DTE Electric's comments on the

Electric Distribution Planning

February 19,2020 Staff Draft Report

in Case No. U-20147

March 5, 2020

Background

On February 19, 2020, Michigan Public Service Commission's (MPSC or Commission) Staff released a draft report on Electric Distribution Planning. The draft report represents the MPSC Staff's review, summary and recommendations following five public forums held between June and November 2019.

DTE Electric (DTEE) appreciates the opportunity to work with the Staff and stakeholders on Michigan's electric distribution planning process, and to learn from industry experts on best practices that will shape Michigan's modernized grid and serve customers' needs.

DTEE applauds MPSC Staff's effort to compile this comprehensive draft report and appreciates the opportunity to provide comments and feedback.

DTEE would like to emphasize its agreement with the Staff's assertion on page 30 of the report that says, "staff doesn't support the suggestion that aggregate stakeholders replace utilities as the lead actors proposing Michigan electric distribution investment plan". DTEE appreciates the feedback obtained through the collaborative stakeholder process, but would like to further reiterate that, the utility is ultimately responsible for identifying system needs, managing distribution planning process and making the investment decisions to meet the four distribution planning objectives by the Commission: (1) Safety, (2) Reliability and Resiliency, (3) Cost Effectiveness and Affordability (4) Accessibility.

DTEE's response is in two sections. The first section includes DTEE's responses to the Staff recommendations; the second section includes clarifications regarding some of the items discussed in the draft report. DTEE looks forward to further discussion and collaboration with the Staff and industry stakeholders on Michigan's distribution planning process.

Section I – Recommendations and Responses

Section I-1 - Distribution Planning Objectives

Section I-1-1

The Staff draft report states that the Commission should reiterate the importance of these four objectives (1) Safety, (2) Reliability and Resiliency, (3) Cost Effectiveness and Affordability (4) Accessibility in a subsequent order in the U-20147 docket, and also provide confirmation with Staff's assumption that "Safety" is the first priority – both for customers and the utility employees – with the second priority being "Reliability and Resiliency. The utility electric infrastructure in Michigan has many assets that are operating way past the end of expected life and utility investments must consider the vast ratepayer resources needed to assure reliable service during all types of weather. Staff believes this additional emphasis on Commission stated objectives and subsequent priorities will provide clarification for utilities and stakeholders as utility distribution plans continue to be developed and submitted to the Commission.

Response:

DTEE supports these four general objectives: (1) Safety, (2) Reliability and Resiliency, (3) Cost Effectiveness and Affordability (4) Accessibility. At the same time, DTEE believes that the utility must maintain discretion in interpreting what these objectives mean and how to pursue them.

Section I-2 - Definitions

Section I-2-1

For purposes of referencing distribution planning terms going forward, Staff suggests the following definitions to be included in a forthcoming Commission order:

- **Hosting Capacity Analysis (HCA) – Amount of distributed energy resources (DER) that can be accommodated without adversely impacting operational criteria, such as power quality, reliability, and safety, under existing grid control and operations and without requiring infrastructure upgrades.**
- **Non-Wires Alternatives (NWA) – A portfolio of DER, such as distributed generation, energy storage, energy efficiency (or energy waste management), demand response, combined heat and power, and grid software and controls, used to defer, mitigate, or eliminate the need for traditional utility infrastructure investments.**
- **Locational Value Assessment – Locational value assessment is intended to quantify the benefits and costs of DER, which are often locational in nature.**

Response:

DTEE agrees with the definitions stated above for Hosting Capacity Analysis (HCA) and Non-Wires Alternatives (NWA).

DTEE does not recommend the definition of locational value assessment at this time. Very little discussion occurred on locational value assessments during the collaborative workshops. Based on DTEE's research, there has not been any definition of locational value assessments generally accepted by the industry, and the attempts to conduct locational value assessments by other jurisdictions have received mixed reviews. DTEE does not consider this as a near-term priority for the Commission, utilities and stakeholders in Michigan. Therefore, DTEE recommends removing the definition recommendation on Locational Value Assessment.

