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September 11, 2019

VIA ELECTRONIC CASE FILING

Ms. Barbara Kunkel
Acting Executive Secretary
Michigan Public Service Commission
7109 W. Saginaw Highway
Lansing, Michigan 48917

Re: ***MPSC Case No. U-20147: 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.***

Dear Ms. Kale:

Enclosed for filing is the ***Association of Businesses Advocating Tariff Equity's Comments*** and ***Proof of Service*** in the above-referenced case.

Respectfully,

CLARK HILL PLC

Stephen A. Campbell

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Date: 2019.09.11 10:01:58 -05'00'

Stephen A. Campbell

SAC/lkd

STATE OF MICHIGAN

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

*** * * * ***

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
<u>ASSOCIATION OF BUSINESSES ADVOCATING TARIFF EQUITY</u>

Prepared by:

Paul Alvarez and Dennis Stephens EE
Wired Group

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I. INTRODUCTION

On September 4, 2018, Michigan Public Service Commission ("MPSC" or "Commission") Staff ("Staff") issued a draft proposed Michigan Distribution Planning Framework ("Framework") regarding the scope of the initial five-year distribution investment and maintenance plans to be filed by DTE Electric Company ("DTE") and Consumers Energy Company ("Consumers"). The Framework was based on five-year distribution plans submitted by DTE and Consumers as well as stakeholder comments, including comments submitted by the Association of Businesses Advocating Tariff Equity ("ABATE"), and a stakeholder workshop. Additionally, in Case No. U-18370 the Commission ordered Indiana Michigan Power ("I&M") to submit a five-year distribution plan as well.

Staff has overseen continued stakeholder activity in the docket in 2019. One informational workshop was held on June 27th, consisting of presentations by national experts on traditional distribution planning processes, and on the modern components which are becoming standard practice, such as the consideration of non-wires alternatives and the development of distribution generation hosting capacity analyses. A second informational workshop was held on August 14th, consisting of presentations by national experts, including Paul Alvarez and Dennis Stephens, who helped ABATE prepare these comments, regarding emerging best practices in the evaluation of utility grid investment proposals. DTE, Consumers, and I&M also provided information on the status of various pilot projects related to modern distribution planning components. Following the workshop, Staff invited stakeholders to provide comments on the workshop and the docket to date. ABATE appreciates the opportunity to provide these comments in response to Staff's invitation and, with the assistance of its experts, takes an expansive view of the potential benefits of a sound distribution planning process. Given the latest developments in end-user technologies and the electric distribution industry which have given rise to this proceeding, ABATE believes the time has come for investor-owned distribution utilities nationwide, and in Michigan specifically, to adopt a new, transparent, stakeholder-engaged distribution planning process. Further, ABATE would like to see such a process developed in advance of the next round of five-year distribution investment and maintenance plans, and utilized to create those plans.

In these comments ABATE experts describe a transparent, stakeholder-engaged distribution planning process designed to advance Michigan's economy. A sound distribution planning process offers the opportunity to make Michigan's economy one of the most productive in the United States by focusing utility spending in a manner which delivers the greatest customer and state policy benefits for the least cost to customers. ABATE's recommendation regarding such a distribution planning process includes discussions of the following issues:

- Why a transparent, stakeholder-engaged distribution planning process is needed now;
- What a transparent, stakeholder-engaged distribution planning process should include:
    1. Stakeholders identify and prioritize distribution plan goals (outcomes).

    2. Stakeholders define distribution performance metrics, targets, timeframes, and reporting requirements for priority outcomes.

    3. Utilities collect and publish distribution planning inputs.

    4. Utilities propose a list of recommended distribution projects.

    5. Stakeholders identify potential alternative and/or additional projects.

    6. All potential projects are evaluated using one of three methods based on the nature of each project (non-discretionary; discretionary with readily quantified benefits; and discretionary with difficult-to-quantify benefits).

    7. Stakeholders select projects and determine capital budgets.

8. **Utility implements selected projects and procures selected non-wires alternatives through competitive solicitation.**

9. **Performance is measured using metrics and targets established in Step 2.**

- The Advantages of a Transparent, Stakeholder-Engaged Distribution Planning Process

II. COMMENTS

A. Why a transparent, stakeholder-engaged distribution planning process is needed now.

1. Distribution planning is business as usual.

For over 100 years, distribution utilities have addressed technical distribution challenges as they have arisen through distribution planning. When the suburbs grew, utilities built new substations and circuits to serve them. When loads grew due to air conditioning and commercial development, utilities added substation and circuit capacity to avoid overloading equipment. Reliability issues were addressed through protective equipment like circuit breakers, proactive or reactive equipment replacement as justified by cost-benefit analyses, and good old-fashioned vegetation management. Where voltage and power factor issues arose, voltage regulators and capacity banks were added.

Over the decades, distribution investment became a background issue as generation and transmission planning took center stage. Distribution investments were typically given only a cursory review by regulators and stakeholders, as they were typically "in the routine course of business;" the dollars were smaller than in generation and transmission; and there was typically only one option for addressing each well-known technical challenge. Regulators, for their part, were typically impressed by utilities' technical competence, and gained confidence in utility representations related to distribution grid "needs." In the event of distribution over-investment, ever-increasing electric sales volumes would always catch up, and served as a virtually guaranteed source of funds for cost-recovery.

2. Distribution planning is overdue for an overhaul.

Things are very different today. Across the U.S., as in Michigan, electric sales volume per customer is falling for the first time despite growing gross domestic product.[1] Investments must be paid for through rate increases, not sales volume increases. The issues for which utilities are now preparing, such as increases in distribution generation, are unfamiliar to them. The characteristics of the associated challenges – in terms of significance, geographic extent, and speed of approach – are unknown. The impacts of the associated challenges, from bi-directional power flow to masked loads, have not yet been experienced, and can only be anticipated. The optional solutions available are many, and they are also unfamiliar and unproven.

Investor-owned utilities ("IOUs"), faced with these uncertainties and supported by policymaker interests in "readiness" and "modernization," are increasingly turning to their trusted favorite, capital investment. With generation capacity in excess of need, and transmission capacity requiring ten years or more from conception to commissioned, distribution is now U.S. IOUs' favorite investment. It is essentially the only low-risk path an IOU can take to achieve the earnings per share growth targets it has promised to Wall Street and shareholders. National data indicates that distribution rate base is growing three times faster than the rate of inflation.[2] Yet reliability is deteriorating, and operating spending mirrors inflation. As indicated in the following

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[1] Per IOU-submitted data on FERC Form 1 and EIA Form 861 as compiled by the Utility Evaluator, 2010-2017. For more information visit www.utilityevaluator.com.

[2] Ibid. Consumer Price Index data sourced from US Bureau of Labor Statistics at http://www.bls.gov/data/inflation_calculator.htm.

charts, it is appropriate for U.S. electric customers to ask, what are we getting in exchange for all these distribution rate increases?

