STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

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In the matter, on the Commission's own motion, to open a docket for certain regulated electric utilities to file their five-year distribution investment and maintenance plans and for other related, uncontested matters.	))))))	Case No. U-20147

COMMENTS OF THE

ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY

REGARDING STAFF'S DRAFT REPORT

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I. INTRODUCTION

While the Staff Report does a reasonably good job of summarizing activities and perspectives to date, certain of its ultimate recommendations should be altered as described in these Comments. Specifically, it appears Staff's recommendation is effectively the status quo for distribution plan development by Michigan investor-owned utilities (IOUs), augmented through guidance provided by the Commission on several outstanding tactical issues. While the guidance Staff seeks from the Commission is needed, Staff's recommendation does not go far enough in addressing the fundamental challenges related to electricity distribution regulation, ratemaking, capabilities, risks, and IOU investment. As a result, the Commission should establish a formal proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting (TSEDPCB) process to be employed in the development of Michigan IOUs' future distribution plans and capital budgets.

These Comments provided by the Association of Businesses Advocating Tariff Equity (ABATE) serve to support this recommendation and are organized into the following sections:

- Points in the Staff Report that should be endorsed and reiterated;
- Points in the Staff Report which merit higher priority;
- Context for distribution planning the Staff Report overlooks;
- Staff Report assertions and implications that should be altered or rejected; and
- Response to IOU observations on the recommended distribution planning process.

These Comments conclude with details related to ABATE's ultimate recommendation. Before proceeding, however, certain context is required for these Comments. As described in more detail below, existing electric distribution regulation and ratemaking practices were not designed to address current issues related to capabilities, risks, investment characteristics, and IOU motivations which arise in distribution plan development. First, the Commission should consider the following characteristics associated with grid investments:

- Investments required to enable capabilities which may be needed in the future will be large;
- Grid investment choices have long-term consequences;
- The Michigan economy's ability to accommodate associated rate increases is finite; and
- IOU incentives run counter to ratepayer and stakeholder incentives.

Second, the Commission should consider whether Michigan IOUs are able to effectively answer fundamental questions associated with distribution planning without a significant, formal stakeholder engagement process. While none of the following questions have "right" answers, they illustrate the challenges a distribution planning process must address:

- What is the appropriate balance between affordability and reliability/resilience?
- What relative priorities should be assigned to various grid risks, from reliability/resilience and distributed energy resource (DER) interconnection delay risks, to employee/public safety and cybersecurity risks?
- What are the drivers of each of these risks, and what are the most cost-effective ways to mitigate each?
- What is the most cost-effective mix for risk mitigation spending? For example, how does the reliability risk reduction value of $X million in increased tree-trimming spend compare to DER interconnection delay risk reduction value of a $Y million investment designed to increase grid reconfiguration flexibility?
- How can layperson stakeholders (or Staff, or Commissioners) be assured that a multi-hundred-million-dollar investment program an IOU categorizes as "business as usual" shouldn't be subjected to a benefit-cost analysis?
- How can layperson stakeholders (or Staff, or Commissioners) be assured that assumptions in a benefit-cost analysis an IOU provides as an investment justification are unbiased, and based on historical experience supported by data?
- How can layperson stakeholders (or Staff, or Commissioners) be assured that cost estimates provided by IOUs do not risk significant overruns? How can layperson stakeholders (or Staff, or Commissioners) be assured that the projects proposed by the IOUs actually cost as estimated and provide benefits as stated?

Given the characteristics of grid investment, and the challenges a distribution planning process must address, a formal distribution planning process complete with significant stakeholder engagement will likely be the standard for state utility regulators ten years from now. The Commission is to be commended for recognizing the need for greater stakeholder engagement in distribution planning, as indicated by this proceeding. The Commission should now, however, follow through on its inclinations by establishing a proceeding to develop a transparent, stakeholder-engaged distribution planning and capital budgeting, or TSEDPCB, process.

Truly transparent and stakeholder engaged distribution planning involves more than just IOU presentations of the distribution plans they have developed, or workshops designed to elicit feedback and input on such plans from stakeholders. It involves clear stakeholder understanding of emerging issues, relative risks and consequences, potential solutions, and the pros and cons of each allowing stakeholders to help inform and participate in the decisions prompted by the questions listed above. These Comments are intended to demonstrate the need for a TSEDPCB process, and to explain how such a process might work in practice, in order to justify a formal proceeding to develop such a process for future use in Michigan.

II. COMMENTS

A. ABATE supports numerous points in the Staff Report.

The Staff Report does a reasonably good job of summarizing activities and stakeholder perspectives to date, and many points made in the Report merit reiteration. For example, successive, poorly designed pilots can delay the implementation of capabilities with excellent benefit-to-cost ratios for customers by many years. Pilots must therefore be preceded by a list of questions the technology pilot should answer and a plan for implementation should the pilot prove successful. In addition, pilots should be avoided when available research to answer pilot questions is already available.

Regarding resilience risks, valuing resilience is difficult and identifying risk drivers is an important first step. Identifying drivers and valuing risk are critical components of the risk-informed decision support process ABATE experts presented at the August 14th distribution planning workshop and described in greater detail in ABATE's September 11, 2019 Comments. Indeed, resilience is an excellent example of a domain which could benefit significantly from risk-informed decision support.

ABATE reserves its strongest endorsement for Staff's apparent commitment to the extensive use of benefit-cost analysis (BCA) in distribution planning. Of course, the devil is in the BCA details and the Wired Group and Staff expert Tim Woolf have observed high variability in the quality and accuracy of the benefit-cost analyses IOUs have conducted nationwide. While informed BCA recommendations are found throughout these Comments, a few quotations from the Staff Report merit specific reiteration:

- "The purpose of benefit-cost analyses (and, as ABATE has advocated, risk-informed decision support) is not to monetize values, but to provide a ranking of choices expressed in monetary terms." (Parenthetical added.)
- "Every effort should be made to define benefits or proxies so that they can be monetized."
- "Utilities should be required to report the benefits and costs after project approval and implementation in rate cases to monitor performance over time."
- "The touted benefits that convinced regulators of reasonable and prudent spending can only be confirmed through actual data after project implementation."
- "It is not enough to examine only the business-as-usual scenario and provide the BCA. The selected option must be compared with (the BCAs of) other possible solutions." (Parenthetical added.)

B. Certain elements of the Staff Report merit higher priority.

There are several points Staff makes in its Report which are insufficiently emphasized by exclusion from the Report's Executive Summary. These include the following: (i) limitations on the use of the "Least Cost/Best Fit" approach in distribution planning; (ii) the use of risk-informed decision support in distribution planning; and (iii) the inclusion of carrying charges in the definition of BCA costs.