Section I-3 - Benefit-Cost Analysis (BCA)

Overall Comments:

It is not possible nor feasible for electric utilities to perform benefit cost analysis on all of the utility's electric distribution investments. Many distribution investments, including storm/trouble, customer connection and relocations, general tools and equipment, and safety and operability-driven expenditures are mandatory in nature and they should not be subject to benefit cost analysis. Ultimately, it is DTEE's responsibility to prioritize and manage its distribution investments. To best perform this managerial requirement, DTEE's Global Prioritization Model (GPM) model was developed and refined over several years with inputs from many DTEE engineering and operational experts. The GPM model leverages historical reliability and system data, incorporates up to date assessments of the asset and system conditions, assigns values and a weighting system to analyze non-monetized benefits and prioritizes projects and programs among the investment portfolio. The GPM model is maintained and updated every year to incorporate changing system and asset conditions, evolving customer needs, and most up-to-date knowledge from subject matter experts. DTEE has developed the GPM model as the tool to effectively prioritize strategic capital investments and maximize customer benefits.

In contrast, the utility cost (UCT) and regulatory tests are both financially based analysis and rely on quantifying investment benefits into dollar values. Due to the non-monetized nature on safety, system planning, customer satisfaction, reliability and major event risk, it is not appropriate to use UCT or regulatory tests as the benefit cost analysis approach across all utility investments. DTEE also does not believe that it is beneficial or possible to meaningfully compare investments across different utilities. Each utility has its unique system condition, service territory and customer base. Any attempt to compare investments across utilities would not be meaningful or appropriate for the vast majority of the investments. At the same time, DTEE acknowledges that there may be some limited spend categories that may lend themselves to a financially based BCA. Some types of discretionary investments, such as utilizing energy efficiency or demand response as non-wire alternatives, could lend itself to a financially based BCA.

Section I-3-1

- **BCA sensitivities be required for all distribution investments using rate-payer funds. If the Commission elects to require only one BCA sensitivity, Staff recommends the Utility Cost test. If the Commission elects to require more than one sensitivity, Staff also recommends the Regulatory Test (also known as the Resource Value Test).**

Response:

It is not possible nor feasible for electric utilities to perform benefit cost analysis on all its distribution investments. For example, electric utilities' top priority during trouble or storm conditions is to restore customer power in a safe manner. Investments in customer connections and relocations are related to specific customer's requests to connect to the grid or relocate electric equipment, underlining the fundamental obligations that electric utilities have. The baseline general tools and equipment capture the basic needs for electric utilities to operate the system. None of these investment categories should be subject to benefit cost analysis, which is more appropriate for "discretionary" categories of investments that are tied to some other policy goals outside of the core goals of safety, reliability and resiliency (e.g., energy efficiency, demand response and electric vehicle charging infrastructure investments). In addition, some investments driven by safety and operability considerations are effectually "must-do" to allow safe operation and maintenance of the system. It is not possible to assign a benefit cost value to these safety or operability related projects. Therefore, DTEE does not support the Staff recommendation that the BCA analysis be conducted for all distribution investments.

Utility cost test and regulatory test are both financial based analysis – which relies on quantifying benefits into dollar values. Staff acknowledged that "non-monetized areas were safety, system planning and customer satisfaction". DTEE would also like to add major event risk and reliability are also non-monetized areas. Most of DTEE's distribution investments are targeting safety, reliability and resiliency, which are also identified as the top two objectives of distribution planning by the Commission. Excluding the benefits on these non-monetized areas from the financially based UCT or regulatory tests means ignoring the majority of the benefits for the programs and projects that DTEE is pursuing today, making benefit cost analysis not meaningful. Therefore, DTEE believes it is not appropriate to use UCT or regulatory tests as the benefit cost analysis approach across all utility investments.

