STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief. /

Case **No. U-20471**
(e-file paperless)

MICHIGAN PUBLIC SERVICE COMMISSION STAFF'S
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I. Introduction

DTE Electric Company (DTE Electric or the Company) requests approval of its first stand-alone integrated resource plan (IRP) filed pursuant to Public Act 341 (Act 341 or the Act). The issue in this case is whether DTE Electric's choice of a "starting point," lack of competitive resource procurement, and use of "flexible" plans in the out years are fatal flaws, acceptable, or areas to address in its next IRP filing. DTE Electric submits these attributes are acceptable. Many intervenors believe these areas constitute fatal flaws. In contrast, Staff submits that the forced starting point, lack of competitive resource procurement and flexible plans, while not ideal, are areas to be addressed in DTE Electric's next IRP. Staff recommends that DTE Electric file its next IRP within 3 years, and that the current plan should be approved for the fixed years with certain caveats.

On December 21, 2016, Governor Rick Snyder signed into law Act 341, later made effective on April 20, 2017, MCL 460.6t. The Act added new provisions related to standalone IRPs. All rate-regulated electric utilities, including DTE Electric were required to file an IRP with the Commission by April 20, 2019.

Under section 6t, subsection 3 of Act 341, utilities are required to file an IRP that illustrates its plans, explaining its goals and directions it is heading for 5, 10, and 15 years of the utility's load. MCL 460.6t(3). The Commission developed modeling parameters and assumptions for the IRPs. DTE Electric requests approval of its defined plan for the years 2020 through 2024 and flexible four pathway plans for the years 2025-2035. In addition to a 15-year plan, DTE Electric also provides projections through 2040. Cost preapprovals are only requested for the first 3 years.

II. History of Proceedings

On March 9, 2019, DTE Electric filed its IRP. On April 29, 2019 the Administrative Law Judge (ALJ) issued a scheduling memorandum. Intervenors admitted to the case include: the Attorney General Dana Nessel (Attorney General or AG), Association of Businesses Advocating Tariff Equity (ABATE); Energy Michigan Environmental Law and Policy Center/Ecology Center/Solar Energy Industries Association/Union of Concerned Scientists/Vote Solar (ELPC et al); Great Lakes Renewable Energy Association (GLREA); Michigan Energy Innovation Business Council/Institute for Energy Innovation (EIBC/IEI); Michigan Environmental Council (MEC) Natural Resources Defense Council (NRDC) and Sierra Club (SC) or collectively (MEC); Convergen Energy; City of Ann Arbor; Geronimo Energy Soulardarity; ITC Transmission Company; Cypress Creek Renewables; Midland Cogeneration Venture (MCV); Heelstone Development and Michigan Public Power Agency (MPPA).

On July 19, 2019, the parties stipulated to move the scheduled dates in the case one month to account for an error that Staff identified and DTE Electric corrected in its modeling. On October 2 through October 9, 2019, the parties appeared for cross examination. The hearing was adjourned to October 18, 2019. That date was subsequently cancelled. The transcripts consist of 3,385 pages of direct and rebuttal testimony, cross-examination. (7 TR 3385.) Additionally, numerous exhibits were admitted into the record. The record is full, copious, detailed and complete.

III. Overview of Proposed Course of Action and Recommendations

Some of the main areas of dispute with respect to DTE Electric's proposed course of action regard energy efficiency (EE) or energy waste reduction (EWR), renewables and coal plant retirements. For EWR, DTE Electric proposes a ramp up to 1.625% by 2020 and 1.75% by 2022. (Application, p. 2.) By 2040, DTE Electric proposes at least 1.75% EWR and perhaps 2%. (Application, p. 2.) Staff recommends a goal of 2% EWR. (7 TR 3323.) Staff notes that in MPSC Case No. 18419, DTE proposed 1.5% EE by 2021 as an achievable goal and also notes DTE's progress toward higher EE and EWR goals since 2009. *DTE's Applications for Certificates of Necessity*, Case No. U-18419, 4/27/2018 Opinion and Order, p. 31. The Company's proposal contains multiple pathways to get to the proposed level.

Regarding renewables, DTE relies heavily on voluntary green pricing (VGP.) The controversy surrounding VGP is that it is voluntary and, therefore, customer dependent. DTE's proposals regarding retiring or converting coal plants are as follows. DTE plans to retire St. Clair Unit 1 in 2019; convert River Rouge Unit 3 in 2020, by switching to recycled industrial gases until retirement in 2022; and consider multiple pathways for St. Clair Plant Unit 7 and Trenton Channel Unit 9 in 2022. (Application, p. 2.) DTE projects a possible 2029 or 2030 retirement for

Belle River Units 1 and 2 and 2040 retirement of Monroe Power Plant.

(Application, p 3.)

With respect to cost pre-approvals, MCL 460.6(t)11, the Company requests: 1) $103 million of 2020 through 2022 EWR capital costs, 2) $24 million of projected DR capital costs from the period of May 1, 2020 through December 31, 2022, and 3) $0.7 million in capital costs associated with CVR/VVO pilot programs from 2019 through 2020.

The Staff recommends approval with certain caveats addressed below, importantly that DTE Electric file another IRP within 3 years, incorporating Staff's recommendations.

IV. Authority, Jurisdiction and Burden of Proof

This contested case is appropriately before the Commission under 2016 PA 341, MCL 460.6t. The MPSC was created by 1939 PA 3 to hear contested cases regarding state regulated utilities. Administrative Law Judge (ALJ) Sally Wallace, who presided over this case, has the authority to issue a proposal for decision (PFD) in this matter that "contain(s) a statement of the reasons therefor and of each issue of fact and law necessary to the proposed decision..." MCL 24.281(2).

It is within the purview of the ALJ and Commission to weigh the expert evidence provided by DTE, Intervenors and Commission Staff. *Great Lakes Steel Division of National Steel Corporation v. Michigan Public Service Commission,* 130 Mich App 470 (1983). DTE has the burden of proving its case by a preponderance of the evidence. Preponderance of the evidence is defined as:

> "[t]he greater weight of the evidence, not necessarily established by the greater number of witnesses testifying to a fact but by evidence that as the most convincing force; superior evidentiary weight that, though not sufficient to free the mind wholly from all reasonable doubt, is still sufficient to incline a fair and impartial mind to one side of the issue rather than the other." [Black's Law Dictionary 1301 (9th ed 2009).]

The Commission will consider the Proposal for Decision (PFD) and all of the and evidence and pleadings filed in this case. The Commission will base its factual decisions on competent, material and substantial evidence on the whole record, as required by Mich Const 1963 Art VI, §28. Staff has meticulously reviewed the Company's filed case and discusses its review under MCL 460.6t, upon which it bases its recommendation to the ALJ and Commission, below. 2016 PA 341 requires the IRP should include "various reasonable scenarios" at MCL 460.6t(5) in accordance with the modeling parameters. The Commission will only approve a plan modeled to "represent the most reasonable and prudent means of meeting the electric utility's energy and capacity needs," as required at MCL 560.6t(8).

V. Integrated Resource Plan (IRP) Filing Requirements at PA 341

As Staff witness Nicolas G. Luciani testified, the Company met its filing requirements set by MCL 460.6t, though Staff requested supplemental information through discovery requests for several requirements. (7 TR 3230.) The Michigan Filing Requirements, adopted in MPSC Case No. U-15896, require more specific details in both the Executive Summary section and the Introduction section than DTE Electric provided; however, Staff confirmed that all the relevant information was included elsewhere in the Company's IRP filing. (7 TR 3230-3231.) Staff recommended that the Company include this information in a manner more consistent with the Michigan Filing Requirement layout in future IRPs. (7 TR 3231-3232.) Several other sections of the filing requirements required additional attention due to insufficient or missing information. The Company resolved these issues informally through regular discussion with Staff. (*Id.*) Additionally, witness Luciani corrected the Company's reference to testimony not applicable to the corresponding Filing Requirement and updated this reference with the correct information (7 TR 3231.) Company witness Sharon P. Pfeuffer agreed with witness Luciani's revisions and other suggestions for future IRP submissions (2 TR 77.) Witness Pfeuffer even included an A-1 Revised to correct for revisions suggested by witness Luciani. (*Id.*) Staff requests that the Commission recommend that the Company provide, in future, more details in the Executive Summary section and the Introduction section, as there is no dispute as to the benefits of a more complete application.

VI. Statutory Filing Requirements: Act 341, Section 6t, establishes the process set out by the Legislature that utilities and the Commission must follow when filing and reviewing integrated resource plans.

2016 PA 341 (Act 341 or the Act), section 6t(1) authorizes the Commission to establish modeling scenarios and assumptions for creating an IRP. In accordance with section 6t(3), the Commission established "filing requirements, including application forms and instructions, and filing deadlines" for IRPs filed by regulated utilities. MCL 460.6t(3). In its November 21, 2017 Opinion and Order in Case No. U-18418, the Commission approved the Michigan Integrated Resource Planning

Parameters (MIRPP). In its December 20, 2017 Opinion and Order in Case No. U-15896 the Commission approved the Integrated Resource Plan Filing Requirements. *In re Section 6t(1) of 2016 PA 341*, MPSC Case No. U-18418, 11/21/2017 Order, Exhibit A; *In re MCL 460.6s(10) and (11)*, MPSC Case Nos. U-15896, 12/20/2017 Order, Exhibit A.

Under section 6t(3) of Act 341, utilities are required to file an IRP that "provides a 5 year, 10-year, and 15-year projection of the utility's load obligations and a plan to meet those obligations," MCL 460.6t(3). As discussed above, DTE has gone beyond this to provide projections even to 2040. The IRP must include information about the utility's load profile, demand forecasts, generation resources, renewable energy resources (RE), and energy waste reduction (EWR) among other requirements. *See* MCL 460.6t(5). In preparing for an IRP, utilities must issue a request for proposals (RFP) for any new supply-side generation capacity resources to be considered in the IRP proceeding. MCL 460.6t(6).

The Commission must approve an IRP if it is "the most reasonable and prudent means of meeting the electric utility's energy and capacity needs." MCL 460.6t(8). The Commission must consider numerous quantitative and qualitative factors, such as:

- Whether the plan is affordable, reliable, in compliance with environmental regulations, and the diversity of proposed assets when making its decision.

- Whether the plan includes enough "capacity to serve anticipated peaks and electric load, applicable planning reserve margin, and local clearing requirement." *Id.*
- Whether demand response (DR) and EWR measures are reasonable and cost effective.
- Whether the plan meets applicable state and federal environmental regulations. *Id.*

Act 341 sets specific Commission, party and utility deadlines and actions. The deadlines include the following:

- 150 days after the original filing, the utility may provide cost updates MCL 460.6t(7).
- 300 days after the original IRP is filed, the Commission must reject, approve, or recommend changes to the plan (hereafter 300-day order). *Id.*

If the Commission's 300-day order recommends changes:

- 15 days later party comments are due, and 30 days later the utility may respond to any changes and/or submit a revised IRP, incorporating 1 or more changes. *Id.*
- 360 days after filing the original IRP, the Commission must approve or deny any revised plan; this order is appealable to the Court of Appeals. *Id.*

If the Commission's 300-day order recommends denial:

- 60 days after any denial, the utility may revise the plan, and the Commission must hold an expedited contested case. MCL 460.6t(9).
- 90 days after the utility files its revised plan the Commission will issue an order "approving or denying, with recommendations, the revised integrated resource plan," if the changes are not substantial. *Id.*
- 150 days after the utility files its revised plan the Commission will issue an order, if the utility's changes are substantial. *Id.*
- If the Commission denies the revised plan, the utility can proceed with its plan without any cost preapprovals provided in the statute. MCL 460.6t(10).

Section 6t(11) allows the Commission to identify and preapprove capital costs for "specifically identified investments" that begin three years after a plan is approved so long as they are "considered reasonable and prudent for cost recovery purposes" under the section. For costs to be approved, the utility must comply with competitive bidding requirements for major engineering, procurement and construction (EPC) contracts and demonstrate the costs are reasonable and prudent. MCL 460.6t(12)(a)-(c). The statute requires the utility to file reports on the status of preapproved projects. MCL 460.6t(14).

If the Commission preapproves eligible costs in an IRP, those preapproved reasonable and prudent costs must be included in retail rates in a later rate case.

MCL 460.6t(17). If the "actual costs incurred by the electric utility exceed the costs approved by the commission," the cost overruns are presumed to be imprudent and may be disallowed. *Id.*

Section 6t(19) and (20) allow utilities to amend approved IRPs and require utilities to file an application to for review of their IRP "not later than 5 years after the effective date of the most recent Commission order approving a plan. The Commission may "on its own motion or at the request of an electric utility, order an electric utility to file a plan review." MCL 460.6t(21). Staff recommends that the Commission approve the plan with recommendations for future IRPs.

VII. Proposed Course of Action: Defined and Flexible

A. Defined: Year 2020 through end of year 2024

DTE outlines in detail their plan for the next five years. DTE plans to add 11 MW of solar plus storage pilot projects and 693 MW of wind energy. (Application, p 2.) DTE plans to retire the Trenton Channel Power Plant in 2022 and to retire St. Clair Unit 1 in 2019 and St. Clair Power Plant Unit 7 in 2022. River Rouge Unit 3 will operate from 2020 until 2022 on recycled industrial gases and natural gas. (*Id.*)

DTE requests cost pre-approval for the Company's proposed EWR investments and resources through 2022, consistent with the Company's proposed EWR plan filing in 2019 for the years 2020 through 2021. DTE requests cost pre-approval for its DR investments and resources through 2022. (*Id.*) This spans the currently pending electric general rate case U-20162 and beyond. DTE requests $.7 million pre-approval for the Company's proposed Conservation Voltage Reduction and Volt-Var Optimization (CVR-VVO) pilot investment and resources through 2020. (*Id*, p 3.) Staff recommends preapproval of the CVR-VVO.

The Company also requests preapproval of DR in the amount of $24 million and $103 million in EWR through 2022. Staff recommends that capital requests for DR programs be made in rate case filings and that EWR programs be considered in context with EWR plans.

B. Flexible: Years 2025 through end of year 2035 and Beyond

Beyond the first 5 fixed plan years, for the subsequent 10 years, DTE provided four flexible pathways, stating that they are subject to further review in the next IRP. (Application, p 3.) Two pathways contain CVR/VVO programs with a 50 MW increase by 2030. (*Id.*) Belle River Units 1 and 2 are expected to retire in 2029 and 2030. (*Id.*) If voluntary green pricing takes off, DTE would like to include 675 MW of voluntary renewable energy between 2025 and 2030. (*Id.*) The Company intends to build renewables to support its clean energy and carbon reduction goals and adding 525 MW of solar between 2025 - 2030, with another 2000 MW of solar by 2040. DTE expects that the 1.75% annual reduction level of EWR that beginning in 2021 will be continued through 2040. DTE expects to achieve 859 MW DR by 2024 and to sustain that level until 2040. (*Id.*)

The Company proposes to decide on the optimal replacement for the Belle River coal plant in its next IRP and presents four potential pathways that could be followed to fill that capacity need. (3 TR 348.) Two of DTE's flexible pathways include 414 MW gas plants, on top of the 1100 MW gas plant approved in Case No.