1. The Least Cost/Best Fit approach should be strictly and explicitly limited to specific situations.

In its Report, Staff indicates a preference to utilize BCA to as great as extent possible in distribution planning. Though Staff does not say so directly, ABATE perceives this as a tacit suggestion that the "Least Cost/Best Fit" approach to evaluating IOU investment proposals be used sparingly. Given ABATE's experts' experiences conducting in-depth technical evaluations of IOUs' grid modernization plans, a stronger condemnation of the Least Cost/Best Fit approach is required.

IOUs typically invoke the Least Cost/Best Fit approach – meaning, no BCA need be conducted – in instances in which the IOU classifies an investment as "just something we have to do to maintain reliability," or "simply business as usual." ABATE's expert, with over 35 years' experience in grid planning, operations, investment, and asset management for an IOU, has examined multiple billion-dollar grid modernization plans from a technical perspective. Time and again, IOUs undertake unjustified investment outside of standard industry practice and employ such classification as an excuse for failing to complete a BCA. The basis for interpreting or classifying an investment as "needed" or "required" or "business as usual" also varies widely, and is often so broad as to be misleading.

Staff's expert Tim Woolf acknowledges this limitation, stating "[t]he validity of this (Least Cost/Best Fit) test rests upon justification of the expenditure."[i] (Parenthetical added.) These experiences serve as both the rationale for ABATE's recommended TSEDPBC process, and as a cautionary tale regarding the application of the Least Cost/Best Fit approach to evaluating an IOU investment proposal. As a result, ABATE recommends strict guidelines be established for the categorization of IOU investments for which no BCA is required. These should be limited to those investments for which evidence can be provided indicating a need to:

- Accommodate load growth;
- Accommodate DER;
- Comply with law or NERC/CIP standards;
- Accommodate public works (such as road expansion or mass transit construction);
- Accommodate a (particular) customer request (customer-paid);
- Replace equipment reactively when it fails; and
- Replace equipment prospectively as indicated by the results of tests or formal inspections.

2. Risk-informed decision making will help establish the value of certain types of distribution system investment benefits.

The Staff Report makes several references to the challenges associated with valuing certain types of benefits. The Staff Report asserts, and ABATE agrees, that resilience has some value, and that grid flexibility (which Staff calls "grid modernization scenarios") has some value. The challenge is in how to quantify these and other "difficult to quantify" benefits, such as reductions in DER interconnection delay risk, or cybersecurity risk, or safety risk. While different stakeholders are likely to quantify different types of benefits at different levels, all of these challenges can be addressed by the risk-informed decision support process ABATE suggests be part of its recommended TSEDPCB process. Yet, Staff fails to mention risk-informed decision support in the Report's Executive Summary, or to recommend the Commission consider risk-informed decision support as it considers distribution planning processes, stakeholder engagement, or capital budgeting.

Risk-informed decision support, and its role in the TSEDPCB process, are described in detail in ABATE Comments filed on September 11, 2019.[ii] These descriptions provide valuable information on, and rationale for, all steps in ABATE's recommended TSEDPCB process. The September 11 Comments are included and incorporated here by reference.

3. Carrying charges must be included in the definition of BCA costs.

One final issue which the Staff Report touches upon, but which deserves much higher priority for Commission consideration than indicated, is investment carrying charges. IOUs typically use BCAs to compare the benefits customers will receive over asset depreciation periods (generally about 30 years) to the capital amount the IOU proposes to spend. IOUs declare as "cost effective" any investments or program in which customer benefits exceed capital. But of course, customers pay more than just capital costs. Customers must also pay carrying charges on IOU capital, including authorized rates of return, federal income taxes on that return, interest expense on debt, state sales taxes, local property taxes, and sometimes municipal franchise fees.

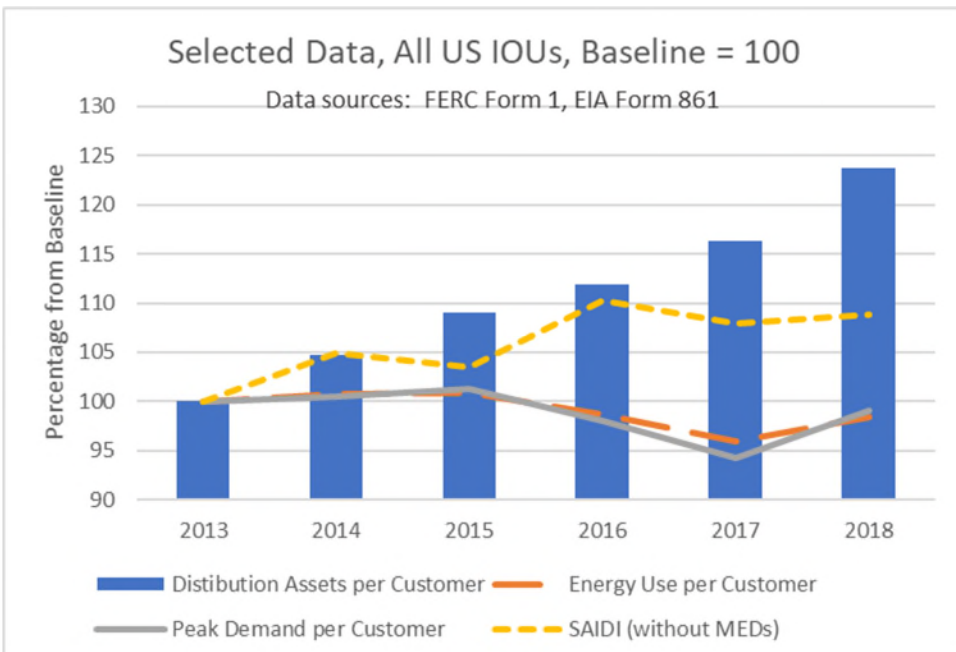
For long-term investments such as those proposed in grid modernization plans, carrying charges can amount to almost double the initial capital cost. This rule-of-thumb estimate does not take into account the fact that authorized rates of return, which change over time, are currently near all-time lows. Nor does the rule-of-thumb take into account the impact of regulatory innovations such as performance-based ratemaking, multi-year rate plans, and reforms associated with reducing capital bias, all of which are likely to increase the carrying charges customers must pay.

The notion that BCA cost definitions should include carrying charges is an extremely important precedent for the Commission to establish. Not only is such a cost definition the most relevant to which to compare customer benefits, it is useful in other domains. Consider the evaluation of non-wires alternatives, for example. A third party interested in providing energy storage services must pay a rate of return to its shareholders, federal income taxes on profits, interest expense on debt, etc. The third party's price proposal must undoubtedly be high enough to cover these expenditures. If a third party's price proposal is compared only to the capital costs the IOU could avoid through the third party's services, the third party's price proposal is utterly disadvantaged. Only by comparing the third party's price proposal to the customer costs of an IOU's capital – including carrying charges – will the playing field be level.