DTEE agrees with the Staff's recommendation on page 34 of the report that "efforts should still be made to quantify the non-monetized benefits through a point system to assign value to non-monetized benefits, a weighting system to assign priorities to non-monetized benefits, or multi-attribute decision-making techniques". DTEE has been using its Global Prioritization Model (GPM) to prioritize the majority of the Company's strategic investments. As discussed, some of the investments, although categorized as "strategic", are effectually "must-do" projects due to safety and system operability concerns. DTEE recommends that Staff incorporates a GPM-like benefit cost model in their summary recommendation for BCA analysis. DTEE has included the GPM results in its rate case filings and expects to continue doing so in the future.

Last but not the least, DTEE would like to seek clarification on "BCA sensitivities". From an analytical modeling perspective, sensitivities are usually conducted by changing capital cost assumptions or any key input assumptions. It is not clear what BCA sensitivities that Staff refers to have the same implication.

Section I-3-2

- **BCA analyses be conducted for platform components individually and bundled with the modular applications that it enables.**

Response:

DTEE would like to point out the concept for "platform components individually and bundled with the modular applications that it enables" may only apply to the grid modernization investments associated with DOE's DSPx framework, which only represents a subset of today's DTEE distribution investments. This concept does not apply to investments associated with storm and trouble, new business and relocation, system planning and aging infrastructure replacements and upgrades. Rather, benefit cost analysis may be more appropriate for "discretionary" categories of investments that are tied to some other policy goals outside of the core goals of safety, reliability and resiliency (e.g., energy efficiency, demand response and electric vehicle charging infrastructure investments).

Section I-3-3

- **At least one discount rate sensitivity for all conducted BCAs be required where a low-risk discount rate ranging from 0-3% is selected by the Commission to reflect the regulatory viewpoint.**

Response:

DTEE appreciates Staff's recommendation on the discount rate, however, DTEE reiterates that the GPM model fulfills the need for prioritizing the Company's strategic distribution investments. The GPM model was developed with much consultation from engineering and operational experts who have the institutional knowledge of the grid and many years of experience on how investments can impact electric grid safety, reliability, and affordability for the customers. As discussed in Section I-3-1, it is not appropriate to use UCT or regulatory tests as the benefit cost analysis approach on distribution investments. Therefore, the discount rate sensitivity, as part of the financially based benefit cost analysis is not necessary for the discussion on distribution investments. The discussion of discount rate is more relevant to specific "discretionary" categories of investments that are tied to some other policy goals outside of the core goals of safety, reliability and resiliency (e.g., energy efficiency, demand response and electric vehicle charging infrastructure investments).

Section I-3-4

- **Traditionally non-monetized benefits, especially those related to safety and system planning, be required to be included in BCAs using related monetized proxies or through other quantitative methods.**

Response:

As discussed in Section I-3-1, DTEE has been using a GPM model to assign values and a weighting system to analyze non-monetized benefits and prioritize majority of the strategic projects and programs among its investment portfolio. DTEE's GPM model satisfies this item in the Staff recommendations.

Section I-3-5

- **The Commission clearly relay its ranking of non-monetized benefits, including safety and system planning, so that utilities can use this ranking, if needed, when examining non-monetized benefits in BCAs.**

Response:

DTEE maintains its position that it is not appropriate to conduct financially based UCT or regulatory tests for benefit cost analysis on distribution investments. DTEE's GPM model leverages historical reliability, trouble volume and wire down data, incorporates assessments of the asset and system conditions, assigns values and a weighting system to analyze non-monetized benefits. DTEE's GPM model satisfies the need of the benefit cost analysis to effectively prioritize strategic capital investments. DTEE welcomes more opportunities to share and discuss the ranking of non-monetized benefits on safety, reliability, resiliency, major event risk, and system planning.

Section I-3-6

- **Require a "grid modernization" scenario be analyzed for all distribution investments.**

Response:

DTEE would like to seek clarification from Staff as to what is meant by "grid modernization" scenario.