18419, as a fall back if the other 2 plans prove unachievable. (Application, pp 3-4.) The Company clarifies further in discovery (Exhibit S-6.0 DTE Discovery Response STDE 13.10-13.13) that the Company does not expect to select the specific resources from any of the four analyzed pathways. Rather, the flexible pathways were meant to represent a range of possible futures. Thus, the pathways are somewhat opaque, as will be discussed further below in the section regarding modeling parameters. Staff recommends that the Commission request greater clarity on what pathway they have selected as the best option in future IRP filings.

VIII. DTE Electric's Integrated Resource Plan and Modeling

A. Compliance with the Process and Statutory Goals of the IRP

1. The Company complied with the Michigan Integrated Resource Planning Parameters.

Staff's detailed review confirms that the Company complied with modeling requirements of the Michigan Integrated Resource Planning Parameters (MIRPP). The November 21, 2017 Order in Case U-18418 established the MIRPP pursuant to section 6t of PA 341. The MIRPP includes the required scenarios, sensitivities, and assumptions that each regulated utility's IRP must include. Utilities are free to include additional scenarios and sensitivities beyond those that are required.

The Company modeled each of the three MIRPP required scenarios; Business as Usual (BAU), Environmental Policy (EP), and Emerging Technology (ET). The Company also evaluated the MIRPP required sensitivities on the appropriate scenarios. (7 TR 3303.) In addition to the MIRPP required scenarios and sensitivities, the Company evaluated a DTE Reference (REF) scenario which uses the Company's internal planning assumptions, forecasts, and goals. The Company also ran several additional sensitivities, some proposed by stakeholders and some at the Company's discretion, on the various scenarios. (7 TR 3305.) Company witness Laura K. Mikulan provides testimony (3 TR 362-374) describing the various scenarios and sensitivities modeled by the Company for this IRP.

Staff reviewed most of the key assumptions used by the Company including load forecasts, market energy and capacity prices, fuel prices, existing unit costs and generic technology costs. Staff identified some minor discrepancies with the data used by the company and the MIRPP but, after consideration of their overall impact to the IRP, believes these discrepancies did not materially affect the outcome of the modeling, as described in greater detail below. Although Staff finds that the Company complied with the MIRPP requirements, Staff has several recommendations to improve the Company's modeling efforts in its next IRP.

2. Starting Point: The modeling starting point in future IRPs should include only existing resources and new resources that have been approved or legislatively required.

The Company's starting point should be the IRP modeling baseline resources. This starting point should include only resources that are already approved, under construction, or will be with firm certainty (such as renewable resources required to meet a legislatively required renewable portfolio standard). Staff's primary concern with the Company's modeled starting point, as DTE calls it, is that it literally forces in the Company's self-imposed clean energy goal, rather than allowing the models to optimize the resources. (7 TR 3299.) The IRP is supposed to be a comprehensive look at supply-side resources that will be needed to meet generation capacity needs, rather than starting with a plan in mind, and imposing it upon the model.

The Company's starting point for all scenarios and sensitivities modeled in the IRP include its existing fleet as well as the following resources:

- 1.5% EWR savings target
- 732 MW in 2019 increasing up to 863 MW total DR in 2024 and beyond
- 855 MW incremental wind and 538 MW incremental solar between 2019 - 2030
- 300 MW incremental wind and 2,000 MW incremental solar between 2031- 2040
- 300 MW VGP wind in 2021
- 1,150 MW BWEC CCGT addition in 2022
- 34 MW Dearborn CHP addition in 2020
- Retirement dates:
    - River Rouge [Unit 3] in 2020
    - St. Clair 1-3, 6 in 2022
    - St. Clair 7, Trenton 9 in 2023
    - Belle River 1 in 2029
    - Belle River 2 in 2030
    - Monroe before 2040 [3 TR 405.]

The Company used this starting point "as a basis for each of the four scenarios." (2 TR 58.) Company witness Mikulan states that "the starting point resource plan is made up of DTE's current state and current plans. This includes the current retirement dates, approved new units, current state of the renewable plan, 1.5% EWR, and planned demand response program changes." (3 TR 405.)

The Company uses the same starting point resources for each modeling scenario. Including these resources in the starting point ensures that the Company meets its stated goals, but an unfortunate impact is that it prevents modeling analysis of the resources. The resulting model will not optimize to fill the capacity and energy needs served by these resources, which reduces the model's ability to arrive at an optimum solution. The Company's entire integrated resource plan adds over 7,000 MW of resources through 2040, of which only about 10% or 700 MW, coinciding with the need created by the retirement of Belle River (see Staff Exhibit S-6.1), were optimized in the Company's original modeling. (7 TR 3298-3299.)

Staff's main contention is that the Company should not give itself a head-start with its self-imposed clean energy goal, no matter how laudable, and then force the model to achieve that goal, rather than to optimize resources from which DTE Electric can select the best plan. Such an approach is not in accordance with the statute. (7 TR 3299.)

In discovery, Staff requested that the Company optimize the model without the clean energy goal renewable resources. The Company complied with this request (Exhibit S-6.2; DTE Discovery Response STDE-2.3b.) However, the results of this modeling were inconclusive. Depending upon the market conditions and assumptions used, the results range from a savings of $44 million to a cost of $105 million over the four scenarios that DTE Electric ran--BAU, ET, EP, DTE REF. The after-the-fact nature of these fully optimized runs also means that the build plans generated are excluded from the robust analysis given to the rest of DTE's IRP and supporting testimony. (7 TR 3299-3300.) Other intervening parties also expressed valid concerns with the Company's "starting point."

DTE may not be a *tabula rasa*, but the modeling should be allowed to do what it is supposed to do rather than being constricted unnecessarily. ELPC witness Eric Woychik explains why the starting point is faulty.

> "DTE did not base its "starting point" on least cost; instead it plugged in its current plans and state of affairs, including its planned retirement dates for existing units, its plans for new units, its renewable and energy waste reduction plans, and planned changes to its demand response program." (7 TR 1885.)

ELPC witness Will Kenworthy stated that, "The Commission should require the Company to develop a PCA that is based on optimization of resources in the model rather than building outdated plans from its last Renewable Energy Plan into the non-variable Starting Point." (7 TR 2139.) ABATE witness Brian Andrews, "DTE's IRP is completely void of anything resembling a comprehensive look at supply side resources. DTE has assumed as its starting point a portfolio of resources that have not been approved." (7 TR 3041.)

In response, the Company's rebuttal indicated that the plan to include these resources in the modeling starting point was presented at the Technical Stakeholder workshops held in late 2018 and early 2019. (3 TR 482-484.) This reasoning is not helpful because (1) the Staff and Intervenors did not fully understand what DTE Electric claims it was presenting, and (2) the Stakeholder workshops are not intended to displace this contested case.

The Company identifies one slide out of nearly eighty from the September 2018 workshop and one slide out of nearly 50 from its January 2019 workshop that vaguely included this information. (3 TR 483.) The two slides referenced are very similar. By focusing on the renewable energy added being *consistent* with the renewable energy plan, the slides obscure the fact that the renewables added actually go far beyond the renewable energy plan. The heading for the slide from the September 2018 workshop was "The starting point for renewable energy, in all cases, is *consistent* with the filed renewable energy plan, 50% Clean Energy goal by 2030 and 80% CO_2 reduction by 2050." Emphasis added. (Exhibit A-66 Page 112.) The heading for the Slide from the January 2019 workshop was "The starting point for renewable energy is *consistent* with the filed renewable energy plan, 50% Clean Energy by 2030, and 80% CO_2 reduction by 2050. Emphasis added. (Exhibit A-75 Page 21.) Members of Staff and stakeholders were present at these technical stakeholder workshops. It is evident by the lack of comments during the technical stakeholder workshop regarding this issue that both Staff and stakeholders did not have a clear understanding about the data contained in this single slide in both presentations. It is understandable how these slides could have been missed given it was two slides out of approximately 125 presented over approximately six hours of technical presentations. DTE Electric's intent in presenting the information this way in a stakeholder forum is not in question, necessarily, but it does not validate their "starting point." More to the point, the stakeholder sessions do not take the place of this contested case.

Therefore, in accordance with MCL 406.6t(5), Staff recommends that the base starting point resources in future IRP cases consist of only new units that are already approved, under construction, or planned with firm certainty (such as resources needed to meet a legislative requirement).

B. Demand and Energy Forecast

DTE modelled no capacity need until 2030 when Belle River is retired. Staff's detailed analysis of the demand and energy forecast is under operating assumptions below. Staff views the forecast as an input into the model. As well, PURPA is covered in Other Issues at X.

1. Sales Forecasts

The sales forecast is analyzed below under Operating Assumptions under the subheading Energy and Sales forecasts and Peak Load.

2. Supply and Demand Side Resources

a. Market and Energy Capacity Forecasts

See Operating Assumptions below at C.(4)(b).

b. The Commission should approve the Company's proposed demand response (DR) projections with Staff's modification of tariffs in the future.

The Company describes its various on-going DR programs and pilots, and Staff takes no issue with the prudency of these existing programs currently. (7 TR 3333.) In total, the Company's PCA projects an increase from 790 MW of existing

DR in 2019 to 859 MW in 2024. (6 TR 1672.) Staff does not contest the Company's projected MW of DR in its PCA. (7 TR 3332.)

The Company also discusses the absence of Rider 12 in its currently available DR resource portfolio is due to the lack of customers taking service on the rider. (6 TR 1665.) However, the Company includes some growth from Rider 12 in its PCA in anticipation of increased marketing of the rate to customers. (6 TR 1674.) The Commission recently approved an *ex parte* tariff case adjusting the Rider 12 tariff that allow more customers to participate.

Currently, the Company's only residential DR products registered as a load modifying resource (LMR) with MISO are (1) the interruptible air conditioning rate D1.1 and (2) the controlled water heating rate D5. (7 TR 3338.) The remainder of the Company's residential DR programs and pilots are only included in the Company's historical load data, and not explicitly modeled in the Company's peak load forecast or residential load shapes. *Id*. Qualification as an LMR with MISO would grant the Company resource credits for these programs, and thus match their value at the wholesale level. *Id*.

The Company's Programmable Communicating Thermostat (PCT) pilot currently cannot qualify as an LMR due to the customer notification requirements in its tariff. (7 TR 3337.) Similarly, the Bring-Your-Own-Device (BYOD) pilot is not currently an LMR and would require a change in its relevant tariff for such a qualification. *Id*. Staff proposes that the Company modify its tariffs such that once these two DR pilots become fully available programs they be bid into MISO as

LMRs. (7 TR 3339.) The Company does not object to and is already planning on implementing Staff's proposal, and no other parties dispute Staff's recommendation. (6 TR 1688-1689.)

For these reasons the Commission should approve Staff's recommendation to require the Company to modify tariffs and bid appropriate DR programs at the wholesale level.

C. Assumptions, Inputs, Scenarios, and Sensitivities

1. Cost Assumptions

As stated by Anna N. N. Schiller in her testimony, the Company's modeled assumptions reasonably covered modeling assumptions with respect to operating parameters and cost assumptions for new and existing fossil generation units, including: (1) Operating parameters for new and existing units (2) Cost assumptions for new and existing units, and (3) River Rouge 3 Conversion to Industrial Gas.

2. Fossil fuel inputs: The cost assumptions for existing and proposed new fossil-generation units that the Company used in its modeling are reasonable.

Concerning the Company's modeling, Staff recommends the Commission find that the cost assumptions provided by the Company for existing and proposed new thermal generation units in the resource screen are reasonable. The Company provided the cost assumptions for existing and proposed new thermal generation in the Company's workpapers and provided the public sources used to procure this information. Staff witness Schiller testified to Staff's review of the accompanying documents utilized to source this information. (7 TR 3285.)

The direct testimony of MEC witness Avi Allison asserts that the Company over-discounted fixed costs for all new generation cost assumptions by discounting back to the initial construction start year. Witness Allison recalculated the fixed cost values accordingly. (7 TR 2535-2538.) As DTE witness Laura Mikulan testified, in the Company's rebuttal testimony, the Company performed an optimization run using MECs fixed cost values and received "… essentially the same least-cost build plan originally filed by the Company in this proceeding." (3 TR 500.) The error noted by witness Allison did not significantly affect the model results; DTE's cost assumptions are reasonable despite a small error.

3. Energy Waste Reduction (EWR): the goal should be 2.0%

Staff witness David S. Walker presented Staff's position regarding the Company's energy waste reduction (EWR) levels in testimony. (7 TR 3318-3326.) The Company adopted a planned course of action (PCA) of 1.625% energy savings in 2020 and 1.75% in 2021 through 2024. (6 TR 1566.)

As Staff witness Walker testified, Staff submits that the EWR goals set by the Company meet the minimum goals of PA 2016 342, but it would be reasonable for the Company to set a goal of 2.0% in this IRP proceeding conducted under PA 2016 341. Section 6t(8)(a)(vii) of PA 2016 341 requires the Commission to consider whether levels of EWR proposed in an IRP are reasonable and cost-effective. Company witness Kevin L. Bilyeu provided a table indicating that all levels of EWR considered by the Company, from 1.5% to 2.5%, are cost-effective (6 TR 1565), so the issue of whether EWR is cost-effective is not debated by the parties.

Not only would 2.0% EWR be cost-effective, the Company's IRP model selected 2.0% among its EWR levels (2 TR 68). Thus, the Company should work toward achieving this level. There are no explicit penalties in either 2016 PA 341 or 2016 PA 342 for failing to achieve higher levels of EWR if the efforts to do so were reasonable and prudent.

In setting the EWR levels, Staff testified that the Company seemed to have a more conservative approach than in a previous EWR plan filing in which the Company "raised the approved 2017 EWR Plan goal from 1.17% to 1.50%, and achieved 1.57%, when 2016 PA 342 raised the bar for earning the maximum allowable financial incentive." (7 TR 3323.) Staff also noted that, if the Company's 2018 EWR plan reconciliation is approved, the Company will have earned a financial incentive for exceeding savings targets in every year of energy efficiency programs since they began in 2009. These accomplishments or mile markers make Staff "confident that the Company has the program infrastructure established and the experience necessary to implement a plan that will reach 2.0%." (7 TR 3323.) Witness Bilyeu countered that "Past performance is not a guarantee of future EWR savings." (6 TR 1575.) Staff agrees that is not a guarantee, however, it is a great indicator that it can be done, especially in the next five years that are the defined period of the PCA.

Staff's impression of the EWR costs used by the Company, which it characterizes as "quite uncertain" (3 TR 460), is that they seem conservative and higher than necessary. Staff summarized that Company witness Laura K. Mikulan twice mentioned the possibility that EWR costs might by higher than projected, but "The Company never appears to contemplate that the EWR costs might be lower than anticipated, thereby providing higher benefit cost ratios and better standing among resources in the IRP." (7 TR 3324.) In rebuttal, the Company notes that it considered lowered technology costs in the 'Flat Incentive Costs: Low' sensitivity in which costs for EWR were reduced by 35%. (6 TR 1576.) While this is true, there is a wide range between the Company's projected costs and costs lowered by 35%. Staff would not expect costs to drop 35% in the near-term, however, it is much more realistic to consider the possibility that implementation and/or technology costs might drop 5% - 10%.