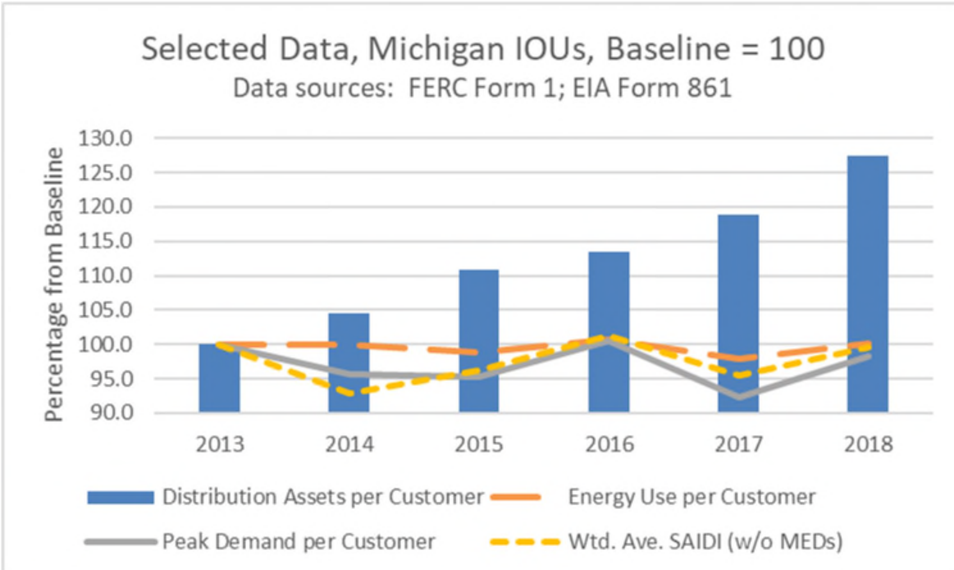
C. The Staff Report overlooks certain important context for distribution planning generally.

In its Report, Staff remains silent on significant developments in the electric distribution industry the Commission should consider when making decisions in this proceeding. While ABATE recognizes the Commission is largely aware of such developments, the omission of these developments from Staff's Report increases the risk that the Commission won't fully consider such developments in relation to the need for a transparent, stakeholder-engaged distribution planning and capital budgeting process. Such interrelated developments and trends include the following: (i) the pressure on IOUs to make grid investments in excess of need have never been greater; (ii) there is no correlation between distribution rate base growth and reliability improvements among US or Michigan IOUs; and (iii) current ratemaking and stakeholder processes were not designed for today's electric distribution grid or business challenges.

IOUs have long attracted capital by promising growth in earnings per share (EPS), and therefore growth in share prices. In comparison to today's situation, EPS growth was relatively easy to secure. Loads grew indefinitely, leading to EPS growth from greater-than forecast sales volume between rate cases. Increasing loads also led to increased need for generation, transmission, and distribution investment, which led to additional EPS growth. Today's situation is vastly different. For the first time ever, due to a variety of factors, energy and demand per customer is falling in the US and in Michigan. Generation capacity is in excess, and transmission lines take at least ten years to site, approve, and construct. Yet the EPS growth targets remain, and CEO interest in distribution rate base growth has therefore never been higher. The chart below indicates that growth in US distribution ratebase has been outpacing growth in US energy and demand for years.



While popular and political interest in DER accommodation and reliability provide a perfect excuse for grid investment, in Michigan as in most states, DER adoption is not yet high enough to justify large distribution investments. One would hope that distribution rate base growth in excess of energy and demand would deliver improved reliability. The relationships between investment and reliability in Michigan is similar to nationwide experience. The chart below indicates that the reliability of Michigan IOUs has barely budged despite dramatic grid investment growth in excess of flat to falling energy and demand.



Distribution planning process needs must be considered in the context of ratebase growth pressure and lack of correlation to reliability improvements. Clearly what IOUs have been doing on their own has not been working. Furthermore, the current ratemaking and stakeholder engagement processes were not designed to handle these and other electric distribution challenges. As the investments proposed by IOUs grow into the billions, regulatory disallowance after the fact becomes an increasingly hollow threat. When such magnitudes are involved, disallowances deliver cost of capital increases, which in turn increases customer rates, effectively tying regulators' hands. Advance distribution planning, as contemplated in this case, holds promise for managing ratebase growth. But distribution planning processes which pay lip service to stakeholder engagement have not been shown to deliver meaningful improvements in customer value creation per grid investment dollar.

In a rate case in North Carolina three years ago, for instance, regulators rejected an IOU's \$13 billion, 10-year grid modernization plan due to inadequate stakeholder engagement.[iii] Last year, after three workshops and several webcasts, the IOU declared the stakeholder requirement fulfilled. It submitted a $2.5 billion, 3-year grid modification plan consisting largely of the same plan elements, multiple BCA deficiencies (as judged by ABATE's experts), and no progress on multiple stakeholder requests, from DER hosting capacity increases to performance measures.[iv,v] The lesson is that stakeholder engagement is not something that will be accomplished by a regulator's order, particularly when the stakes are so high for IOUs. To avoid such delays in Michigan, the best course of action is a formal regulatory proceeding to carefully and thoroughly define a distribution planning and capital budgeting process which features informed and involved decision making. Elements needing definition include process steps, limitations, participant roles, stakeholder sign-offs, dispute resolution, BCA guidelines, timelines, frequency, and other parameters. The details of ABATE's recommendation are provided at the conclusion of these Comments, as well as the Comments ABATE previously submitted in this proceeding.

D. Certain assertions and implications of the Staff Report should be modified or removed.

While complimentary of Staff's efforts in this proceeding overall, there are certain assertions and implications in Staff's Report which should be altered or removed. Indeed, every one of these errant assertions and implications serve as excellent examples of the need for a transparent, stakeholder-engaged distribution planning and capital budgeting process. Staff Report assertions and implications that should be modified or removed include the following:

- Assets operating "way past useful life" are unreliable or unsafe;
- The Department of Energy (DOE)'s DSPx (distribution planning) framework should be accepted wholesale;
- IOU limitations on DER hosting capacity/NWAs should be taken at face value;
- Paying incentives to IOUs to address capital bias merits consideration;

- ABATE's proposed TSEDPCB process "replaces utilities with stakeholders as lead actors";
- The DOE's "Cost of Interruption" estimates are accurate, and can be used in BCAs; and
- Grid "Visions" need not be quantified.

1. Assets operating past useful life are not necessarily unreliable or unsafe.

The Staff Report states "[t]he utility electric infrastructure in Michigan has many assets that are operating way past the end of expected life,"[vi] implying that this is definitionally unacceptable. Despite this assertion, asset age is not necessarily a justification for replacement; field equipment routinely operates reliably decades beyond the depreciable lives used as accounting conventions, while a transformer installed tomorrow may fail in year five, or it may fail in year 75. IOU's have increasingly attempted to use accounting concepts such as "useful life" to justify replacing assets which are in perfectly good working order. In fact, ABATE is concerned that IOUs and their experts are attempting to supplant well-established, industry standard practices in asset management[1] with unwarranted polices which seek to replace assets for which book value is zero.

