special contracts; it does not displace that specialized framework with blanket application of the Competitive Procurement Guidelines.

That is precisely the distinction the Company's witnesses made. Company Witness Foley explained that the Company will use the Competitive Procurement Guidelines for the CCAA energy-storage RFP, whereas the renewable resources supporting the Customer's VGP Special Contract will be selected under the VGP Settlement Agreements, with the details of the competitive process agreed upon with the Customer. (Foley, 3T 161-162). Company Witness Bilyeu similarly testified that the Competitive Procurement Guidelines should not apply "as a blanket requirement" to the VGP Special Contract renewable resources because procurement for customer-requested special contracts is governed by the VGP Settlement Agreements, which incorporate applicable competitive-procurement protections together with build-transfer and customer-specific requirements. (Bilyeu, 3T 296-298). The fact that Case No. U-21172 selectively incorporates specified portions of the Competitive Procurement Guidelines therefore confirms—not refutes—the Company's position that the operative procurement framework is the VGP Settlement Agreements as written.

- *Special Contract Capacity Is Expressly Treated Differently from Ordinary VGP Capacity*

Indeed, Paragraph 9 of the Case No. U-21172 settlement expressly treats capacity required to fulfill Special Contracts differently from resources acquired for ordinary VGP and nonparticipating-customer demand. Although Paragraph 9 proportionally allocates projects selected through the Company's ordinary all-source RFP between VGP program customers and nonparticipating customers, it states that "[c]apacity required to fulfill Special Contracts is not subject to the requirements of this paragraph" or the referenced proportional-allocation provisions of the prior IRP settlement. Case No. U-21172 Settlement Agreement, ¶ 9. Staff's proposal would erase that distinction by placing Special Contract and system resources into a common procurement pool and subordinating CCAA selection to prior IRP and REP selections.

- *No Governing Authority Supports Staff's Proposed IRP/REP-First Sequence*

Staff further characterizes its single-solicitation proposal as consistent with the Competitive Procurement Guidelines "as modified" by the VGP Settlement Agreements. Staff Initial Brief, pp. 29-30. But Staff's conclusion does not follow from its premise. That the VGP

Settlement Agreements incorporate specified Competitive Procurement Guideline procedures subject to negotiated exceptions does not allow Staff to add procurement requirements found in neither the Competitive Procurement Guidelines nor the VGP Settlement Agreements. None of those authorities require the Company to combine VGP special contract procurement with procurement for IRP or REP requirements, select system resources first, or fulfill the CCAA only from projects remaining afterward. The VGP Settlement Agreements establish specialized, customer-specific procurement rules; Staff's proposal would replace those rules with a new sequencing mandate.

Nor does Staff's concern that IRP or REP customers might pay more for "similar" resources supply evidentiary support for doing so. As Company Witness Bilyeu explained, whether resources are comparable depends on the procurement framework, project characteristics, commercial requirements, eligibility criteria, allocation of risk, and customer-specific attributes—not merely technology type and timing. A price difference alone therefore would not establish preferential treatment or subsidization. (Bilyeu, 3T 297-298).

Staff's proposal is also procedurally misplaced. The VGP Settlement Agreements establish the procurement framework applicable to customer-requested VGP Special Contracts, and Company Witness Bilyeu explained that Staff's original recommendation would "effectively add a new procurement-priority condition" to that Commission-approved framework. (Bilyeu, 3T 296-298). Staff's newly proposed single-solicitation structure would go further: it would combine procurement for the Company's IRP and REP requirements with procurement for the Customer's VGP Special Contract, require system resources to be selected first, and limit the CCAA to projects remaining afterward. Staff Initial Brief, pp. 29-30. That structure does not merely apply the existing VGP Settlement Agreements; it would materially alter how their specialized, customer-specific procurement framework operates. If that Commission-approved VGP framework is to be reconsidered or modified, the appropriate forum is a VGP Plan proceeding in which the settlement provisions, their interaction, and the consequences for the VGP program and its participants can be addressed on a developed record—not an expedited proceeding concerning approval of one customer's special contracts. This proceeding should not be used to impose a new, generally applicable VGP procurement structure that no witness sponsored and that the parties to the VGP Settlement Agreements had no opportunity to address.

- *Staff's Reallocation Concern Confuses Resource Disposition with Cost Responsibility*

Staff separately argues that broader application of the Competitive Procurement Guidelines is necessary because, if the Customer or its parent became nonviable, CCAA renewable resources could ultimately be reallocated to other customers and therefore remain "backstopped" by them. Staff Initial Brief, p. 30. That argument confuses the possible disposition of a resource after termination with responsibility for its unrecovered costs. As explained in Section V.B.2, upon a default termination, the CCAA termination payment requires the Customer to pay the unrecovered revenue requirement of each deployed project; the later use or allocation of a resource does not transfer that unrecovered obligation to other customers. DTE Electric Initial Brief, pp. 57-58, 63-64; (Bilyeu, 3T 310-312; Foley, 3T 124). Staff's reallocation concern therefore supplies no independent basis either for blanket application of the Competitive Procurement Guidelines or for its newly proposed single-solicitation structure.

- *The Commission Should Reject Staff's Unsupported Procurement Mandate*

The Commission should reject Staff's single-solicitation proposal consistent with the above because it is a materially new recommendation first advanced in Staff's Initial Brief without supporting testimony or an opportunity for evidentiary testing, and its practical effect would be to modify the Commission-approved procurement framework for customer-requested VGP Special Contracts in the wrong forum.

Based on the foregoing, none of the Staff or intervenor procurement and deployment recommendations warrant modifying the CCAA. The Company intends to deploy the contemplated renewable and storage amounts; the CCAA and Affordability Backstop protect other customers if project-specific circumstances affect deployment; resource-feasibility and accreditation questions will be addressed in the appropriate IRP and Amended REP proceedings; and the VGP renewable resources will be procured under the Commission-approved framework governing customer-requested Special Contracts. The Commission should approve the CCAA's procurement and deployment provisions as filed and reject MNS' mandatory-deployment condition, MEICEO's proposal to increase or remove the contractual caps, and Staff's procurement-priority and single-solicitation proposals.

C. Cost Allocation and Rate Design are Reserved for Future Proceedings

DTE Electric's Initial Brief, pp. 86-94, explained that this proceeding concerns whether the Special Contracts are reasonable, prudent, in the public interest, and protective of other customers—not the future allocation of the Company's revenue requirement among customer classes or the design of rates for those classes. The costs reflected in the Company's customer-benefit analysis are not being allocated or approved for recovery in this proceeding; actual cost allocation, class formation, and rate design will be determined in future general rate cases when the relevant costs, revenues, load characteristics, and billing determinants are known.

The Company's Initial Brief further demonstrated that this division of issues follows the Commission's established approach. Approval of the Special Contracts neither approves a particular future allocation of costs nor requires the Commission to permit subsidization or recovery of stranded costs from existing customers. The Company therefore agreed with Staff that cost allocation and rate design belong in general rate cases, but disagreed to the extent Staff suggested that an IRP could determine how production costs should ultimately be assigned to the Customer or a customer class. The IRP identifies the reasonable and prudent resource portfolio; the general rate case establishes revenue requirements, allocates costs, creates or modifies customer classes, and designs rates. DTE Electric Initial Brief, pp. 86-92; (Willis, 3T 419; Isakson, 3T 864, 880).

DTE Electric's Initial Brief addressed ABATE witness Dauphinais' recommendation that the Customer immediately be placed in a separate customer class. The Company explained that the proposed class initially would use the same Rate D11 rates and therefore would produce the same immediate charges as service under Rate D11; it would not resolve any presently demonstrated allocation problem. The recommendation instead seeks to address a possible future allocation issue before the Commission has the cost-of-service information needed to determine whether a separate class is warranted or how such a class should be designed. DTE Electric Initial Brief, pp. 92-94; (Dauphinais, 3T 548-549; Willis, 3T 426). The Company relies on and incorporates those arguments rather than repeating them.

The parties' Initial Briefs substantially confirm the Company's central position that cost allocation and rate design should be decided in future general rate cases. Staff expressly agrees that the effects of the Customer's sales and revenues on the class cost-of-service study are not yet fixed and that approval of the Special Contracts will not determine cost allocation or rate design before the Customer's load is reflected in a general-rate-case test year. Staff Initial Brief, pp. 13-15; (Isakson, 3T 864). MNS likewise acknowledges that resource cost allocation and rate design belong in rate cases, although it advocates eventual direct assignment of certain costs and proposes an additional contract condition concerning future rate schedules. MNS Initial Brief, pp. 14-19. ABATE continues to seek creation of a separate class now, while GLREA urges without evidentiary support consideration of both direct and asserted indirect data center costs in future cost-of-service determinations. The remaining areas of disagreement are addressed below.

- *Staff Agrees That Cost Allocation and Class Formation Belong in General Rate Cases*

Staff's Initial Brief agrees that "cost allocation, including whether or not to create a new customer class, should be determined in future rate cases." Staff Initial Brief, p. 13. Staff explains that the Customer's effects on the cost-of-service study and base rates "are not set in stone," and that the Commission should not predetermine those effects before the Customer's load is expected to appear in a general rate case's test year. Staff Initial Brief, pp. 13-15; (Isakson, 3T 864). Staff also relies on the Commission's prior determination that approval of special contracts does not itself approve or require future subsidization or recovery of stranded costs from existing customers. *Id.* That position aligns with the Company's Initial Brief and supports the same disposition here: approve the Special Contracts without prejudging future class formation, allocation, or rate design.

Staff's Initial Brief also makes clear that the Commission-ordered cost-allocation and rate-design studies—including scenarios involving the existing Rate D11 class, a separate large-load class, alternative coincident-peak allocation, and direct assignment—are tools for evaluating future general rate case treatment, not grounds for deciding the appropriate methodology in this special contract proceeding. (Isakson, 3T 864-866). The existence of multiple required studies confirms that the proper allocation method remains an open question requiring comparison on a developed rate-case record. It does not support selecting one methodology now.

- *The IRP Identifies Resource Differences but Does Not Allocate or Recover Costs*

To the extent Staff maintains that future IRPs should "support" determinations of cost responsibility, that proposition should be understood consistently with the distinct functions of the IRP and general rate cases. The Company's IRP may identify, through its with-and-without modeling, the incremental resources caused by the Customer's load. It does not allocate the revenue requirement of those resources among customer classes or establish the rates through which that revenue requirement will be recovered. Those determinations remain for general rate cases. DTE Electric Initial Brief, pp. 90-92; (Isakson, 3T 880; Willis, 3T 419).

Accordingly, the Commission may recognize that information developed in the IRP will inform later cost-allocation analyses, but it should not direct or imply that the IRP itself will assign production costs to the Customer or any customer class.

- *ABATE Has Not Demonstrated a Present Intra-Class Subsidy*

ABATE's Initial Brief repeats witness Dauphinais' concern that the Customer and the previously approved Oracle load will materially change the demand and energy characteristics of Rate D11. ABATE adds detail concerning the alleged mismatch between the allocation of production plant to customer classes—using a 75% four-coincident-peak demand and 25% annual-energy methodology—and the design of charges among individual Rate D11 customers using monthly peak demand and energy. ABATE Initial Brief, pp. 11-12; (Dauphinais, 3T 548-549). From that asserted mismatch and the Customer's relative size, ABATE predicts that part of the costs of serving the Customer will be borne by other Rate D11 customers.

ABATE's argument remains predictive rather than demonstrative. The fact that the Customer will affect Rate D11's aggregate billing determinants does not, standing alone, establish that Rate D11's existing design will produce an intra-class subsidy, identify which costs allegedly would be subsidized, quantify any resulting subsidy, or demonstrate what revised rate design would correctly recover those costs. As Company Witness Willis explained, actual cost allocation and rate design must be evaluated in a general rate case using the Company's full costs, revenues, class characteristics, and billing determinants. (Willis, 3T 419, 425-426). The Commission-ordered studies are designed to permit precisely that comparison before the Commission decides whether a separate large-load class, direct assignment, an alternative production allocator, or another methodology is appropriate.

Nor would ABATE's proposed remedy provide any immediate rate protection. ABATE's new class initially would apply the same Rate D11 rates that the Customer otherwise would pay, producing no initial difference in the Customer's charges. (Willis, 3T 426). ABATE's proposal would therefore create a class in form while deferring the substantive class cost-of-service and rate-design questions to the same future general rate case in which the Company proposes that they be addressed. DTE Electric Initial Brief, pp. 92-94.

- *Future Class Formation Should Be Decided on a Developed Rate-Case Record*

The Company does not ask the Commission to determine in this proceeding whether a separate large-load customer class or different rate design may be appropriate in a future general rate case. The narrower point is that the Commission should decide class formation and rate design when the relevant cost-of-service studies and actual or reasonably forecasted costs, revenues, load characteristics, and billing determinants are before it in that forum. (Willis, 3T 426-427). Until a different rate schedule becomes applicable in accordance with the PSA's terms, the Customer will take service under Rate D11 and pay all applicable surcharges, together with the additional obligations imposed by the Special Contracts—including the minimum billing demand, payment of the revenue requirements associated with CCAA resources, applicable termination payments, and the Affordability Backstop. (Foley, 3T 88-97, 120-121). This approach preserves the

Commission's authority to determine future cost allocation and rate design in a general rate case without prejudging either the outcome of that proceeding or the application of the PSA's rate-schedule provisions. Based on the above and the reasons set forth in DTE Electric's Initial Brief, pp. 92-94, ABATE's request to create a separate rate class in this proceeding should be rejected.