Figure 1: U.S. IOU distribution investment relative to inflation, energy use, and demand

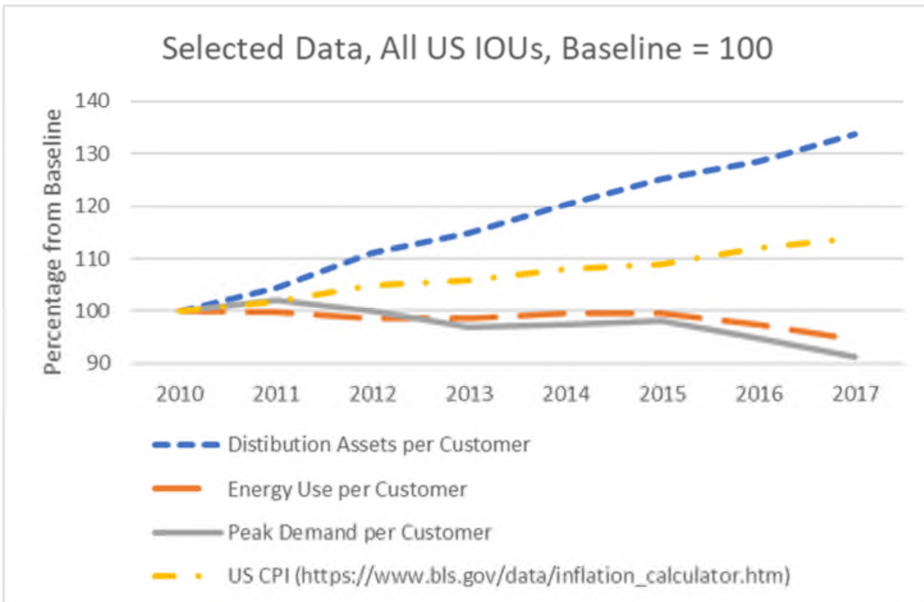


Figure 2: U.S. IOU distribution investment relative to reliability performance

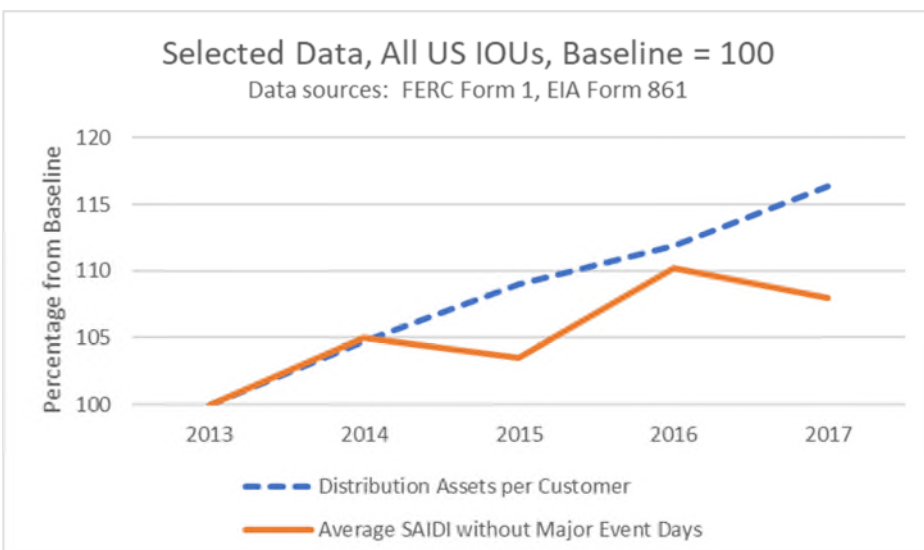
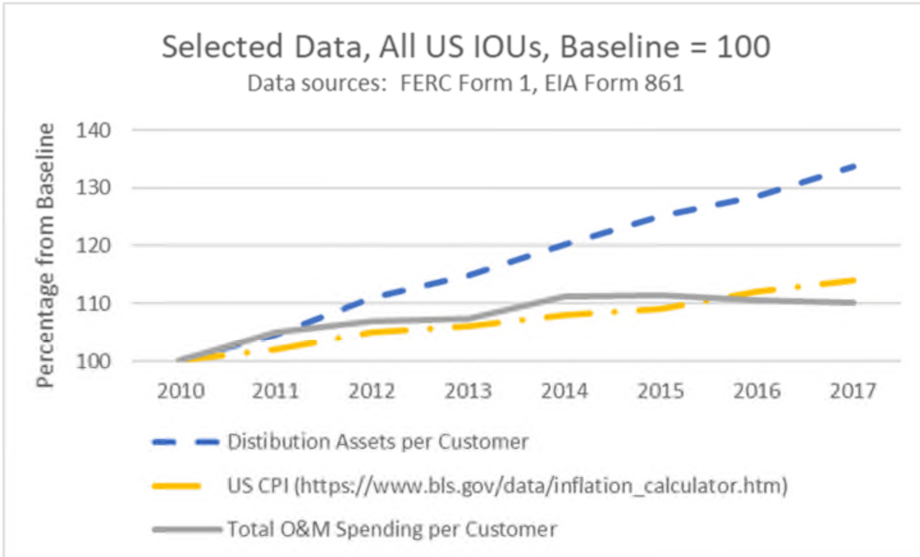


Figure 3: U.S. IOU distribution investment relative to inflation and O&M spending



IOUs are happy to make large distribution investment proposals which regulators and stakeholders are wholly unprepared and unqualified to evaluate. The harder a layperson looks, the more complex the technical description of an anticipated problem the IOU presents. While the layperson struggles to gauge the legitimacy of the anticipated problem, the IOU provides complex technical justifications for potential solutions. These "potential" solutions often lack demonstrated efficacy and are instead solutions in search of problems to solve.

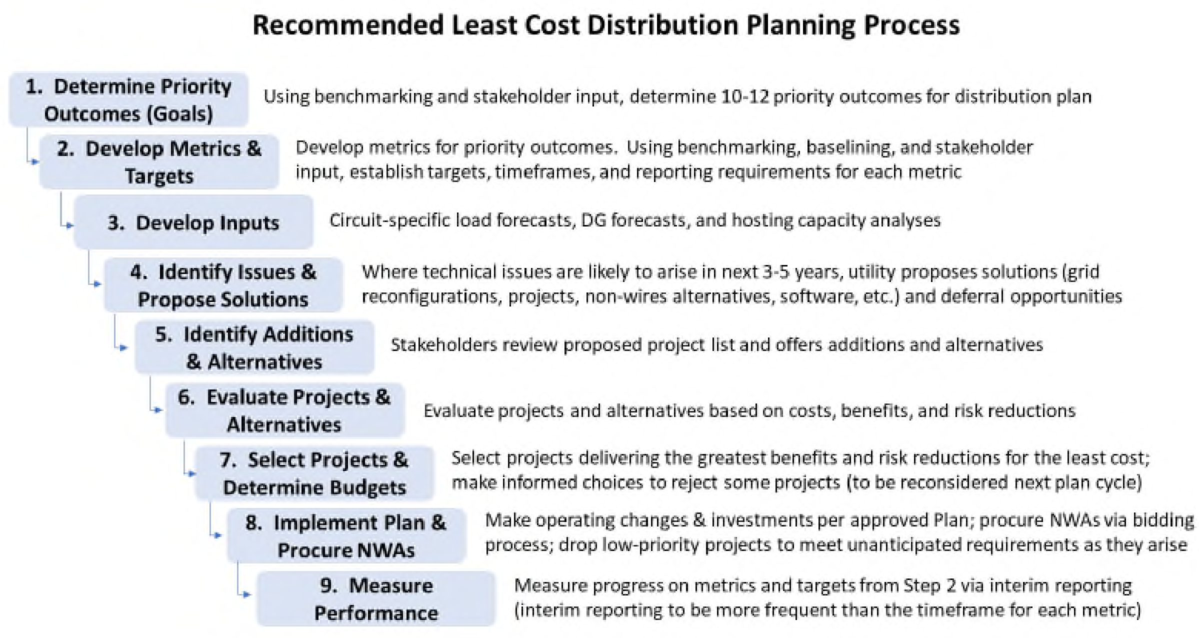
3. The regulator's grid modernization conundrum.