[1] The electric utility industry has always been a leader in the field of asset management due to its huge installed base of equipment of similar types. A body of knowledge has developed over many decades regarding maintenance, inspection, testing, and replacement policies for field assets which optimizes the balance between cost-effectiveness and reliability. One of the best-known and widely practiced of these policies is "run to failure" for distribution equipment. The policy is based on the fact that distribution asset failure rates are so low, and so few customers are served by any single piece of distribution equipment, that reliability improvements do not justify the cost of testing and prospective replacement. For example, as distribution transformers typically serve just 3-5 customers each, and as annual distribution transformer failure rates as low as 1% are common, the cost of testing tens or hundreds of thousands of transformers periodically to identify the 1% which are likely to fail in any one year is simply not cost-effective. There are exceptions to the "run to failure" practice; utility poles are inspected on a regular schedule due to the public safety risk pole failure represents. Substation equipment is another exception, as a single piece of equipment may serve thousands of customers. As a result, it is standard industry practice to test substation transformers and circuit breakers on regular schedules, and to proactively replace assets

Utilities have long sought to accelerate depreciation periods of assets, as shorter depreciation periods offer a faster return of capital than longer depreciation periods. An entire discipline has arisen around the conduct of depreciation studies which justify shorter depreciation periods, although the concept is really quite simple. In any pool of assets of the same type, some will fail before others. While 100 of 100 assets installed tomorrow expect to be operating next year, perhaps only one of those assets will still be operating 60 years from now. This particular pool of assets will have an average useful life of 30 years, which is why the pool of assets is depreciated over 30 years. However, this does not mean that the 50% of assets in the pool likely to still be operating in year 31 should be replaced; these assets have decades of reliable operation remaining. Yet this is precisely what IOUs in California,[vii] Indiana,[viii] and North Carolina[ix] are now proposing, supported by the testimony of consulting engineering firms which stand to benefit from increases in grid investment. In Indiana, legislation favorable to IOUs led regulators there to approve the practice,[x] while cases in the other jurisdictions are ongoing. Because it unnecessarily increases rates and does not reflect the actual useful life of utility property, this practice should not be used in Michigan.

As the Commission is well-aware, assets with zero book value earn no authorized rate of return for shareholders. Due to the earnings-per-share growth pressure IOUs are under, IOUs will attempt to justify zero book value asset replacement through claimed improvements in reliability or safety. *These claims must be backed by historical equipment failure rate data to merit serious consideration.* The attempt by IOUs to replace equipment by supplanting sound operating practices

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which fail the tests. But the practice of replacing assets prospectively due to age in the absence of test or inspection failure is not acceptable.

with inapplicable accounting conventions is a good example of the need for a transparent, stakeholder-engaged distribution planning and capital budgeting process. The Commission and Staff should therefore reject the notion that assets operating past their average useful accounting life are unreliable or unsafe absent objective test or inspection results which document otherwise.

2. The DOE's DSPx (distribution planning) framework should not be accepted wholesale.

Staff (consistent with regulators in most states) appears to rely heavily on the DOE's perspectives regarding distribution planning. This is to be expected; the DOE's DSPx, framework was developed by highly-respected experts from many disciplines working in a variety of national laboratories. ABATE agrees with a great deal of the DOE's grid modernization work, and large parts of the DSPx framework. ABATE strongly encourages Staff and the Commission to review the DOE publication, "A Valuation Framework for Informing Grid Modernization Decisions: Guidelines on the Principles and Process of Valuing Grid Services and Technologies,"[xi] a joint effort between the DOE's Grid Modernization Laboratory Consortium (the same group behind the DSPx framework) and the National Association of Regulatory Utility Commissioners (NARUC).

Despite the DSPx credentials, certain unsupported fundamental perspectives from which almost all DOE grid modernization work originates should be rejected. These fundamental perspectives are captured in DOE statements such as "[f]uture (DER) adoption rates (potentially accelerated), will always occur on a timeframe that is faster than new grid infrastructure implementation"[xii] and "[r]ates of DER adoption have outpaced the deployment of grid systems that can enable their effective integration."[xiii] These statements, and the perspectives they represent, are not supported by factual evidence. ABATE experts, with experience evaluating the distribution plans of California IOUs with relatively high levels of DER penetration, have not observed these phenomena. The reality is that utilities have been employing distribution planning processes which have adequately anticipated load growth and incorporated new technologies as they become available for over a century now. Of course distribution planning must indeed change, stakeholder engagement must increase, and practices like hosting capacity analyses and DER forecasting must be added. At the same time, however, the notion that multi-billion-dollar grid modernization efforts, or the enhanced cost recovery approved and/or being debated in many states, are required to make the grid more reliable, or to prepare for an onslaught of DER, should be rejected. Utilities are experts at identifying and prospectively accommodating technical issues as they arise on the grid on a geographic and circuit-specific basis. This expertise has provided the affordable, reliable electric service we enjoy today, and it can be relied upon to do the same in the future.

The extent to which DOE perspectives contain bias (and the bases upon which the Commission should be cautious of over-reliance on the DOE's DSPx framework) can be identified through reviewing the authors and contributors to the almost 300-page, three volume report on which the DSPx is based.[xiv] The authors consist of respected engineers, researchers, economists, and attorneys, and their work was guided by well-intended regulators in several states. Contributors included IOUs and IOU suppliers of equipment, software, and services, as well as their associations – all with vested interests in maximizing grid investments. However, there is no evidence whatsoever that alternative viewpoints to the DOE perspective presented above were considered. No consumer, business, or environmental advocates, or experts with actual experience in distribution planning, investment, or asset management for IOUs, appear to be parties to the DOE report. The Commission and Staff should therefore be cautious in over-relying on the DOE's DSPx framework.

3. IOU limitations on DER hosting capacity/NWAs should not be taken at face value.

While Staff refers to hosting capacity analyses (HCAs) over 100 times, it never addresses the validity of technical justifications IOUs often use to limit DER (or NWA) capacity. As the Commission is well-aware, IOUs have several types of economic incentives which discourage DER and non-wires alternatives (NWA) investment relative to traditional IOU capital investments. Capital bias figures prominently, as NWAs can defer or avoid distribution ratebase growth, and customer or third-party DER can defer or avoid generation or transmission investments. The throughput incentive is also an issue, as customer-owned DER reduces IOU sales volume, acting as a drag on earnings between rate cases. ABATE experts have also observed good old-fashioned resistance to change among IOU functions and employees. Every circuit and grid configuration presents grid operators with challenges they must circumnavigate on a daily basis; when presented with another such challenge in the form of large DER or NWA installations, grid operators understandably prefer not to deal with them (of course, this does not mean they can't be dealt with).