Staff suggested that the Company's costs might be approximately 8% lower when, in Staff's Exhibit S-7, Consumers Energy Company's projected average EWR costs at 2% savings, $257 per MWh saved, were compared to DTE Electric Company's estimated costs, $279 per MWh saved. (7 TR 3324.) The Company proposed that is was not reasonable to compare its costs to Consumers Energy's costs due to differences in the companies, their customers, and the costs contained in their IRPs and cautioned against a "transfer" of data between the companies. (6 TR 1576-1577.) Staff, however, was not attempting to transfer cost data from one utility to another, as Company witness Bilyeu suggested. Rather, Staff was making an estimate of how much lower the costs used by the Company could be since this was not provided in the IRP. There are enough similarities between the two largest utilities in the state that have both been providing energy efficiency programs since 2009 that this is a reasonable estimate and comparison.

In addition, Staff agrees in general with MEC witness Neme's position that many non-incentive costs of EWR would increase, but not increase in direct proportion to increases in EWR spend as assumed by the Company. (7 TR 2683-2686.) Therefore, this portion of costs would be lower. Staff also agrees with witness Neme's example that the Company did not optimize the incentive-level setting, i.e., considering whether to offer 100% incentives for lower-cost measures versus 35% incentives for higher-cost measures. (7 TR 2672-2673.) Both of these points reinforce the possibility that the Company's costs may be lower than it projected.

MEC witness Neme reported flaws in the Company's analysis and modeling of EWR in its IRP and determined that corrections result in an economically optimal level of 2.0% EWR. (7 TR 2656-2707.) Staff continues to recommend the Company adopt a 2.0% EWR savings goal.[1]

4. Wind, Solar, Demand Response (DR), CVR/VVO

Each of these areas are important to Staff and are addressed below in the section regarding cost approvals.

[1] See below Staff's continued discussion of EWR in the area of cost approvals.

5. Operating Assumptions

a. Energy and Sales Forecasts and Peak Load

i. The Commission and the ALJ should recommend that the Company conduct, for purpose of reporting in its next IRP filing, the MAPE evaluation on the monthly peaks for the historical period between IRP cases.

Staff recommends that the Company conduct and report the mean absolute percentage error (MAPE) evaluation on the monthly energy sales and peak loads in its next IRP filing. (7 TR 3264.) Staff witness Makinde explained the Company's load growth expectations under various reasonable scenarios. The Company's exhibits A-34 and A-35 present the business as usual, BAU, and High load, high electric vehicles, choice increased to 25%, and choice returns to full-service sensitivities. (7 TR 3262.) Mr. Makinde also explained that the load growth projections provided by the Company, -0.06%, 0.07% and 0.0% for its service area, bundled load, and electric choice load, in addition to -0.27%, -0.29%, and 0.0% for peak demand in those areas, are consistent with the general trend of stagnant to decreasing growth in demand and energy sales in the industry. (7 TR 3263.) Mr. Makinde's conclusion is based on a comparison of the annual growth rate (AGR) and combined annual growth rate (CAGR) of the Company's forecasted energy sales to the forecasts of the Energy Information Administration (EIA) in the 2018 Annual Energy Outlook. *Id.* Mr. Makinde further found that the Company's forecasts are consistent with its recent 2019 PSCR Plan Case, MPSC Case No. U-20221. *Id.* Mr. Makinde examined the Company's forecasting derivation methodology and found the Company's use of regression models and the inputs and outputs to be appropriate. (7 TR 3264.) However, Staff witness Makinde explained that reporting the MAPE on a monthly basis will provide more complete view of the accuracy of the Company's forecasts. *Id.* In conjunction with the use of more granular data, this will ensure that forecasts are within an acceptable range for all months and not only the peak day. *Id.* Additionally, this will allow the Company's forecasters to fine tune their models to ensure results are within an acceptable range for all hours of the year, not just the annual peak day.

The Attorney General's witness David Dismukes criticized various aspects of the Company's demand and load forecasting process. After describing the Company's utilization of the HELM model, witness Dismukes discussed the importance of relying on best practices and highlighted the danger of over-forecasting electricity consumption leading to unnecessary investment in generation resources. (7 TR 2361.) Further, the Attorney General criticized the lack of standards related to the timing of historical forecasts, leading to what witness Dismukes referred to as an "arbitrary forecast design." (7 TR 2364-2365.) Based on these concerns. Witness Dismukes asserted that the Company's forecast of Electric Vehicle (EV) growth as unreasonably high. (7 TR 2366.) He also asserts that the Company's demand forecast, utilizing the proprietary HELM model, is flawed in the same manner as the Company's annual sales forecast because that forecast is used as the primary input for the HELM model. (7 TR 2368.) As a result, witness

Dismukes recommends that the Commission reject the Company's sales forecasts and adopt the Attorney General's alternative load forecast present in exhibit AG-4.

Staff maintains its conclusion that the methodology used by the Company to derive its long term forecasts is appropriate, based on Staff's examination of the inputs and outputs of the end-use model, but reiterates that the Company should be directed to report the MAPE in its next IRP filing. (7 TR 3264.)

ii. The Commission and the ALJ should recommend the Company conduct weather nominalization using a shorter historical period.

Staff witness Makinde recommended that the Company use a shorter historical period, or a weighted historical 30-year average and incorporate humidity, precipitation, and wind speeds and directions to normalize historical energy sales and peak demand. (7 TR 3266.) Staff witness Makinde explained that the Company's current methodology of averaging monthly data for a 30-year period will dilute recent trends in weather. (7 TR 3265.) The temperature data used for the normalization was an average of the daily average temperature (mean of the high and low of the day) over the 30-year period. *Id.* However, more recent historical trends show an increase in the occurrence of extreme weather events and would be captured using either a shorter historical period or a weighted historical 30-year average. (7 TR 3265-3266.) Additionally, the monthly time format suffers from the "Problem of Averages." The averages are skewed towards the greater number of observations that are less recent in ratio to those of more recent years.

Using more recent data will eliminate the "Problem of Averages", ensuring weather normalization captures the correct weather trends. Incorporating humidity, precipitation, and wind speeds and directions to normalize historical data, will provide the normalization process an accounting of the increased occurrences of extreme weather events.

iii. The Commission and the ALJ should recommend the Company consider increasing the granularity of the data used in its load forecast regression models.

Staff witness Makinde recommended that the Company further leverage AMI data and study the hourly use trends of customers on DR tariffs, from the time of inception of those tariffs and track the periods and magnitude of load shifting. (7 TR 3268.) These shifts should then be applied to the forecasting models in the Company`s next IRP filing. *Id.* Witness Makinde also recommended that the Company conduct future peak load and energy sales forecasts on an hourly basis at a minimum. (7 TR 3266.) In addition, the Company should be directed to use more granular data, such as hourly or daily time intervals, for energy sales and peak demand forecast regression and end-use models. *Id.* Staff asserts that more granular time intervals would result in more accurate forecast and result in better Mean Absolute Percentage Error (MAPE) scores, not only for annual peak demand, but for the peak demand of all the hours of the year, particularly during the shoulder months. (7 TR 3267.)

Regression forecasts with monthly time interval data, versus more granular data, have a lower observation per year, observation per variable and total number of observations. These low observation counts can lead to inaccurate forecasts. Hourly data will require less than 15 years of historical data. Trends within the last two years are better accounted for without being diluted by older data. The forecasts will be more accurate during the shoulder months and provide a better representation of the variations of the weeks and days within the months. The monthly time format suffers from the "Problem of Averages." The average could be skewed by the number of observations that are outliers in ratio to those that are closer. Peak demand and/or energy sales can be skewed by outliers within a month and the use of a more granular time interval will eliminate this "Problem of Averages." Staff is aware that the Company is in the process of adopting a more granular time interval but asserts that the use of AMI data to develop hourly load forecasts should be implemented a faster rate.

b. Market Energy and Capacity Price Forecasts

i. The Commission and the ALJ should recommend that the Company use the same set of load assumptions across the various models.

Staff recommends that the Company utilize the same set of load assumptions in all the models utilized. After finding that the capacity prices presented by the Company were reasonable through his analysis of the Company- provided Aurora files, Staff witness Makinde explained the derivation of the Company's market energy prices, stating,

> "The market energy prices used in the IRP were developed by PACE using the Aurora® model to forecast LRZ-7 (MISO Michigan Hub) prices. The Company used a methodology that started with forwards, which then used a transition period to smoothly shift to the PACE forecast. Company Witness Mikulan stated, "We start with market prices obtained from forwards for the same years (2018-2019) as described in the fuel prices. A three-year transition was used in years 2020-2022 to smoothly shift to the fundamental energy price forecast in 2023. Then, for years 2023 to 2040, the Company used the fundamental forecast from PACE Global."5 The Company provided different energy market price forecasts for each scenario." [7 TR 3269.]

However, witness Makinde noted that the PACE load assumptions, consisting of monthly and annual peak load and energy sales and 8760 load shapes, were not the same as those developed by the Company. *Id.* While this does not render the energy price input invalid, the Aurora model incorporated the entire eastern interconnect while the Strategist model utilized the Company's bundled load system with proxy connections to the MISO system. (7 TR 3270.) To address this mismatch, Staff recommends the Company use the same set of load assumptions in all the models it utilizes. *Id.* Alternatively, Staff recommends that the Company use a modeling software that is capable of production cost modeling and long-term capacity expansion. *Id.*

ii. The heat rates the Company used in its modeling are reasonable.

Concerning the modeling, Staff recommends the Commission find that the heat rates provided by the Company for existing and proposed new thermal

generation units are reasonable. The Company provided the heat rates for existing and proposed new thermal generation in an exhibit of the Company's revised direct testimony. Staff witness Anna N. N. Schiller testified to Staff's review of the accompanying documents utilized to source this information. (7 TR 3284)
No other party filed direct or rebuttal testimony on the heat rates provided by the Company for existing or proposed new thermal generation units. Thus, Staff recommends that the heat rates supplied by the Company be deemed appropriate.

iii. The capacity factors the Company used for thermal units in its modeling are reasonable.

Concerning the modeling, Staff recommends the Commission find that the capacity factors provided by the Company for existing and proposed thermal generation units are reasonable. The Company provided the capacity factors for proposed new thermal generation in an exhibit of the Company's revised direct testimony. Staff witness Schiller testified to Staff's review of the accompanying documents utilized to source this information. (7 TR 3283.)

ELPC witness Kevin Lucas claimed in direct testimony that the new combustion turbine capacity factor of 17% was too high based on previous years data. (7 TR 2061-2062). DTE witness Mikulan argued that witness Lucas used the incorrect reference period, and that the capacity factor drew from projected future runtimes. Using the same methods as the ELPC, the Company projected a capacity factor of 17%. (3 TR 580-581.) Agreeing with the analysis of DTE, Staff believes there is no error in the Company's projection and recommends that the Commission finds that the capacity factors used for potential new thermal units are reasonable.

The Company provided the capacity factors for existing thermal units across six exhibits and in workpapers detailing outputs for the four PCA scenarios as well as additional scenarios in response to Staff discovery requests. Staff witness Schiller testified to Staff's review of the resultant capacity factors for select modeling runs. (7 TR 3283.) Staff also compared the resulting capacity factors to publicly available sources of data on capacity factors delineated by fuel source.

iv. The estimated remaining times of operation for thermal peaking units are reasonable but require further analysis by the Company in its next integrated resource plan.

Staff recommends that the Commission direct the Company to evaluate the cost impact of running the Company's fossil-fuel peaking units past their stated useful life in its next IRP. The Company provided the estimated remaining time of operation for its fossil-fueled peaking units and renewable units in response to a Staff discovery request. Staff witness Schiller testified to Staff's review of the estimated remaining time of operation for all units. (7 TR 3281.) Witness Schiller testified that all renewable units will be within their useful life throughout the IRP period. However, the Company indicated that all peaking units will operate until 2040 while listing the peaking units as having a thirty-year useful life. Witness Schiller noted that most of the Company peaking units are already over the listed useful life or will be by 2040. The Company failed to analyze the costs of retaining these units past their useful life. ELPC witness Lucas also testifies to the Company lack of analysis on the operation of an aging peaking fleet in his direct testimony in his direct testimony. (7 TR 2058-2060.)

Witness Schiller recommends that the Commission order that the Company's next IRP evaluate the impact of increased operations and maintenance on the relevant fossil-fuel units listed in the Company's application and address all IRP Filing Requirements in its initial application. This would include those items that are not expected to change such as the remaining estimated time of operation of the Company's generation portfolio. (7 TR 3284.) In rebuttal testimony filed on behalf of the GLREA, witness Richter agreed with Staff's assessment and recommendation in regard to the fossil-fueled peaking units. (7 TR 3164.)

6. Data and forecasting assumptions.

Staff confirms that the Company included price forecasts for natural gas, coal, and oil, though due to the overly burdensome modeling process, it was not possible for Staff to verify prices were the ones input into the Strategist model. Staff details its concerns with DTE Electric's modeling choices further below.

a. The Company's natural gas price forecasts.

The Company used several sources for its natural gas price forecasts. The Company used the Chicago Mercantile Exchange (CME)/New York Mercantile Exchange (NYMEX) near-term futures prices for its 2018 and 2019 forecasts. (6 TR 1704-1705.) Between 2020 and 2022 the Company used a weighted blending of the CME/NYMEX futures with the 2023 Energy Information Administration's Annual

Energy Outlook (AEO). Starting in 2023, the Company used the AEO natural gas forecast for the BAU, ET and EP scenarios. (3 TR 374-375.) For the reference scenario, the Company utilized a similar method for the near-term years (2018-2022), however the CME/NYMEX futures were blended with the fundamental forecast prices provided by PACE Global. (*Id.*) The Company supported its reference scenario forecast as the most reasonable gas price forecast by comparing the forecast supplied by PACE Global, the AEO and the CME/NYMEX futures to actual market prices at applicable natural gas hub locations. (See Exhibits A-41 through A-43.) Staff reviewed the Company's natural gas forecasting methodology and verified that the Company met the requirements of MCL 460.6t and the IRP Filing Requirements, approved in the 12/20/17 Commission Order in Case U-15896, as it pertains to natural gas forecasting. Although the Company did not utilize the unaltered AEO forecast as directed by the MIRPP, Staff found, based on historical data, the blending of market futures with the AEO forecast to be a reasonable methodology for the near-term natural gas forecast. (7 TR 3235.)

Contrary to Staff's assessment, GLREA witness John Richter deemed the Company's natural gas forecasts unreasonable, or as he identified it, "selectively inconsistent." (7 TR 3116). He argues that the lower natural gas price forecast used for the reference scenario unfairly favors resource plans from that scenario when comparing the NPVs amongst resource plans. (7 TR 3117). Witness Richter underscored the impact of the natural gas forecast on the cost of resource plans that include natural gas-fired resources, citing the PACE Stochastic Write Up. (7 TR

3118.) Witness Richter concludes that the Commission should not approve cost recovery for any gas-fired plants unless the Company includes an analysis using identical inputs. (*Id*.)