Given current ratemaking processes, large distribution investment requests present regulators with quite a conundrum. Approve the requests in the absence of need, and rates may increase unnecessarily. Reject the requests, and reliability may suffer (if the problems the IOUs claim will arise turn out to be true). Reject cost recovery post-investment, and rates will increase unnecessarily anyway (due to the large size of the disallowances and associated impacts on IOU cost of capital). On top of this conundrum, regulators face reliability risk aversion, information asymmetry, and a dearth of unbiased technical experience in grid planning and operations. In such a situation, no one could blame a regulator from defaulting to IOU recommendations. But as Figures 1, 2, and 3 above indicate, defaulting to IOU recommendations is not a valid response to the conundrum. A sound distribution planning process, reminiscent of integrated resource planning, is one (and possibly the only) solution to the conundrum. It should consist of defined goals for the grid, clear methods of performance evaluation, periodic data gathering and needs assessments, objective critique and innovation, rigorous proposal evaluation, informed investment selection, and ongoing performance measurement. Stakeholders can, and should, participate in every one of these steps.

B. What a transparent, stakeholder-engaged distribution planning process should include.

A rational and responsible process for developing a distribution plan and associated capital budget in a transparent, stakeholder-engaged manner includes nine discrete steps. We list them below and follow the list with more detailed descriptions of each. Most regulators will probably prefer to hire independent facilitators to co-ordinate the development of each distribution plan. It is also important for regulators to define "stakeholders," as we do throughout this document, to include IOUs. The figure below summarizes the distribution planning process ABATE recommends.

Figure 4: Summary of ABATE's Recommended Distribution Planning Process



1. Stakeholders identify and prioritize distribution plan goals (outcomes).

2. Stakeholders define performance metrics, targets, timeframes, and reporting requirements for priority outcomes.

3. Utilities collect and publish distribution planning inputs.

4. Utilities propose a list of recommended distribution projects.

5. Stakeholders identify potential alternative and/or additional projects.

6. All potential projects are evaluated using one of three methods based on the nature of each project (non-discretionary; discretionary with readily quantified benefits; and discretionary with difficult-to-quantify benefits).

7. Stakeholders select projects and determine capital budgets.

8. Utility implements selected projects and procures selected non-wires alternatives through competitive solicitation.

9. Performance is measured using metrics and targets established in Step 2.

1. Step 1: Stakeholders identify and prioritize distribution plan goals (outcomes).

The distribution planning process must begin with the identification and prioritization of performance improvement opportunities or, in other words, the goals for an IOU's distribution plan. Avoiding this step can introduce critical errors in the resulting plan. For instance in Ohio, which does not utilize a transparent, stakeholder-engaged approach to distribution planning, First Energy has proposed $450 million in rate base growth for distribution platform modernization, which it expects primarily to "result in enhanced reliability of the system and outage restoration."[3] Yet of the three First Energy subsidiaries serving Ohio, only one (Ohio Edison, serving greater Akron) exhibits below-average reliability performance (measured by System Average Duration Interruption Index, or SAIDI, without Major Event Days) over the past five years relative to other U.S. IOUs. First Energy's Cleveland Illuminating routinely delivers above-average SAIDI results (four out of the last five years), and First Energy's Toledo Edison has ranked in the top 10 percent of all US IOUs on SAIDI for the last 5 years straight.[4]

Benchmarking performance in distribution basics – reliability, affordability, operating efficiency, customer satisfaction, and the like – can therefore provide important guidance for distribution plan goals and goal prioritization. Stakeholders can help identify other goals, such as reducing the risk of distributed generation ("DG") interconnection delays, or reducing energy distribution inefficiency (for which all customers, and the environment, pay a price). Once

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[3] Ohio PUC Case No. Case No. 17-2436-EL-UNC. First Energy Application for Distribution Platform Modernization Plan Approval. December 1, 2017. Page 4.

[4] Reliability data is sourced from U.S. Energy Information Administration form 861, 2013-2017 inclusive, as compiled by the Utility Evaluator (www.utilityevaluator.com). Access is available by subscription.

identified, stakeholders can debate the relative merits and priorities of various goals, translating the roles of IOUs and stakeholders from opponents to co-contributors. In a sound distribution planning process, the role of the IOU changes from dominant (e.g. “Here’s what we propose”) to consultative (e.g. “If that’s what you want, there are three ways to go about it, each with its own pros and cons”) Without an understanding of the goals of the investments, resulting distribution plans will lack focus.

2. Step 2: Define performance metrics, targets, timeframes, and reporting requirements.

To add even more focus to IOU distribution plans, we recommend that stakeholders define performance metrics, targets, timeframes, and reporting requirements early in the distribution planning process. In this manner an IOU knows exactly how its distribution rate base growth will be judged, and can adjust its distribution project proposals accordingly. This early point in the distribution planning process is also ideal for measuring baseline performance and identifying historical trends, thereby establishing a basis for initial targets and timeframes. Benchmarking against the performance of other IOUs can also play a role in setting targets and timeframes. Finally, this is the time to determine performance reporting requirements. For a multi-year target, we suggest annual performance reporting; for an annual target, we suggest quarterly performance reporting. The idea is to hold the IOU accountable for performance improvements while minimizing opportunities for gaming through baselining and interim performance reporting. By knowing the starting point, and observing progress over time, stakeholders have greater opportunities to identify any changes IOUs might make in data gathering or data exclusion which would inaccurately indicate that a performance target has been met.

Performance metrics are a hot topic in regulation today, and ABATE experts have perspective to lend. First, performance metrics should be kept to a few, critical performance issues. Like people, utilities can only focus on a limited number of priorities at any one time; too many metrics dilutes focus. The Hawaii PUC, in its current proceeding on performance-based ratemaking, has identified only 12 regulatory outcomes for performance metrics.[5] On a related note, it is preferable to establish metrics for the distribution business, not for individual investments or initiatives (like "grid modernization"). Though we can foresee one or two exceptions, such as for conservation voltage reduction, establishing goals for each major project will quickly cause metric overload, which in turn will cause an IOU to lose sight of distribution plan priorities. Further, metrics should be objective, not subjective (measurable), and based on outcomes, not processes. The metric "dollars spent on pilot projects" means absolutely nothing to a customer.