Staff recommended "the utilities provide the range of options investigated, each of their BCA findings, and the final selected options" on page 35 of the draft report. Many projects do not necessarily lend themselves to evaluating multiple alternatives (e.g. storm and trouble). Even for projects that have multiple alternatives, many of the options are evaluated for technical and execution considerations, rather than simple comparisons on benefit cost analysis. In addition, forcing evaluation of multiple alternatives, documenting all the alternative evaluations for individual projects and programs, and packaging the documents for MPSC submissions would be very costly and time consuming. DTEE currently does not have the resources or the funding to support this level of effort particularly given hundreds of projects and programs in its portfolio and thousands of options being evaluated in a planning cycle. Therefore, DTEE does not support the requirement that the utility provide the range of options investigated, each of their BCA findings, and the final selected options for individual projects and programs. With that said, DTEE can provide a demonstration of the project evaluation process starting from Project Value Analysis (PVA) to Technical Peer Review, Project Governance Review Board, and Corporate Review, as well as consideration of alternatives investigated for some projects and programs.

It is important to understand that Non-Wires Alternatives (NWA) can be applied to less than six percent of the total DTEE distribution investments today as discussed in the Company's collaborative presentation on November 19. It does not make sense to analyze NWA for all distribution investments for reasons listed in Section I-3-1 and I-5-3.

Section I-3-7

- **Require reporting of BCAs for distribution planning related utility investments in rate cases with clear definition of all BCA assumptions.**

Response:

DTEE does not believe that it would be possible to provide the requested information in a rate case.

DTEE has included the GPM results in its rate case filings and expects to continue that in future rate case filings. DTEE believes that the discussion of the project/program ranking and GPM modeling assumptions in its rate cases satisfies this item in Staff's recommendations.

Section I-3-8

- **Report actual investment benefits and costs in rate cases after project implementation consistent with the original BCA methodology used for project justification to monitor performance over time.**

Response:

DTEE agrees to report actual investment costs in rate cases after project implementation. With that said, DTEE does not believe that it will be possible to report on the actual benefits associated with individual projects and programs in a quantitative manner, as some of these actual benefits cannot be calculated. For example, what is the benefit of replacing a section of cable that is 100 years old, or a circuit breaker that was installed in the 1940's and is obsolete and at risk of catastrophic failure? The actual benefits of these investments are difficult to measure; however, DTEE does provide quantified information on metrics such as reduced system risk levels from the replacement of aging infrastructure when the project is identified and prioritized.

<u>Section I-4 - Hosting Capacity Analysis</u>

Staff recommends that the following be adopted for the HCA pilots requested by the Commission:

Section I-4-1

- **Adopt the "interconnection of DER" as the use-case for HCA**

Response:

DTEE agrees to adopt the "interconnection of DER" as the use-case for HCA. With that said, we refrain from making any recommendations at this time on how to conduct system-wide HCA until we have reviewed the DTEE pilot findings. As stated in the report on page 37, the "DTEE system has a mesh network in the thumb area which is sensitive to distribution system changes." Any system changes on certain feeders would require an in-depth analysis to determine the impact on the distribution system from DERs and require a review to see if those said changes could potentially back feed the substation thereby posing a safety risk. DTEE agrees with the Staff statements on page 36 of the draft report: "Recommendations regarding system-wide HCA cannot be made at this time and will depend on the pilot findings".

Section I-4-2

- **Adopt a phased implementation approach for the HCA pilots where phased implementation ranges from a base-level approach like a zonal go/no-go map to a more detailed map with feeder voltage levels information. This will allow utilities to focus on providing cost-effectively obtained, basic system-level information and at the same time highlighting areas of their system that cannot safely accommodate an increase in DER penetration.**

Response:

DTEE agrees with a phased implementation approach for the HCA pilots. DTEE agrees with the zonal go/no-go map as the first phase of the HCA pilots. DTEE also agrees with the Staff that any HCA pilots selected would be in areas, per page 37, "where a larger number of potential DER's may be integrated".