- *This Proceeding Should Not Predetermine the Treatment of Costs Caused By Serving the Customer*

MNS asks the Commission to endorse direct assignment of incremental costs in a future rate case. MNS Initial Brief, pp. 14-19, 30. As explained in Section V.A.6, the identification of costs by serving the Customer does not itself require separate assignment of those costs. Section 5.1.3 of the PSA first requires an aggregate assessment of costs caused by serving the Customer and applicable Customer-derived benefits. If that aggregate assessment shows a Commission-determined shortfall, the Customer must address it, but the PSA does not prescribe the implementation method.

This proceeding should not predetermine that future implementation. Cost allocation, rate design, and the appropriate means of addressing any Commission-determined shortfall should be decided on the record presented in the applicable ratemaking proceeding. The December 18 Order's six cost-allocation and rate-design studies permit comparison of potential approaches; they do not select direct assignment or establish that it applies to this Customer regardless of the outcome under Section 5.1.3 of the PSA. December 18 Order, pp. 38-40.

MNS agrees with the Company's fundamental distinction between resource planning and ratemaking. MNS witness Woods testified that the IRP is where the utility generation investments needed to serve the Customer are selected, while a rate case is the appropriate forum to establish the associated revenue requirement and decide cost allocation and rate design. (Woods, 3T 619).

That procedural division confirms that this Special Contract proceeding should not determine the future ratemaking treatment of costs that have not yet been identified or quantified.

- *The Six Studies Permit Comparative Review; They Do Not Predetermine Direct Assignment*

The December 18 Order also does not support predetermining a particular methodology. The Commission directed DTE Electric to file in its next general rate case at least six studies reflecting materially different approaches to cost-allocation and rate-design for large-load interconnection customers. December 18 Order, pp. 38-40. Direct assignment appears in two of those alternatives; the others evaluate traditional ratemaking, class formation, and alternative allocation treatment. The Commission's use of multiple scenarios confirms that it required comparative analysis, not adoption of direct assignment.

The inclusion of direct assignment among the required studies permits that methodology to be evaluated; it does not establish that it is correct, that it applies to this Customer regardless of PSA Section 5.1.3, or that the Commission has selected it. The studies likewise do not decide which costs are attributable to a particular customer, whether the aggregate Section 5.1.3 assessment will show a shortfall, or how any Commission-determined shortfall should be addressed. Those questions depend on the facts and record presented in the applicable future proceedings. The Commission should not use this Special Contract proceeding to select among those future ratemaking approaches or prejudge their application to the Customer.

Staff's evidence reinforces the same conclusion. Staff witness Isakson testified that the costs reflected in Exhibit A-19 are not allocated among customer classes and that allocation will be addressed as costs become known and are included in future general rate cases. (Isakson, 3T 864-866). Staff's recommendation concerning how a direct assignment study should be displayed does not constitute a recommendation that direct assignment be adopted. Staff Initial Brief, pp.

13-15; (Isakson, 3T 864). Neither the December 18 Order nor Staff's position supports deciding future cost allocation or rate design here.

- *Future Resource Costs Must Be Evaluated Under Section 5.1.3 of the PSA Before Any Shortfall Is Addressed*

The actual resource implications of serving the Customer cannot be determined until the Company completes the upcoming IRP, wherein the Company will perform the with-and-without modeling analysis used to identify the incremental resources caused by serving the Customer's load but will not assign individual resources exclusively to the Customer. The revenue requirements of resources identified through that process as caused by serving the Customer's load will be included in the Company's presentation of aggregate costs and benefits under the Affordability Backstop. (Foley, 3T 143-144, 153, 244-246). The IRP supplies resource-planning information; it does not allocate the resulting revenue requirements or establish rates. (Willis, 3T 419-420).

If the Commission determines that the aggregate assessment under Section 5.1.3 of the PSA shows a shortfall, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs caused by serving it. If the aggregate assessment remains positive, Section 5.1.3 does not provide for separately assigning an individual resource cost to the Customer merely because the IRP identified that cost as caused by serving its load. The PSA does not prescribe the means by which any Commission-determined shortfall must be satisfied, and even a ratemaking proceeding should not bypass the aggregate Section 5.1.3 trigger when determining the Customer's obligation under the Special Contracts.

MNS' preference for directly assigning particular future resource costs therefore does not support a directive in this proceeding. The Commission should first permit the IRP to identify the relevant portfolio changes and then apply the Affordability Backstop framework the contracting parties negotiated. Cost allocation, rate design, and the means of implementing any Commission-determined shortfall should be addressed in the proceeding containing the relevant costs, revenues, and ratemaking evidence, not predetermined here.

- *MNS' Mandatory Rate-Switching Condition Would Prejudge an Unidentified Future Tariff*

MNS separately asks the Commission to condition approval of the Special Contracts on requiring the Customer to move to any future rate schedule the Commission determines would otherwise apply to the Customer and similarly situated large-load customers. MNS Initial Brief, p. 19. MNS contrasts the PSA's rate-switching provisions with those set forth in a different utility's generally applicable large-load tariff in Case No. U-21859 and argues that the Commission should impose a comparable migration requirement here. MNS' request should be rejected.

The PSA addresses circumstances in which the Commission orders the termination or replacement of Rate D11. (Foley, 3T 96-97). And under the Affordability Backstop, if the Commission determines that the aggregate costs of serving the Customer exceed the aggregate benefits, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs associated with its service. The Company confirmed that such an order could include a requirement that the Customer take service under a newly established rate, subject to PSA Sections 5.1.3 and 5.1.4 and applicable procedural protections. Exhibit AG-8, p. 9.

Thus, rejecting MNS' condition would not deprive the Commission of authority to address a demonstrated cost shortfall, a Customer-requested rate change, or the termination or replacement of Rate D11. The dispute is narrower: whether the Commission should declare now that any future large-load rate automatically supersedes the negotiated and approved Special Contracts, regardless of the future rate's text, applicability provisions, transition requirements, effective date, or treatment of existing Special Contracts. Nothing in the record supports that sweeping result.

In sum, the Commission should reject MNS' mandatory rate-switching condition. The Customer should remain subject to the PSA's negotiated rate provisions unless and until a different rate becomes applicable in accordance with those provisions or a Commission order authorized by them. This result retains the Commission's authority to ensure that the Customer pays all costs associated with its service.

- *MEICEO's Reallocation Argument Involves Benefit Valuation, Not Present Cost Allocation*

MEICEO argues that a significant portion of the projected customer benefit reflects a reallocation of fixed production and transmission costs to the Customer rather than a reduction in total system costs. MEICEO Initial Brief, pp. 19-20. MEICEO witness Kenworthy characterizes the cost-of-service effect of adding the Customer to Rate D11 as "a reallocation of fixed cost responsibility, not a reduction in total system cost," emphasizing that the Customer's substantial load increases Rate D11's allocated share of production costs and correspondingly reduces the residential class's allocated share. (Kenworthy, 3T 671-672). MEICEO further acknowledges that the actual amount of the resulting benefits will be determined and verified through future rate and PSCR proceedings. MEICEO Initial Brief, p. 20.

MEICEO's argument does not establish that the projected benefit is illusory or that the Customer receives a subsidy. The cost-of-service comparison measures how the addition of the Customer's substantial revenues and billing determinants affects the allocation of the Company's revenue requirement among customer classes under the Commission-approved methodology. A reduction in the amount of fixed system costs that otherwise would be recovered from existing customers is a customer benefit even if the underlying system costs do not disappear. The relevant protection is that the Customer contributes its properly allocated share of those costs and that costs determined to be caused by serving the Customer are included in the aggregate assessment under Section 5.1.3, together with aggregate Customer-derived benefits. If the Commission determines that the aggregate assessment shows a shortfall, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs caused by its service. It is not necessary that every benefit arise from eliminating an existing system cost.

Nor does the cost-of-service comparison purport to capture every incremental cost of serving the Customer. It is one component of the broader customer-benefit analysis, which separately accounts for incremental rate base costs, fuel and purchased-power expense, transmission costs, CCAA resource costs, and other costs and benefits. (Willis, 3T 406-411). Staff independently recreated the cost-of-service analysis and confirmed that its result "matches the Company's finding on Exhibit A-20." (Isakson, 3T 863; Willis, 3T 418). Thus, MEICEO's observation about the mechanism producing the class-allocation benefit does not reveal an omitted Customer-caused cost or an improper allocation; it describes the operation of the Commission-approved cost-of-service methodology used for the analysis.

The Company agrees with MEICEO's proposition that actual cost allocation and rates will be determined in future contested proceedings rather than fixed by the illustrative cost-of-service comparison in this case. MEICEO Initial Brief, pp. 19-20. The Company has committed to present the aggregate costs and benefits of serving the Customer in future general rate cases and PSCR proceedings, including the revenue requirements of resources deployed under the CCAA; RPS resources not covered by the CCAA; incremental resources identified in the IRP, through the with-and-without analysis, as caused by serving the Customer's load; increased fuel and purchased-power costs; transmission revenue requirements; Customer revenues; and avoided costs realized through the Special Contracts. (Foley, 3T 143-144, 153). Those proceedings will permit the Commission and the parties to evaluate the actual costs, revenues, billing determinants, and approved allocation methodologies as they become known.

MEICEO's contention therefore reinforces—not undermines—the Company's position concerning the proper forum. This special contract proceeding does not establish the cost allocation that will govern future rates. It evaluates whether the Special Contracts, including their customer-protective provisions, are reasonable and should be approved. The magnitude, timing, and valuation of the projected customer benefit are addressed in Section VI; the ultimate allocation and recovery of actual costs remain questions for the future general rate cases and PSCR proceedings in which aggregate costs and benefits are presented.

- *Cost Allocation and Rate Design Should Remain Reserved*

In conclusion, the parties substantially agree on the central procedural point: approval of the Special Contracts does not determine future cost allocation, create or foreclose a customer class, approve a particular rate design, or authorize shifting costs to existing customers. Staff testified that the costs reflected in Exhibit A-19 are not allocated among customer classes and that allocation will be addressed as those costs become known and are included in future general rate cases. (Isakson, 3T 864). MNS witness Woods similarly testified that the IRP is the proceeding in which generation investments needed to serve the Customer are selected, while rate cases are the appropriate proceedings to establish revenue requirements and decide cost allocation and rate design. (Woods, 3T 619). Consistent with those principles, ABATE's asserted intra-class subsidy remains predictive and unquantified, and its proposed separate class initially would charge the same Rate D11 rates and provide no immediate substantive remedy. (Willis, 3T 426). MNS' direct assignment preference is one of several methodologies included in the six studies now before the Commission in Case No. U-22046; its inclusion as a study scenario does not predetermine its adoption, and the record in that proceeding should be allowed to develop before the Commission determines what allocation and rate-design treatment the evidence supports. (Willis, 3T 420-421; Isakson, 3T 864-866).

MNS' proposed mandatory rate-switching condition likewise is unnecessary in light of the PSA's existing provisions governing rate changes, replacement of Rate D11, and Commission remedies addressing a demonstrated cost shortfall. (Foley, 3T 96-97; Exhibit AG-8, pp. 8-9; Willis, 3T 423-424). MEICEO's observation that one component of the projected benefit reflects a reallocation of fixed-cost responsibility concerns the characterization and valuation of that benefit, not whether this proceeding should establish future cost allocation; MEICEO itself acknowledges that the actual benefit and applicable allocation will be determined and verified in future rate and PSCR proceedings. MEICEO Initial Brief, pp. 19-20; (Kenworthy, 3T 671-672).

GLREA's support for consideration of a separate data center class presents a future rate case issue. GLREA witness Richter expressly stated that the concurrent general rate cases would provide a "more holistic view" for consideration of that proposal. (Richter, 3T 609). But GLREA's Initial Brief goes further by requesting, for the first time, that the Commission include a statement in its order concerning consideration and recovery of asserted direct and indirect data center costs in concurrent and future proceedings. GLREA Initial Brief, pp. 15-16. That newly formulated request, along with GLREA's scarcity fee theory, is addressed in Section V.D.3.

Based on the foregoing, the Commission should approve the Special Contracts without prejudging future cost allocation or rate design; reject ABATE's request to create a separate class now; reject MNS' requests that the Commission order adoption of direct assignment in Case No. U-22046 or impose mandatory future rate migration; and confirm that the IRP may identify through with-and-without modeling incremental resources caused by serving the Customer's load but does not exclusively assign such resources to the Customer nor allocate or establish recovery of those costs in the IRP. (Foley, 3T 244-246; Willis, 3T 419-420).

D. Other Issues

1. Rider 12 Demand Response Agreement

The Customer elected service under the Company's Commission-approved Rider 12 and entered into the Rider 12 DR Agreement, under which it will provide approximately 250 MW of demand response, reducing the Facility's demand to a 650 MW firm-service level when called during the agreement's June 1, 2027 through May 31, 2033 term. (Foley, 3T 90; Burgdorf, 3T 377-378). The Rider 12 DR Agreement supports the Company's near-term resource-adequacy position and forms part of the overall arrangements under which the Company will serve the Customer. DTE Electric Initial Brief, pp. 14, 94-95.