These incentives to discourage DER and NWA can be observed in the dubious technical arguments some IOUs use to limit DER and NWA. Indeed, IOUs have also raised dubious technical arguments to justify DER accommodation investments which were not required, which further evidences capital bias. All these arguments must be evaluated by unbiased experts with the technical expertise to effectively challenge them. It is incumbent upon the Commission and Staff to challenge the technical grounds of any DER or NWA limitations IOUs declare.

4. Paying incentives to IOUs to address capital bias is an affront to the regulatory compact.

The Staff Report encourages the Commission to consider alternative regulation and ratemaking practices. While this Staff recommendation is beneficial in principle, the specific options described by the Advanced Energy Economy (AEE) (and referenced in the Report)[xv] – some of which have been adopted in other jurisdictions – are fundamentally problematic. The AEE options all involve the use of incentives to counter IOU capital bias, including the capitalization of operating costs, the payment of a rate of return on O&M spending, and provisions for NWA benefit sharing.

These accommodations are a fundamental affront to the regulatory compact. The compact allows an IOU to operate a monopoly in exchange for regulation of rates. These rates are to include a rate of return on prudently spent capital so that an IOU can raise the capital necessary to provide monopoly services. The notion that a capital investment is "prudent" necessarily incorporates the notion that no cheaper alternatives to capital spending were available to the IOU when the investment was made. If a less-costly (to customers, including carrying charges) alternative to a capital investment is available to an IOU, the IOU must select the less-costly alternative. Recovery of capital spent when less-costly alternatives were available is, by definition, imprudent, and should be rejected. There is no reason to pay IOUs an incentive to comply with the regulatory compact to which IOUs have already agreed. The Commission and Staff should therefore reject any such component of alternative regulation or ratemaking.

5. ABATE's proposed TSEDPCB process does not replace utilities with stakeholders as lead actors and comports with the Commission's overall guidance and objectives in this proceeding.

The Staff Report states that the TSEDPCB process ABATE described in its September 11, 2019 Comments requires that "stakeholders replace utilities as lead actors proposing Michigan electric distribution investment plans," and rejects the idea of a TSEDPCB process on that basis.[xvi] This is a significant misunderstanding of the TSEDPCB process ABATE proposes. While any TSEDPCB process necessarily requires either stakeholders or IOUs to take the lead on various steps, it was not ABATE's intention to imply that stakeholders replace IOUs in electric distribution investment planning. Indeed, in ABATE's version of a TSEDPCB process, IOUs take the lead on Step 4, "Utilities propose distribution projects." ABATE simply believes distribution planning and investment decisions will better serve customers when stakeholders participate in informing critical decisions. Such participation must extend beyond workshops, webcasts, and "input." A truly transparent distribution planning and capital budgeting process involves clear stakeholder understanding of emerging issues, relative risks and consequences, potential solutions, and the pros and cons of each. Such involvement is a valuable protection for customer and community interests and comports with the Commission's numerous directives in establishing the distribution system planning process being undertaken in this proceeding.

This is first demonstrated in the Commission's Notice of Opportunity to Comment entered in Case Nos. U-17990 and U-18014 on August 4, 2017, in which the Commission solicited comments from interested persons regarding the draft distribution system investment and maintenance plans submitted by DTE Electric and Consumers Energy. The Commission specifically sought comment on the following questions:

1) Does the company's draft distribution planning report provide a transparent review to identify and make cost-effective grid modernization and aging infrastructure investments necessary to support improved reliability, power quality, and future growth? Do the proposed investments provide a clear strategic path to address resiliency, reliability, and grid modernization, consistent with the Commission's stated goals as outlined in recent electric rate case orders?

2) Do the plans identify system upgrades or investment strategies and concrete, measurable performance targets and timeliness in areas such as safety and reliability?

3) Are there longer term enhancements to the plan or the planning process that the Commission, utilities, and stakeholders should be considering in future rounds?

4) Any other feedback for the Commission's or Commission Staff's consideration.

After reviewing the comments submitted by interested parties, the Commission stated that the collective, stakeholder-involved effort "will lead to greater safety, reliability and resiliency, cost-effectiveness and affordability, and accessibility of electric service for all." *In the Matter of the Application of Consumers Energy Company/DTE Electric Company*, order of the Public Service Commission, entered October 11, 2017 (Case Nos. U-17990 and U-18014), p 9-10. The Commission also found that "the rate case process would benefit from [utilities] providing a more comprehensive, forward-looking capital investment and operations plan" for review and development outside of contested electric rate cases. *Id*. (citation omitted). As described by the Commission, utilities' "conventional distribution system planning efforts have occurred internally with limited opportunity for outside stakeholder input outside of formal rate case proceedings" and "investment in the distribution planning system has been steadily increasing in recent years and is, thus, a major driver for recent rate case requests." *Id*. at 13-14 (citations omitted).

As such, and in order to accommodate the "emerging trend, particularly in jurisdictions with higher electricity prices, from centralized one way power flows to more complex, decentralized systems capable of real-time monitoring, controls, and two-way power flows," the Commission stated its belief that "there are significant benefits associated with a comprehensive and forward-looking approach to distribution planning that leverages greater Commission and stakeholder input." *Id*. at 14. As such, the Commission supported "a longer-term planning approach" to "help the Commission and stakeholders better understand the long-term goals and objectives underlying utility investment plans and how the execution of these plans can meet these goals and objectives in an affordable manner." *Id*. at 14-15. Furthermore, an "[o]pen and effective planning processes will . . . allow the Staff and stakeholders to weigh in on planning assumptions, particularly those that address factors outside the utility's control, such as rooftop solar and electric vehicle adoption" and the "development of these processes over time is essential in ensuring Michigan is making 'no regrets' investment decisions in the long term." *Id*. at 15.

In other words, stakeholder input and direction have been central to the distribution system planning process since its inception.[2] Indeed, the Commission acknowledged the "great interest from both service providers and customers in participating and providing input into the utility distribution planning process," which served as the basis of the Commission's directive to initially "convene these stakeholders after the filing of the final distribution plans by the utilities to develop a framework for the development of future distribution plans." *Id*. at 17-18. This focus on stakeholder involvement is also evident throughout the Commission Orders in this Docket. See e.g. *In the Matter, on the Commission's Own Motion*, order of the Public Service Commission, entered April 12, 2018 (Case No. U-20147), p 3 ("creating a single repository for all five-year distribution plans in this docket (Case No. U-20147) will allow a comprehensive and concerted

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[2] While the Commission originally noted that "this planning process would not provide regulatory approvals for cost recovery purposes," it noted that "the transparency around the need for, scope of, and expected outcomes resulting from specific investment strategies may facilitate ratemaking processes and the development of potential new approaches to provide greater regulatory certainty, such as performance-based ratemaking currently being studied pursuant to the 2016 energy laws." *In the Matter of the Application of Consumers Energy Company/DTE Electric Company*, order of the Public Service Commission, entered October 11, 2017 (Case Nos. U-17990 and U-18014), p 15. Thus, while the planning process was not initially meant to result in regulatory approvals for cost recovery purposes, this process would benefit from a more formal regulatory structure or, at the very least, the TSEDPCB process outlined in ABATE's prior Comments should provide the framework for this distribution system planning proceeding going forward.

review by all distribution system stakeholders of issues related to five-year distribution plans in one central, efficient location . . . the Commission is also inviting Staff and stakeholder comments on the distribution plans"). Indeed, the Commission has continued to reiterate that the "primary impetus for this initiative . . . was for the Commission and interested stakeholders to be able to examine distribution investments, including capital and operations and maintenance, in a comprehensive manner—beyond the limited 12-month snapshot of time (i.e., projected test year) provided by utilities in their general rate cases." *In the Matter, on the Commission's Own Motion*, order of the Public Service Commission, entered November 21, 2018 (Case No. U-20147), p 1-2.