The table below contains sample metrics, targets, timeframes, and reporting frequencies. These are just ideas, not recommendations, and should be determined by stakeholders in accordance with the goals for each individual IOU and distribution plan as established in Step 1.

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[5] Hawaii PUC Case No. 2018-0088, Decision and Order 36326 ("Phase 1 Order"), at 7. Regulatory outcomes include affordability; reliability; interconnection experience; customer engagement; cost control; DER asset utilization; grid investment efficiency; capital formation; customer equity; greenhouse gas reduction; electrification of transportation; and resilience. The metrics to be used to measure progress on these outcomes are currently being negotiated by stakeholders.

Table 1: Example performance metrics, targets, timeframes, and reporting requirements

Priority Area	Metric	Target	Timeframe	Reporting
Affordability	Rate base per Customer	CAGR 2.0% or less	Annually	Quarterly
Reliability	Grid-wide SAIDI w/o Major Event Days	90 minutes	Annually	Quarterly
Grid Energy Efficiency	Average annual voltage per circuit	115 volts	Annually	Quarterly
Cost Control	O&M spending per customer, per year	$295	By year-end 2022	Annual
DG Interconnection	Approval time for compliant applications within circuit hosting capacity	2 business days	By Jan 1, 2023	Annual

3. Step 3: Utilities collect and publish distribution plan inputs.

The next step would be for utilities to collect and publish distribution planning inputs. This is the step most familiar to utilities, as they have been developing capital budgets from circuit-specific load forecasts for over 100 years now. There are new wrinkles to circuit-specific load forecasting, such as incorporating the impact of strategic electrification, and the use of probabilistic (rather than deterministic) forecasting techniques. The publication of inputs is new too, and is critical for a transparent distribution planning process. Overall, however, the spirit of load forecasting remains unchanged: to estimate the loads a utilities' substations, circuits, and laterals will need to accommodate in the next five years, and using probability distributions, to identify likely overloads of equipment design capacities.

A new input to the distribution planning process is the DG forecast. DG forecasts, like load forecasts, are circuit-specific. They are designed to help a utility project where on their grids the capabilities to manage high levels of DG capacity will be needed first. Like probabilistic load forecasting, DG forecasts make use of (generation) profiles to improve forecast accuracy and detail. For example, photovoltaic solar panel generation on a cloudless day can be predicted by season of the year and by time of day based on the sun's position in the sky.

Finally, probabilistic load and DG forecasts by circuit are combined into hosting capacity analyses. Combined with other circuit-specific data, such as impedance, a utility's hosting capacity analysis identifies, by circuit, the additional amount of DG capacity which can be accommodated without significant circuit investment, as well as grid locations in which DG capacity and other distributed energy resources (such as targeted demand response or energy storage) could avoid or delay investments designed to increase substation, circuit, or lateral capacity due to load growth. The hosting capacity analysis also identifies circuits for which DG capacity increases will be limited absent grid investment.

Of course all forecasts and probabilistic models are only as good as the inputs, constraints, and assumptions incorporated therein. Distribution plans will clearly be impacted by these forecasts and models, making their accuracy and assumptions critical. All of these should be subject to stakeholder review and, if warranted, to re-working under revised inputs, constraints, and assumptions. Stakeholders must scrutinize IOU work carefully. While Michigan IOUs may be uncomfortable with DG capacity equal to five percent of a circuit's peak demand, grid operators in California routinely deal with DG capacity exceeding 25 percent of a circuit's peak demand, and grid operators in Hawaii routinely deal with DG capacity exceeding 50 percent of a circuit's peak demand. Bi-directional power flow is not the mortal enemy IOUs often portray it to be.

4. Step 4: Utilities propose a recommended list of distribution projects.

With known priority outcomes (goals and targets) and completed load forecasts, DG forecasts, and hosting capacity analyses, a utility is in position to identify and recommend distribution projects. As alluded to previously, utilities should compare load forecasts, DG forecasts, and hosting capacity analysis results to distribution equipment capacities to identify issues likely to arise on the grid in the next 3-5 years. Before proposing capital projects to resolve these issues, utilities should evaluate low-cost options such as grid reconfigurations. For most utilities, area engineers (those responsible for substations, circuits, and laterals in a defined geography) are the source for capital project recommendations. Software and control systems can also be included in capital projects, but should be driven by needs expressed by grid operators, not by executives interested in growing the rate base. As part of this step the IOUs should also identify opportunities to avoid or defer recommended capital projects through demand response and non-wires alternatives.

5. Step 5: Stakeholders recommend additional projects and alternatives to projects.

Stakeholders should have an opportunity to review the utility's inputs as described above and be offered an opportunity to recommend their own operating changes and capital projects, along with estimated costs. Stakeholders should have the opportunity to question IOU "needs" and estimated project costs, to request supporting data and justifications, and to examine the likelihood of problems occurring to the extent the IOU projects. Stakeholders should be encouraged to propose other projects, or project alternatives, they believe might be better suited to accomplishing plan outcomes at a lower cost.

6. Step 6: Evaluate projects/alternatives using methods appropriate to each project's type.

All capital projects can be identified as one of three types: (1) non-discretionary; (2) discretionary, with readily-quantifiable benefits; or (3) discretionary, with difficult-to-quantify benefits. The type of evaluation to employ should be based on the type of capital project being evaluated, with stakeholders determining the most appropriate type for each project. We provide examples of common grid projects for each type in the table below, though some would argue that service interruption risk and outage duration reduction projects belong in the readily-quantifiable benefit category.

Table 2: Examples of Grid Investments by Evaluation Category

Non-discretionary Projects	**Discretionary Projects with Readily Quantifiable Benefits**	**Discretionary Projects with Difficult to Quantify Benefits**
• Load growth accommodation • DG accommodation • NERC/CIP compliance • Public works • (particular) Customer request (customer-paid) • Equipment failures • Compliance with law	• Smart meters • Automated conservation voltage reduction • Replace labor or service with capital • Enabling technology platforms	• Safety risk reductions • Cybersecurity risk reductions • Service interruption risk reductions • Outage duration reductions • DG interconnection delay risk reductions • Enabling technology platforms

a. Non-discretionary project evaluation.

Projects classified as non-discretionary, meaning that some action must be taken to meet a customer or regulatory requirement, or to address an equipment failure, should be evaluated on the basis of cost. Unless there is a compelling argument otherwise, when several optional solutions are available to satisfy a requirement, the solution associated with the lowest cost to customers should be chosen and added to the capital budget. Stakeholders must be diligent here. For example, there might be multiple ways to satisfy in technical terms a North American Electric Reliability Corporation ("NERC") or Critical Infrastructure Protection "CIP") requirement, but IOUs are likely to propose the most capital- intensive solution.