ABATE and MEICEO nevertheless ask the Commission to require the Customer to remain curtailable to 650 MW beyond May 31, 2033. ABATE would require that extension to the extent the Company has not brought 550 MW of replacement capacity online in MISO Zone 7. ABATE Initial Brief, pp. 10-11; (Dauphinais, 3T 547-548). MEICEO similarly argues that expiration of the Rider 12 DR Agreement and the Customer's 300 MW ZRC transfer will contribute to a capacity need in 2033 and may foreclose a potentially lower-cost alternative to additional generation. MEICEO Initial Brief, pp. 38-39; (Hotaling, 3T 716-718).

DTE Electric's Initial Brief fully addressed those recommendations, including why the Rider 12 DR Agreement is outside the scope of the requested approval, why compelling its extension would conflict with the voluntary and negotiated nature of DR, and why any post-2033 capacity concern belongs in the Company's upcoming IRP. DTE Electric Initial Brief, pp. 71-73, 94-96. The Company relies on and incorporates that discussion rather than repeating it and replies further only to address the arguments developed in the intervenors' Initial Briefs.

- *The Intervenors' Initial Briefs Provide No Basis to Modify or Extend the Rider 12 DR Agreement*

ABATE's and MEICEO's Initial Briefs add no materially new evidence or legal authority supporting an extension to the Rider 12 DR Agreement. ABATE acknowledges that the Rider 12 DR Agreement is one of the agreements for which the Company does not seek approval, yet asks the Commission to modify it to require continued curtailability if the Company has not brought specified replacement capacity online. ABATE Initial Brief, pp. 3, 10-11. That relief is outside the scope of the Company's Application. The Commission may consider the benefit supplied by the Rider 12 DR Agreement when evaluating the PSA and CCAA without treating that separate, standard tariff agreement as itself subject to approval or modification in this docket. DTE Electric Initial Brief, pp. 6-7, 94-96; Exhibit AB-1, p. 24 (STDE-3.12).

MEICEO's assertion that the Special Contracts "foreclose" continued DR as a potential means of meeting a future capacity need is also incorrect. MEICEO Initial Brief, pp. 38-39. The Rider 12 DR Agreement establishes the term the Customer has agreed to provide DR; it does not prohibit the Company and the Customer from negotiating continued participation after May 31, 2033. If the upcoming IRP identifies a capacity need and continued DR is then available, technically feasible, and commercially acceptable, nothing in the Special Contracts prevents the parties from negotiating an extension.

The remaining premise underlying ABATE's and MEICEO's recommendations, that expiration of the Rider 12 DR Agreement may contribute to a capacity need in 2033, is addressed in Section V.B.4. As explained there, the extent of any 2033 system need, the factors contributing to it, and the reasonable and prudent portfolio for meeting it are questions for the Company's upcoming IRP. Ordering an extension here would select and compel one particular resource alternative before the IRP determines the need, evaluates the available alternatives, or establishes that continued DR is a reasonable means of addressing it. DTE Electric Initial Brief, pp. 71-73, 95-96; (Burgdorf, 3T 399).

- *Rider 12 Nonperformance Penalties Will Be Tracked Through PSCR Reconciliation Proceedings*

The AG separately recommends that any penalties assessed for the Customer's nonperformance under the Rider 12 DR Agreement be accounted for separately, disclosed in DR or other proceedings, and credited to other customers. AG Initial Brief, p. 21. The Company agrees with the substance of that recommendation but disagrees that an additional reporting or accounting condition is necessary. Company Witness Burgdorf confirmed that the Company will assess any nonperformance penalties under the Rider 12 DR Agreement directly to the Customer and track those penalties separately. He further explained that the Company will present any such penalties in the PSCR reconciliation proceeding for the year in which they occur, because that is the proceeding in which DR revenues and performance are addressed. (Burgdorf, 3T 397-398).

The AG does not oppose use of the PSCR reconciliation proceeding but asks the Commission to require the Company to identify any Rider 12 noncompliance and associated credits in testimony and supporting exhibits. AG Initial Brief, p. 21. That additional directive is unnecessary. The Company has already committed to separately track the penalties, credit them to other customers through power-supply-cost accounting, and present them in the applicable PSCR reconciliation proceeding. (Burgdorf, 3T 397-398). The Commission and parties may review that treatment on the actual record for the year in which a penalty occurs. The Commission therefore need not prescribe today the particular testimony or exhibit format the Company must use in a future PSCR reconciliation.

- *The Proposed Modifications to the Rider 12 DR Agreement Should Be Rejected*

The Rider 12 DR Agreement provides a meaningful, voluntarily negotiated DR commitment during its agreed term. It is a standard agreement under the Company's existing, Commission-approved Rider 12, is not submitted for approval in this proceeding, and was described to provide a complete picture of the arrangements supporting service to the Customer. DTE Electric Initial Brief, pp. 6-7, 14, 94-96; (Foley, 3T 90, 163).

The Commission should therefore recognize the Rider 12 DR Agreement as part of the broader service arrangement, confirm that it is not before the Commission for approval or modification, and reject ABATE's and MEICEO's requests to extend the Customer's DR obligation beyond May 31, 2033. Any continuation should depend on the resource needs identified through the IRP and a voluntary future agreement between the Company and the Customer, not a compelled extension imposed years in advance in this Special Contract proceeding. DTE Electric Initial Brief, pp. 71-73, 94-96.

2. Line Extension Agreement and CIAC

Staff and MNS continue to seek changes to the treatment of distribution-interconnection costs. Staff asks the Commission to apply to the Customer, if approved, the contribution-in-aid-of-construction ("CIAC") methodology proposed in pending Case No. U-22061 for costs exceeding the Customer's $50 million commitment under the Line Extension Agreement ("LEA"). Staff Initial Brief, pp. 8-10. MNS asks the Commission to require the Customer to pay all distribution-related interconnection costs without any $50 million limit. MNS Initial Brief, pp. 16-18, 31.

DTE Electric's Initial Brief fully addressed both recommendations, and the Company incorporates that discussion rather than repeating it. DTE Electric Initial Brief, pp. 97-102. As demonstrated there, the LEA is not submitted for approval; the Customer's $50 million commitment substantially exceeds its obligation under the currently approved CIAC policy; the estimated distribution costs are below that commitment; the LEA separately assigns unexpected-site-condition and event costs to the Customer; and prospective large-load CIAC policy is being litigated in Case No. U-22061. *Id*. The parties' Initial Briefs do not undermine those conclusions.

- *The LEA Is Not Before the Commission for Approval or Modification*

Staff's and MNS' requested relief remains outside the scope of the Company's Application. The LEA is a standard agreement that supports the Company's provision of service to the Customer, but the Company seeks approval only of the PSA, CCAA, and related accounting treatments. DTE Electric Initial Brief, pp. 6-7, 14, 97-98; (Foley, 3T 90). The Company likewise does not propose to change its existing CIAC policy in this proceeding. DTE Electric Initial Brief, p. 98; (Benyard, 3T 451).

MNS now places its uncapped-payment request among proposed conditions designed to "strengthen" the Affordability Backstop. MNS Initial Brief, pp. 17-18, 31. But that reframing does not bring the LEA within the relief requested or convert modification of a Related Agreement into a permissible condition on approval of the Special Contracts. MNS' proposal would replace the LEA's negotiated $50 million commitment with an uncapped obligation that the contracting parties did not negotiate or accept. For the reasons explained in Section III, the Commission should evaluate the Special Contracts presented for approval rather than impose a materially different bargain by revising a separate agreement that is not before it.

- *The Customer's $50 Million Commitment Exceeds Current Rate-Book Requirements*

Staff's Initial Brief does not dispute that the LEA requires the Customer to assume distribution costs it would not bear under the Company's currently approved CIAC policy. Under that policy, the Customer's CIAC allowance would be approximately $550 million, while the estimated cost of the distribution work is $29.1 million to $44.3 million. The Customer nevertheless agreed to fund the first $50 million of Customer-caused distribution costs and to construct and own its substation. DTE Electric Initial Brief, pp. 98-100; (Willis, 3T 423-425; Benyard, 3T 456-457). The LEA therefore shifts to the Customer costs that otherwise would be eligible for inclusion in rate base under the existing tariff.

Staff asserts that it is unreasonable for the Company both to negotiate special terms for this Customer and to propose different generally applicable terms in Case No. U-22061. Staff Initial Brief, p. 10. However, the existence of a later-filed tariff proposal does not diminish the protection the Customer accepted under the tariff in effect when the agreements were executed. The relevant comparison in this proceeding is between the Customer's obligations under the LEA and the requirements of the approved Rate Book, not an unresolved proposal in another docket. On that proper comparison, the LEA materially benefits other customers. DTE Electric Initial Brief, pp. 98-100.

- *Distribution Costs Above the LEA Threshold Are Captured by the Affordability Backstop*

MNS argues that any distribution costs exceeding $50 million would be placed in rate base and recovered from all customers, making the Affordability Backstop more difficult to administer. MNS Initial Brief, pp. 16-18. That argument conflates the initial ratemaking treatment of an expenditure with the ultimate allocation of any net cost caused by serving the Customer. The Company does not expect the distribution costs to exceed $50 million. The $29.1 million to $44.3 million estimate in the record incorporates potential inflation, varying design complexity, and the stated accuracy range, and the LEA separately makes the Customer responsible for unexpected site conditions or events. DTE Electric Initial Brief, pp. 100-101; (Benyard, 3T 456).

More fundamentally, if recoverable Customer-caused distribution costs exceed the Customer's LEA payments, those costs are included in the aggregate assessment under PSA Section 5.1.3. Company Witness Foley confirmed that distribution costs would enter the Affordability Backstop assessment if they exceeded the $50 million commitment. (Foley Cross, 3T 251-252); DTE Electric Initial Brief, pp. 37, 100-101. The Commission and parties may evaluate those actual costs through the applicable proceedings rather than assume now that a presently unanticipated overrun necessarily becomes a subsidy.

MNS' preference for direct payment of every distribution-cost dollar therefore does not demonstrate a gap in customer protection. The LEA provides substantial front-end protection beyond the currently approved tariff, while the Affordability Backstop addresses any net shortfall determined from actual costs and benefits. Replacing that arrangement with uncapped liability is neither necessary to protect other customers nor properly accomplished by modifying the LEA in this proceeding.

- *The Pending Large Load Provision Cannot Be Applied Retroactively*

Staff's Initial Brief adds two reasons for applying the proposed Case No. U-22061 CIAC methodology here: Case No. U-22061 was filed only four days after this proceeding, and the Customer has not yet begun taking service. Staff Initial Brief, p. 10. Neither point establishes that the unapproved proposal governs these agreements.

The timing of the Large Load Provision filing does not change the controlling sequence. The Special Contracts and Related Agreements were negotiated and executed before the proposed Large Load Provision was filed, and the CIAC methodology in Case No. U-22061 had not been approved or incorporated into the Rate Book. DTE Electric Initial Brief, pp. 101-102; (Willis, 3T 423-424). Staff's proposal would give the future tariff substantive effect in this proceeding before the Commission has determined its final text, applicability, transition provisions, or treatment of customers governed by previously negotiated special contracts.

Nor does the fact that service has not commenced answer the prospective application concern. Tariffs operate prospectively so that the utility and customer can make informed decisions based on the framework governing their transaction. (Willis, 3T 423-424). The relevant commercial commitments were made when the agreements were executed, not when electricity first flows to the Facility. Applying a later-adopted CIAC rule to alter those commitments would subject an existing transaction to a standard that was neither effective nor finally defined when the bargain was reached.

The Company does not ask the Commission in this proceeding to determine the applicability of every provision that may ultimately be approved in Case No. U-22061. That question should be resolved through the final tariff language and record developed in that docket. The narrower point is sufficient here: a proposed CIAC methodology cannot be treated as controlling law and imported into this case to modify the LEA before the proposal itself has been adjudicated.

- *The Commission Should Decline to Rewrite the LEA or CIAC Treatment*

Staff's and MNS' Initial Briefs provide no reason to revisit the analysis in DTE Electric's Initial Brief. The LEA is not submitted for approval; the Customer has accepted substantial distribution-cost responsibility beyond the currently approved tariff; the estimated distribution costs remain below the Customer's commitment; unexpected-site-condition and event costs are separately assigned to the Customer; and the presentation of aggregate costs and benefits in support of the Affordability Backstop will take into consideration any Customer-caused distribution costs exceeding the LEA payments. DTE Electric Initial Brief, pp. 97-102; (Benyard, 3T 456-457; Willis, 3T 423-425; Foley, 3T 251-252).

The Commission should therefore reject MNS' request to impose uncapped distribution-cost liability and Staff's request to apply the proposed Case No. U-22061 CIAC methodology to the Customer. Prospective CIAC policy for future qualifying large loads should be determined in Case No. U-22061 on the record developed there, without using this special contract proceeding to modify the LEA or prejudge the treatment of existing agreements.