Section I-4-3

- **Examine HCA best practices and methods for cost reduction, as demonstrated by other jurisdictions nationally**

Response:

DTEE agrees that benchmarking with other utilities and jurisdictions nationally is helpful and beneficial. DTEE has engaged other utilities in benchmarking HCA best practices on topics including tools/software platform, methodology, data issues, use cases, etc. and will continue to do that. DTEE would like to note that benchmarking on study costs can be complex and dependent on inclusion of cost components, particularly given different utilities do not usually measure cost uniformly. For example, it would require extra efforts for DTEE to clean up circuit information in varying degrees of complexity on its 4.8 kV delta system and the looped sub transmission system.

DTEE is currently in the process of reaching out to other utilities highlighted by Staff and others to benchmark the cost of HCA. DTEE would like to note that these costs are typically confidential and subject to non-disclosure agreements with vendors. DTEE expects that it would be difficult to ascertain the true cost at this point. With that said, DTEE will perform due diligence on HCA costs.

Section I-4-4

- **Benchmark projected and actual HCA pilot costs against HCA costs nationally**

Response:

DTEE agrees that benchmarking with other utilities and jurisdictions nationally is helpful and beneficial. DTEE would like to note that cost benchmarking can be confidential and complex for reasons discussed in Section I-4-3.

Section I-4-5

- **HCA information should be publicly available with a downloadable map and spreadsheet**

Response:

DTEE agrees to share results from the first phase of the HCA pilot with a downloadable map and spreadsheet that can be publicly available.

<u>Section I-5 - Non-Wires Alternatives</u>

Section I-5-1

Staff agrees that the questions presented in Paul DeMartini's October 16 stakeholder presentation[3] should be asked by the Commission and answered by the utilities prior to refining and implementing NWA pilots:

- **Why are non-wires alternatives being pursued?**
- **What are the pressing issues?**
- **What are the desired outcomes?**
    - **Optimize utility distribution expenditures?**
    - **Enable greater value for customer/developer DER investments?**
    - **Enable greater adoption of DER to meet renewable/customer choice goals?**
- **What are the range of potential solutions?**
    - **Pricing, programs and procurements (3P's)?**

  What is the role of customers, DER developers, utilities, aggregators and others?

Response:

DTEE agrees with Staff and Paul DeMartini that these questions should be further explored prior to refining and implementing NWA pilots. DTEE welcomes the opportunity for further dialogue with Staff and stakeholders on these questions.

Section I-5-2

Once these questions are answered, a focus on the parameters of non-wires alternative pilots is important. Staff agrees with the relevance of stakeholder recommendations requiring utilities to formulate a hypothesis of expected (improvement in) performance metrics, a methodology for measuring (improvement in) performance metrics, and a plan for reporting (improvements in) performance metrics. Utilities should also investigate the ability to obtain and incorporate customer or third-party resources in future non-wires alternative pilot proposals.

Response:

DTEE 's NWA pilots are underway to help further understand a diverse set of parameters such as customer propensity, savings and benefits, deployment timeline and cost effectiveness. Per page 20 of the report, DTEE agrees with the Commission, stakeholders and other utilities that NWA is not a one-size fits all solution and expect to continue its learning of NWA solutions from the ongoing and future pilot projects. DTEE welcomes the opportunity to engage further discussions with the Staff and stakeholders on the formulation, measurements and reporting of performance metrics associated with the NWA pilots.

It is important to note that DTEE is already engaging customer and third-party support in the planning and execution of the NWA pilots, and plans to continue to integrate that said support in NWA solutions as they evolve in the future. DTEE would like to highlight that for customer and third-party support to work effectively, DTEE needs to retain adequate oversight capability of the NWA solution resources pertaining to DTEE's distribution system and utility customers. DTEE calls attention to the challenges of and the need of careful consideration of incorporating customer or third-party resources into NWA solutions. Similarly, the Commission, by siding with Staff's opinion, has recently echoed the need for careful consideration of demand resource aggregation. Following a recent Commission's order in Case U-20348, the Commission adopted Staff's recommendations regarding issues in demand response aggregation. In this report, Staff agreed with the Michigan utilities/Electric Distribution Companies that allowing aggregation of bundled retail load would introduce additional uncertainty and complexity into the integrated resource planning process, the distribution planning process, provide operational challenges that would need to be worked through and could result in fluctuating costs to ratepayers if not implemented in a controlled and transparent manner.