In particular, given the observed "significant increase in distribution investments over the past few years and multi-billion-dollar utility capital plans to upgrade and modernize electric distribution systems in Michigan," the "short and long term implications for affordability, safety, reliability, and access to the electrical grid" caused the Commission to stress "the need to thoroughly examine system conditions, needs, and investment strategies and options through a transparent planning process with stakeholder involvement." *Id*. at 2. The Commission described this stakeholder-involved process as "particularly important at this time given the inherent risks and opportunities associated with the rapidly evolving energy landscape with increased distributed energy resources (DERs) and other technologies such as plug-in electric vehicles (PEVs) that may affect the distribution system" and noted is continual solicitation of stakeholder comments. *Id*. at 2-3.

Following from these sentiments and directives, Staff noted the "robust interest in the development of a transparent, inclusive distribution planning process desired by the Commission" and recommended "that the Commission 'establish a formal stakeholder effort to capture the perspectives of all participants in the refinement and finalization of the framework'" for planning.

Id. at 4-5 (citation omitted). Specifically, for example, Staff suggested such a stakeholder effort could "weigh in on forecasting assumptions and other foundational aspects of utility plans that materially impact the outputs of the spending plans." (Case No. U-20147, Doc. 17 at 22-23.) In discussing Staff's recommendations and the comments thereon, the Commission noted that the "positive results from this planning initiative—not only the extensive written plans but, as equally important, the increased understanding and collaborative discussions to support the planning—only reinforce its importance and the Commission's interest in building on this effort." *In the Matter, on the Commission's Own Motion*, order of the Public Service Commission, entered November 21, 2018 (Case No. U-20147), p 30. Indeed, the Commission found "collaboration from all types of stakeholders necessary to advance this distribution planning process and to bring about 'no regrets' grid investments that are adaptable regardless of what the future holds." *Id*. at 30-31.

As such, the Commission stressed "the importance of both top-down and bottom-up planning" and stated that "[as] the Commission, utilities, and stakeholders engage in the development of the next iteration of plans, it is important to have discussions around the longer-term vision for grid architecture and performance expectations." *Id*. at 37. The Commission also noted that it would provide further guidance to "encourage broad stakeholder participation in these efforts related to planning, grid access, and regulatory innovation." *Id*. at 39. The Commission then subsequently directed Staff to examine the value of resiliency in the distribution planning stakeholder process and extended DTE Electric and Consumers Energy's next filing date for the second iterations of their distribution plans. *In the Matter, on the Commission's Own Motion*, order of the Public Service Commission, entered September 11, 2019 (Case No. U-20147). The Commission noted that this additional time would, among other things, "allow for a longer stakeholder process." *Id*. at 5. The Commission has therefore used its Orders relevant to this distribution system planning endeavor to consistently reiterate the essential nature of stakeholder participation, input, and direction. The TSEDPCB process described in ABATE's previous Comments aligns with this stakeholder-focused planning structure and simply provides a more ordered framework for this process going forward.

Furthermore, as discussed below, it is premature to pass judgement on a TSEDPCB process which has yet to be developed. Michigan IOUs and other relevant entities will understandably have significant questions regarding such a process, its application, its role, its administration, and other procedural aspects which have yet to be determined. These issues can be navigated and discussed by establishing a formal proceeding to develop a TSEDPCB process with participation from all parties. The Commission and Staff should therefore explore the development of a formal regulatory TSEDPCB process or, at the very least, use such a process as outlined by ABATE as the framework for this existing planning process moving forward.

6. The DOE's "Cost of Interruption" estimates were not scientifically developed and should not be employed in benefit-cost analyses.

The Staff Report mentioned the presentation by Joseph Eto in the September 18th workshop, which includes a discussion of the DOE's customer interruption cost estimates. These estimates, and their use by IOUs in BCAs, are seriously flawed and inappropriate. Concerns about these estimates, which are likely to lead to overstated economic benefits in BCAs, include the following:

- The commercial and industrial (C&I) customer interruption cost estimates are based on a limited number of surveys conducted by just a few utilities;
- These few utilities included no representation from many geographies, including "minimal representation from cities along the Great Lakes;"[xvii]
- The C&I cost estimates are based on surveys of manufacturing and retail ratepayers only, which today represent a minority of C&I customers;

- There is no consistency in how survey respondents took back-up generation and uninterruptible power supply systems into account when completing surveys, despite the fact that over half of C&I facilities in the US have these systems;[xviii]

- Only one of the surveys addressed the cost of interruptions longer than eight hours, making them inappropriate for use in estimating benefits associated with long-duration outages; and

- C&I survey respondents were aware that the IOUs providing them with services were conducting the surveys, which likely biased responses.

Furthermore, in ABATE's experience IOUs can mis-use the interruption cost estimates (for example, $15,000 for a momentary interruption or $30,000 for a 4-hour interruption, etc.). The surveys and secondary research the DOE completed were designed to estimate the economic impact to each individual ratepayer of service outages of various durations. It is inappropriate to aggregate the impact of individual C&I service outage impacts into a total C&I ratepayer impact estimate without considering countervailing beneficial impacts to other C&I ratepayers, as this leads to exaggerated overall avoided cost benefit estimates. Consider several scenarios that are likely common in the event of a service outage:

- A residential customer, faced with no electricity for cooking and air conditioning, decides to go out to dinner, or to shopping mall, benefitting some businesses.

- A motorist in need of gasoline bypasses a gas station without power in favor of a gas station with power.

- A retail shop experiencing a momentary outage continues to ring up sales and process credit card transactions using the UPS systems attached to each register.

- A farmer who uses electric pumps to irrigate his or her fields simply elects to irrigate later in the day once power is restored, or to double irrigation the next day.