3. GLREA Scarcity Fee

GLREA renews its recommendation that the Commission remain open to imposing temporary "scarcity pricing fees" on data-center customers in concurrent and future rate cases. GLREA Initial Brief, pp. 14-16; (Richter, 3T 607-608). GLREA also reiterates its support for considering a separate data-center customer class, an issue its witness expressly reserved for fuller consideration in the concurrent rate case. GLREA Initial Brief, pp. 14-16; (Richter, 3T 609). GLREA does not present a specific fee or ask the Commission to create a separate class in this proceeding; instead, it asks the Commission to signal a willingness to modify traditional allocation practices once concrete proposals are presented. GLREA Initial Brief, pp. 15-16.

DTE Electric's Initial Brief demonstrated that GLREA's scarcity-fee recommendation lacks a Customer-specific causal foundation and presents no definite mechanism for Commission review. DTE Electric Initial Brief, pp. 102-105; (Richter, 3T 586-587, 606-609; Burgdorf, 3T 400-402). The Company incorporates that discussion rather than repeating it. GLREA's Initial Brief adds no concrete fee methodology, triggering standard, calculation, duration, or evidentiary means of attributing the asserted category-wide market effects to this Customer. Its new request for a Commission "signal" and its related separate-class proposal do not cure those defects.

GLREA argues that rapid data center growth is increasing regional capacity and energy prices and raising the costs of transformers, switchgear, and gas-fired generation. GLREA Initial Brief, pp. 13-16; (Richter, 3T 573-580, 600-607). But GLREA's evidence concerns the asserted cumulative effects of data centers as a category, not costs demonstrated to have been caused by this Customer or the Special Contracts. GLREA itself states that "no single data center" is responsible for the asserted increases and attributes them instead to "the combined effect of so much load being added so fast." GLREA Initial Brief, pp. 14-15.

That concession is consistent with GLREA witness Richter's testimony. He distinguished "the cost impact of data centers as a group" from "the cost impact of any particular data center," attributed the asserted price increases to demand "across the country, and the world," and acknowledged that the risks underlying his proposal are "not particular to this data center." DTE Electric Initial Brief, pp. 103-104; (Richter, 3T 586-587, 606-607). Those category-wide observations do not identify a particular DTE Electric expenditure, quantify a Michigan cost caused by serving this Customer, or establish the amount that could properly be assigned to the Customer under cost-causation principles.

GLREA responds that this Customer will construct "one more data center" contributing to aggregate demand and that its cited materials therefore establish the necessary causal connection. GLREA Initial Brief, p. 16. However, participation in a broad market trend is not, without more, evidence of the amount of any cost caused by this Customer. GLREA offers no method for separating the Customer's alleged contribution from the effects of other data centers, other new loads, supply-chain conditions, national or worldwide demand, generation retirements, fuel prices, transmission conditions, or other market factors. Nor does it explain how an unidentified share of a generalized market effect could be converted into a just and reasonable Customer-specific charge. GLREA's Initial Brief therefore does not answer the causation deficiency identified by Company Witness Burgdorf. DTE Electric Initial Brief, pp. 103-105; (Burgdorf, 3T 401-402).

- *GLREA Proposes No Workable Fee Methodology, Trigger, or Amount*

GLREA emphasizes that it is not asking the Commission to impose a scarcity fee in this proceeding, but only to remain open to one in concurrent and future rate cases. GLREA Initial Brief, pp. 15-16. That clarification confirms why no relief concerning a scarcity fee is appropriate here. GLREA has not identified the fee's measure, the costs it would recover, the customers to whom it would apply, the evidentiary showing required to impose it, the conditions triggering its commencement or termination, or the interaction between the fee and rates otherwise established through an approved cost-of-service methodology. DTE Electric Initial Brief, pp. 102-105; (Burgdorf, 3T 401-402). As Company Witness Burgdorf explained, without an actual proposal tied to the Company and the issues in this proceeding, there is "nothing substantive for the Commission to evaluate." DTE Electric Initial Brief, p. 105; (Burgdorf, 3T 402).

The Commission should not issue an advisory statement endorsing an undefined future charge. Whether a specific cost exists, whether a particular class or customer caused it, and how it should be allocated must be determined from the record in the proceeding in which an actual ratemaking proposal is presented. A generalized statement that the Commission is willing to consider a scarcity fee would resolve no issue before it and could be misconstrued as accepting GLREA's unproven premise that category-wide market developments are properly chargeable to this Customer.

- *GLREA Cannot Cure the Absence of a Record Proposal by Requesting New Relief in Its Initial Brief*

GLREA's Initial Brief effectively concedes the dispositive deficiency identified by Company Witness Burgdorf. In rebuttal, Witness Burgdorf explained that GLREA had presented no actual proposal for the Commission to evaluate, but only general commentary that was neither specific to DTE Electric nor to the issues in this proceeding. (Burgdorf, 3T 402). GLREA responds: "That is true." GLREA Initial Brief, p. 15. It then attempts to cure that evidentiary failure by requesting, for the first time in its Initial Brief, that the Commission's order state that it will consider direct and indirect data center costs and impose remedies requiring recovery of those costs from data-center customers as a group or customer class in concurrent and future proceedings. *Id.*, pp. 15-16.

Counsel's argument in an Initial Brief cannot supply the factual foundation or evidentiary support that GLREA elected not to present through testimony. No GLREA witness sponsored the requested order language, defined the "direct and indirect costs" the statement would encompass, explained the legal or ratemaking consequences of the requested commitment, identified the evidence necessary to establish causation, or showed how those costs could properly be assigned to data center customers as a group or class. Because the request first appeared after the evidentiary record closed, the Company had no opportunity to address it through discovery, rebuttal testimony, or cross-examination. The Commission should not grant new affirmative relief based solely on counsel's post-record formulation.

Nor is the requested statement merely an innocuous reservation of future Commission authority. The Commission already possesses authority in future rate cases to consider properly presented evidence concerning utility costs, cost causation, class formation, allocation, and rate design. GLREA asks for more here: an order in this proceeding signaling that asserted indirect, category-wide costs may be recovered from data center customers as a group or class. Such a statement could prejudge questions that must be decided on the developed records in those future proceedings, including whether an identified cost exists, whether it was caused by a particular customer or class, whether a separate class is appropriate, and which allocation methodology produces just and reasonable rates.

The proper disposition is straightforward. The Commission should decline to include GLREA's requested statement in its order. This special contract proceeding should not be used to provide advance approval, or even a favorable policy signal, of a proposal that was not presented in testimony and remains undefined.

- *GLREA's Separate-Class Proposal Belongs in a General Rate Case*

GLREA also reiterates its support for considering a separate data-center customer class. GLREA Initial Brief, pp. 14-16. Unlike its newly requested order statement discussed above, the general concept of a separate class appeared in GLREA witness Richter's testimony. He also expressly stated, however, that he would provide further support in the concurrent general rate cases, "where a more holistic view will be available for the Commission's consideration." (Richter, 3T 609). The Company agrees that class formation, cost allocation, and rate design belong in a general rate case, although it does not concede that a separate class is necessary or appropriate. As explained in Section V.C, the Commission should evaluate the competing methodologies on the developed rate case record rather than prejudge class formation or endorse group-based cost recovery in this special contract proceeding. Staff's Initial Brief confirms the proper forum, explaining that the Customer's effects on cost allocation and rates "are not set in stone" and that, although it may be tempting to predetermine how service to the Customer will affect rates paid by other customers, that question belongs in a general rate case where the marginal costs of serving the Customer can also be evaluated. Staff Initial Brief, pp. 13-15; (Isakson, 3T 864-866).

Additionally, the creation of a separate class itself would not establish that the alleged regional-market effects mentioned by GLREA were caused by the customers placed in that class. A class structure determines how demonstrated costs and revenues are grouped and allocated; it does not supply missing evidence of causation or transform nationwide and worldwide market developments into identifiable DTE Electric costs. GLREA would still need to demonstrate the nature, amount, and causal basis of any cost it proposes to assign. Its Initial Brief does not do so.

- *The Commission Should Reject GLREA's Scarcity-Fee Recommendation*

GLREA's Initial Brief confirms rather than cures the deficiencies identified in DTE Electric's Initial Brief. GLREA seeks no specific scarcity fee in this case, presents no methodology or amount for Commission review, and acknowledges that the alleged effects arise from data centers collectively rather than this Customer alone. DTE Electric Initial Brief, pp. 102-105; GLREA Initial Brief, pp. 13-16; (Richter, 3T 586-587, 606-609; Burgdorf, 3T 400-402). The Commission should therefore decline GLREA's invitation to signal advance approval of an undefined future scarcity fee. It should also decline to address GLREA's separate rate class proposal in this Special Contract proceeding and leave class formation, allocation methodology, and rate design to general rate cases.

4. Emergency Electric Procedures and Priority Load Shedding

Staff and ABATE agree with the Company on the substantive protection required: during a qualifying system emergency, the Customer should be subject to firm load shedding before other customers when shedding the Customer's load can prevent shedding other firm load and would not compromise system reliability. Staff Initial Brief, pp. 19-21; ABATE Initial Brief, pp. 9-10. The Company agrees. Its proposed amendments to the Emergency Electric Procedures in Case No. U-22059 expressly apply to customers beginning service after October 1, 2025 with capacity of at least 500 MW, which includes this Customer based on the Facility's expected load. DTE Electric Initial Brief, pp. 49-50; (Willis, 3T 427-429; Matthews, 3T 821-822).

The parties disagree only about whether the Commission should impose additional or alternative requirements in this Special Contract proceeding while Case No. U-22059 remains pending. Staff asks that, if the proposed amendments are not approved, the Company either amend the Special Contracts to incorporate equivalent protections or further amend its Emergency Electric Procedures to ensure that the protections apply to this Customer. Staff Initial Brief, pp. 19-21; (Matthews, 3T 822). ABATE asks the Commission to require the Company to modify its emergency procedures to subject the Customer to priority firm load shedding until all resources necessary to serve the Facility are in service, while simultaneously arguing that the amendments filed in Case No. U-22059 should have been limited to the large-load customer addressed in Case No. U-21990. ABATE Initial Brief, pp. 9-10; (Dauphinais, 3T 545-548). Neither recommendation supports a condition on approval of the Special Contracts.

- *The Customer Will Be Subject to the Applicable Emergency Electric Procedures*

There is no substantive dispute about the Customer's treatment under the proposal pending in Case No. U-22059. The proposed procedures provide that, as a measure of last resort, customers beginning service after October 1, 2025 with capacity of at least 500 MW, or customers taking service under the proposed Large Load Provision, will be subject to firm load shedding before other customers when doing so does not compromise system reliability and can prevent shedding other firm customer load. (Matthews, 3T 821-822). Staff expressly acknowledges that the Customer falls within those provisions, and Company Witness Willis confirmed the same point. DTE Electric Initial Brief, pp. 49-50; (Willis, 3T 427-429).

The proposed applicability standard also reflects the appropriate tariff structure. The Company explained that it endeavors to treat similarly situated customers similarly and that the December 18 Order did not exclude other qualifying loads from the required updates. Exhibit AB-1, pp. 11-12 (CEOMEIBCIEIDE-1.39a). Rather than naming an individual customer, the proposed procedures establish generally applicable criteria based on service date and load size. That approach ensures that this Customer is covered while avoiding the need to amend the Rate Book whenever another similarly situated customer begins service. (Willis, 3T 428-429).

ABATE's position is internally inconsistent. ABATE argues that the Case No. U-22059 amendments should have been limited to Oracle because that filing responded to the December 18 Order, but also agrees that "given the 1,000 MW size" of this Facility, subjecting this Customer to priority firm load shedding is justified. ABATE Initial Brief, pp. 9-10. The generally applicable criteria proposed in Case No. U-22059 achieve precisely that result while applying the same emergency protection to similarly situated customers. ABATE identifies no substantive deficiency in the treatment the Customer would receive under those criteria.

- *The Commission Should Not Duplicate or Prejudge Case No. U-22059*

Staff's concern is expressly contingent. Staff agrees that the amendments proposed in Case No. U-22059 would address its reliability concern if approved because they apply to this Customer. Staff Initial Brief, pp. 19-20; (Matthews, 3T 822). Staff asks for alternative relief here only if the Commission does not approve those amendments. Staff Initial Brief, pp. 20-21.

That contingency does not justify modifying the Special Contracts now. Case No. U-22059 is the proceeding specifically established to evaluate the Company's proposed amendments to Section C3 of its Rate Book and any issues concerning their wording, scope, applicability, or approval. This Special Contract proceeding should not presume that the amendments will be rejected, establish a parallel Customer-specific requirement in anticipation of that possible outcome, or effectively resolve questions concerning the proper scope of the tariff before the Commission decides them in Case No. U-22059.

Embedding emergency-procedure language in the PSA would also unnecessarily duplicate the applicable tariff framework. If the proposed amendments are approved, the Customer will be subject to them by their terms. Adding substantially equivalent language to the PSA would create overlapping sources of the same operational obligation and invite questions concerning which language controls if the Commission later modifies the generally applicable procedures. The cleaner regulatory structure is for emergency-load-shedding requirements to reside in the Company's approved Emergency Electric Procedures and apply according to their generally applicable criteria.