The purpose of an IRP is to analyze resource plans that result from varying inputs across multiple modeling runs, many of which reduce the cost, or "favor," one resource type over another. The Company has supported the reference scenario natural gas forecast as the more accurate natural gas forecast. Therefore, a similar argument could be made that utilizing the AEO forecast would favor other resource options that are not natural gas-fired. Considering the three-year cost approval window that an approved IRP grants, witness Richter's suggestion to not approve a natural gas-fired plant selected by the model has no weight on the Commission's decision, as the Company's PCA does not include natural gas-fired generation in the timeframe for which costs can be pre-approved. Additionally, the Company's multiple pathways will be further considered in the Company's next IRP filing. Ultimately, Staff recommends that the ALJ and Commission find that the natural gas forecast utilized by the Company is reasonable.

b. The Company's oil and coal price forecasts.

Staff testified that the oil and coal price forecasts used by the Company are reasonable for the purposes of modeling an IRP, despite taking issue with the lack of transparency around the proprietary forecasts used. Coal price forecasts were developed by adding the commodity costs and transportation rates to determine the delivered cost of coal to each facility. (6 TR 1707.) Coal commodity forecasts were developed by blending existing contract prices and forecasted forward market prices for the near term and were based on a forecast by PACE Global in the long-term. (7 TR 3234-3235.) The commodity forecast for fuel oil was similarly based on forecasted market future prices provided by NYMEX in the near-term, and a forecast developed by PACE Global in the long-term. (7 TR 3235.) Due to their proprietary nature, Staff was unable to reconstruct the commodity price forecasts for coal and oil, although the Company did provide Staff with a comparison of these forecasts with the AEO. (7 TR 3235-3236). While Staff noted that the commodity price forecasts for both coal and oil were increasingly lower than the corresponding AEO forecasts, the price forecasts did not influence the development of the Company's resource plans as resources utilizing these fuels were not selected in any of the resource plans. (*Id.*) Staff reviewed the transportation rates for coal, which were based on existing contract prices and were escalated using contractually prescribed increases. (*Id.*) However, Staff was unable to verify the transportation rates for the oil price forecast, as this information was not provided in the Company's filing. (7 TR 3236-3237.)

Staff made recommendations for the Company to improve the transparency of its sources for developing its oil and coal commodity and transportation price forecasts in future IRPs but ultimately found the oil and coal price forecasts used by the Company reasonable.

GLREA witness Emily Prehoda disagreed with Staff's findings, stating that the complexity of the modeling and its reliance on data that was not publicly available prevented Staff from completing its evaluation, and is grounds for the Commission to reject the IRP. (7 TR 3073.) While Staff agrees that the lack of publicly available fuel forecasts inhibited its review, witness Prehoda mischaracterizes Staff's ultimate assessments. This lack of transparency did not prevent Staff and the Commission from evaluating whether these price forecasts were reasonable. Therefore, while Staff recommends the Company improve on the availability and transparency of the fundamental data utilized for its fuel price forecasting purposes, Staff does not view this as a reason to reject the Company's IRP. Staff finds the resulting coal and oil price forecasts the Company utilized to be reasonable.

c. The Company's Capacity Price Forecasts

See Market Energy and Capacity Price Forecast above at Operating Assumptions. C.4(b)(i).

7. Proposed Voluntary Green Pricing and Other Renewable Energy, Including Wind and Solar

In its IRP application at paragraph three, DTE proposes increasing in its defined PCA the Voluntary Green Pricing (VGP) program renewables (MIGreenPower) between 465 MW and 715 MW depending on customer interest. The VGP renewable energy projections are reasonable in this IRP, and the Company has not requested further cost recovery for VGP beyond what was already approved in Case No. U-20343.[2]

With respect to its defined PCA, Company has previously contracted 372.5 MW (Exhibit A-18, lines 77-80) out of 465 MW for the Defined PCA for the LCVGP. (7 TR 3314-3315.) Beyond that, the LGVP could increase to 1,090 MW of incremental VGP, which is outside the Defined PCA. Company witness Terri L. Schroeder testified that the Company proposed up to 1,390 MW (650 voluntary wind and 775 voluntary solar) for growth, which represents additional renewable generation compacity through 2030, contingent upon future circumstances. (6 TR 1256.)

Staff recommends for this IRP that the renewable energy supply was reasonable based on the available information at the time of the hearing and contingent upon the Company's plans to refine its future forecasts. (7 TR 3314-3315.) As Staff witness April M. Stow testified, the "range of VGP renewable energy projections are reasonable." (7 TR 3315.) The Company is not asking for cost recovery for additional VGP capacity in this IRP. (*Id.*) In rebuttal testimony, GLREA's witness John Richter agreed with the Staff and emphasized that "[t]he Commission should be very clear in it's [sic] order about what it is or is not approving regarding the

[2] In its October 5, 2018 Order in MPSC Case No. U-18352, the Commission instructed the Company to create a voluntary green pricing (VGP) program for large customers, pursuant to MCL 460.1061. As a result, in MPSC Case No. U-20343, filed November 8, 2018, the Company applied for a proposed Large Customer Voluntary Green Pricing Program (LCVGP). In its January 18, 2019 Order, the Commission approved the LCVGP as a pilot program, subject to changes and updates in its next biennial review in April 2020.

VGP." (7 TR 3160.) Staff respectfully requests that the Commission specify that it does not disapprove of the VGP proposal as projected in this IRP, based on future contingencies, but not authorizing any specific cost-recovery that has not been prior approved.

D. Modeling Analysis and Recommendations for Improvement

1. The Company's approach to modeling was overly complex and lacked transparency.

The Company should use a simpler approach to modeling in its next IRP, to provide more transparency into the modeling and to allow intervening parties to better evaluate all scenarios and sensitivities. (7 TR 3309.) The Company's modeling process was complicated and involved the integration of several different modeling platforms, illustrated in Staff Exhibit S-1.0 and described below by witness Doherty:

> PACE Global (PACE) used EPIS Aurora® to perform a national fundamental forecast which provided the Company with fuel, market, and emission prices. The outputs from PACE were used as inputs to PROMOD® which captures the outage rates, heat rates, emissions and energy prices of the Company's existing fleet. The Powerbase database is used as an interface between PROMOD® and Strategist®. Strategist® was used to generate the build plans. Other inputs for the Strategist® model include the Levelized Cost of Energy (LCOE) model, which was used to develop the fixed costs portion of the present value of revenue requirements (PVRR) costs, and the Revenue Requirement model, which was used to develop the PVRR costs for technologies not included in the LCOE screening. The build plans generated by Strategist® could be loaded into PROMOD® to model hourly dispatch of existing and new supply-side resources. For the Tier 2 retirement analysis an output from the PROMOD dispatch model was used as an input into the Revenue Requirements model to evaluate the potential early retirement of St. Clair and Trenton Channel. (7 TR 3295-3296)

The complexity of the process leads to greater opportunity for error and less opportunity for a careful review.

Staff identified several errors during the case that may have been avoided if a simpler process were used. Witness Doherty describes a major error:

> "in the original modeling for the ET and EP scenarios with respect to technology cost reduction of renewable resources. The Company was able to correct this error and filed updated testimony, exhibits and workpapers. The case schedule was extended 4 weeks to allow for review of this additional data. (7 TR 3304.)

This error was corrected, but it delayed the case and the parties' review. As well, there was a minor monthly gas price discrepancy in Strategist® (further described in Staff Exhibit S-11.0 Page 2). With respect to this error, Staff agrees with the Company that these minor deviations in the monthly forecasted gas price are immaterial.

As with any IRP, errors are possible due to the volume of data necessary to create such a complex model. However, the increased complexity of the Company's modeling, increases the potential for errors even further. The complexity of the process also reduces the overall transparency for Staff and stakeholders involved in the review of the IRP. The Company provided Staff with an enormous amount of data to review, over 500 workpapers not including the exhibits provided by the Company in its application. (7 TR 3304.) Staff was challenged with tracking modeling inputs/outputs through various stages of the Company's modeling process, which considering the compressed IRP schedule made it difficult to give as much attention as it would prefer. In addition, Staff did not have a license for all modeling platforms used in this process. Therefore, Staff was unable to replicate the modeling used by the Company. Staff prioritized the data in exhibits provided with the Company's initial application and workpapers most pertinent to the application. (*Id.*)

2. The Company should explore other modeling software options prior to their next IRP.

The Company should perform a comprehensive review of available modeling software platforms and consider using something other than Strategist®. During this case, the limitations of Strategist® were highlighted multiple times by the Company and intervening parties. ELPC and MEC witness Anna Sommer stated that, "ABB, Strategist's vendor, will, in the future, no longer support the software. This is an opportunity to move to a model with more detailed resource optimization and dispatch capabilities." (6 TR 1769.)

The Strategist® model is limited to 1,250 unique build plans per optimization run. This presented issues when the model was solving for higher capacity need scenarios. For example, the resource block sizes available for selection needed to be increased in high load growth scenarios. (3 TR 421-422.) Also, the additional modeling done by the Company in response to discovery, in which the clean energy goal renewables originally included in the model starting point were removed and Strategist® was allowed to optimize through 2040, required the deployment of several model adjustments to allow the model to solve due to the 1,250 build plan limits. (Staff Exhibit S-6.2 Discovery Response SDTE-2.3b, p. 3.)

ELPC witness Kevin Lucas stated in direct testimony that, "…this case shows that Strategist is simply unable to provide a robust optimization of DTE's system that is reflective of modern technologies such as energy storage, that properly accounts for non-linear cost changes that solar is experiencing, and that dynamically solves for the best time to retire DTE's coal assets to the favor of its customers." (7 TR 1958.)

The Company acknowledged that modeling software has evolved over time and states its desire to use the best tool available for integrated resource planning. To that end, the Company agreed to complete a comparison of different modeling tools to determine whether Strategist® is still the best tool for the Company's IRP modeling needs before its next IRP. (3 TR 583.) Simplifying the model procedure will help provide increased data transparency throughout the Companies next IRP process. Staff recommends that the Commission request that the Company execute its pledge to explore modeling options.

3. The Company should be directed to feature a proposed course of action with a single, identified pathway for the entire planning period of future IRPs.

Staff recommends that the Commission direct the Company to include a single identified proposed course of action that covers the entire planning period of the IRP. In addition to the selected PCA, the Company could identify alternative paths (specifically for the long-term portion of the IRP) that could become preferable if the future changes and identify what those changes are. The Company's proposed course of action separates the planning period into two parts, a defined short-term

(2020-2024) and a flexible long-term (2025-2040). For the flexible period the Company identifies commitments to increase renewable generation to meet the Company's clean energy and carbon reduction goals, and to retire the Belle River Power Plant by 2030. The Company proposes to decide on the optimal replacement for the Belle River coal plant in its next IRP and presents four potential pathways that could be followed to fill that capacity need. (3 TR 348.)

The Company clarified further in discovery that the Company does not expect to select the specific resources from any of the four analyzed pathways and that the flexible pathways were meant to represent a range of possible futures. (Exhibit S-6.0 DTE Discovery Response STDE 13.10-13.13) The Company's PCA should have identified a specific replacement plan for the Belle River Power Plant in this IRP. However, absent a single PCA, Staff recommends that it do so in its next IRP. This will allow for a more thorough examination of the Company's resource plans over the entire planning period. Although the Company is not requesting and the statute does not provide for pre-approval of costs associated with investments outside of the five-year planning horizon, as presented, it is difficult to provide meaningful feedback on the Company's long-term plans.

The Company's position is that the IRP complies with the IRP filing requirements established in the Commission's December 20, 2017 Order in Case U-18461, Exhibit A which uses "plans" as a plural in the introduction. The order states, "[t]he utility shall describe resource plans to satisfy at least the objectives identified in MCL 460.6t." (2 TR 95.) There may be various plans involved, but more importantly the Company must select one coherent best overall plan of choice or "preferred resource plan."

The Company points out that Section XVI mentions various plans to be included within the plan:

> Section XVI of the same order, same exhibit, lists the following description of the PCA:
>
> > Include a detailed description of:
> > a) The type of generation technology proposed for a generation facility contained in *the plan* and the proposed capacity of the generation facility…
> > b) *Plans* for meeting current and future capacity needs with the cost estimates for all proposed construction and major investments…
> > c) The projected long-term firm gas transportation contracts… and
> > d) How the utility will meet local, state, and federal laws, rules, and regulations under the proposed course of action. [Emphasis added. MPSC Case No. U-18461, 12/20/17 Order, Exhibit A, p 20; (2 TR 95)]

The Company omits the rest of the passage:

> The utility shall describe the process used to select the *preferred resource plan*, including the planning principles used by the utility to judge the appropriate tradeoffs between competing planning objectives and between expected performance and risk. [Emphasis added. MPSC Case No. U-18461, 12/20/17 Order, Exhibit A, pp 20-21.)

While there may be various steps or plans within the plan, the Company is required to select the *preferred resource plan* for the Commission and Staff review. *The* Company also states its "proposed course of action is to remain flexible and not make pre-mature decisions or pretend that we know which scenario is more likely in the more distant future". (2 TR 96.) The Staff appreciates the detailed plans and analysis of alternatives but urges the Company to specify the preferred resource plan it desires to execute in its next IRP.

Staff is not advocating for a replacement decision for Belle River to be actually made or executed at this time, but a single best plan should be identified. The Company appears to be conflating the long-term planning portion of an IRP with a firm decision. Staff supports the Company's desire to remain flexible. A flexible PCA that provides the ability to adapt to future conditions is better than a PCA that doesn't have that adaptability. (7 TR 3306-3307.) However, there is a difference between a clearly identified plan to meet future resource needs that allows for changing course in the future if conditions warrant and the Company's approach which essentially says the plan is to plan later. Therefore, for this other reasons outlined elsewhere in this brief, Staff requests that the Commission direct the Company file its next IRP within 36 months from the date of the order in this IRP.

Staff has been consistent with its approach to evaluating IRPs filed pursuant to 460.6t. Staff has placed the priority on the near-term plan, focusing on resources investments within the first five years of the planning period, especially the resources added during the first three years that include pre-approval of capital costs. Staff finds the Company's plan is reasonable and prudent for the short-term period through 2024. However, Staff recommends that future IRP's contain a single long-term plan for the purposes of resource planning in accordance with the statute.

4. Because most deficiencies are in the out years, rejection of plan is not necessary, rather Staff requests that the Commission direct the Company to file IRP within 36 months of the final order in this case.

The previously described issues create a need to further evaluate the long-term portions of the plan but don't invalidate the Company's short-term plans identified in the defined period. It is Staff's position that the Commission direct the Company to file their next IRP within 36 months of the final order in this case and incorporate Staff's modeling recommendations above.

Several intervenors have called for the Commission to reject the Company's IRP. Staff does not support this position. The Company's PCA through the defined period ending 2024 is reasonable and prudent. The concerns raised by intervening parties do not impact the Company's short-term plan. Additionally, some of the issues identified above will take more time to address than would be afforded the Company through the denial process in MCL 460.6t(9). For example, the Company would not have time to evaluate, procure, and train its modelers on a new software platform. Without a new software platform, the Company might not be able to provide a robust optimization of DTE's system, including potential examination of superfluous units and early retirements, to identify a PCA for the entire planning period.