Our description may sound to many like an endorsement of the "least cost, best fit" approach a few state regulators have allowed. Our concern is that least cost, best fit is being applied in the absence of a transparent, stakeholder-engaged distribution planning process. Without a sound planning process, IOU proposals are simply deemed to be required, with no oversight as to what projects are truly necessary to maintain safe and reliable service in the face of challenges, be they DG adoption, strategic electrification, or others. *In our informed opinion this Achilles heel has been exploited routinely by many IOUs in their grid modernization plans.*

When estimating costs, care must be taken to estimate equivalent (all else being equal) costs of projects to the customer, not costs to the IOU. This means that carrying charges customers will be asked to pay over the life of an asset should be added to the cost of all IOU investments to be evaluated. It also means that the remaining book value of any functional equipment removed prematurely must be considered as a cost to customers. Customers will continue to pay for the original equipment without specific accounting remedies to the contrary, in addition to paying for the new equipment through rate increases.[6] Care must be taken to ensure that the ongoing (over the life of the asset), incremental operations and maintenance costs associated with any capital project is not underestimated. Stakeholders must also rigorously evaluate the reasonableness of IOU capital cost estimates, as customers, not IOUs, will pay for cost-overruns absent Commission-approved protections and/or remedies. Capital bias discourages IOUs from concerning themselves too much with any variability in actual capital costs from estimates. Absent malfeasance, which is notoriously difficult to prove, shareholders benefit from project cost over-runs, as they are simply added to the rate base.

b. Evaluation of non-discretionary projects with readily-quantifiable benefits.

Discretionary projects with readily-quantifiable benefits must be evaluated using a standard benefit-cost analysis. The cost estimates used in a benefit-cost analysis should comply with all the guidelines described immediately above, and we recommend specific guidelines for benefit estimates as well.

As with project customer cost estimates, care should be taken when estimating the customer benefits from a project. Stakeholders should be wary of the size of benefit estimates, as IOUs are motivated by capital bias to over-estimate the benefits they can be reasonably certain of securing. Customers should be wary of the timing of benefit recognition, as many types of benefits, from reductions in operations and maintenance ("O&M") costs to improvements in revenue recognition, only result in rate reductions after they are reflected in a rate case test year's

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[6] It is also worthwhile to note that failure to implement accounting remedies to prevent this situation constitutes a violation of the well-established 'used and useful' regulatory principle.

accounting records. This could be several years, if not many years, after an IOU first secures such benefits, which accrue to shareholders in the interim. As an aside, we believe this timing/shareholder benefit issue to be one of the shortcomings of multi-year rate plans. Without due care, customers pay the rate increases on the assets from which shareholders derive benefits (until some future rate case).

Many benefits extend out many years, corresponding to the long lives of the assets that deliver them. But benefit periods should not be longer than asset lives, a tactic many IOUs have used to over-estimate the benefits of a project. Benefits should be discounted into present day terms, as a benefit delivered in project year 20 is worth much less to a customer than a benefit delivered in project year 3. Consideration should also be given to the use of customers' weighted average capital costs, rather than an IOU's capital costs, as a discount rate for calculating present value. Using a customer discount rate better reflects the opportunity costs of rate increases to residential customers who make payments on mortgages, auto loans, and credit cards, not corporate bonds.

Stakeholders should also take care to ensure that all potential benefits from a distribution project are identified and maximized in the planning stages. By inflating project benefits or deflating project costs, IOUs are able to present a favorable project benefit-cost ratio for their preferred projects while still ignoring large sources of potential benefit an IOU would rather not present. Most often, these are benefits which reduce sales volumes, such as automated conservation voltage reduction, or the energy efficiency and demand response potential associated with various smart meter capabilities.

With all benefits and costs estimated, the final step is to compare benefits to costs in the following manner (figures exemplary):

Present value of customer benefits from project:	$10
LESS: Present value of the project's revenue requirement:	8
EQUALS: Net Present Value of the project to customers	$2

Clearly, projects with a negative net present value should be eliminated from further consideration. However, the corollary is not true; projects with a positive net present value should not automatically be selected for implementation. We will discuss why in the "select projects and determine capital budgets" step later.

c. Evaluating discretionary projects with difficult-to-quantify benefits.

Discretionary projects with difficult-to-quantify benefits present the greatest evaluation challenges to stakeholders, and will require extensive discussion here. The value of risk reductions, such as in safety or cybersecurity, are particularly difficult to estimate and compare. We recommend that risk-informed decision support ("RIDS") be employed to help with this difficult aspect of distribution planning.

An example from a competitive industry may help illustrate the use of RIDS. Large, for-profit businesses employ RIDS to make difficult choices among competing projects when capital is constrained and benefits uncertain. Consider the investment choices facing the Chief Operating Officer of a hypothetical, international auto manufacturer. She must decide among three projects: replacing the roof on plant A, changing out the aging robots on one of the production processes in plant B, or replacing the vehicle painting booths in plant C. If all three projects cost about the same, and she only has enough capital for one project, she must weigh the likelihood and consequences of production delays associated with a leaky roof against those associated with robot breakdown against those associated with paint jobs which must be re-done. RIDS can help her identify, and justify, the best possible choice of the three.

RIDS was first developed by NASA as a way to reduce run-away space program costs. NASA recognized it was economically infeasible to reduce all risks to zero, and that some method to prioritize and select risks for mitigation, with an eye on the cost of various mitigation options, was needed. Since then several government agencies have adapted the concept for their own uses:

- Army Corp of Engineers (to assess dams and levees, which the FERC has added as a guideline for hydroelectric dam safety assessments);[7]
- Department of Defense (to improve its product acquisition process);[8]
- Nuclear Regulatory Commission (to improve plant designs and operations).[9]

Many corporations have adopted risk-informed decision support for prioritizing capital investments, as described in the hypothetical auto manufacturing example presented above. The overview of a corporate RIDS process involving stakeholder engagement is documented in International Electrotechnical Committee ("IEC") standard 31010, and incorporated into International Standards Organization ("ISO") standard 55002 (regarding the implementation of Asset Management standard 55001). RIDS is not a new or untested practice.

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[7] Federal Energy Regulatory Commission. 2014-2018 Strategic Plan. March, 2014. Page 19.

[8] United States Department of Defense. Risk Management Guide for DOD Acquisition, 6th Edition, version 1.0. August, 2006.

[9] United States Nuclear Regulatory Commission. "Use of Probabilistic Risk Assessment Methods in Nuclear Activities; Final Policy Statement," *Federal Register, Vol. 60*, p. 42622 (60 FR 42622), August 16, 1995.

We believe RIDS is employed by many IOUs in the US, though they might perfer to hide that fact. ABATE expert Dennis Stephens employed RIDS at Xcel Energy in his role as Director of Asset Management. We have also seen evidence of RIDS use by Puget Sound Energy[10] in Washington and by Liberty Utilities[11] in New Hampshire. But perhaps the best documented use of RIDS is in California, where the PUC has required its IOUs to use RIDS to develop safety-related investment plans. Of these IOU plans, Southern California Edison's plan comes closest to the RIDS process we describe here.[12]

One might imagine that IOUs would disdain RIDS as a way to restrict rate base growth, but we can think of two common use cases in which an IOU would benefit from the use of RIDS. One is the instance of combination gas and electric utilities. Until recently, electric use per customer was always increasing, while gas use per customer was always decreasing. In such a situation an IOU would much rather invest in electric distribution than gas distribution owing to earnings growth (through sales volume growth) between rate cases. We believe RIDS has been used by combination IOUs to reduce gas distribution investment, in favor of electric distribution investment, with as little an increase in gas distribution safety risk as possible. Another use case is the instance of multi-state utilities, in which an IOU is authorized to earn a higher rate of return in one state than in another. One can imagine RIDS being used to reduce investment in the distribution grid of states with lower rates of return with as little an increase in reliability and

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[10] Washington UTC UE-190529/UG-190530. Exh. CAK 1-t, Prefiled Direct Testimony of Catherine A. Koch (June 20, 2019) at 44.