Staff's alternative suggestion that the Company further amend its Emergency Electric Procedures if the current proposal is not approved likewise belongs in Case No. U-22059 or any subsequent proceeding the Commission directs concerning those procedures. Staff Initial Brief, pp. 20-21. The Commission retains full authority in that proceeding to approve, reject, or modify the proposed tariff language. It need not condition approval of unrelated Special Contracts on a forecast of how it may resolve the separate compliance filing.

- *Additional Load-Shedding Conditions Are Unnecessary*

ABATE's requested condition is substantively duplicative of the pending procedures. ABATE asks that the Customer be subject to firm load shedding before other customers when doing so would not compromise system reliability and could prevent shedding other firm load. ABATE Initial Brief, pp. 9-10. Those are the operative protections included in the proposed Case

No. U-22059 language, and the Customer satisfies that language's applicability criteria. DTE Electric Initial Brief, pp. 49-50; (Willis, 3T 427-429; Matthews, 3T 821-822).

ABATE would additionally continue the Customer-specific condition "until such time all of the resources necessary to serve the Google data center load are in service." ABATE Initial Brief, p. 10. That formulation should not be adopted. It does not identify which resources qualify as "necessary," how the Company or Commission would determine that all such resources are "in service," or how the condition would interact with the generally applicable emergency procedures after that point. More fundamentally, emergency firm load shedding is an operational measure invoked to maintain system integrity under the circumstances existing during an emergency. Its application should turn on the reliability criteria stated in the approved Emergency Electric Procedures, not on a separate Customer-specific resource-completion test imposed through the Special Contract approval order.

ABATE's proposed endpoint also confuses resource planning with emergency operations. The Company plans for system resource adequacy through its IRP and related procurement processes, while the Emergency Electric Procedures establish the sequence of operational measures available during an actual emergency. Whether a particular resource has been identified, approved, constructed, or placed in service does not replace the operative determination identified in the proposed procedures: whether priority shedding of the Customer can prevent shedding other firm customer load without compromising system reliability.

Accordingly, there is no gap requiring an additional Special Contract condition. The Company agrees that the Customer should be subject to priority firm load shedding under the identified circumstances; the amendments proposed in Case No. U-22059 apply to the Customer; Staff agrees that those amendments would provide the requested protection if approved; and the

PSA independently provides an earlier mechanism for adjusting the Customer's load ramp or maximum load when resource limitations arise. DTE Electric Initial Brief, pp. 48-50; (Foley, 3T 101; Willis, 3T 427-429; Matthews, 3T 821-822).

The Commission should therefore approve the Special Contracts without adding Customer-specific emergency procedure language. It should permit Case No. U-22059 to resolve the generally applicable Emergency Electric Procedures on the record developed there and reject Staff's requested contingent amendment and ABATE's duplicative resource-completion condition. This result preserves the substantive protection on which the Company, Staff, and ABATE agree without rewriting the PSA, duplicating a pending tariff proceeding, or tying emergency operations to an undefined resource-planning milestone.

5. Grid Reliability and Operational Protections

MEICEO and GLREA ask the Commission to impose additional conditions concerning the Facility's operating parameters and interconnection. MEICEO requests that the Company provide completed studies and finalized operating parameters in this docket, conduct a public workshop concerning those materials, and confirm that the operating parameters may be modified to comply with future requirements imposed by the Commission, NERC, FERC, MISO, or ITC. MEICEO Initial Brief, pp. 41-44. GLREA supports MEICEO witness Shaver's proposed ramp-rate and ride-through requirements, urges the Commission to delay approval until final parameters are available, and separately asks the Commission to require power-quality monitoring equipment to verify the Customer's compliance. GLREA Initial Brief, pp. 10-13.

DTE Electric agrees with the intervenors' stated objective: the Facility must operate under enforceable requirements that protect system reliability and other customers. The dispute concerns neither the importance of that objective nor whether operating parameters will apply. The dispute concerns whether the Commission should prescribe particular technical requirements in this special contract proceeding before the Customer-specific studies and technical coordination needed to establish those requirements are complete. It should not. The PSA already requires the Customer to comply with operating parameters established for the Facility before energization, and the Company, ITC, MISO, and the Customer are completing the technical work necessary to finalize those parameters. (Benyard, 3T 454-456; Confidential Exhibit A-21).

- *The Commission Should Not Substitute Litigation Proposals for Technically Derived Operating Parameters*

MEICEO and GLREA's recommendations would substitute litigation proposals for the coordinated engineering process already underway. MEICEO witness Shaver[10] proposes, among other things, a fixed 30 MW-per-minute operating ramp limit and ride-through requirements derived from proposed MISO requirements, IEEE 2800, and NERC PRC-029. (Shaver, 3T 758-760). GLREA asks the Commission to adopt those recommendations and impose an additional power-quality-monitoring requirement. GLREA Initial Brief, pp. 10-13. But MEICEO witness Shaver acknowledged that MISO's requirements were not final and that modified or Customer-specific requirements might be appropriate. (Shaver, 3T 759-760). Witness Shaver's recommendations therefore do not establish the final operating limits appropriate for this Facility; they identify subjects and possible benchmarks that must still be evaluated through the Customer-specific technical process.

[10] Neither MEICEO witness Shaver's testimony nor his qualifications (Exhibit MEICEO-18) identify experience conducting the types of transmission-system stability, short-circuit, or electromagnetic-transient studies being performed for this Facility; operating a bulk electric or transmission system; or establishing final operating parameters for a 1,000 MW transmission-connected load. His background and experience have been focused on mircogrids, such as developing and testing hardware and software for "small-scale, remote microgrids." (Shaver, 3T 733). The Commission should not select a fixed engineering value from advocacy testimony where the witness's identified experience does not include performing the studies needed to establish that value for this Facility, and where the responsible technical entities are actively completing those studies.

[redacted] The final parameters can therefore reflect the Facility's actual equipment, observed or modeled electrical behavior, interconnection configuration, transmission-system conditions, and applicable requirements. An order in this special contract proceeding that prescribes a fixed numerical limit or generic standard before that work is complete could displace a more appropriate Customer-specific requirement ultimately supported by the studies.

Rejecting the intervenors' proposed conditions would not permit the Facility to operate without enforceable requirements. It would preserve the technically sound process for determining what those requirements must be. The Commission should find that the PSA's operating-parameter framework reasonably protects system reliability and should decline to substitute witness proposals for the engineering determinations of the entities responsible for studying, interconnecting, and operating the Facility and the surrounding electric system.

- *This Special Contract Proceeding Should Not Create a Parallel Large-Load Reliability Regime*

This proceeding concerns whether the negotiated Special Contracts between DTE Electric and the Customer should be approved. It is not a federal transmission-planning proceeding, a generic large-load interconnection standards docket, or a technical rulemaking or docket establishing requirements for computational loads generally. Yet the intervenors' recommendations would have effects extending beyond the approval of these Special Contracts. MEICEO relies on proposed or developing requirements from MISO and other authorities and asks the Commission to impose a process for future modification of the Customer's parameters. GLREA relies in part on events involving data centers in other regions and requests operating and monitoring requirements intended to address data-center risks as a category. MEICEO Initial Brief, pp. 41-44; GLREA Initial Brief, pp. 10-13.

The broader large-load reliability issues identified by MEICEO and GLREA are already the subject of active, coordinated federal and regional proceedings involving the entities responsible for establishing and administering transmission-system reliability requirements. NERC has issued guidance and assessments concerning emerging large loads; FERC has instituted a proceeding under Section 206 of the Federal Power Act concerning whether MISO's existing tariff adequately addresses large-load interconnection; and MISO is using its Large Load Working Group and stakeholder process to develop MISO-wide requirements addressing data and modeling, ramping, ride-through performance, stability assessments, and related criteria. (Shaver, 3T 753-755); Midcontinent Independent System Operator, Inc., 195 FERC ¶ 61,212 (2026). MISO describes its ongoing effort as developing a clear and consistent framework for the reliability review and integration of large loads throughout its transmission system.

The Company does not contend that those federal and regional activities divest the Commission of authority to protect Michigan customers or to consider grid reliability within its jurisdiction. The point is one of orderly regulation, technical coordination, and the appropriate scope of this special contract proceeding. Imposing witness-proposed ramp-rate, ride-through, monitoring, reporting, and parameter review requirements through an order approving one customer's special contracts could create overlapping obligations administered by different entities, uncertainty concerning which requirement controls, and customer-specific standards that diverge from or must be revised to accommodate the MISO-wide framework now being developed. Hence, transmission-level concerns are being addressed through ISO/RTO and federal processes, and premature state-level measures may produce policies that diverge across regulatory jurisdictions.

[redacted] The contractual and technical process therefore provides present protection while allowing the final requirements to remain aligned with the federal and regional standards ultimately adopted.

Accordingly, this special contract proceeding is not the appropriate forum to establish generally applicable large-load operating standards, prescribe final engineering values before the supporting studies are complete, or create a parallel Commission-supervised technical process that duplicates the work of DTE Electric, ITC, MISO, NERC, and FERC. The Commission can approve the contractual framework without freezing technical requirements prematurely or introducing an additional layer of potentially inconsistent regulation. The more orderly approach is to allow the responsible technical entities and ongoing federal and regional processes to complete their work while enforcing the PSA's existing requirement that Customer-specific operating parameters be finalized before the Facility is energized.

- *The Company and ITC Are Completing the Studies Needed to Establish Customer-Specific Parameters*

The Company does not dispute that a facility of this size requires carefully developed operating parameters addressing its interaction with the electric system. [redacted]

The studies supporting that work are not speculative future undertakings. Company Witness Benyard testified that ITC—the transmission owner responsible for the relevant stability and short-circuit work—was conducting the stability studies and had completed screening-level short-circuit analysis. The Company had also commenced its electromagnetic-transient-based simulations and estimates. (Benyard, 3T 454). The studies require coordination among the Company, ITC, MISO, and the Customer because the operating parameters must reflect the Facility's particular equipment, operating characteristics, interconnection configuration, and effect on the electric system. (Benyard, 3T 454-456).

MEICEO's suggestion that the Company has failed to address the relevant reliability considerations therefore mischaracterizes the record. The Company has identified the subjects the parameters must address, produced its draft framework, commenced the studies needed to establish the final values, and committed that the parameters will be finalized before energization. MEICEO itself acknowledges that the Company "appears to be taking the proper steps to ensure the Google facility does not adversely impact grid reliability." MEICEO Initial Brief, p. 44. The fact that technically derived values were not final when the record closed does not establish that the Special Contracts are unreasonable or that an additional condition of approval is necessary.

- *Operating Requirements Should Be Based on Completed Technical Studies*

MEICEO and GLREA treat the absence of final values during this proceeding as a reason for the Commission either to prescribe operating requirements itself or to require additional post-hearing procedures before the Special Contracts may be approved. But the record explains why final values were not presented: the relevant analyses are iterative, site-specific, and dependent on continuing technical coordination. Finalizing operating requirements before completing that work would invert the prudent engineering process by selecting numerical limits first and evaluating their technical suitability afterward.

Nor does the Commission need the final parameters to determine whether the Special Contracts should be approved. The issue here is whether the contractual framework reasonably protects the Company's system and other customers. That framework does so by requiring the Customer to comply with operating parameters established for the Facility before energization. The precise engineering values implementing that obligation are operational details developed under the PSA; they are not additional commercial terms that must be fixed in the Commission's approval order.

MEICEO's proposed public workshop and supplemental filing would likewise add a new review process without identifying what Commission approval the completed studies or parameters would even require. MEICEO Initial Brief, p. 44. Accordingly, the Commission should not condition approval of the Special Contracts on a new workshop and supplemental record process when the PSA already requires completion of the relevant operating requirements before service begins and MEICEO identifies no statutory, tariff, or contractual requirement for separate Commission approval of each technical parameter.

The parameters also need not remain frozen if later-applicable reliability requirements change. DTE Electric and the Customer remain subject to applicable law, Commission orders, tariffs, and requirements imposed by entities possessing authority over the interconnection and operation of the system. The Commission need not rewrite the PSA to require compliance with otherwise applicable requirements, nor should it impose an open-ended condition purporting to incorporate every future proposal before that proposal is adopted and its applicability is known.

- *A Fixed 30 MW-per-Minute Ramp Limit Is Not Supported on this Record*

MEICEO witness Shaver recommends that the Facility's operational ramp rate be limited to 30 MW per minute and that its voltage and frequency ride-through requirements be based on IEEE 2800 and NERC PRC-029. (Shaver, 3T 758-760). GLREA asks the Commission to adopt those recommendations. GLREA Initial Brief, pp. 10-13. However, MEICEO witness Shaver acknowledged that MISO's proposed requirements had not been finalized and that modified or Customer-specific requirements might be appropriate. (Shaver, 3T 759-760). His proposal therefore does not establish that 30 MW per minute is the technically correct final limit for this Facility; it offers a proposed starting value derived from requirements that were themselves still under development.