In each of these scenarios, the aggregation of individual C&I ratepayer impacts to estimate total C&I impacts leads to an exaggeration of overall costs incurred by C&I ratepayers. In the first scenario, the service outage results in an economic benefit for some C&I ratepayers. In the second scenario, the economic cost to one gas station represents an economic benefit to a second gas station. In the third scenario there is virtually zero economic C&I ratepayer cost (limited to ratepayers who approach the store during the 30-seconds in which the power is out, and decide not to shop), and in the fourth scenario there is zero C&I ratepayer economic cost. Yet the aggregation and application of the individual C&I impacts per customer interruption or per customer minute interrupted consider none of the offsetting impacts of these scenarios. Given the inadequacies of these estimates, they should not be included in BCAs for proposed distribution investments until an independent party conducts an unbiased survey of Michigan customers, or at least C&I customers, by rate class, to estimate interruption costs.

7. Grid "Visions" need to be quantified.

Finally, the Staff Report recommends that distribution grid "visions" be a part of every IOU's 5-year distribution plan.[xix] While ABATE agrees with this recommendation, it is concerned by the non-quantitative nature of the word "vision." Objective measures should be part of every aspect in a distribution plan. Vague phrases such as "improved reliability" and "increases in DER capacity" are subject to interpretation and inconsistent valuation. "Visions" for an IOU's grid can incorporate performance metrics, targets, and tracking. The Commission and Staff should require objective measures for every aspect of a distribution plan, including visions for the future. Objective measures are critical to IOU performance accountability and are requisite for determining if a "vision" has been realized. Examples for quantifying the successful realization of a utility's "vision" for its system include the following:

- What is the IOU's SAIDI and SAIFI performance today?
- What will the IOU's SAIDI and SAIFI performance be if the vision is completed?
- What is the IOU's DER hosting capacity today?
- What will the IOU's DER hosting capacity be if the vision is completed?

E. Multiple IOU comments mischaracterized and overstated the implications of ABATE's recommended distribution planning process.

In response to the distribution planning and capital budgeting process ABATE described in its September 11, 2019 Comments, the IOUs, and Indiana Michigan Power (I&M) in particular, raise various objections to ABATE's recommendations. Because these points mischaracterize ABATE's proposed TSEDPCB process and overstate the implications of its recommendation, they should be rejected.

I&M states that since a similar concept, resource planning, required legislation, a TSEDPCB process does too.[xx] However, as I&M acknowledged in its comments, the Commission "used its general ratemaking authority to require 5-year distribution plans from three major utilities in this state." As explained above, the TSEDPCB process ABATE described in its September 11, 2019 Comments is simply a more detailed framework for the process Staff is already pursuing in this docket. ABATE is simply recommending that the framework be more fully developed in a formal regulatory proceeding or, alternatively, utilized as the structure for developing IOU 5-year distribution plans in the current ongoing proceeding.

Furthermore, to the extent initiating authority is required, as multi-billion-dollar discretionary grid investment proposals are likely to result in price changes, the Commission's general ratemaking authority already encompasses the ability to establish a formal regulatory process related to stakeholder participation in distribution planning and capital budgeting processes. This is in keeping with I&M's acknowledgement of the Commission's authority to originally establish this proceeding. Indeed, at the very least the Commission has the authority to specify application, roles, and administration of stakeholder participation in reviewing distribution planning and investment in the present docket. As set forth above, the Commission and Staff have effectively acknowledged as much in establishing and administering the planning process in the present docket.[xxi]

I&M also states that the Commission must "follow procedures for publishing and adopting rules under APA Chapter 3, MCL 24-231-24.266."[xxii] In the event the Commission desires to establish the TSEDPCB process as a set of administrative rules, ABATE would welcome the Commission enshrining this framework as an administrative process to develop future distribution system planning processes in Michigan. Regarding I&M concerns over the cost of a TSEDPCB process, it is important to consider such costs relative to the underlying substantive investments at issue (i.e. a million-dollar distribution planning and capital budgeting process conducted every 3-5 years, relative to billions of dollars in investments which do not optimally pursue customer, stakeholder, and state policy goals). Considering the Commission objectives and concerns described above, such cost cannot be considered prohibitive.

Finally, both I&M and Consumers Energy state that the Commission's role is "not to tell the utility how to run its business."[xxiii] This argument was previously addressed by the Commission, which stated that "the purpose of a framework" for distribution system planning "is to provide focused discussion, longer-term visibility than what is available in a rate case, and better understanding, not to set prescriptive mandates on the utilities." *In the Matter, on the Commission's Own Motion*, order of the Public Service Commission, entered November 21, 2018 (Case No. U-20147), p 36. In other words, the Commission's efforts in this proceeding, and the TSEDPCB process, are focused on "protect[ing] the public by ensuring safe, reliable, and accessible energy services at reasonable rates for Michigan's residents," and would not "usurp utility management prerogatives." *Id*. (citation omitted). Consistent with the distribution system planning to date, the TSEDPCB process would simply be used as a more formal "guide for the next iterations of distribution plans to be filed by those directed to do so." *Id*. As this IOU objection to the distribution system planning process was previously considered and rejected, it should be similarly dismissed here.

The erroneous nature of the IOU objections and the Commission's statements regarding the goal and shape of this process make clear that the TSDEPCB process could and would best be defined through a formal, authoritative regulatory proceeding. Alternatively, though leaving much to be desired, the TSDEPCB process could also be utilized as the framework for distribution system planning in the present docket. Thus, to clarify, a TSDEPCB, once developed, could take place over a 12-month period specific to each IOU. Steps 1-7 (the distribution planning and capital budgeting steps) would be completed during this time. The deliverable at the end of Step 7 would be a distribution plan and capital budget, with any differences between stakeholder and IOU versions and positions clearly documented. Steps 8 and 9 (the execution and performance measurement steps) would be completed over a 3-5-year period and serve as the subject of ratemaking in rate cases as conducted today.

In other words, the recommended TSDEPCB process would operate consistent with the Commission's general vision of the distribution system planning process as established. The planning process conducted through Steps 1-7, while "not provid[ing] regulatory approvals for cost recovery purposes," would provide a record of stakeholder positions outside a formal rate case proceeding and produce a plan serving as the basis for cost recovery through another existing proceeding, such as a rate case (Steps 8 and 9). See *In the Matter of the Application of Consumers Energy Company/DTE Electric Company*, order of the Public Service Commission, entered October 11, 2017 (Case Nos. U-17990 and U-18014), pp 13, 15. In short, development of a

TSDEPCB process does not require legislation and Commission and Staff should reject any such notions from Michigan IOUs.

III. RECOMMENDATIONS

Based on these Comments, a formal regulatory proceeding should be established to develop a distribution planning and capital budgeting process for future use in Michigan. Alternatively, the process recommended in ABATE's previous Comments could be utilized as the distribution system plan framework in the present proceeding. However, use of the present proceeding to increase stakeholder engagement in distribution planning is likely to result in the workshop/webcast variety of engagement, and will not deliver the customer and community protections offered by a formal TSEDPCB regulatory process.