Section I-5-3

The Commission should encourage the utilities to explore additional opportunities for NWA to provide distribution solutions for the "system expansion" portion of their capital plans, as well as other opportunities that may exist such as "new business".

Response:

As stated in the November 19, 2019 DTEE presentation on investment portfolio relative to NWA, the total capital expenditure on load relief or system expansion currently stands at six percent. Within that six percent, not all the projects qualify for an NWA solution for the following considerations:

- Timeliness of the need: Some load relief projects need to be addressed immediately prior to the next peak season due to the critical loading conditions. Benchmarking with other utilities and states suggest the timeline for an NWA implementation is three to five years.
- Additional benefits that cannot be replaced by NWA: Often projects are developed to address multifaceted benefits including replacing aging, at risk assets and addressing reliability concerns in addition to loading conditions. An NWA solution often has limited ability in addressing these multiple issues altogether.
- Amount of overload to be addressed: Generally, the amount of overload that can be addressed with an NWA solution is five to ten percent of substation loading, whereas most of the near-term load relief projects within DTEE have much larger overload or over firm conditions.
- Availability of lower cost solutions to address the need: The desired investment threshold in replacing a traditional solution with an NWA solution is $2 million and above. Some loading issues can be addressed by lower cost solutions such as phase balancing, load transfers, installation of capacitor banks, or substation transformer replacements. These traditional solutions can be most likely executed under the $2 million threshold.

It is important to note that new business projects are related to specific customer requests to connect to the electric grid. This category of the investments often involves poles, wires and sometimes substations to provide customer grid connections. DTEE has the obligation to provide electric service to all customers in its service territory. It is highly unlikely that any new business-related investments could be replaced by NWAs.

In summary, DTEE agrees that NWA can be explored as an alternative for the Company to address distribution system loading issues. DTEE has several NWA pilots underway and is working with stakeholders to learn how we can improve our implementation of the NWA solutions to address geo-targeted loading issues. With that said, due to its unique characteristics and novelty, the NWA applications at this stage can be restricted.

Section I-5-4

Staff believes that NWA is a topic that merges with the work of the MI Power Grid Energy Programs and Technology Pilots workgroup, and some of the forthcoming clarifications and recommendations from this workgroup will be directly applicable to specific NWA pilots.

Response:

DTEE welcomes the opportunity to continue the discussion on NWA with the Staff and stakeholders in the MI Power Grid Energy Programs and Technology Pilots workgroup.

Section I-6 - Alternative Regulatory Approaches

Section I-6-1

As the MI Power Grid Financial Incentives/Disincentives workgroup develops a workplan with stakeholder participation, Staff suggests that the alternative regulatory approaches outlined in the AEE August 14, 2019 stakeholder presentations be explored by the workgroup. If the landscape is changing for electricity delivery, then part of that changing landscape includes alternative regulatory approaches that can address the possibility of a more service focused distribution model. Regulators have a responsibility to explore their role in this changing environment.

Response:

DTEE welcomes the opportunity to explore alternative regulatory approaches with the Staff and stakeholders in the MI Power Grid Financial Incentives/Disincentives workgroup.

Section I-7 - Pilot Programs

Section I-7-1

In their on-going work, the Energy Programs and Technology Pilots workgroup should take into consideration the important stakeholder comments that were included in the U-20147 docket as well as the discussions that took place during the distribution planning stakeholder sessions of 2019.

Response:

DTEE welcomes the opportunity to explore the developments of the pilot programs with the Staff and stakeholders in the Energy Programs and Technology Pilots workgroup.

Section I-8 - Resiliency

Section I-8-1

Instead of providing a definition of resiliency, Staff recommends the Commission identify the events that have the potential to effect electrical system resiliency. Once we identify the events that we are most concerned about when we think about resiliency, then metrics should be identified.