The limited evidentiary foundation for selecting MEICEO witness Shaver's proposed numerical limit is also apparent from his stated professional background. His experience reflects electrical-engineering education and experience principally involving distributed technologies, with an emphasis on microgrids, and metering equipment. (Shaver, 3T 733; Exhibit MEICEO-18). His graduate research focused on developing and testing hardware and software for small-scale, remote microgrids. *Id.* Neither his testimony nor his qualifications identify experience conducting transmission-system stability, short-circuit, or electromagnetic-transient studies for a

1,000 MW transmission-connected load; operating a bulk electric or transmission system; or establishing final operating parameters for a facility of this type. That does not render his testimony irrelevant per se, but it does underscore why his proposed 30 MW-per-minute limit should not displace the Customer-specific engineering judgment produced by the entities conducting and reviewing the applicable studies.

Moreover, the Company's approach is more prudent. Ramp-rate limits should be established from the completed analyses, together with input from ITC and MISO, rather than prematurely selected in isolation through a Commission order. (Benyard, 3T 454-456). That process can account for the Facility's actual equipment and operating characteristics, the transmission-system configuration, interactions with protection systems, and any applicable requirements in effect when service is energized.

The Commission should therefore decline to prescribe a fixed 30 MW-per-minute limit on this record. Doing so would substitute a litigation recommendation for the technical judgment of the entities conducting and reviewing the relevant system studies. It could also prevent adoption of a more appropriate Customer-specific requirement if the completed analyses support a different limit.

- *Separate Power Quality Monitoring Conditions Are Unnecessary*

GLREA separately asks the Commission to require the Company to install power-quality monitoring equipment to verify compliance with the final operating parameters. GLREA Initial Brief, pp. 12-13. That recommendation was first formulated in GLREA's Initial Brief as an addition to MEICEO witness Shaver's proposed requirements. GLREA identifies no specific equipment, placement, technical standard, data requirement, ownership responsibility, or evidence demonstrating that the monitoring and data provisions being developed through the Customer-specific operating framework are inadequate.

[redacted] Thus, the Company is not relying on unenforceable requirements incapable of verification; monitoring, data, mitigation, and operational response are components of the framework being developed.

To the extent the completed studies demonstrate that dedicated monitoring equipment is necessary at a particular location or for a particular parameter, that requirement can be incorporated into the final technical and operating arrangements. But the Commission should not impose GLREA's undefined equipment mandate without evidence identifying the appropriate equipment, the measurements required, or a deficiency in the Company's existing framework. Those are engineering determinations that should follow from the same technical analyses used to establish the parameters being monitored.

- *The PSA's Customer-Specific Technical Process Protects Grid Reliability Without Creating a Duplicative Regulatory Regime*

The Commission should approve the Special Contracts without converting this proceeding into a continuing technical review docket or prescribing operating parameters before the supporting studies are complete. The PSA already requires Customer-specific parameters before energization, the Company and ITC are completing the analyses needed to establish those parameters, and the draft framework addresses the reliability subjects identified by MEICEO and GLREA. (Benyard, 3T 454-456; Confidential Exhibit A-21). The Commission should therefore decline to delay approval, impose a fixed 30 MW-per-minute limit, mandate unspecified monitoring equipment, or require supplemental workshops and filings. Those proposals would substitute an incomplete litigation record for the coordinated technical process designed to produce enforceable, Customer-specific operating requirements.

VI. THE CUSTOMER BENEFIT ANALYSIS AND AFFORDABILITY BACKSTOP DEMONSTRATE THAT THE SPECIAL CONTRACTS BENEFIT, AND DO NOT SHIFT COSTS TO, OTHER CUSTOMERS.

DTE Electric's Initial Brief demonstrated that the Special Contracts are projected to produce an approximately $1.7 billion aggregate benefit to the Company's other customers from 2028 through 2047, while the contractual protections described in Section V ensure that the Customer remains responsible for the costs associated with its service. DTE Electric Initial Brief, pp. 105-130; (Willis, 3T 404-418; Foley, 3T 103-105, 143-153). The projected benefit is the net result of separately identified revenue, power-supply, operating-cost, generation-resource, carbon-capture, and storage components reflected in Exhibit A-19. (Willis, 3T 408-411).

Staff and intervenor Initial Briefs do not identify an error that converts the projected aggregate benefit into a net cost to other customers. Instead, they principally challenge particular assumptions, the valuation or characterization of particular components, and the certainty with which an estimate extending through 2047 can be stated today. Those challenges do not establish that the Special Contracts are unreasonable or that the Customer's service will shift costs.

The Company has consistently described the approximately $1.7 billion amount as an estimate based on the best information currently available, not as a guaranteed future result. DTE Electric Initial Brief, pp. 105-107, 120-130; (Willis, 3T 404, 408-418). Importantly, the customer benefit analysis is not the only customer protection in the record. The Affordability Backstop requires the Customer to comply with a Commission ruling or order if the Commission determines that the aggregate costs of serving the Customer exceed the aggregate benefits of the Special Contracts, thereby ensuring that the Customer bears any Commission-determined shortfall. DTE Electric Initial Brief, pp. 39-43; (Foley, 3T 103-105, 143-153). As explained in Section V.A.6, differences between estimated and actual costs or benefits therefore do not make those differences the responsibility of other customers.

- *The Special Contracts Produce a Substantial Positive Benefit*

MNS characterizes the approximately $1.7 billion estimate as lacking meaningful independent scrutiny because this proceeding advanced on an expedited schedule. MNS Initial Brief, pp. 4-5. That characterization overlooks Staff's extensive independent review and the voluminous discovery produced by the Company in response to Staff and intervenor discovery. Staff witness Isakson audited the billing determinants and rates used to calculate Customer revenues, examined the individual values in Exhibit A-19, independently recreated the base-sales analysis, and sponsored separate exhibits addressing the overall customer benefit, the cost-of-service comparison, customer-choice effects, and alternative scenarios. Staff's analysis "largely matches Company Exhibit A-19," and Staff's independent recreation of the base-sales benefit "matches the Company's finding on Exhibit A-20." DTE Electric Initial Brief, pp. 112-115; (Isakson, 3T 857, 863; Willis, 3T 418).

Staff took issue with the Company's use of a 1.5% annual escalation of base-rate revenue and removed that escalation from Staff's analysis. (Isakson, 3T 857-858). Staff nevertheless continued to find a substantial positive net benefit. Staff's alternative treatment therefore does not demonstrate that serving the Customer produces a net cost; it demonstrates that the projected magnitude changes when a different revenue-escalation assumption is used. DTE Electric Initial Brief, pp. 113-116. That distinction is central. The governing concern is whether costs caused by serving the Customer will be shifted to other customers, not whether every reasonable modeling assumption produces the same numerical estimate. Staff's more conservative analysis confirms that it does not.

MNS' assertion that the absence of the 1.5% escalation nearly halves the projected benefit does not change that conclusion. MNS Initial Brief, pp. 6-7. Company Witness Willis explained that the 1.5% assumption represents estimated Rate D11 growth absent the addition of this Customer and was based on the average annual Rate D11 full-service increase across three prior rate cases. (Willis, 3T 414-415). Exhibit A-20 isolates the effect of adding the Customer to the cost-of-service analysis; it does not assume that the Customer itself causes the historical rate growth reflected in the escalation factor. DTE Electric Initial Brief, pp. 115-116. At the same time, Staff's non-escalated case provides a conservative alternative that removes the disputed assumption and still shows a positive aggregate result. The Commission therefore need not decide that the precise $1.7 billion amount will necessarily materialize to find that the record demonstrates a substantial projected benefit and no basis to reject or condition the Special Contracts.

- *The 90% Load-Factor Assumption Supports the Benefit Estimate, While the 80% Minimum Billing Demand Protects Other Customers if Actual Usage Is Lower*

MNS and ABATE argue that the customer benefit analysis assumes the Customer's load reaches its projected ramp and operates at a 90% load factor, while the Special Contracts require payment based on an 80% minimum billing demand. MNS Initial Brief, pp. 5-6; ABATE Initial Brief, pp. 4-7. But the parties conflate a forecasting assumption with a contractual protection. The 90% load factor is the Company's forecast of expected Customer usage based on the anticipated Facility operation. The 80% minimum billing demand is not a forecast of actual energy consumption; it is a contractual floor establishing minimum demand-based revenues if actual demand is lower than anticipated. DTE Electric Initial Brief, pp. 120-123; (Foley, 3T 97-99).

MNS witness Woods did not present an alternative analysis showing that a load factor below 90% produces a net cost over the contract term. Her narrower point was that lower actual utilization would reduce the projected benefit. (Woods, 3T 626). A reduction in the magnitude of a positive estimate is not evidence of cost shifting. DTE Electric Initial Brief, pp. 121-123. Moreover, as explained in Sections V.A.2 and V.A.3, Staff independently tested circumstances in which Customer revenues fall to the minimum-bill level and concluded that the minimum bill covers non-production costs in every year analyzed. Staff Initial Brief, pp. 5-7; (Isakson, 3T 874-877). The production-related costs in Staff's downside scenario were driven by the assumed proxy combined-cycle resource and carbon-capture costs, matters addressed through actual IRP resource selection and the Affordability Backstop rather than by replacing the negotiated minimum billing demand with MNS's preferred utilization assumption.

ABATE similarly emphasizes scenarios involving a delayed ramp, incomplete load realization, or an early reduction in load. ABATE Initial Brief, pp. 4-7. Those scenarios are not unprotected. Before the Load Ramp Completion Date, the minimum billing demand increases with the contractual load ramp. Once the Customer reaches the applicable contract demand, the minimum bill guarantees demand-based revenues regardless of actual usage. If the Customer terminates, the PSA termination payment applies; if the CCAA terminates through Customer default, the CCAA termination payment recovers the unrecovered revenue requirement of deployed projects; and the credit and collateral provisions support those obligations. DTE Electric Initial Brief, pp. 16-38, 59-65. Sections V.A.2 through V.A.5 address those protections in detail and demonstrate why the downside possibilities ABATE identifies do not establish a cost shift.

- *The Base Sales Benefit Is a Recognized Customer Benefit, Not an Improper Claim That System Costs Disappear*

MEICEO argues that much of the projected benefit reflects a reallocation of fixed production and transmission cost responsibility to the Customer rather than a reduction in total system costs. MEICEO Initial Brief, pp. 19-20; (Kenworthy, 3T 671-672). That observation describes the mechanism by which a substantial new customer benefits existing customers; it does not negate the benefit. The Customer's revenues and billing determinants cause it to assume a portion of the Company's fixed system costs that otherwise would remain the responsibility of existing customers. The fact that the underlying fixed costs do not disappear does not make the resulting reduction in existing customers' allocated responsibility illusory. DTE Electric Initial Brief, pp. 107-112; (Willis, 3T 412-418).

Company Witness Willis' cost-of-service comparison incorporates the Customer's revenues, sales, power-supply expenses, taxes, and load characteristics into the Commission-approved cost-of-service framework and compares the resulting revenue sufficiency with and without the Customer. The difference measures the modeled benefit that would flow through to customers in a general rate case. (Willis, 3T 412-418). Staff independently recreated that comparison and confirmed that its result matches Exhibit A-20. (Isakson, 3T 863; Willis, 3T 418). Thus, MEICEO does not identify an accounting error or an omitted Customer-caused cost. It describes how adding substantial revenues and billing determinants affects the allocation of fixed system costs under the approved methodology.

Nor does the base sales comparison purport to capture every cost of serving the Customer. Exhibit A-19 separately includes incremental power-supply costs and benefits, other operating costs, the full revenue requirements of the proxy combined-cycle and carbon-capture resources, and the storage pull-ahead benefit. (Willis, 3T 408-411; Exhibit A-19). Future general rate cases and PSCR proceedings will use then-current costs, revenues, billing determinants, and allocation methods. As explained in Section V.C, the current analysis neither fixes future cost allocation nor guarantees that Rate D11 will remain unchanged. Its purpose is to provide a reasonable estimate of the Customer's expected effect under the best available information, while preserving future Commission authority over actual ratemaking treatment.

- *Presenting the Benefit in Nominal Dollars Does Not Overstate What the Analysis Measures*

ABATE and MEICEO highlight that the approximately $1.7 billion customer-benefit estimate is a nominal sum rather than a present value. The Company has never represented the approximately $1.7 billion estimate as a present value. Exhibit A-19 transparently presents the annual nominal values for each benefit and cost component from 2028 through 2047, permitting the annual amounts to be discounted using an identified discount rate and base year. DTE Electric Initial Brief, pp. 116-118. Staff and intervenors' ability to calculate and present their own discounted totals from the annual values confirms that the format did not obscure the timing or amount of the modeled costs and benefits.

More fundamentally, discounting changes the time basis on which the projected benefit is expressed; it does not transform the projected benefit into a cost. Both ABATE's and MEICEO's calculations remain substantially positive. ABATE's calculation produces an approximately $1.0 billion present-value benefit, while MEICEO's calculation produces an approximately $984 million benefit. ABATE Initial Brief, pp. 5-6; MEICEO Initial Brief, pp. 18-19; (Dauphinais, 3T 539-541; Kenworthy, 3T 676-678).