In response to Staff's recommended filing date for the next IRP, GLREA witness Richter walks through the implied timeline:

> The Proposal for Decision in this case is scheduled for December 20, 2019. In an optimistic scenario, we might get a ruling in January, 2020. Under this Staff recommendation, a new IRP would then be due in January, 2023. With 300 days to resolve that future IRP case, a

> decision in that case should be expected not earlier than November, 2023. That simply does not leave sufficient time for contracting and constructing facilities to be in-service in 2024. Therefore, requiring a new IRP in 3 years would not achieve the objective the Staff sets out for it. To achieve that objective, a new IRP would be required in 2 years. (7 TR 3145.)

GLREA witness Richter continues, "[w]e recommend that the Commission reject the IRP, citing a specific and exhaustive list of material deficiencies for immediate correction. If the Commission is unwilling to do that, then a new IRP two years from the issuance of a decision in the instant case could address this timing issue." Staff believes these timing issues can be resolved, assuming the PCA from the next IRP is approved and that it calls for the addition of renewable resources of a similar size and on a similar schedule as those the Company included in this IRP. It is Staff's position that these resources could be slightly delayed allowing for that competitive procurement of these resources. Based on current information these resources are being added to the Company's portfolio solely to meet the Company's clean energy and carbon reduction goals. There should be enough flexibility to adjust the procurement timing and still have the Company on schedule to meet its 2030 goal. If the Commission decides to approve the Company's IRP, it is preferable to allow the Company some time on the front end to completely address the flaws of this IRP and adjust the theoretical procurement of these superfluous renewable resources in five to six years.

Staff's primary concerns with the IRP modeling arise outside of the defined period of the plan 2020-2024. Rejection of the IRP will not allow for the correction of some of these issues. A filing date 36 months after an order in this case sets DTE on a schedule to refile prior to procurement of the renewables that were forced into the model and thus most appropriately addresses Staff and intervenor concerns.

E. The Company's stakeholder engagement

1. Staff found that the Company reasonably complied with its stakeholder engagement requirements.

Staff found that the Company conducted stakeholder engagement workshops in the form of open houses and technical workshops and were marketed with public notice in an appropriate manner to reach stakeholders. The Company provided sign-in sheets, comments and presentations, and detailed ways in which it considered additional sensitivities as part of the modeling scenarios it considered.

Staff included the following recommendations for deepening its engagement efforts. First, the Company should have listed information on each of its workshops along with any and all published materials on its Empowering Michigan Webpage. Second, Staff recommended enhancing transparency efforts by publishing each question and response that was submitted. This would allow other interested parties to view the view the questions and answers exchanged between the Company and the questioners, as well as information on all available open houses and technical workshops. These practices would promote ongoing stakeholder engagement.

2. The Company demonstrated that its stakeholder process was extensive.

The Company stated that its approach to public outreach provided ample opportunities for participants to have one-on-one discussions with DTE staff or leave feedback on comment cards. (2 TR 99.) The Company noted the evolution of its public engagement by broadening the publication of the meetings, adding an additional open house, and by making a call or web ex option available.

3. Contrary to Staff's finding, GLREA witness Rafson and Soulardarity witness Koeppel found that the Company fell short in conducting its stakeholder engagement.

GLREA witness Rafson argued that that DTE had not made enough effort to engage the public and expressed concern regarding the lack of engagement with the public. (7 TR 3175.) Soulardarity witness Koeppel found that the Company's stakeholder engagement process excluded opportunities for low-income people and people of color. Koeppel argued that the Company's technical workshops provided an overly complicated analysis, a skewed version of its analysis, and did not make its meetings accessible to all individuals. (7 TR 2323.)

Staff found that the Company's public engagement through three technical conferences and four stakeholder workshops was sufficient and complied with the statutory obligations. Going forward, Staff and intervenors agree that DTE could consider improvements to the content of workshops and accessibility of materials in future stakeholder engagement efforts.

F. Distribution and Transmission Planning

1. The Company satisfied MCL 6t(5)(h) and Section XII of the IRP filling requirements; however, the requirements should be updated.

Staff recommends that the ALJ and Commission find that the Company complied with MCL 460.6t(5)(h) and provided a sufficient transmission analysis in this case. However, consistent with the Michigan Statewide Energy Assessment, Staff recommends that the Michigan Integrated Resource Planning Parameters (MIRPP) and Michigan Integrated Resource Plan Filing Requirements be updated to give additional guidance and structure as to how transmission constraints should be modeled for the purposes of an IRP.

Staff asserts that the Company complied with the requirement to provide "[a]n analysis of potential new or upgraded electric transmission options of the electric utility" as directed in MCL 460.6t(5)(h) and Section XII of the Integrated Resource Plan Filing Requirements. (7 TR 3348.) Staff found that DTE complied with Sections XII(a) and (b) of the Michigan IPR Filling Requirements, and notes that no party argued that DTE failed to meet the requirements of those sections. (7 TR 3348-3349.) However, while ITC witness Marshall does comment on the Company's analysis, he does not offer an opinion on whether DTE's IRP should be accepted or rejected. Witness Marshall offers the opinion that Michigan does not have sufficient import capacity as evidenced by price separation between Zone 7 and the other zones in the PRA. (7 TR 2243.) In addition, witness Marshall opines that the IRP process could be improved and that closer co-ordination between utility and transmission owners would allow for more meaningful transmission analysis in IRP proceedings. (7 TR 2247.). Witness Marshall's proposed solution is to have utilities distribution planning process be more open and mimic that of an RTO planning process. (7 TR 2248-2249.) Staff agrees with witness Marshall's general concern that the transmission analysis in IRP filings could be improved though Staff does not necessarily agree that the solution is to make utilities' distribution facility planning process mirror that of an RTO transmission planning process. Therefore, Staff recommends that the utility work more closely with transmission owners to develop a more appropriate range of transmission assumptions for its next IRP model and that the filing requirements and MIRPP be updated to provide additional clarity around this issue.

2. MISO Resource Adequacy Tariff: As recommended in the Statewide Energy Assessment, Staff will be working with MISO and stakeholders to investigate opportunities to expand Michigan's capability to import electricity in a holistic manner[3].

Staff finds that the Company complied with Section XII(c) by providing the prompt year Capacity Import Limit (CIL) as well as out-year estimates provided by ITC. (7 TR 3349.) The Attorney General's witness David Dismukes believes the static CIL in and of itself is an unreasonable assumption and that it is inconsistent with MCL 460.6t(5)(h). (7 TR 2548- 2549.) However, Section XII of the filling requirements provide the guidance and requirements for compliance MCL

[3] In other briefs, this section might be called capacity import limit.

460.6t(5)(h). The Company has complied with those filing requirements. MEC witness Robert Fagan states that, despite the availability of other estimates of CIL for the 2023/2024 planning year presented in this case, DTE used a constant CIL of 3211 MW (the 2019/2020 planning year value). (7 TR 2487.) In response, the Company argued that the MISO LOLEWG out-year methodology is unreliable due to the low capacity credit given to generation in the MISO queue, citing specifically the Blue Water Energy Center (BWEC) given the ongoing construction. (6 TR 1476.) However, MEC witness Dale Osborn argues that the BWEC will not have much of an effect on the CIL as it is electrically distant due to voltage line constraints. (7 TR 2827.) Witness Fagan also states that it would have been desirable to have DTE model scenarios and sensitivities where the CIL is modeled at different levels. (7 TR 2489.) Witness Fagan says that it is unreasonable to assume that the CIL will remain static for the entirety of the planning horizon because the transmission system will certainly change. (7 TR 2490.) Furthermore, witness Fagan, referencing the ITC study related to this IRP proceeding, asserted that the Attachment Y proceeding and the possible relaxation of voltage requirement at the Enrico Fermi 345kV bus could have profound impact on the CIL. (7 TR 2491.) In addition, Witness Fagan argues that the Company erred in assuming a static CIL in modeling because it did not account for the increased CIL resulting from Consumers Energy's plans for added solar generation. (7 TR 2492.)

While Staff does not have an opinion about MEC witnesses' arguments regarding the CIL at this time, the Company is not currently required to perform such analysis and the validity of such an analysis is predicated by the availability of resources in the adjacent zone. The filing requirement pertaining to the CIL merely state "[t]he utility's analysis shall include the following information: … Current transmission system import and export limits as most recently documented by the RTO and any local area constraints or congestion concerns." *In the matter, on the Commission's own motion, to implement the provisions of MCL 460.6s(10) and (11)*, MPSC Case No. U-15896, 12/20/2017 Order, Exhibit A., p 17. DTE Electric has complied with this requirement. Additionally, the Company supplied a range of possible future CIL from both MISO and ITC transmission studies. As witness Fagan stated, DTE Electric assumed the 2019/2020 CIL for the entire planning horizon in its Strategist model and does not run additional scenarios and sensitivities around varying CIL values. (7 TR 2486-2487.) The MIRPP however states that the IOU should "[c]onsider including transmission assumption in the IRP portfolio, such as the impact of transmission and non-transmission alternatives (local Transmission, distribution planning, locational interconnection coast, environmental impact, right of way availability and costs) to the extent possible." (*In the matter, on the Commission's own motion to implement the provisions of Section 6t(1) of 2016 PA 341*, MPSC Case No. U-18418, 11/21/2017 Order, Exhibit A., p 27.) DTE has met both requirements as laid out by the filling requirement and the MIRPP. In combination, the filing requirements and the MIRPP do not speak to witness Fagan's concerns regarding the CIL forecast and do not give a great deal of direction about how transmission capabilities should be modeled in a capacity expansion model for an IRP. Staff recommends that any future updates to the MIRPP and filing requirements take into consideration both witness Osborn's and witness Fagan's concerns while also considering how the CIL fits into the greater MISO resource adequacy construct. This recommendation is supported by the State Energy Assessment as it directs Staff to "work with Michigan utilities and stakeholders to propose revisions to the Commission-approved IRP modeling parameters and filing requirement to better accommodate the consideration of transmission alternative in IRPs." (Michigan Statewide Energy Assessment, MPSC Case No. U-20464, Docket No. 0031, 07/1/2019, p 192.)

Staff finds that the combination of the public version of the Attachment Y proceeding and the studies by ITC satisfy Section XII (d) and (e) of the filing requirements. (7 TR 3353.) DTE witness Jestin Hunnell testified that the Trenton Channel Unit 9 retirement Attachment Y process and the ITC proposed SVCs are linked. (6 TR 1468.) ITC upsized the SVCs that were entered into the MISO MTEP process to increase the CIL. This approach was taken because the stand-alone SVCs to increase the CIL would be difficult to get through the MISO MTEP process. (7 TR 2257-22578.) MEC witness Osborn and Fagan present arguments surrounding the ITC proposed SVC proposal. Here again, the filing requirements simply require that the information be presented regarding potential changes to the transmission system. Also, MIRPP does not require the information gathered by the transmission analysis to be explicitly included in the model. (*In re implementation of MCL 460.6s(10) and (11),* MPSC Case No. U-15896 12/20/2017

Order, Exhibit A., p 17.; *In re implementation of Section 6t(1) of 2016 PA 341*, MPSC Case No. U-18418, 11/21/2017 Order, Exhibit A., p 27.)

DTE has presented the information and complied with sections XII (d) and (e). Staff finds that DTE complied with the requirements in the instant case. Staff recommends, however, that the utility work more closely with transmission owners to develop a more appropriate range of transmission assumptions for inclusion in its next IRP model and that the filing requirements and MIRPP be updated to provide additional clarity around this issue.

3. Expanding the Capacity Important Limit: As recommended in the Statewide Energy Assessment, Staff will be working with MISO and stakeholders to investigate opportunities to expand Michigan's capability to import electricity in a holistic manner.

Staff should include an examination of the MISO resource adequacy tariff for errors and inconsistencies with its work recommended in the Statewide Energy Assessment:

> E-8.2: Utilities, electric transmission companies, Staff, RTOs, and stakeholders, should further investigate opportunities to expand Michigan's capability to import additional electricity to address short- and long-term reliability and resource adequacy needs in a more holistic manner as Michigan experiences additional power plant retirements. This effort should also consider a methodology to quantify the value of such projects and related cost allocation, as appropriate. (U-20464 Statewide Energy Assessment Final Report Page 197)

Energy Michigan proposes "an option to increase Michigan's ability to import capacity from out of state to meet the MISO resource adequacy standard." (7 TR 2952.) Energy Michigan's position is that MISO's current method for determining the "useable portion" of the CIL (what DTE has termed ECIL) contains "errors and inconsistencies" and proposes a remedy that would require a tariff change at MISO. According to Energy Michigan's proposal:

> "[It] would revise the MISO Module E-1 tariff to change the way that the Local Clearing Requirement for a zone is determined. Nothing would be changed in the way MISO performs its statistical analysis or power flow modeling. Nothing would be changed in the way Load Serving Entities and Electric Distribution Companies submit forecast data to MISO. Nothing would be changed in the way PRMR obligations are determined for LSEs. Nothing would be changed in the options that LSEs have for meeting their PRMR obligations." (7 TR 2977.)

Energy Michigan requests "the Commission…lead the effort to take the issues explained [in its direct testimony] to MISO and to the FERC." (7 TR 2979.)

No other party, including Staff provided direct or rebuttal testimony that addresses the issues raised by Energy Michigan. This proceeding is specific to DTE's IRP and the MISO tariff issues are beyond the scope of DTE's IRP. Staff supports further examination of the MISO resource adequacy tariff for errors and inconsistencies and believes the best place for that work is in conjunction with the work already being planned in response to the observations and recommendations of the Statewide Energy Assessment. (Michigan Statewide Energy Assessment, MPSC Case No. U-20464, Docket No. 0031, 07/1/2019.)

F. Modeling Risk Analysis

The Commission ordered utilities to "include a thorough risk analysis of the preferred plan and optimal plans for each of the scenarios specified in the MIRPP." *In the matter, on the Commission's own motion, to implement the provisions of Section 6s of 2016 PA 341*, MPSC Case No. U-15896, 12/20/2017 Order, Exhibit A. Furthermore, In the Commission's order for the Company's Certificate of Need (CON) case for its Bluewater Energy Center, MPSC Case No. U-18419, the Commission stated as follows:

> [I]n preparation of the upcoming IRPs, the Commission intends to explore with the Staff to further examine risk assessment methodologies and best practices from other jurisdictions…Staff shall evaluate and make recommendations for best practices for requests for proposals, competitive bidding, and risk assessment to be included in the integrated resource plan filing requirements and integrated resource plan guidelines. [4/27/2018 Order, p. 127.]
>
> As a result, Staff provided both a deterministic and stochastic risk assessment methodology to the Commission. As explained by Staff witness Makinde, a stochastic model, possess some inherent randomness. Randomness is present and variable states are not described by unique values, but rather by user defined probability distributions. The same set of parameter values and initial conditions will lead to a variety of different outputs. Stochastic analysis allows for an analysis of risk of the proposed plan in undefined futures within a set of variables and a range of distributions chosen at random. Stochastic analysis provides a measure of risk under numerous randomly selected parameters. [7 TR 3273-3274.]
>
> The Company did perform a stochastic risk analysis which analyzed 13 portfolios. (7 TR 3274.) However, the Company failed to include any of the PCA pathways in the stochastic risk analysis. *Id.* As explained by Mr. Makinde, the Company's failure to include PCA pathways into the analysis creates certain issues, Not explicitly including the PCA portfolio(s) in the stochastic risk analysis precludes the Company from assessing the impact of the of key market drivers on the chosen portfolio(s). Stochastic risk assessment measures the possible impact

> selected uncertainties can have on a PCA when exposed to probable distributed variations in the specified key market drivers when build plans cannot be reversed. Understanding the risks and the associated impacts helps to determine if the build plan is truly the best plan, when coupled with the selected uncertainties, associated probabilities, and their interplay. This understanding gives decision makers the ability to alter plans by reducing and/or eliminating exposure to the risk variables in the future. [7 TR 3275.]