Whatever the Commission decides, the scopes, parameters, and issues to be addressed in the development of a TSEDPCB process are provided below. These include the following: (i) a definition of the process; (ii) the application of the process; and (iii) guidelines for BCA and associated risk-informed decision support. Finally, suggestions regarding the timing and development of both the process and initial IOU distribution plans for Commission consideration are also addressed.

A. Defining a TSEDPCB process.

As alluded to earlier, the notion of a TSEDPCB process should not be rejected before it has even been developed. A process definition effort would take into account the interests, perspectives, and positions of all IOUs and stakeholders as the steps of the process are defined and refined, including the roles of stakeholders in each step. Some type of "sign off" might be appropriate for each step, with stakeholders and IOUs (or Staff as regulator) documenting when a step has been completed, or documenting outstanding differences before moving on. The timelines of distribution plan development would also need to be established; a TSEDPCB process could deliver a distribution plan and capital budget within 12 months, with IOU-specific plans due on a staggered schedule (such that only one IOU's plan would be in development at any one point in time). Plan frequency would also need to be addressed, although 3-5 year Distribution Plan periods are recommended.

B. Applying the TSEDPCB process.

Another issue to be addressed in TSEDPCB process development is its application. Stakeholders should not be inserted into IOUs' day-to-day business decisions and, as such, limitations on the kinds of investments and programs to which a TSEDPCB process should be applied may be appropriate. On the other hand, as described earlier, loopholes which IOUs might use to avoid completing BCAs on an investment or program simply by categorizing it as "in the normal course of business" should be identified and closed. Part of TSEDPCB process development should therefore include a definition of the instances in which the "Least Cost/Best Fit" approach (no BCA) can be invoked. These specific instances (such as those listed above) should be very limited and the burden of proof for BCA avoidance should be placed on the IOUs.

C. Guidelines for benefit-cost analyses and associated risk-informed decision support.

As described above, ABATE agrees with all Staff requests regarding BCA guidelines, although certain issues deserve additional attention. First, carrying charges should be included in the definition of costs. Second, the DOE's interruption cost estimates, particularly for C&I customers, are flawed, and should not be used by the IOUs in BCAs until an independent, scientifically-administered survey of Michigan C&I customers is conducted with the express intention of estimating aggregate service interruption costs. Third, the TSEDPCB process development exercise should address the use of risk-informed decision support. As described in

ABATE's September 11, 2019 Comments, risk-informed decision support can be used to help estimate the value of investment proposals with difficult to quantify benefits. Risk-informed decision support can also be used to help prioritize proposed investments, and determine the most appropriate capital budget level, through informed investment selection/rejection choices. Informed investment selection/rejection choices result when stakeholders understand the benefits, risks, pros, cons, and trade-offs associated with various plan portfolio scenarios which IOUs and stakeholders will undoubtedly confront and consider as they develop distribution plans. Finally, if the Commission agrees that efforts to better define a TSEDPCB process are in order, changes to the due dates for the IOU's distribution plans are in order. A proposed schedule for Commission consideration is included below:

Start Date	Finish Date	Activity
Date of Order	June 30, 2021	IOUs, Staff, and stakeholders develop a TSEDPCB process.
July 1, 2021	June 30, 2022	The process is used to develop the first IOU's distribution plan.
July 1, 2022	June 30, 2023	The process is used to develop the second IOU's distribution plan
July 1, 2023	June 30, 2024	The process is used to develop the third IOU's distribution plan

ABATE wishes to thank Staff for its good work in the present docket thus far and the opportunity to provide Comments thereon. Several jurisdictions are now wrestling with distribution planning and it is encouraging to see the Commission taking a proactive leadership role. With continued Commission leadership, Staff support, and IOU and stakeholder participation, a distribution planning process which can serve as an excellent example for other jurisdictions to follow is within reach. ABATE looks forward to continued contributions in the development of Michigan's distribution planning process, and in the development of Michigan IOUs' next distribution plans.

Respectfully submitted,

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[i] Woolf, T. (August 14, 2019). *Benefit-Cost Analysis for Utility-Facing Grid Modernization Investments*, p 29.

[ii] Michigan Public Service Commission. Case Number U-20147. ABATE Comments (September 11, 2019).

[iii] NCUC Docket No. E-7 Sub 1146. *Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction* (June 22, 2018), p 149.

[iv] NCUC Docket No. E-7, Sub 1214. Direct testimony of Jay W. Oliver (September 30, 2019).

[v] NCUC Docket No. E-7, Sub 1214. Direct testimony of Paul J. Alvarez (February 18, 2020).

[vi] Case No. U-20147, Staff Report (April 1, 2020) ("Staff Report"), p 6.

[vii] California PUC A.19-08-013, Direct testimony of G. Bloom and R. Tucker (August, 30, 2019), p 8, line 3+.

[viii] Indiana URC 45264. Direct testimony of Jason D. DeStigter (July 24, 2019).

[ix] North Carolina UC . Direct testimony of Jay W. Oliver (September, 20, 2019), Exhibit 10, pp 40 (Transformer Bank Replacement), 42 (Oil Breaker Replacement).

[x] Indiana URC 44720; 44733; and 44910; Orders dated June 29, 2016; July 12; 2016, and September 20, 2017 respectively.

[xi] US Department of Energy. *A Valuation Framework for Informing Grid Modernization Decisions: Guidelines on the Principles and Process of Valuing Grid Services and Technologies*.*"* Whitepaper by the Grid Modernization Laboratory Consortium and the National Association of Regulatory Utilities Commissioners (March, 2019).

[xii] US Dept. of Energy. Modern Distribution Grid, Decision Guide Volume III (June 28, 2017), p 28.

[xiii] Ibid at 29.

[xiv] Ibid, Acknowledgements at 1.

[xv] Staff Report at 40.

[xvi] Staff Report at 30.

[xvii] Sullivan et al. *Updated Value of Service Reliability Estimates for Electric Utility Customers in the United States*. Lawrence Berkeley National Laboratory report 6941E (January, 2015), p xiv.

[xviii] Phillips J, Wallace K, Kudo T, and Eto J. "Onsite and Electric Power Back-up Capabilities at Critical Facilities in the US." Primary research by the Argonne National Laboratory (April, 2016), p 13.

[xix] Staff Report at 44.

[xx] Case No. U-20147, Indiana Michigan Power Company Comments (December 16, 2016) ("I&M Comments"), p 8.

[xxi] See Commission Orders in Case No. U-20147; see also October 11, 2017 Order in Case No. U-17990 ("The Commission believes there are significant benefits associated with a comprehensive and forward-looking approach to distribution planning that leverages greater Commission and stakeholder input").

[xxii] I&M Comments at 9.

[xxiii] I&M Comments at 6; Michigan PSC Docket U-20147, Consumers Energy Comments, (December 16, 2015) p 8.