[11] New Hampshire PUC Docket No. DE 19-064, Liberty Utilities response to OCA DR 4-6 (August 7, 2019).

[12] California PUC I.18-11-006. *Southern California Edison Company's (U 338-E) 2018 Risk Assessment and Mitigation Phase Report* (November 15, 2018).

safety risks as possible. As almost half of U.S. IOUs are either combination utilities or multi-state utilities or both, we believe the use of RIDS to be more widespread than IOUs care to admit.

Though less capital-constrained than for-profit businesses, IOUs are faced with similar project and risk reduction choices. In a particular distribution planning cycle an IOU could recommend investments in an almost infinite number of risk-reduction efforts. As examples, an IOU could spend capital to reduce stray voltage risk, wire down risk, cybersecurity risk, service interruption risk, or distributed generation interconnection delay risk. (Some projects are likely able to reduce more than one type of risk.) Unconstrained, an IOU with capital bias would like to spend a lot of capital reducing all of these risks. But customers ask: "How can the IOU maximize risk reduction value across all risk types for the least amount of capital?" RIDS can help answer this difficult question by comparing equalized risk reduction levels relative to costs for various projects or alternatives, and selecting projects or alternatives on the basis of risk reduction per dollar.

The recommended RIDS process is somewhat similar to the overall distribution planning process. It consists of 6 steps, which we will describe in more detail:

1. Identify priority threats;
2. Characterize sources of risk/identify threat drivers;
3. Identify potential risk control measures (e.g. business process changes, service procurements, or capital expenditures);
4. Estimate cost of risk control measures (using guidelines listed above);
5. Estimate potential measures' risk reduction value (likelihood % x consequence $ x reduction in likelihood); and
6. Develop list of control measures prioritized by risk reduction value.

Once a list of control measures prioritized by risk reduction value is developed, stakeholders help determine which control measures are selected, and associated costs are added to departmental and capital budgets as appropriate. This part is described later in the "select projects and determine capital budgets" Step 7 of the recommended distribution planning process.

Though the IOUs will play a leading role, a stakeholder process is used to identify top-priority threats as the first step in RIDS. Top-priority threats could include contact with energized equipment; cybersecurity attacks resulting in service interruptions, customer data theft, or website disruption; DG interconnection delays; or others. Stakeholders should agree upon the top-priority threats IOUs should manage.

Next, the sources of risk and threat drivers must be identified. Consider the "contact with energized equipment" threat, for example. A utility might identify the following drivers as leading to contact with energized equipment: 1) A fault occurs; 2) the breaker fails to open; 3) the faulted line snaps (falling to the ground); and 4) a bystander touches the downed line, or the downed line starts a fire. Similar drivers should be identified for all top-priority threats identified in RIDS Step 1.

With threats and drivers identified, the utilities would propose potential risk control measures in RIDS Step 3. Continuing with the wire down example, a utility might propose to increase circuit breaker testing frequency, or to replace circuit breakers of a certain type or vintage. Utility experience with the drivers, backed by data to the greatest extent possible (root cause analysis) is the key to identifying risk control measures which are most likely to have a significant impact on the drivers and threats. Stakeholders must be vigilant here, as an IOU's capital bias encourages them to implement solutions which have not necessarily been proven to reduce the risks associated with a driver or threat.

In RIDS Step 4, the costs of mitigation options are estimated. The guidelines for cost estimates described in the non-discretionary project evaluation earlier should be followed here.

In RIDS Step 5, the likelihood of an adverse event occurring is estimated. Likelihoods are simply the products of the likelihoods of individual threat drivers leading to an adverse event. Continuing with our wire down example, the "contact with energized equipment" risk could be estimated as follows:

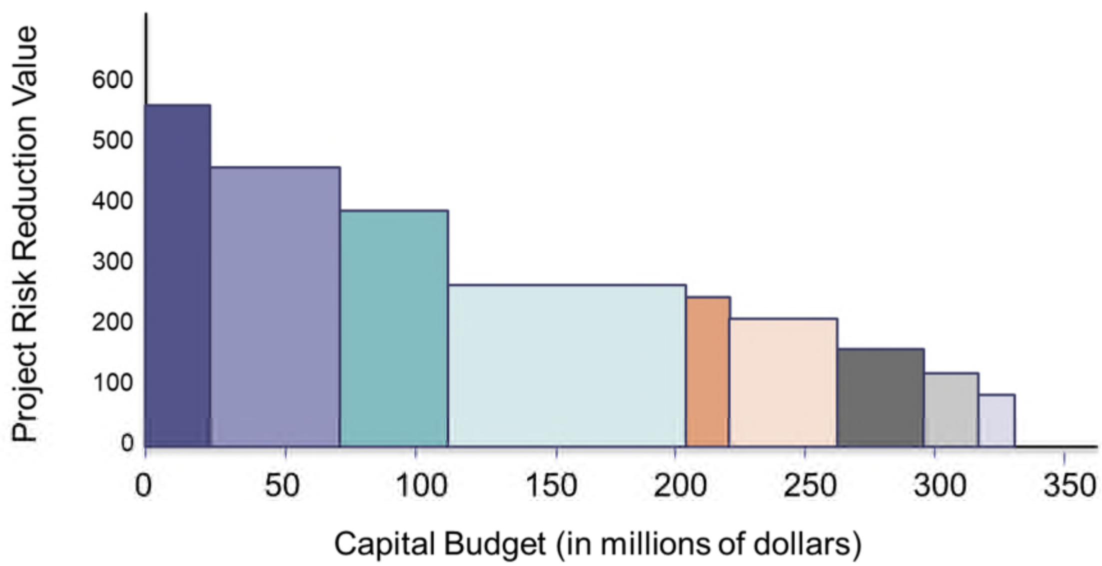
Table 3: Estimating the likelihood of an adverse event (example)

Item #	Event	Probability of occurrence per year
1	Fault	75%
2	Breaker stays open despite fault	1%
3	Line snaps and falls to ground	10%
4	Bystander injury or property damage	10%
	Combined probability (1 x 2 x 3 x 4)	.000075 (75 out of a million each year)

Likelihood could then be multiplied by the financial consequences to estimate the value of the risk reduction. For example, using an estimated valuation of $1 million per injury or property loss event, the value of eliminating this risk entirely would be $75 per circuit, per year. Let's assume further that a utility's proposed risk control measure is anticipated to reduce the likelihood that the breaker stays open by 50 percent, but leaves the other driver likelihoods unchanged. With a 50 percent reduction in likelihood associated with the driver, the value of the risk control measure would be $37.50 per circuit, per year ($75 x 50% reduction in likelihood). Establishing an economic value not only helps with the evaluation of an individual project, it facilitates comparisons between projects which reduce different (or multiple) types of risk. Cybersecurity risk is very different from safety risk, yet some way to compare the value of reducing each is important for prioritization when faced with multiple project proposals. Economic valuation of safety risk reductions may be distasteful for some, but without some common denominator, project prioritization is wholly subjective. Subjectivity is exactly the kind of circumstance RIDS is designed to avoid.