Therefore, Staff recommends that the Company incorporate its PCA into the stochastic risk assessment in its future IRP filings. The Company appears to be considering Staff witness Makinde's recommendations, and those of other witnesses, and the resource requirement of those suggestions as shown on table 21 in DTE witness Mikulan's rebuttal testimony. (3 TR 584.) Staff maintains that incorporating PCA pathways into the stochastic risk analysis will result in a better understanding of the risks involved with specific build plans.

G. Michigan Workforce

1. The Company complied with the Michigan Workforce Requirements.

Staff witness Mullkoff discusses how the Company complied with the Michigan Workforce Requirements. MCL 460.6t Subsection (8)(b). The statue requires that "to the extent practicable, the construction or investment in a new or existing capacity resource in this state is completed using a workforce composed of residents of this state." *Id.* She suggested that while Staff has minimal concerns over the near-term projected investments, Staff recommends the Company address how it will facilitate the use of Michigan workforce as it continues to implement the PCA in future IRP filings. (7 TR 3247-3248)

Company Witness Sharon Pfeuffer confirmed that the Company will utilize Michigan workers in implementation of its PCA. Specifically, the Company has estimated that they have spent more than $9.2 billion creating 24,000 jobs with Michigan-based suppliers since 2010. Company Witness Paul discussed that of the around 200 workers in the St. Clair Plant, the Company has a plan to train and relocate them after the plant is retired. (5 TR 1165).

Geronimo witness Betsy Engelking also commented on workforce development in her review of meeting the statute set in MCL 460.6t(8)(a). She testified, "[i]n addition, the construction or investment in the project should, to the extent practicable, be completed using a workforce comprised of state residents." (7 TR 3009.) However, she did not explicitly comment on the extent to which the Company should meet this requirement. Thus, Staff, the Company and parties concur on the appropriate use of utilizing the Michigan workforce in construction or investment of new or existing capacity.

H. Rate Issues

1. Summer on-peak rates are not demand response rates.

The Commission approved a transition to a new default residential rate which includes a higher on-peak summer price, or a time-of-use pricing component. 7 TR 3339.) This new default residential rate structure is designed to recover the actual difference in power supply costs during times of higher system-wide demand (and therefore price). (7 TR 3340.) The Company incorrectly identifies this new default residential rate as a DR program in its description of other DR pricing schemes such as variable peak pricing or demand buyback (e.g. Rider 12.) (6 TR 1678.)

While the new summer on-peak rate structure does vary prices by the time of day, it is not a time-of-use DR rate because it is not designed to change customer behavior. (6 TR 3340-3341.) Demand response rates are designed to, as the name suggests, elicit a response in demand. *Id.* Demand response rates are evaluated on how much demand can be lowered or shifted away from peak times (and at what price). Conversely, the new summer on-peak default residential rate is only meant to match rates with actual price changes faced by the utility, which are regularly included in other, larger customers' rate designs. (7 TR 3341.) For these reasons the Commission should not accept the Company's accidental identification of the summer on-peak residential rates as a DR rate.

I. IRP Project Status Reports: Staff disagrees with the Company's reporting proposal and proposes 3-year reporting.

Staff Witness Mullkoff discussed annual IRP Status Reporting and included a 3-year reporting template as Staff exhibit 3.0. PA 341, Subsection 14 requires that, "[a]n electric utility shall annually, or more frequently if required by the commission, file reports to the commission regarding the status of any project included in the initial 3-year period of an integrated resource plan approved under subsection (7)." MCL 460.6t(14). Staff requested the Company annually complete a reporting template paired with a narrative that explains any adjustments in status and changes in scope, timing, size, or expected costs. (7 TR 3249.) This recommendation is consistent with guidance from the Commission Order in Case No. U-18419. *DTE's Applications for Certificates of Necessity*, Case No. U-18419, 4/27/2018 Opinion and Order, p. 137. In addition, Staff requested to maintain open and transparent dialogue with the Company and expects the Company to provide immediate communication if there is a significant change or anticipated change to the expected cost, timing, or size of any resource additions in its IRP. (7 TR 3249, 3250.)

In rebuttal testimony, Company witness Pfueffer responded to Staff's suggestion on reporting. She disputes the need for additional annual reporting status reports due to the fact that there are separate annual reconciliation processes in place for Energy Waste Reduction (EWR), Demand Response (DR), and renewable energy resources, and provides a table detailing where current reporting requirements are found[4]. (2 TR 98.)

In its rebuttal, Company witness Schroeder refuted the request for "immediate communication to Staff and the Commission if there is a significant change…" (5 TR 1322.) She argued that project negotiation is typically fluid, and changes occur on a frequent basis, thus making it impractical for "immediate"

[4] Table 1 "Current Reporting Requirements".

communication. The Company commits to present any changes to Staff upon completion of negotiations. (5 TR 1322.)

GLREA supports Staff's position of annually updating a 3-year reporting template. Staff disagrees that a status of all approved resources would be duplicative, because while the reconciliation dates for each of the above-mentioned cases occurs annually, they take place at staggered times throughout the year. Providing data in a pre-approved reporting form at the time on an annual basis would help provide the Commission and Staff a more up-to-date picture of ongoing Capital, O&M, and MW projections and actuals. Staff believes this level of detail is useful to ensure prudency of spending and may have implications on related rate cases, as well as IRP Resource filings and reconciliation plans. Staff requests that the ALJ and Commission require DTE to use its 3-year reporting proposal.

IX. Cost Approvals for Future Recovery

1. Costs eligible for preapproval should not include operations and maintenance (O&M) costs, energy waste reduction costs, or demand response costs.

Staff considers all the provisions in PA 341 Section 6(t), the IRP filing requirements approved by the Commission in Case No. U-15896, and the Michigan Integrated Resource Planning Parameters approved by the Commission in Case No. U-18418 to define the reasonable scope of an IRP. (7 TR 3218.) Act 341 Section 6t(11) directs the Commission to "specify costs approved for the construction of or significant investment in an electric generation facility" MCL 460.6t(11). Once approved, in the IRP, the "costs for specifically identified investments" are then essentially preapproved, or in terms of Act 341, "considered reasonable and prudent for cost recovery purposes" so long as the investment is made within three years of the plan approval. MCL 460.6t(11), (17). Consistent with its position in U-20165, Staff recommends the Commission limit cost recovery under Act 341 Section 6t(11) to capital costs, as defined in statute, such as "an electric generation facility, the purchase of an existing electric generation facility, the purchase of power under the terms of a power purchase agreement, or other investments or resources used to meet energy and capacity needs that are included in the approved integrated resource plan." MCL 460.6t (11).[5] Costs eligible for preapproval should not include operation and maintenance costs, as the statute does not provide for preapproval of these costs.

Staff recommends the Commission provide explicit cost approval for only the first three years of the current plan and allow for continued scrutiny, such as in subsequent rate cases, of certain IRP related cost approvals. (7 TR 3213-3214.) The Company has made cost pre-approval requests that Staff believes should be considered in other proceedings where updated information would provide more accuracy in determining whether costs are reasonable and prudent. As outlined in Section III, the Company requested the following cost pre-approvals in this case:

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[5] See Initial Brief of Staff in Case No. U-20165, *In the Matter of the Application of Consumers Energy Company for Approval of an Integrated Resource Plan under MCL 460.6t and for Other Relief,* 12/21/2018 (Staff interpretation of "specifically identified investments.")

- $103 million of energy waste reduction (EWR) capital costs from 2020 to 2022.
- $24 million of projected demand response (DR) capital costs from the period of May 1, 2020 through December 21, 2022.
- $0.7 million in capital costs associated with CVR/VVO pilot programs from 2019 through 2020.

Staff does not dispute the Company's $0.7 million in capital costs associated with CVR/VVO pilot programs spending from 2019 to 2020 as outlined by Staff witness Tayler Becker. Staff recommends pre-approval of costs associated with the CVR/VVO pilot as part of the proposed course of action (PCA).

2. Energy waste reduction cost approvals should be reviewed with annual energy waste reduction plans.

Staff submits that the $103 million, requested in the Application, in capital costs is reasonable for pre-approval. Staff requests that the Commission reserve Staff's right to review and make recommendations related to EWR programs in the context of annual EWR plans. (7 TR 3217).

3. Demand response capital requests should be reviewed in a subsequent rate case.

Staff does not dispute the Company's proposed capital spending on interruptible AC switch replacement or programmable communicating thermostats and the associated increase in demand for DR resources; though Staff witness Isakson recommends a reduction in capital spending on other DR pilots as described in testimony. Staff requests that the Commission allow Staff to review and make recommendations related to DR programs based upon the most recent program information and costs in context with rate case filings. *Id.* As stated by Staff witness Proudfoot, "[t]he scrutiny in rate cases would allow for the approval of DR operation and maintenance (O&M) costs that are not approved in an IRP proceeding." *Id.*

Cost approvals pursuant to Act 341 Section 6(t)(11) should ultimately be subject to the specific proceeding in which the cost approval requests take place. (7 TR 3221). These proceedings review the cost approvals in context using current data to determine if the cost recovery is reasonable and prudent. Staff recommends that EWR programs be considered in context with EWR plans, capital requests for DR programs be made in rate case filings, and the Commission only pre-approve costs for the first three years of the current plan.

4. The Commission should not approve of the Company's proposed Other DR Pilot capital spending.

The Company proposes a capital spend of $24 million on DR programs and pilots from May 1, 2020 through December 31, 2022. (6 TR 1680.)

According to the three-phase DR framework approved in Case U-18369, the Company receives approval for capital spending on DR in IRP cases, the Company is granted rate recovery in general rate cases, and the net over- or under-spending on DR programs is reconciled annually for inclusion in future rate cases. (7 TR

3331-3332.) Demand response O&M costs are presented in rate cases and likewise reconciled in the same annual cases as capital spending. *Id.*

Staff supports the Company's proposed DR capital spending for currently on-going DR programs. (7 TR 3333.) The Company's current DR pilots—Bring-Your-Own-Device and Electric Power Research Institute Transportation Program pilot—are also reasonable and supported by Staff. *Id.* However, the Company also proposes preapproval for recovery of capital spending on future pilots which are only described in vague terms in the Company's application. (7 TR 3334.) Staff does not support capital spending approval for the Company's "Other DR Pilots" which are still in the exploratory phase. (6 TR 1671.)

While Staff recommends that the Commission not grant preapproval for capital costs intended for other DR pilots, the recommendation does not preclude the Company from making a future request for DR pilot capital spending outside of the IRP when more details are available for review. (7 TR 3334.) The Company agrees. (6 TR 1686.) Staff discusses the fact that while pilots are valuable in developing future DR programs, the three-phase DR framework reduces the risk to the Company if a program is unsuccessful in the future, thus reducing the need for as much piloting as is typical. (7 TR 3334-3336.) The Company agrees on the importance of pilots, and that its request for preapproval of capital costs amounts to having a budget for such pilots. (6 TR 1683-1684.) Staff is concerned that preapproving a capital budget for pilots may cause the Company to "feel pressured into spending regardless of the prudency of new pilots." (7 TR 3334.) The Company counters Staff's concern by noting that the three-phase DR framework allows the Commission to revisit and review the prudency of DR capital spending in annual reconciliations. (6 TR 1687.)

The Company disagrees that the DR framework does not provide for lower risk of DR capital spending on pilots. (6 TR 1684.) Staff argues that the three-phase framework decreases risk that program outcomes do not match program expectations, whereas the Company appears to believe that risk to the Company is only lowered with less prudency review. (6 TR 1685.)

The Company also offers to include Staff in developing future DR pilots early on in the process as a way to assuage the Commission and Staff of the prudence of those still loosely defined pilots. (6 TR 1687-1688.)

Staff appreciates the Company's willingness to include Staff in the development of future DR piloting endeavor but finds that such a promise is insufficient to support the pre-approval of more than $4M in capital expense for those pilots. As discussed by Staff, the Company has opportunities to request additional spending for pilots in other proceedings when more details on those pilots can be presented to Staff, stakeholders, intervenors, and the Commission. Approval of open-ended spending such as the Company's request may be beneficial to customers, but the Commission is tasked with setting reasonable rates, and must consider the likelihood of that benefit accruing to those customers. The benefit of additional DR capital spending is always obvious to the utility, namely in the ability to earn a return on that additional spending. Essentially, the Commission is faced with two competing arguments for the additional capital DR spending: approve a budget for unspecified pilots now for reconciliation later or acknowledge that the Company can specify and spend capital on pilots now for reconciliation later. Through either the Company's or Staff's proposal the spending will be reviewed for prudence at a later date. *Id*. The difference is in the Company's request for preapproval, with which Staff disagrees. The Company does not need Commission approval to spend capital on DR pilots. The Company only needs Commission approval to recover that spending in rates, which will occur should that spending meet its prudency review. The prudency review will happen regardless of the determination made here.

For these reasons the Commission should reject the Company's proposal for pre-approval of $24 million in DR capital spending as shown on Exhibit A-26. The Commission should instead approve Staff's adjusted DR capital spending as depicted on Confidential Exhibit S-8.0.[6]

5. CVR/VVO: Staff recommends preapproval of costs associated with the CVR/VVO pilot as part of the defined PCA.

DTE proposed CVR/VVO pilot program costs and capacity reductions appear to be reasonable. (7 TR 3375.) Although Staff continues to have concerns with the CVR/VVO pilot program. (7 TR 3375.) Staff is confident that the Company will

[6] A specific value for Staff's recommended DR capital budget (Staff Exhibit S-8.0) is not provided here because it is based on a confidential exhibit, as explained in Staff witness David Isakson's direct testimony. (7 TR 3333.)

work to evaluate and address these concerns through the pilot program to make the CVR/VVO program a success[7]. If these concerns are not alleviated and the benefit cost analysis is not what was expected through the pilot program, the CVR/VVO program could be deemed unreasonable or imprudent as part of the flexible PCA and future IRP filing(s). Staff provided recommendations to alleviate Staff's concerns with the CVR/VVO pilot program. (7 TR 3367-3377.)

a. The Company should consider existing investments such as grid modernization infrastructure when selecting CVR/VVO circuits.

Staff recommends that DTE consider existing investments such as grid modernization infrastructure when selecting CVR/VVO circuits and to fully utilize the potential and capabilities of existing infrastructure to make CVR/VVO successful. (7 TR 3376.) As part of the pilot to ensure the program's feasibility and cost-effectiveness, Staff recommends the Company carefully select CVR/VVO circuits with the consideration of existing investments and leveraging those investments to improve the success of the program. No other party rebutted Staff's recommendation. Staff requests that its recommendation be adopted.

b. The Company should consider the impact of DER penetration in conjunction with its CVR/VVO piloting programs.