The Commission should provide guidance to be used for the MI Power Grid Integration of Resource/Transmission/Distribution Planning workgroup about which methodologies to explore as a best fit for Michigan to enable Staff, stakeholders and utilities to further explore ways to improve the resiliency of the Michigan electric grid.

Response:

DTEE agrees that more clarity on the events that have the potential to effect electrical system resiliency would help electric utilities develop measures to enhance the system resiliency. DTEE also agrees that this topic should be further explored in the MI Power Grid Integration of Resource/Transmission/Distribution Planning workgroup.

<u>Section I-9 - Standardized Components for Future Utilities' Distribution Plans</u>

Section I-9-1

The Commission supports the joint utility proposal that was presented at the October 16, 2019 stakeholder session, and outlined in the presentation, where utilities agree to standardized components for upcoming distribution plans, as well as areas in their plans that will likely differ based on company specific circumstances.

Staff recommends that the utilities should view SAIDI, SAIFI and CAIDI in total, as outlined with quartiles, and by cause for the same period. Additionally, Staff recommends that utilities use the CEMI and CELID metrics to directly measure the current unacceptable levels set by the Commission in the Service Quality and Reliability Standards for Electric Distribution Systems, R 460.722.

Response:

DTEE agrees to provide SAIFI, SAIDI and CAIDI by cause and industry quartile for the same period. Additionally, DTEE is working with the Staff and stakeholders in the Service Quality and Reliability Standards collaborative on the reporting requirements of reliability indices. DTEE recommends the Commission to utilize orders and regulatory proceedings other than administrative rulemaking on the reporting of the reliability indices.

<u>Section I-10 - Michigan Infrastructure Council</u>

Section I-10-1

The utilities should reference the Michigan Infrastructure Council as they develop their utility distribution plans. As referenced in the Commission November 2018 order, utilities should coordinate

distribution planning efforts with the Michigan Infrastructure Council efforts in order to benefit all MI residents through more efficient and effective planning.

Response:

DTEE agrees that the utilities should reference the Michigan Infrastructure Council as DTEE develops the utility distribution plans. DTEE will continue engaging with the Michigan Infrastructure Council around the best way to share project data to allow improved project coordination with roads and other utility projects, such as water and sewer.

<u>Section I-11 - The Role of Energy Efficiency with Distribution Planning</u>

Section I-11-1

The Commission direct the utilities to include an assessment of energy efficiency resource options in their forthcoming electric distribution plans.

Response:

Energy Waste Reduction (EWR) files an assessment of energy efficiency resource options in the Company's IRP. This assessment includes a potential study as an exhibit. A separate energy efficiency assessment for the distribution planning report would be redundant. Current Commission's orders require that EWR update its potential study prior to a new IRP filing.

In addition, EWR is a broad-based resource. As stated in PA-342, all customers pay into EWR programs, therefore all customers are eligible to participate. Specifically, Section 73 of PA 342 states the Commission must consider the extent to which EWR programs are available to *all* customers. Concentrated efforts of EWR for DO planning might conflict with the intent of the legislation. Therefore, a more appropriate solution would be to discuss EWR within the context of NWA solutions.

<u>Section I-12 - Core Functionality of the Grid and the Role of "Vision" with Grid Planning</u>

Section I-12-1

Staff suggests that the utilities' articulation of "vision" be emphasized every step of the way for future iterations of distribution plans. Such vision becomes the roadmap for results. As the utilities proposed at the October 16 stakeholder session, a long-term strategic vision and plan should be a featured component of every utility distribution plan going forward.

Response:

DTEE agrees a long-term strategic vision and plan should be a featured component of the utility distribution plan going forward. DTEE has shared the Company's vision on its electric distribution grid in the last plan filing and is committed to continue refining and sharing the vision in the future.