MEICEO also points to modeled net-cost years from 2035 through 2038. MEICEO Initial Brief, pp. 18-19; (Kenworthy, 3T 678). But the Special Contracts are integrated 20-year arrangements, and the governing customer-protection inquiry is whether the aggregate costs of serving the Customer exceed the combined benefits over the relevant contractual period. DTE Electric Initial Brief, pp. 107-108; (Foley, 3T 105, 147; Willis, 3T 404). Section V.A.6 explains why this aggregate standard does not prevent Commission action during the term. PSA Section 5.1.3 permits action at any time during the term; it simply directs the Commission to evaluate the combined costs and benefits rather than treating an isolated year of modeled cost as proof that the contracts shift costs overall. The positive results in the remaining years more than offset the interim modeled costs reflected in Exhibit A-19.

Both ABATE's and MEICEO's calculations confirm that discounting the Exhibit A-19 values does not reverse the projected result. Their calculations challenge the magnitude of the Company's estimate, not the direction of the projected result during the Special Contracts' term.

- *ABATE's Post-2047 Sensitivity Does Not Undermine the Customer-Benefit Showing*

ABATE separately challenges the Company's analysis of the proxy resource's remaining value after the PSA expires in 2047. ABATE converts the $75.01 million present-value benefit shown in Exhibit A-15 for the post-contract period into a $129.55 million present-value cost. ABATE Initial Brief, pp. 5-6; (Dauphinais, 3T 539-541; Exhibit AB-2).

DTE Electric's Initial Brief fully addressed that sensitivity, and the Company relies on and incorporates that discussion. DTE Electric Initial Brief, pp. 123-125. As explained there, ABATE's calculation is not a present projection of an actual stranded resource obligation. The proxy CCGT with CCS is a modeling assumption used to assign a cost to the reliability need reflected in the customer benefit analysis. The Company's upcoming IRP will determine the nature of any actual need and the reasonable and prudent portfolio for meeting it. (Burgdorf, 3T 393-395). The Commission need not determine in this proceeding that the modeled proxy will be selected, much less that it will enter service on the modeled schedule and remain in DTE Electric's portfolio after 2047.

- *The Proxy Resource Assigns a Reasonable Cost to the Modeled Reliability Need Without Predetermining the IRP*

MNS and MEICEO challenge the CCGT with CCS proxy resource used in the customer benefit analysis, but they advance somewhat different arguments. MNS Initial Brief, pp. 19-21; MEICEO Initial Brief, pp. 16-18. MNS argues that the analysis is preliminary because the Company has not completed the IRP modeling that will identify the resource need caused by the Customer's load or select the resources used to meet that need. MNS therefore asks the Commission not to endorse the proxy's asserted benefits. MNS Initial Brief, pp. 19-21; (Woods, 3T 650-651). MEICEO argues that the proxy performs "double duty" by supplying the substantial modeled cost associated with the reliability need while also supplying assumptions used to value certain benefits. MEICEO also identifies the assumed continued availability of federal carbon-capture tax credits as an additional uncertainty. MEICEO Initial Brief, pp. 16-18; (Kenworthy, 3T 679-682).

Those arguments do not eliminate the need to include a reasonable cost for the modeled reliability requirement in the current customer benefit analysis. The Company does not seek approval in this proceeding to construct a CCGT with CCS. The proxy is a generic modeling construct used to quantify a potential cost associated with the 2033 reliability need identified in the resource adequacy analysis. The actual resource portfolio, including whether any such generating resource is selected, will be determined in the Company's upcoming IRP. DTE Electric's Initial Brief, pp. 118-121; (Burgdorf, 3T 375, 394, 399). The Company does not designate a particular generation resource as exclusively serving the Customer or directly assign the revenue requirement of a specific generation asset to the Customer. Exhibit MEC-5, p. 1.

However, that does not prevent the IRP's with-and-without analysis from identifying any resource changes caused by serving the Customer's incremental load and including the associated incremental revenue requirements among the costs evaluated under PSA Section 5.1.3. DTE Electric Initial Brief, pp. 36-37; (Foley, 3T 143-144, 244-246).

The proxy's inclusion is nevertheless important to evaluating the projected benefit. Exhibit A-19 charges the analysis with the proxy resource's full modeled revenue requirement and the modeled cost of carbon capture. Those two components reduce the projected benefit over the contract term as set forth in Exhibit A-19. The approximately $1.7 billion projected benefit therefore is not calculated by assuming that the modeled reliability need can be met at no cost. It is the net result after the analysis includes a modeled cost for meeting that need.

MNS asks the Commission to disregard the Company's discussion of the proxy resource's asserted benefits because the proxy is hypothetical and any actual resource will be selected through the IRP. MNS Initial Brief, pp. 19-21; (Woods, 3T 650-651). But MNS' request does not undermine the proxy's separate and limited cost-modeling function. The Commission need not endorse the proxy as the preferred future resource. It need only recognize that the Company did not omit the cost of the modeled reliability need when estimating the Customer's net effect. DTE Electric Initial Brief, pp. 36 118-121; (Burgdorf, 3T 375, 394, 399; Willis, 3T 410-411). MNS' separate request that actual future resource costs be directly assigned to the Customer concerns a potential ratemaking methodology and is addressed in Sections V.A.6 and V.C; it provides no basis to remove the modeled resource cost from Exhibit A-19. MNS Initial Brief, p. 21.

MEICEO's tax credit concern likewise identifies uncertainty in the amount of the modeled proxy cost, not a basis for treating the proxy as an approved resource or assigning no cost to the modeled reliability need. MEICEO argues that changes to, or the unavailability of, federal carbon-capture tax credits could increase the proxy's modeled cost and reduce the projected benefit. MEICEO Initial Brief, pp. 17-18; (Kenworthy, 3T 681-682). But the approximately $1.7 billion amount is a forecast rather than a guaranteed result. It does not establish the actual tax treatment of an actual resource that has not been selected.

As discussed in Section V.B.4, the Company's 2026 IRP will determine the nature of any incremental 2033 need and evaluate the reasonable and prudent alternatives for meeting it. The IRP's with-and-without analysis will identify any resources caused by serving the Customer's load, but it will not assign an individual resource exclusively to the Customer or determine how its revenue requirement will be allocated or recovered. The revenue requirements of resources identified through that analysis as caused by serving the Customer's incremental load, and not recovered through the CCAA, will be included among the aggregate costs evaluated under Section 5.1.3 of the PSA. Cost allocation and recovery remain matters for the applicable rate case proceedings. DTE Electric Initial Brief, pp. 36-43, 118-121; (Foley, 3T 143-144, 153, 244-246; Burgdorf, 3T 394, 399).

If updated resource selections, costs, or tax assumptions differ from the proxy, those differences may change the projected or actual aggregate result. The Affordability Backstop addresses that possibility by requiring Customer action if the Commission determines that the aggregate costs of serving the Customer exceed the applicable Customer-derived benefits. It does not make the proxy an approved resource, directly assign its modeled revenue requirement to the Customer, or guarantee that every proxy assumption will remain unchanged. The Commission should therefore reject MNS's request to disregard the proxy analysis and MEICEO's contention that use of the proxy improperly prejudges the IRP.

- *The Storage Pull-Ahead Benefit Is Properly Included, but the Overall Showing Does Not Depend on Its Precise Valuation*

MEICEO challenges the approximately $1.16 billion storage pull-ahead benefit, emphasizing that the amount depends on future resource timing, accreditation, and portfolio decisions. MEICEO Initial Brief, pp. 16-19. The Company's analysis counts a benefit because the Customer-funded CCAA storage advances resources that otherwise would need to be deployed for broader system purposes. The estimate represents the revenue requirement avoided or deferred for resources that the Company otherwise would have to supply. DTE Electric Initial Brief, pp. 123-126; (Burgdorf, 3T 372-376).

That treatment does not assume that every future storage decision is fixed today. The CCAA obligates the Customer to pay the full revenue requirement of the deployed storage projects, while other customers receive the associated system and resource-adequacy value. DTE Electric Initial Brief, pp. 59-65, 123-126. Section V.B.6 explains why the CCAA's "up to" quantities and project-sizing flexibility do not undermine the protection: the Company's analysis assumes 450 MW of storage even though the CCAA permits deployment up to 480 MW, and the Company intends to deploy at least 450 MW. (Foley, 3T 157-159).

MEICEO's alternative present-value calculation removing the entire storage pull-ahead benefit nevertheless remains positive. MEICEO Initial Brief, p. 19; (Kenworthy, 3T 677). Thus, even MEICEO's sensitivity does not show a net cost. It shows that the size of the projected benefit changes if one removes an entire benefit category while retaining the modeled costs. The appropriate response to future differences in resource timing or value is to use actual information in the IRP, rate cases, and aggregate Affordability Backstop presentations, not to assign the customer-funded storage portfolio zero value in this proceeding.

- *MNS' Renewable Avoided-Cost and Banked-REC Arguments Do Not Establish an Omitted Customer Cost*

MNS argues that Exhibit A-19 improperly credits the Customer with avoiding 200 MW of renewable additions in 2033 and 50 MW in 2034 and fails to assign a cost to the use of banked RECs for the Customer's non-VGP load. MNS Initial Brief, pp. 7-13. Section V.B.5 addresses the underlying renewable-energy accounting in detail. As explained there, the Customer's 1,600 MW VGP enrollment reduces the increase in the Company's RPS requirement relative to the requirement that would apply if the Customer's entire load were treated as non-VGP sales. The analysis does not claim that VGP enrollment eliminates every incremental REC associated with the Customer's load or that the Company may use the VGP RECs again for non-VGP RPS compliance. DTE Electric Initial Brief, pp. 73-80; (Bilyeu, 3T 279-304, 333).

MNS' disagreement concerns attribution and valuation. The forecast maintained the common planning assumptions from the Company's approved Amended REP in Case No. U-21662 so the Company could compare the incremental effect of the Customer's load and VGP enrollment on an equivalent basis. (Bilyeu, 3T 302-304). Other resources contributing to the forecasted REC balance do not negate the reduction in the RPS requirement caused by removing properly enrolled VGP sales from the sales denominator. Nor does reliance on an existing REC balance establish that a particular REC is assigned to the Customer without compensation. The Customer's non-VGP sales remain included in the RPS analysis, and the Customer continues to pay PSCR charges supporting the Company's overall renewable-resource and power-supply costs. DTE Electric Initial Brief, pp. 73-75; (Bilyeu, 3T 283-284).

Most importantly as applied to the customer benefit analysis, MNS does not present a revised analysis showing that its preferred treatment produces a net cost over the Special Contracts' term. If future IRP or REP analyses identify additional renewable resource or REC costs caused by serving the Customer, those costs are among the categories the Company will present in the aggregate Affordability Backstop assessment. (Foley, 3T 143-144, 153). Conversely, an avoided cost should be recognized when record evidence establishes that the Customer's service and contractual commitments permit the Company to avoid or reduce a cost that otherwise would have been incurred. MNS' request to foreclose recognition of the 250 MW reduction now would predetermine an attribution question that future IRP and REP proceedings will evaluate using updated assumptions.

- *The Customer Benefit Analysis Includes Transmission Expense, and Future Aggregate Cost-Benefit Presentations Will Use Updated Transmission-Cost Information*

The AG and MEICEO question whether the Company's customer benefit analysis fully captures the transmission costs associated with serving the Customer, and MNS adopts their proposed reporting conditions. AG Initial Brief, pp. 21-24; MEICEO Initial Brief, pp. 21-24; MNS Initial Brief, pp. 17-18, 30-31. However, the customer benefit analysis presented in this case does not omit transmission expense. Company Witness Burgdorf explained that the approximately $91 million increase modeled for 2029 consists of approximately $49.2 million associated with estimated ITC network upgrade costs and approximately $41.8 million associated with the effect of the Customer's load on the Company's total load and resulting transmission expense. He also provided the schedule-by-schedule calculation supporting that division. DTE Electric Initial Brief, pp. 126-128; (Burgdorf, 3T 396-398).

As explained more fully in Section V.A.6, the Company will include transmission-investment revenue requirements in future aggregate cost-and-benefit presentations using the best available information, including available network upgrade capital costs and modeled effects under the applicable transmission schedules. DTE Electric Initial Brief, pp. 39-45; (Foley, 3T 143-146, 153, 249-250). The Company does not receive project-specific ITC ratemaking bills and therefore cannot utilize the precise project-by-project traceability some parties propose. That limitation does not exclude transmission costs from the Affordability Backstop. It defines the information and methodology through which those costs reasonably can be identified and presented in future proceedings.

- *Future Uncertainty Does Not Make the Customer Benefit Analysis Unreasonable*

MEICEO argues that the projected customer benefit depends on matters that will be resolved in later proceedings, including actual Customer load, future IRP resource selections, resource accreditation, final transmission and distribution related costs, and applicable cost-allocation methodologies. MEICEO Initial Brief, pp. 15-21. MEICEO therefore characterizes the approximately $1.7 billion result as a directional estimate whose precise amount cannot be established in this proceeding.

The Company does not contest the limited proposition that an analysis extending from 2028 through 2047 necessarily depends on forecasts and cannot guarantee the realization of every future input. The Company has not represented otherwise. Exhibit A-19 transparently identifies the assumptions and annual values producing the estimate, while Company Witness Willis described the approximately $1.7 billion amount as the estimated net benefit over the Special Contracts' term. DTE Electric Initial Brief, pp. 105-112; (Willis, 3T 404-411; Exhibit A-19).