[7] Success of the pilot is based on the net present value of the impact to customer revenue requirement. If the energy and capacity savings exceed the investments of the CVR/VVO pilot, then the pilot will be considered successful. (7 TR 3376.)

Staff recommends that DTE establish DER penetration forecasting on their circuits to be used in selecting CVR/VVO circuits. (7 TR 3376.) Distributed energy resource (DER) forecasting of selected CVR/VVO circuits will assist the Company's ability to avoid the potential for future circuit modifications impacting the once cost-effective circuits. Staff also believes that incorporating DERs in the 2019-2020 pilot program would be effective in evaluating the impacts to the circuits. (7 TR 3377.) It is critical to consider DER penetration forecasts and evaluate the impacts to the electric system although the current DER penetration at the distribution circuit level is low. Company witness Zhou does not agree with this recommendation at this time and expresses concerns arguing that tools and methodologies cannot effectively forecast DER penetration at the circuit level, and it would be challenging to develop an accurate algorithm on individual circuits. (6 TR 1740.) But it does appear that DER penetration, typical of the rest of the system (<0.1%), is being considered. (6 TR 1740.) Although Staff agrees there is currently low penetration and these types of resources are very new, the impacts need to be proactively evaluated in some way to avoid reactive spending to accommodate DERs while achieving the same results. GLREA witness Prehoda believes that the Company's lack of DER modelling in the IRP is proof that the lowest-cost option has not been considered and believes the IRP should be denied since it cannot be considered reasonable and prudent. (7 TR 3081.) Although Staff understands the importance of DER forecasting and evaluation of its impacts, it does not believe this is a reason to deny the CVR/VVO pilot program as part of the defined PCA of the IRP. The pilot program is the first step in determining the success of the program prior to potential implementation as part of the flexible PCA beginning in 2026. Staff believes that the piloting is a prudent first step approach purposefully performed to evaluate whether or not the program is reasonable and prudent to include in future IRP capacity filings and further recommends that the Company incorporate circuits using DERs into the 2019/2020 CVR/VVO piloting program to evaluate the impacts to the electric system and CVR/VVO enabled circuits.

c. The Company should submit annual CVR/VVO-specific reporting to the Commission in addition to what it intends to gather and track.

Staff recommends the Company file an annual CVR/VVO specific report to the Commission since the benefit cost analysis is needed to evaluate the performance and success of the pilot program. Reporting is necessary for the Company to alleviate Staff's concerns such as the Company's ability to stay within the 120-114V range to optimize the capabilities of each circuit (7 TR 3375.) Staff does not believe that the Company's planned pilot program tracking metrics of measured energy reduction (MWh), peak demand reduction (MW), and voltage levels (7 TR 3374) throughout the circuit are enough to determine the success of the pilot. Company Witness Zhou expresses Staff's recommended reporting is unnecessary at this time, and the reporting will not be needed until the program is initiated beyond the pilot. (6 TR 1741.) Staff disagrees that CVR/VVO reporting is only necessary after the pilot program and believes that reporting is necessary during the pilot stages to evaluate the pilot program's performance and assist Staff in determining whether or not the costs associated with the program are reasonable and prudent in the rate cases. If the pilot program is not performing as planned, Staff holds the authority to recommend termination of the program at any time to avoid the program costs from being included in customer rates. Company witness Zhou later expresses that the Company can provide an informal update or one-time report after further clarification from Staff regarding the results of the CVR/VVO pilot if approved since the information requested by Staff would be difficult and expensive to collect. (6 TR 1741.) It is not the intent of Staff to provide increased burden or cost to the Company with the reporting request. After further consideration in the case and other IRP filings, Staff recommends the Company update Staff annually in a standardized format agreed upon between Staff and the Company. Staff believes that annual reporting of the CVR/VVO pilot program is necessary and recommends such reporting to the Commission.

The CVR/VVO pilot program is a new program that has been briefly incorporated into the Company's five-year distribution investment and maintenance plan with a clear objective (7 TR 3372-3373.) The Company's pilot program is a necessary and prudent step in evaluating the cost effectiveness of a program prior to its proposed execution as art of the flexible PCA.

In summary, Staff recommends the Company's full requested capital amount for CVR/VVO pilot program be preapproved as part of the defined PCA pursuant to PA 341, Section 6t.

6. The conversion of River Rouge Unit 3 to natural gas should be reviewed in a further proceeding for cost approval of the project.

Staff recommends that the Commission clarify that approval of the River Rouge Unit 3 conversion in this case does not automatically approve future recovery of capital investments of this project. DTE is not requesting any cost recovery in this IRP, though it provided estimated costs to convert River Rouge Unit 3 from a coal fuel source to that of natural gas and recycled industrial gas in 2020 and continue its operation until 2022. Natural gas will be procured from third-party gas marketers and industrial gas from a DTE subsidiary. The net present value analysis for this project in the IRP was not fully detailed. DTE is not asking for cost approval in this case. (7 TR 3287-3288)

Due to the nonspecific capital costs of the project and the affiliate nature of the proposed transaction, Staff believes that cost approval should be sought in other proceedings such as a PSCR or rate case. Staff witness Schiller testified that approval of the project in this IRP does not guarantee cost approval in future proceedings; any future request for cost recovery would be subject to a review by the Commission to ensure costs were reasonable and prudent. (7 TR 3289.)

In direct testimony filed on behalf of the Great Lakes Renewable Energy Association, witness John Richter agrees with Staff that "[t]he IRP provides incomplete data on the proposal to convert [River Rouge unit 3] from coal to industrial gases." (7 TR 3119.) Witness Richter poses several rhetorical fuel economic questions to highlight the lack of assessment on the conversion and recommends that the Commission should not approve the plan to convert River

Rouge unit 3 until the questions are answered. (7 TR 3121.) However, in the rebuttal testimony of DTE witness Matthew Paul, the Company testifies that it has already performed testing on conversion feasibility and is not asking for cost approval for the project in this proceeding. The Company agrees with Staff's assessment that cost approvals should be requested in other proceedings. (5 TR 1127.)

X. Other issues

J. Asset ownership

1. Staff believes future renewable energy procurement should be split 50/50 between company-owned projects and PPAs and completed through a resource procurement process that includes multiple procurement and resource options.

Based on its July 18, 2019 Order in Case No. U-18323[8], the Commission found that there was insufficient evidence to demonstrate as to whether company-owned generation can be cost effective compared to alternative models of ownership, and encouraged that in the future, an analysis of alternatives like third-party PPAs would have proven helpful in coming to a determination. (7 TR 3362.) EIBC/IEI also supports Staff's recommendation that the Company should utilize a 50/50 split between Company-owned renewable resources and third-party PPAs, and noted that under the previous law, PA 295 of 2008, this resource strategy resulted in annual cost reductions. (7 TR 3033.) Staff showed a similar trend in witness

[8] MPSC Case No. U-18323, 7/18/19 Order, p. 21.

Proudfoot's testimony. (7 TR 3224.) They distinguish that while EIBC/IEI supports access for third party involvement, they believe that developers should be allowed to meet on an equal playing field, and a requirement of future guidelines should not permit company or affiliate owned projects to compete among independent power producers. (7 TR 3033.)

2. In contrast, the Company believes that utility ownership should not be prospectively limited through this IRP proceeding, and does not find it appropriate for the MPSC to definitively address asset ownership concerns in this IRP case.

The Company's opposition to addressing asset ownership is primarily based on their interpretation of PA 342, and the omission of a prior clause requiring 50% ownership of renewable assets. Second, the Company restates that the IRP filing is intended to serve as a plan which uses multiple forecasts and estimates during a point of time, and its data that informed such plans did not distinguish if aspects of the plan were owned by the Company or third parties. Instead, the Company believes the MPSC should consider asset ownership when there is a specific proposal seeking approval for a Certificate of Necessity, approval of one or more specific contracts, or when seeking cost recovery if pre-approval was not sought for the project. The Company firmly postures that it is "impossible to generically and prospectively determine whether utility-owned renewable assets will cost more or less than PPAs. Each renewable project is a unique combination of many factors including size, technology, design choices, supply chain strategies and efficiencies, siting, land management strategies, community factors, tax strategies, and financing structures." (2 TR 84.)

The Company used assumptions of company-owned assets based on the belief that utility ownership of renewables generally benefits customers over the long run, and that their cost of ownership is competitive with, or lower than third-party renewable developers. The Company refutes that PPAs by third parties are lower in cost to customers than utility-owned projects. However, in its rebuttal, the Company stated it remains open to engaging with Staff and interested stakeholders on a new process to discuss RFP best practices. Staff witness Paul Proudfoot suggested a new docket be opened to solicit comments on such a process (7 TR 3222.) The Company wants to ensure that it can procure the most cost-effective resources to meet its RPS targets and wishes to not potentially delay any projects projected to come online in 2021 and 2022. (5 TR 1316.) These interests must be balanced; however, action should not be taken in haste. Staff continues to support the use of a docket.

Company witness Schroeder discussed her theoretical analysis of comparing the levelized cost of energy for assuming third party and utility ownership. Her analysis showed that PPAs will be 10-15% more expensive than utility ownership. (5 TR 1317.) Her discussion of this levelized cost of energy for utility ownership assumes a life of 30 years, whereas common terms of PPAs are 20 years; the Company's analysis considered the total cost of ownership under a span of 30 years.

Staff doesn't necessarily disagree with witness Schroeder's analysis, but finds that engaging in a robust third-party competitive bid would ensure ratepayers receive the full benefit of the resource investment. EIBC/IEI also supports Staff's recommendation that the Company should utilize a 50/50 split between Company-owned renewable resources and third-party PPAs, and noted that under the previous law, PA 295 of 2008, this resource strategy resulted in annual cost reductions. (7 TR 3033.) They distinguish that while EIBC/IEI supports access for third party involvement, they believe that developers should be allowed to meet on an equal playing field, and a requirement of future guidelines should not permit company or affiliate owned projects to compete among independent power producers. (7 TR 3033.)

K. Case No. U-18232 and RFP

The Commission addressed competitive resource procurement in its partial approval of DTE's REP Case No. U-18232; in its July 18, 2019 Order. The Commission determined that the Company had not proven that the proposed Company-owned wind projects were cost-effective compared to alternative sources of renewable generation and ownership models.[9] (7 TR 4353.)[10]

As Staff witness Proudfoot testified in this case that the Commission's July 18, 2019 Order in Case No. U-18232, DTE Electric's Renewable Energy Plan Case,

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[9] MPSC Case No. U-18232, 7/18/2019 Order, p. 23.

[10] The Company's lack of competitive resource procurement in this case is further analyzed below.

required renewable generation assets that do not qualify for 100% of the federal production tax credit proposed by the company to be addressed in this integrated resource plan proceeding. (7 TR 3223) The Company did not allow for optimization of renewables used to meet statutory requirements in its modeling. Instead it forced these renewable into the model so that the model would only optimize incremental assets above and beyond the "statutory renewables". Staff witness Doherty addressed this Commission directive in this IRP matter with his critique of the Company's decision to force in renewable assets into the model as opposed to allowing the model to optimize renewables utilized to meet the 15% Renewable Portfolio Standard (RPS) by 2021. (7 TR 3302.) Staff generally criticized this technique but did not strictly oppose the Company's method subject to three contingencies listed below that will provide for a thorough review of the reasonable and prudence of future renewable asset and power purchase agreement (PPA) procurement.

First, Staff recommends, instead, that the Company be ordered to file its next IRP in 36 months from the final Order in the instant case as suggested by Staff witness Proudfoot and Staff witness Doherty (7 TR 3221, 3301). This provides Staff and intervenors an expedited and in-depth look, when compared to the statutorily allowed 5-year frequency, into the Company's plans to procure renewable assets as it continues to develop renewables to meet it renewable portfolio standard (RPS) and goal. As discussed above, this helps to remedy various issues addressed by Staff.

Second Staff recommended future asset procurement be acquired through a competitive procurement process. (7 TR 3303, 3223.) Staff witness Proudfoot explains that through a competitive resource procurement strategy, renewable energy generating assets will be procured in the most reasonable and prudent method possible. (7 TR 3224) Staff witness Mullkoff details Staff's preferred competitive procurement strategies suggesting that DTE Electric model the Consumers Energy Company's process laid out in its IRP Settlement Agreement in Case No. U-20165 which utilized the guidelines developed in Case No. U-15800. (7 TR 3253.)

Lastly, Staff witness Proudfoot recommended a 50/50 split between Company-owned assets and third-party PPAs which has historically led to cost reductions in wind assets. (7 TR 3224.) This should apply to utility scale distributed generation assets that have strong industry track records of third-party ownership and operation.

Staff does not find merit in Company witness Terri L. Schroeder's analysis that Company owned resources are less expensive. (5 TR 1316-1317.) The Company's analysis received a barrage of valid criticism. MEC witness Jester testified that "competitively bid solar PPAs would provide solar costs substantially below those modeled by DTE." (7 TR 2738.) Jester states:

> In addition to providing relevant pricing information for PPAs, Exhibit MEC-56 also shows the results for Consumers Energy's competitively solicited build and transfer solar projects, which are conceptually similar to DTE's approach. The weighted average levelized cost of those proposals for projects coming into service in the next three years was $73.92/MWh, which is slightly above DTE's LCOE for single-axis tracking solar of $69/MWh for a

> unit to come into service in 2024. Given cost trends in the solar industry, it is likely that pricing in 2024 will be lower than projected by DTE. (*Id.*)

The time periods used for an owned asset for the Company was 30 years while a PPA was assumed to be 20 years. (5 TR 1318.) That is not equitable basis unless it is typical that the owners of PPA assets would expect to get recovery for the total asset in 20 years versus 30. Further, as ELPC witness Kevin M. Lucas states, by not sufficiently altering the variables to reflect the actual scenario, the Company assumed that developers would earn the same ROE as the Company's authorized return, which is also not a correct assumption. (7 TR 2087.) Lucas explains:

> In a competitive solicitation for company-owned projects, a solar developer will determine its cost to design, engineer, permit, and construct a PV system and sell it to DTE as a turnkey transaction. All of the developer's costs, including a profit, will be included in the sales price. Once the Company has purchased the project, it will put it into its rate base, where it will be authorized to earn an additional return on and return of its capital. In other words, despite the project being almost entirely de-risked (i.e. the project will be fully operational on day one with fresh warranties on all hardware), DTE will earn its full return on equity – more revenue for the taxes on the profit. Customers are paying a profit to both the developer (embedded in the sales price) as well as to DTE (through its return on equity), even though the project risk is not duplicated between the two parties. This structure needlessly increases the costs of providing energy and capacity to the Company's customers. (*Id.*)

Without an ROE, the PPA, is lower cost than company-owned projects. Therefore, Staff recommends that the Commission order a 50/50 split between Company-owned assets and third party PPAs.

The contingencies for review of renewable generation listed above provide a solid basis for determining reasonableness and prudence going forward. Staff recommends that the Commission order the Company to work with Staff and intervenors to develop a competitive resource procurement strategy that balances the needs of the Company, the ratepayers and all parties involved.