<u>Section I-13 - Next Steps</u>

Section I-13-1

The Commission should provide additional direction and clarification through their orders regarding these important issues prior to the utilities submitting their next electric distribution plans on June 30, 2021. Additionally, the Commission may choose to clarify how often the refresh distribution plans should be submitted by the utilities. Utility distribution plans typically project needed improvements over a five-year period, with portions of the plans addressing a longer-term view of distribution investment. Staff recommends a two-year refresh schedule so that the plans remain updated and relevant to changing technologies and priorities.

Response:

DTEE is committed to submitting its next electric distribution investment and maintenance plan on June 30, 2021. In determining the refresh schedule for electric distribution plans, DTEE would like to note the recommendation by both the Commission and Staff to have electric utilities file their next IRP and distribution plans in a coordinated fashion.

The interim order for the 2019 integrated resource plan (IRP), which was received on February 20, 2020 in Case No. U-20417, proposes the next IRP be filed by September 2023. At this time DTEE is reviewing this recommendation. Presuming the Commission's final order in the IRP sets the next IRP filing for September 2023, that would be approximately 2 years and 2 months following the Company's June 30, 2021 plan, just outside Staff's recommended 2-year refresh schedule. PA 341 6(t) specifically describes the timing of IRPs: "An electric utility shall file an application for a review of its integrated resource plan not later than 5 years after the effective date of the most recent commission order reviewing a plan, a plan amendment, or a plan review. [PA 341(2)]." Because DTEE does not have a final order in its IRP, the timing of the following IRP is uncertain although per PA 341 6(t) it will be no later than five years from the order in that case. The two-year refresh schedule for distribution plans as recommended by Staff may not enable the utility to meet the objective of co-filing both plans.

Given the increasing complexity of the plan requirements and timing coordination between the IRP and distribution plans, it may be appropriate to have utilities file the distribution plans every three years.

Section II – Clarifications

C - 1

The report states on page 27 under the Safety section of the Distribution Planning Objectives that "The electric distribution system and related utility operations to support this system have safety risks due to the inherently dangerous nature of electricity, equipment failures, damage to third parties or inclement weather, older facilities designed without up-to-date safety protections, and potentially unsafe work practices while maintaining equipment."

Response:

DTEE would like to state unequivocally that safety is the highest priority in operating and maintaining the grid. DTEE would not allow any employee to perform "potentially unsafe work practices while maintaining equipment." DTEE is committed to the health and safety of every employee by establishing a safety culture that assesses risks, manages hazards, communicates learnings, and improves safety processes to enable every employee to work safely. Therefore, DTEE would like to request the removal of "potentially unsafe work practices" from the sentence to avoid any misunderstanding of DTEE's safety practices.

C – 2

The report states on page 28 under the Accessibility section of the Distribution Planning Objectives that "The Commission expects the distribution system to be able to reasonably accommodate service to new or expanding customers without such additions causing major network upgrades due to an underlying infrastructure challenge.

Response:

DTEE believes "Accessibility" means that the interconnection process is fair and robust not only for customers who seek distribution interconnection but for all customers served by the grid. A customer who seeks to interconnect to the distribution grid is responsible for upgrades of the system to allow safe and reliable operations of the grid and minimize impacts to other grid customers. Depending on the size and location of the new or expanding customer, major upgrades could be needed. Alternatively, to proactively build excess capacity into the grid to accommodate service to new or expanding customers and to avoid major network upgrades by specific interconnecting customers is not a prudent use of funds. Therefore, DTEE would like to clarify that "Accessibility" does not mean the distribution system can always accommodate services to new or expanding customers without causing major network upgrades. The practical experience has demonstrated that it is not possible to avoid major network upgrades for interconnection of any new or expanding customers in all cases. For example, connecting a large solar array in an area of the Thumb with 4.8kV service would almost certainly require major and costly system upgrades.

C– 3

The report states on page 37 under the Hosting Capacity Analysis section that "While customers can interconnect DER without participating in the <u>DR</u> program, it may not be economic for most residential customers."

Response:

DTEE would like to correct that statement to "While customers can interconnect DER without participating in the <u>DG</u> program, it may not be economic for most residential customers."