The RIDS process concludes in Step 6 with the ranking of potential risk mitigations by risk reduction value while simultaneously noting each mitigation's cost. The figure below is a simplified example. The ranked project list is intended to provoke debate and thoughtful consideration of project selection by stakeholders, and will be discussed in the next distribution planning process step's description.

Figure 5: Example of a list of discretionary distribution projects prioritized by risk reduction value



With evaluations of all potential projects in all three project classifications – non-discretionary, discretionary with readily-quantified benefits, and discretionary with difficult-to-quantify benefits – complete, Step 6 is almost finished. The deliverable from Step 6 is a portfolio of projects from which stakeholders can choose. At this point, stakeholders should take a step back and examine the entire portfolio for reasonableness. If stakeholders disagree about the portfolio's contents, it may indicate that assumptions, priorities, or other inputs to the process require adjustment. Several plan development process iterations may be required to end up with a portfolio suitable for Step 7 (project selection). We will describe this step in the distribution planning process next.

7. Step 7: Stakeholders select projects and determine capital budgets.

With all project proposals evaluated, stakeholders must go about the task of selecting some, rejecting others, and establishing capital budgets as a result. Non-discretionary project selection is the easiest: select the least cost option available to satisfy a requirement, be that option an operating or business process change, an IOU capital investment, or a non-wires alternative (generally, a contract with the provider of a service). Operating expenses associated with chosen solutions are simply added to appropriate departmental budgets, while capital associated with chosen solutions represents the starting point for IOU capital budgets. Risk can also be considered in the selection of the least cost option. For example, the fact that demand response is not quite as reliable as the capacity increase associated with reconductoring can be taken into account in the selection process. However, a low-cost solution to this issue is also available (contracting for somewhat more demand response than may be needed to avoid reconductoring, knowing that some amount of demand response may not be available when called upon).

For discretionary projects with readily-quantifiable benefits, which are evaluated using benefit-cost analyses, project selection is not so black and white. As we noted previously, not every project with a favorable benefit-cost analysis (customer benefits exceed customer costs) should be selected and added to the capital budget. Three factors should be considered as stakeholders attempt to minimize capital investments/optimize capital budgets, and these can result in the rejection of projects despite a favorable benefit-cost analysis. One of these factors is the benefit-cost ratio; that is, the size of the benefit relative to customer costs. A project with a 3:1 ratio of customer benefits to customer costs should be selected over a project with a 2:1 ratio, all else being equal.

The second of these factors is the size of the investment required to deliver the benefit. A project with a benefit-cost ratio of 1.2:1, but which will cost customers only $1 million in rate increases, might take priority over a project with a benefit-cost ratio of 1.25:1, but for which customers will pay $350 million.

The third of these factors is the variability associated with delivering the benefits estimated for the customer costs estimated. Projects with low benefit-to-cost ratios are particularly vulnerable to the variability factor. A project with a benefit-to-cost ratio of only 1.25:1 can become negative if benefits are as little as 20 percent less than estimated, or if costs are as little as 25 percent higher than estimated. Projects with low benefit-to-cost ratios which are also characterized by significant benefit or cost variability should probably be excluded from distribution plans and capital budgets. At a minimum, such projects are examples of instances in which investment-specific performance metrics are called for, particularly if the investment is of large size (like automated conservation voltage reduction added to a third of an IOU's circuits).

Once stakeholders have selected projects for implementation, operating expenses and capital associated with selected projects are simply added to the appropriate departmental expense and capital budgets. Some will argue that the highly financial nature of the recommended approach to distribution planning lacks qualitative input, to address grid locations suffering from underinvestment (perhaps due to socioeconomic factors), or to account for extreme circumstances (such as incidents of extreme cold or heat). We respect these concerns, but suggest they be objectively addressed through the use of numbers and data. For example, if an area on the grid is perceived to suffer from historical underinvestment, there should be evidence of that in reliability data. If there is no evidence of a reliability issue, than either the underinvestment perception is misplaced, or the underinvestment is real but of no consequence. We have seen this in IOU requests to replace 4kV substations and circuits. As older parts of an IOUs grid, 4kV substations and circuits often serve older, less affluent parts of metropolitan areas. Yet in discovery, when asked for reliability data, we've observed 4kV circuits to be no less reliable than other circuits.[13] While the selection of least cost projects requires almost no judgement, and the selection of projects evaluated via benefit-cost analysis requires some judgement, the selection of projects evaluated via RIDS requires a significant amount of judgement. This is not to say that RIDS is a subjective evaluation method, as it is designed to be as objective as possible given benefit uncertainties. However, the manner in which RIDS results are used in project selection can be somewhat subjective.

The RIDS method was designed to enable capital budget flexibility. RIDS recognizes that for every reduction in capital budget, some amount of risk reduction will be lost. This is where the collective judgement of stakeholders comes into play. The question for stakeholders to

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[13] Regarding extremes in temperatures, these concerns can be addressed through probabilistic modeling in load forecasts. Our perspective on distribution planning can be summed up in the colloquialism "In God we trust; all others must bring data."

answer is, how much risk is appropriate to accept? As the Commission reviews Figure 2, the relationship between customer costs and risk reductions becomes clear: the greater the risk retained, the lower the customer costs. RIDS is all about quantifying the trade-offs for stakeholders and regulators, enabling better collective choices and regulatory decisions through improved information and transparency.

An analogy may help drive this point home. We all know that SAIFI and SAIDI (the standard reliability metrics) can be driven to almost zero with enough money. But the law of diminishing returns applies; each capital dollar spent improves reliability less than the last capital dollar spent. While power could be almost perfectly available with enough money, few would be able to afford it. To date, we have collectively made an unconscious choice about the service interruption risk to accept. RIDS helps transition unconscious decisions we've collectively stumbled upon into subjects of informed debate and conscious choices. *Decisions reached through the collective wisdom of multiple stakeholders based on objective and available data will undoubtedly be better than decisions made by a single stakeholder which is biased by an interest in capital investment and which holds all data close to the vest.*

Whereas an IOU is motivated by capital bias to spend as much capital as possible to reduce risk, stakeholders can (and should) evaluate risk reduction spending on a continuum. RIDS allows stakeholders to engage in open and informed debate about the levels (and types) of risk reductions for which customers should be asked to pay. By establishing the budget for discretionary projects with difficult-to-quantify benefits, stakeholders are also selecting projects and the amount of risk to retain rather than reduce. With RIDS, risk reduction efforts are transformed from a black hole for IOU capital to reasoned capital project selection. Furthermore, some stakeholders may prefer projects from the "readily quantifiable benefits" bucket over projects in the "difficult-to-quantify benefits" bucket, or vice-versa. So to some extent, all discretionary projects should be viewed as a portfolio of options from which stakeholders should select the most deserving for implementation. Stakeholder debate and negotiation should be used to resolve differences of opinion with the benefit of information made available in the evaluation step we described earlier.