L. Competitive Resource Procurement

1. This strategy should be developed in a manner that places value on reliability, safety, diversity, and resiliency. This should be solicited by opening a docket to solicit comments on best practices related to competitive resource procurement strategies.

Staff testified that the Company had not analyzed procurement of non-utility owned assets, thus 100% of its future assets are assumed to be Company-owned. While there are no current statutory requirements that require competitive resource procurement for the solicitation of new resources, Staff believes it is an appropriate practice for the company to utilize appropriate competitive resource procurement practices. This recommendation is derived from former energy statutes, such as PA 295 Sec 33, which required that at least 50% of renewable energy credits shall be from renewable contracts that do not require the transfer of ownership of the applicable renewable energy system to electric power provider or from contracts for the purchase of RECs without the associated renewable energy. This statute ultimately led to significant reductions in future company owned and power purchase agreement prices. (7 TR 3251.) Additionally, PA 342 Sec 28 discusses that any electric provider whose rates are regulated by the Commission shall submit a contract entered for the purposes of subsections (3) to the Commission for review and approval. (7 TR 3251.) Finally, effective from the Order from U-18419, DTE's last IRP as presented in in its Certificate of Need (CON) case, the Commission stated that it "expects competitive bidding to be of increasing importance for the selection of resources, and the approved amounts under the pre-approved provisions of CONs and IRPs [and has] directed staff to research approaches and best practices for RFP and competitive bidding in other jurisdictions." (7 TR 3252.) [11]

Staff undertook its research by conducting a 50-state survey of the country's commonly used competitive resource procurement practices and prioritized competitive resource procurement framework the Commission could adopt as guidance for future resource procurement. (7 TR 3252.)

In addition, in the Order approving Consumers Energy IRP Settlement Agreement in Case No. 20165[12], the Company was required to use the guidelines developed under Case No. U-15800 as a baseline for competitive solicitation. Additionally, the Commission required the Company to use those proceedings until the Commission adopts competitive resource procurement guidelines or procedures as part of a future proceeding. In the contested settlement agreement, signatories mutually agreed on guidelines intended to shape the competitive resource procurement process.

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[11] *DTE's Applications for Certificates of Necessity*, Case No. U-18419, 4/27/2018 Opinion and Order, p. 106.

[12] Case No. U-20165, 6/7/2019 Order Approving Settlement Agreement, p. 26.

2. Several intervenors also weighed in on competitive procurement.

MEC witness Douglas Jester's testimony focused on explaining that competitive generation acquisition allowing multiple technology and procurement models is necessary for reasonable and prudent resource selection and should be used in any future IRP process. (7 TR 2727.) Furthermore, he suggested that PA 341 required the Company to issue a request for proposals prior to filing its IRP, suggesting that "any" generation source a utility adds is a result of a need to support load. (7 TR 2724.) He recommended that the Commission reject DTE's reasoning that it did not need nor was required to issue a request for proposals in preparing for this IRP, because consideration of proposals in response to such a request is essential to determining whether the PCA is the most reasonable and prudent. Specifically, he suggests the Commission should be looking into new standards of prudence in regard to resource procurement, and that competitive resource procurement historically has been seen as a practice for determining least-cost, or best-value, for resource selection. He notes, "competitive selection of resources can transfer most development and construction risks to competitive providers and the alternative of using power purchase agreements creates competition in cost of capital and related taxation." (7 TR 2728.) He goes on to strongly encourage DTE to primarily rely on competitive solicitation, which supports building to customer's needs, and can be executed in a manner that is open, transparent, and fairly administered.

MEC witness Jester's testimony also encouraged making RFP's open to all available technologies. He explained how combined heat and power can be a cost-effective supply-side and demand-side resource utilization. In its rebuttal, EIBC and IEI witness Sherman commented on Staff's recommendations on competitive resource procurement. Citing the RFP for new wind and solar projects the Company issued on September 16, 2019, she testified that the commission should adopt best practices for RFPs as well as require the issuance of RFPs prior to the submission of any utility IRP that proposed new supply-side generation. (7 TR 3026.) EIBC and IEI have long been proponents of including independent power producers to encourage customer's access to competitively priced energy. (7 TR 3028.) Both EIBC and IEI support Staff's recommendations for opening a proceeding to identify best practices related to the RFP process and competitive resource procurement process and favor the use of an independent evaluator consistent with the *2008 Guidelines for Competitive Request for Proposal for Renewable and Advanced Cleaner Energy*. MEIBC and IEI also encourage a process "designed to encourage a competitive response from the market". (7 TR 3031.) They distinguish that while Staff finds that it is important to make RFPs open to all available technologies, Staff did not explicitly recommend inclusion of all technologies in future RFPs.

GLREA witness John Richter commented on Staff's position of competitive bidding, stating that GLREA fully supports Staff's recommendation for the Commission to initiate a proceeding to identify best practices on the RFP process. GLREA agrees that that uniform guidance would greatly help support unbiassed resource procurement and should be applied to all regulated Michigan utilities. (7 TR 3163, 3164.) Witness Rafson offers rebuttal testimony that differs from the aforementioned parties' stance on competitive resource procurement. He suggests that Staff should similarly support a comprehensive IRP that includes alternatives such as competitive resource procurement for generation. (7 TR 3075.) Additionally, he states, Staff should support enforcing this process in an IRP which will ultimately allow the Commission and stakeholders to identify and analyze all resource options. He also recommends that Staff should recommend PURPA as an option alongside Company-owned generation and other PPA and competitive solicitation alternatives. (7 TR 3077) This recommendation is consistent with EIBC/IEI's position to make RFPs open to all available technology types.

M. Timing of Next IRP: Future IRPs should closely coordinate to the Company's Five-Year Distribution Planning Filings in effort to holistically analyze the company's entire electric system and potential distribution-sited energy and capacity resource additions.

DTE Electric's five-year investment and maintenance plan and IRP are planning elements designed to allow for better transparency for long -term future investment and capacity needs. It is Staff's position that these two efforts should not be stand-alone filings, but rather, filings that are created in conjunction with each other to align investment plans of the distribution plans with capacity plans of the IRP filings. This notion is also supported in the Statewide Energy Assessment (SEA), MPSC Case No. U-20464, 09/11/2019 Order, pp 191 and 196.

Recommendation E-5 of the final report states:

> "[T]he Commission recommends utilities better align electric distribution plans with integrated resource plans to develop a cohesive, holistic plan and optimize investments considering cost, reliability, resiliency, and risk. As part of this effort, Staff, utilities, and other stakeholders should identify refinements to IRP modeling parameters related to forecasts of distributed energy resources (e.g., electric vehicles, on-site solar) reliability needs with increased adoption of intermittent resources, and the value of fuel security and diversity of resources in IRPs. A framework should also be developed to evaluate non-wires alternatives such as targeted energy waste reduction and demand response in IRPs and distribution plans."

Historically, five-year distribution investment and maintenance plans and IRPs have been created separately and Staff believes that a holistic approach is necessary to analyze the electric system as distribution-sited capacity resources and other non-traditional resources are added to the system. No other party rebutted Staff's recommendation.

N. Contract Approval

Staff recommended that utilities file PPAs, Engineering, Procurement, and Construction (EPC) contracts, and generation asset purchase contracts for approval with the Commission even if they are the result of an approved competitive resource procurement process. Staff envisions that approvals for these contracts would take place as part of IRPs subject to an *ex-parte* filing for Staff review upon execution. Neither the Company nor parties explicitly weighed in on contract approval.

O. Environmental and other Compliance

Rather than breaking out environmental and other compliance into a separate category, Staff addresses environmental and other compliance in its analysis of EWR, DR and EE, as well as its analysis of the retirement of coal plants above.

P. PURPA

1. Decision in DTE's PURPA Matter, MPSC Case No. 18091

In its testimony, Staff recommended that DTE abide by the Commission's holding in MPSC Case No. U-18091 before it was remanded, and the principles articulated before remand have now been affirmed. (7 TR 3364.) The holding that Staff references concluded that: the qualifying facility (QF) retains ownership of any RECs from the renewable generation; the standard offer contract shall be available at 5, 10, 15, or 20 years at the QF's choice; and the size cap for the standard offer will be 550 kW. Staff also supports DTE's five-year planning horizon for determining a capacity need under PURPA. (7 TR 3364.)

DTE witness Mikulan testified that no sensitivities were run pertaining to PURPA since the outcome of DTE's avoided cost case U-18091 was still uncertain. (3 TR 380.) On September 26, 2019, the case concluded with a final Order and the pertinent points made above in testimony are unchanged. The Commission's holdings are as follows:

> "[The Commission affirms] its decision to set the standard offer cap at 550 kW to be reviewed in the company's IRP and next biennial review of the company's avoided cost; (2) adopts the avoided costs proposed by DTE Electric in a scenario where the company requires capacity; (3) approves the use of MISO PRA for an avoided capacity rate and MISO LMP for an avoided energy rate when the company does not have a capacity need in the manner described above; (4) adopts the energy forecast and inputs proposed by DTE Electric for use in determining avoided costs; (5) finds the company does not have a capacity need at

> this time, (6) approves a Standard Offer tariff and Standard Offer PPA with the changes described above; and (7) adopts a five-year planning horizon." [*In re DTE Electric Company*, MPSC Case No. 18091, 9/26/2019 Order on Rehearing and Remand, p. 157.]

Staff's position to base DTE's capacity need on a five-year planning horizon aligns the capacity determination with its IRPs and provide a better look into any capacity needs, as well as potential solutions.

Staff maintains its position that the avoided cost inputs should be based on DTE's BWEC Gas Plant when DTE Electric has a capacity need, as this would allow the avoided cost to be calculated based on actual costs the Company is incurring rather than a theoretical natural gas plant. Therefore, Staff recommends that the ALJ and Commission adopt a five-year planning horizon for capacity need consideration and continue to support the BWEC avoided cost inputs.

2. DTE Electric still has no capacity need, but rather must engage in competitive resource procurement, not just Company builds when a need arises.

Staff agrees that the Company does not have a capacity need as previously determined in the Commission's order on September 26, 2019 in MPSC Case No. U-18091, although the Commission determined that any capacity need would continue to be reviewed in the Company's IRP cases. Additionally, the Commission determined that a 5-year planning horizon should be used for determining capacity need. MEC/NRDC/Sierra Club witness Jester represents that the Company has a "significant" capacity need in the later years of its IRP, PY 2029-2030. (7 TR 2759.)

Any capacity need beyond MISO planning year 2023-2024 is outside of the 5-year planning horizon determined by the Commission in U-18091. Witness Jester also identifies a slight potential capacity shortfall in 2020-2021 and PY 2023-2024 due to the permanent additions of “Company-Owned, In-State, Non-Intermittent, ZRC” that are not explained fully in testimony. (*Id.*) Witness Jester is concerned with the small possible capacity shortfall because, if the Company did have a capacity need, it may be required to accept and pay for QF resources during these periods. It is important to note that the potential capacity shortfall witness Jester discusses is approximately 0.15% (16MW[13] divided by 10,161 in Exhibit A-7, line 1, column f) of the Company’s peak demand bringing into question if it is reasonable to scrutinize a demand forecast at that level of accuracy 5 years out.

With regard to the potential PY 2020-2021 capacity shortfall, the Company has demonstrated through its annual capacity demonstration in MPSC Case No. U-20154 that it has acquired resources for four years forward. Therefore, Staff agrees with the Company that there is no capacity need for PY 2020-2021. Additionally, Staff witness Walker recommends that the Company adopt a 2% EWR. This will have an impact on the Company’s demand forecast.

Witness Jester’s analysis does not take into account Staff’s recommended increase in EWR nor does his analysis take into account MEC/NRDC/Sierra Club witness Neme’s analysis that hypothesizes that the Company has over-estimated the amount of EWR included in its load forecast by an amount of 99 MW in 2023.

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[13] (7 TR 2795)

The increase in EWR resources, as recommended by Staff, alone likely compensate for the total of the possible shortfall identified by witness Jester. If witness Neme's analysis were true, then witness Jester appears to be arguing against his own party.

Further, the Commission has stated in its September 26, 2019 Order in MPSC Case No. 18091 that that QF resources do not compete with demand-side resources. Rather QF resources compete only with supply side resources. The Commission stated:

> PURPA dictates that the generation from a QF is intended to offset the energy and capacity that the electric provider would otherwise have to build or purchase. See, 16 USC 824a-3. Accordingly, for the purposes of PURPA, QF generation competes with supply-side resources, not demand side resources. [In re DTE Electric Company, MPSC Case No. 18091, 9/26/2019 Order on Rehearing and Remand, p. 47.]

If the Commission adopts Staff's position regarding 50/50 split in Company ownership of proposed renewable generation additions and Staff's recommendation to develop a robust competitive resource procurement process for issuing RFP's for future supply-side resources, any future supply-side shortfall would allow for QF's to participate in the RFP process and thereby be considered on equal footing with all other bidders.

Therefore, Staff continues to recommend that the Commission find that the Company does not have a capacity need and encourages the Commission to also adopt Staff's position regarding competitive resource procurement and the 50/50 resource ownership split, ensuring that QF's will have the ability to be part of

Michigan's resource mix to the extent that those resources are economic and provide the necessary benefit to Michigan ratepayers.

3. Request for Relief: Recommendations for Commission Decision

The Company's IRP appropriately balances the factors outlined in Act 341, Section 6t(8)(a-c) and is the most reasonable and prudent means of meeting the electric utility's energy and capacity needs over the three-year near-term planning period. (7 TR 3213-3214.) Staff recommends the Commission find that overall the Company meets the provisions of PA 341 of 2016 section 6t (8) and that the Commission approve the IRP subject to the recommended changes in Staff testimony. (7 TR 3219.) Staff recommends that the Commission provide explicit cost approval only for projects in the three-year near-term after the Commission order in this case. Staff recommends the Company file its next IRP no later than 36 months from the date of a Commission order in the present case to incorporate Staff's suggestions. This would align the IRP process with distribution planning if these plans continue to be filed in accordance with the filing schedule. (7 TR 3221.)

Staff recommends that the Commission continue to allow for scrutiny of specific aspects of IRP related cost approvals in other proceedings. The conditions of the market could change significantly over the course of three years. MCL 460.6t (11) does not provide the Company with assurance to recover costs in future rates beyond preapproval of cost that commence in the first three years of the plan. Staff encourages the ALJ and the Commission to approve DTE's IRP with recommended changes that staff proposed in testimony and supports in this brief.

Respectively submitted,

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October 29, 2019

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

In the matter of the Application of **DTE Electric Company** for approval of its Integrated Resource Plan pursuant to MCL 460.6t, and for other relief. /

Case No. **U-20471**
(e-file paperless)

PROOF OF SERVICE

STATE OF MICHIGAN)
) ss
COUNTY OF EATON)

De Ann Payne, being first duly sworn, deposes and says that on **October 29, 2019**, she served a true copy of **Michigan Public Service Commission Staff's Initial Brief** upon the following parties **via email only**:

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De Ann M Payne

De Ann Payne

Subscribed and sworn to before me
this 29th day of October 2019.

Pamela A. Pung

Pamela A. Pung, Notary Public
State of Michigan, County of Clinton
Acting in the County of Eaton
My Commission Expires: 05-07-2025