But uncertainty regarding the precise amount does not mean the analysis lacks evidentiary value. Staff audited the Company's inputs, independently recreated the base-sales analysis, concluded that its result matched Exhibit A-20, and prepared a more conservative overall analysis that remained substantially positive. DTE Electric Initial Brief, pp. 112-116; (Isakson, 3T 857-863; Willis, 3T 418). No party presented a complete alternative analysis showing that the aggregate costs of serving the Customer exceed the applicable revenues and avoided costs over the term.

The parties' sensitivities instead demonstrate that the amount of the projected customer benefit changes when selected assumptions or benefit categories are modified. As highlighted above, Staff removed the revenue-escalation assumption but retained a positive result. MEICEO discounted the annual values to a selected base year and likewise obtained a positive present value. Even MEICEO's calculation that both discounts the benefit and removes the full storage pull-ahead benefit remains positive. MEICEO Initial Brief, pp. 18-19; (Kenworthy, 3T 676-678). Those calculations do not prove the Company's exact estimate will materialize, but neither do they establish a cost shift or negate the substantial expected benefit shown by the record.

The proper regulatory response to forecast uncertainty is the framework already established by the Special Contracts and future proceedings. The Commission need not freeze the assumptions in Exhibit A-19 for 20 years. It may evaluate actual or updated Customer revenues, resource costs, fuel and purchased-power expense, transmission expense, distribution costs, CCAA revenue requirements, and demonstrated avoided costs as those amounts become known. DTE Electric Initial Brief, pp. 39-45; (Foley, 3T 143-153). As explained in Section V.A.6, the Affordability Backstop provides the contractual customer-protection mechanism if the Commission later determines that the aggregate costs of serving the Customer exceed the applicable benefits.

- *MEICEO Cannot Convert a Forecasted Benefit into a Guaranteed Contractual Outcome*

MEICEO asks the Commission to clarify that its public interest evaluation of special contracts requires "an affirmative affordability benefit to other customers rather than just a showing of no cost-shifting" and to impose conditions ensuring realization of any benefit claimed by the Company. MEICEO Initial Brief, pp. 13-14. As explained in Section III above, MEICEO identifies no statute or Commission order establishing a guaranteed affirmative net benefit as an independent legal prerequisite for the approval of a special contract. The governing inquiry remains whether the Special Contracts are lawful, reasonable, and in the public interest, including whether they protect other customers from costs caused by serving the Customer. The fact that the Company has demonstrated a substantial projected benefit does not transform that favorable evidentiary showing into a new legal condition applicable to special contracts generally.

More fundamentally, MEICEO does not stop at asking the Commission to require an affirmative projected benefit. It asks the Commission to impose conditions that "ensure the realization of any 'affordability benefit' claimed by the Company." MEICEO Initial Brief, pp. 13-14. That request would convert a forward-looking evidentiary projection into a guaranteed contractual outcome. Nothing in the governing public interest standard requires a utility to guarantee that a benefit forecast over a 20-year term will materialize precisely as estimated, notwithstanding future changes in Customer usage, resource selections, costs, revenues, market conditions, and Commission decisions. MEICEO identifies no contractual term, statute, or Commission order authorizing that notable departure.

MEICEO's position is also internally inconsistent. MEICEO repeatedly argues that the approximately $1.7 billion estimate is uncertain because material inputs will be determined in future proceedings, including the Company's IRP, rate cases, and PSCR proceedings. MEICEO Initial Brief, pp. 15-21. Yet it asks the Commission to "ensure" realization of the very result it contends cannot presently be determined with precision. The existence of forecast uncertainty may support later reviews using actual or updated information, but it cannot logically justify compelling the Company and the Customer to guarantee a particular forecasted outcome before the underlying resource, cost, and regulatory decisions have been made.

MEICEO's proposal also obscures the critical distinction between protecting other customers from an aggregate cost shortfall and guaranteeing that they receive a particular affirmative benefit. The Affordability Backstop performs the former function: if the Commission determines that the aggregate costs of serving the Customer exceed the aggregate benefits, the Customer must comply with the Commission's ruling or order ensuring that it pays all costs associated with its service. The provision does not guarantee that every projected avoided cost will be realized, that every modeled benefit will retain its estimated value, or that the aggregate benefit will equal a predetermined amount. Rewriting the Affordability Backstop to guarantee the forecasted upside would materially expand the negotiated Customer obligation from preventing a net cost shift to underwriting a particular level of benefits for other customers.

Nor can MEICEO's requested guaranteed affirmative benefit be justified as mere reporting or verification. The Company accepts reasonable reporting needed to administer the Special Contracts, including the Affordability Backstop. But MEICEO witness Kenworthy proposed more than disclosure: measurable triggers tied to assumptions underlying Exhibit A-19, a defined true-up or claw-back, and a sunset or reopener tied to the IRP cadence. (Kenworthy, 3T 693-696). Notably, under MEICEO's proposals, witness Kenworthy's measurable triggers and defined true-up or claw-back would not simply test whether other customers remain protected from a net cost shift. They would unreasonably authorize contractual and regulatory consequences whenever particular forecasting assumptions or projected benefit components fail to materialize as modeled, even where the Special Contracts continue to cover the aggregate costs of serving the Customer. That would rewrite Section 5.1.3 of the PSA, substitute MEICEO's proposed enforcement structure for the aggregate protection the contracting parties negotiated, and fundamentally alter the Commission's precedent on public interest determinations for special contracts. Nothing in the Special Contracts coverts the approximately $1.7 billion projected benefit into a payment obligation or guaranteed minimum benefit owed by the Customer.

Rejecting MEICEO's guaranteed affirmative benefit would not limit the Commission's authority to evaluate actual costs and benefits in future proceedings. The Commission may review updated resource costs, transmission expense, power-supply costs, Customer revenues, avoided costs, and other relevant information as those matters arise. What it should not do is predetermine that any reduction in a forecasted benefit, standing alone, constitutes contractual nonperformance or requires a true-up or claw-back. That would treat a variance from an estimate as though it were a cost shift, even when the Special Contracts remain beneficial and other customers remain fully protected.

In all events, the record satisfies the more demanding factual showing MEICEO seeks. Staff and intervenor Initial Briefs question the exactitude of the approximately $1.7 billion projected benefit more than the direction of the result. They identify assumptions that may change, propose alternative valuation conventions, dispute particular avoided-cost components, and seek additional reporting or ratemaking conditions. But no party presented a complete analysis showing that the Special Contracts will produce a net cost to other customers over their term. Staff's independent review instead replicated the core analysis and confirmed a substantial positive result after adopting more conservative assumptions. DTE Electric Initial Brief, pp. 105-130; (Willis, 3T 404-418; Isakson, 3T 857-877).

The Commission need not choose between guaranteeing precisely $1.7 billion and disregarding the customer-benefit analysis altogether. The Company's customer benefit analysis is a reasonable, transparent estimate based on the information presently available. It identifies the expected Customer revenues, separately recognizes incremental costs, assigns a material cost to the modeled resource adequacy need, and reflects benefits associated with the Customer-funded storage portfolio. (Willis, 3T 408-411; Exhibit A-19). Any remaining uncertainty is addressed through the contractual protections discussed in Sections V.A and V.B and through future Commission review, not by transforming the projected benefit into a guaranteed payment obligation.

In sum, an affirmative benefit is not an independent legal prerequisite to approval, and a projected benefit is not a contractual guarantee. The Special Contracts protect other customers against an aggregate cost shortfall; they do not guarantee the precise benefit projected in Exhibit A-19. The Commission should therefore find that the Company's transparent benefit analysis, corroborated by Staff's independent review and more conservative alternative analysis, reasonably projects a substantial benefit to other customers, and should reject MEICEO's request to transform the projected benefit into a mandatory and guaranteed contractual outcome.

VII. REQUEST FOR RELIEF

Based on the foregoing, DTE Electric Company respectfully requests that the Michigan Public Service Commission issue a final order on an expedited basis:

1. Approving the Company's Special Contracts with Google LLC as reasonable, prudent, and in the public interest;
2. Approving the Company's request to record regulatory liabilities to Account 254 for the accelerated recovery of costs for storage and renewable energy projects under the CCAA;
3. Approving the Company's request to record to income the financial adder to be paid by the Customer for the ZRC transfer under the CCAA; and
4. Granting such other lawful relief that the Commission deems reasonable and appropriate.

Respectfully submitted,

DTE ELECTRIC COMPANY
Legal Department

John A. Janiszewski Digitally signed by John A. Janiszewski
Date: 2026.08.03 17:04:08 -04'00'

By:___________________________________
Andrea E. Hayden (P71976)
John A. Janiszewski (P74400)
One Energy Plaza, 688 WCB
Detroit, Michigan 48226
Ph: (313) 235-4017

Dated: August 3, 2026

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of	)	
DTE ELECTRIC COMPANY	)	Case No. U-22058
for Approval of Special Contracts	)	
and for other relief	)	

PROOF OF SERVICE

CAITLIN MYERS states that on August 3, 2026, she served a copy of the DTE Electric Company's Reply Brief (Public), via electronic mail upon the persons listed on the attached service list.

Caitlin Myers Digitally signed by Caitlin Myers
Date: 2026.08.03 16:51:48 -04'00'

CAITLIN MYERS

MPSC Case No. U-22058
SERVICE LIST

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY
Michael J. Pattwell
Stephen A. Campbell
Clark Hill PLC
500 Woodward, Suite 3500
Detroit, Michigan 48226
mpattwell@clarkhill.com
scampbell@clarkhill.com

Lauren Degnan
ldegnan@clarkhill.com

ABATE Consultants:
James Dauphinais
Jessica York
Brian Andrews
Christina Hildebrandt
jdauphinais@consultbai.com
jyork@consultbai.com
bandrews@consultbai.com
childebrandt@consultbai.com

ECOLOGY CENTER, THE ENVIRONMENTAL LAW & POLICY CENTER, UNION OF CONCERNED SCIENTISTS, VOTE SOLAR; THE MICHIGAN ENERGY INNOVATION BUSINESS COUNCIL; AND THE INSTITUTE FOR ENERGY INNOVATION
Daniel Abrams
Katherine Duckworth
35 E Wacker Dr., Ste. 1600
Chicago, IL 60604
dabrams@elpc.org
kduckworth@elpc.org

Brad Klein
bklein@elpc.org

Alondra Estrada, Paralegal
aestrada@elpc.org
MPSCDocket@elpc.org

CEOs/MEIBC/IEI Consultants:
Chelsea Hotaling
Anna Sommer
James Gignac
Laura Sherman
Lee Shaver
Jared Deluccia
Taylor McNair
William D. Kenworthy
Charles Griffith
Boratha Tan
CHotaling@energyfuturesgroup.com
ASommer@energyfuturesgroup.com
jgignac@ucsusa.org
laura@mieibc.org
lshaver@ucsusa.org
will@votesolar.org
charlesg@ecocenter.org
btan@votesolar.org

GREAT LAKES RENEWABLE ENERGY ASSOCIATION
Don L. Keskey
Brian W. Coyer
Public Law Resource Center PLLC
University Office Place
333 Albert Avenue, Suite 425
East Lansing, MI 48823
donkeskey@publiclawresourcecenter.com
bwcoyer@publiclawresourcecenter.com

MICHIGAN ENVIRONMENTAL COUNCIL
Christopher M. Bzdok
Troposphere Legal
420 E. Front Street
Traverse City, MI 49686
chris@tropospherelegal.com

MPSC Case No. U-22058
SERVICE LIST

Natasha Fowles, Legal Assistant
Sue Fruchey, Legal Assistant
natasha@tropospherelegal.com
sue@tropospherelegal.com

MICHIGAN ATTORNEY GENERAL
Joel B. King
Lucas Wollenzien
Assistant Attorneys General
Special Litigation Division
525 W. Ottawa Street
P. O. Box 30755
Lansing, MI 48909
kingj38@michigan.gov
wollenzienl@michigan.gov
moodym2@michigan.gov
ag-enra-spec-lit@michigan.gov

AG Consultant
Sebastian Coppola
sebcoppola@corplytics.com

MPSC STAFF
Adam M. Cozort
Amit T. Singh
Daniel E. Sonneveldt
Assistant Attorneys General
Public Service Division
7109 W. Saginaw Highway, Fl 3
Lansing, MI 48917
cozorta1@michigan.gov
singha9@michigan.gov
sonneveldtd@michigan.gov

Jillian Bowden, MPSC Case Coordinator
BowdenJ2@michigan.gov

NATURAL RESOURCES DEFENSE COUNCIL, SIERRA CLUB
Christopher M. Bzdok
Sean C. Clark
Troposphere Legal
420 E. Front Street
Traverse City, MI 49686
chris@tropospherelegal.com
sean@tropospherelegal.com

SIERRA CLUB
Shannon Fisk
Jacob Elkin
Helen Li
sfisk@earthjustice.org
jelkin@earthjustice.org
hli@earthjustice.org

MEC/NRDC/SC Consultants:
Bryndis Woods
Joshua Castigliego
bryndis.woods@aeclinic.org
joshua.castigliego@aeclinic.org