8. Step 8: Utility implements selected projects and procures selected non-wires alternatives.

With the distribution plan finished, and assuming the Commission approves the resulting plan, the IOU simply implements the plan, and seeks cost recovery through rate cases. Some distribution plans will incorporate the selection of non-wires alternatives, such as localized demand response or electric storage. To implement these parts of the plan, an IOU would need to procure services from third parties through a competitive solicitation process. In the event no third party responds with fees within the budgeted amounts, an IOU would implement a more traditional solution to meet the identified need.

At this point in their review of these comments, IOU engineers are likely concerned about their need for flexibility. Equipment fails; ice storms happen; people buy electric cars; and property developers propose new loads. There are ways to address IOU needs for flexibility. One option is to exempt capital projects below a specified dollar amount from the distribution planning process. This amount would likely be different for different IOUs, with larger IOUs granted a higher project exemption level than smaller ones. Stakeholders must be careful with such exemptions, as an IOU might try to conceal unsupported changes in equipment standards, or the establishment of unwarranted precedents, which could become large over time, by defining small pieces of larger wholes so as to fit under the specified dollar amount. Another option is to establish a non-specific capital budget for equipment as it fails, or for storm repairs.

Another idea is to allow IOUs to abandon lower-priority discretionary projects in favor of other projects as more urgent, non-discretionary projects emerge between planning cycles. Proposals for real estate developments, public works, or high-voltage electric vehicle charging stations requiring grid upgrades may be tendered after a distribution plan is approved. In such cases, we propose IOUs be granted the authority to replace the capital budget intended for lower-priority discretionary projects with an equivalent amount of capital spending on emergent, non-discretionary projects. The lower-priority projects so abandoned can simply be re-considered in the next distribution planning cycle, along with all the other potential projects which were not selected for the approved distribution plan. This is called a "portfolio approach" in the product development discipline and is highly relevant for distribution planning.

9. Step 9: Measure performance using metrics and targets established in Step 2.

As the final step in distribution planning, IOUs should be required to deliver performance reports on the metrics specified in Step 2 at the frequencies specified for each metric. A critical part of performance measurement is to evaluate whether the projects implemented per the approved distribution plan are delivering the financial and risk reduction benefits estimated for the customer costs estimated. This feedback can be used in future planning cycles to develop ever more effective distribution plans.

C. General observations on transparent, stakeholder-engaged distribution planning processes.

We note that regulators in some states require distribution plan updates between planning cycles. We do not believe reports which simply confirm that an IOU is implementing the approved distribution plan would be very valuable. However, annual exception reports describing any deviations from the approved distribution plan would be very valuable. These exception reports could describe capital projects planned or implemented which were not part of the approved distribution plan because their cost was below the specified investment level described immediately above. Annual exception reports would also be the ideal opportunity to explain any lower-priority project substitutions made or planned as a result of emerging non-discretionary projects as described immediately above.

Furthermore, rate cases represent an ideal opportunity to reconcile the capital an IOU actually spent to the capital budgets approved as part of a distribution plan. The Commission should establish such a reconciliation as a required and routine expectation of the rate case process going forward. Such a reconciliation will hold IOUs accountable for project cost overruns. Capital an IOU spends to replace equipment which fails would be exempt from scrutiny, as would any replacements of low-priority projects with emergent, non-discretionary projects (subject to prudence reviews, of course).

Regarding the timing of planning cycles, the distribution planning process we've described will be resource-intensive for all parties. While we believe the customer benefits to be well worth these efforts, we wish to avoid any planning efforts which do not deliver incremental value relative to incremental effort. These arguments for less frequent planning cycles are countered by arguments for more frequent planning cycles. Given the rapid changes the distribution business is likely to face in coming years, we are concerned that distribution planning cycles which are too infrequent are likely to miss capital conservation and technology-leveraging opportunities. Given the links between distribution planning and capital budgeting we propose, we are also concerned that infrequent distribution planning cycles could become unwieldy. A three-year planning cycle seems appropriate, and strikes the right balance between resource requirements, value, opportunity cost, and capital budget complexity concerns.

On a related note, given that there are three large IOUs in Michigan, we ask the Commission to consider staggering distribution planning cycles such that no more than one IOU distribution plan be developed in any calendar year. Finally, while on the subject of resources, it is clear from both emerging issues in distribution planning and our recommendations in this docket that stakeholders must become better educated on technical issues and concepts in electric distribution. Stakeholders may not have the resources or bandwidth to secure the technical resources required to adequately challenge IOU technical representations, justifications, estimates, assumptions, and other aspects of electricity distribution likely to arise as stakeholder engagement in distribution planning grows. Some Commissions have employed an Independent Professional Engineer to serve as an unbiased evaluator of technical issues as they arise in distribution planning, and we believe such a role is important for Michigan stakeholders to have available. It is critical that such a role be filled by someone with electric distribution grid planning and operations experience.

D. The advantages of a transparent, stakeholder-engaged distribution planning process.

In these comments we have described rational approaches to distribution planning which we believe will deliver the distribution grid Michigan will need in the future at just and reasonable rates. The process we've described offers something of value to all parties, including IOUs.

Customers in general, and the Michigan economy more broadly, are clearly the focus of our recommendations. If the Commission chooses to follow these recommendations, customers will benefit in three ways. First, rate increases will be held to a minimum. Second, customers will secure greater benefits per dollar of rate increase. Third, the Michigan distribution grid will be able to accommodate the level of DG capacity customers care to install, as well as the level of electrification they care to pursue, at a reasonable cost to all.

We believe regulators will also see benefits from a transparent, stakeholder-engaged distribution planning process. Perhaps most importantly, the recommendations will improve the Michigan economy by avoiding low-value rate increases employers would otherwise pay, an outcome of great interest to regulators and the Legislature. Although more difficult to quantify, the recommendations will also enable regulators to make more informed decisions by providing them with more objective and understandable information about the impacts and trade-offs of various grid investments. We believe ABATE's recommended planning process will also reduce regulator reliance on IOUs' technical representations and justifications, thereby increasing the confidence with which regulators will consider and challenge IOU requests. Last but perhaps most importantly, the process we recommend will allow regulators to advance state and Commission policy objectives at the least possible cost to the Michigan economy.

Though IOUs will likely see these recommendations as challenging to shareholders' and managers' interests, there are some legitimate silver linings in our recommendations for IOUs to consider. Probably the greatest of these is a reduction in the risk of cost disallowance. Rate base increases backed by a distribution plan developed through a transparent, stakeholder-engaged process will be difficult for a Commission to reject. Another benefit will be a change in IOUs' role. Today, IOUs make proposals which stakeholders critique. Each stakeholder pursues its own interests, putting IOUs in the difficult position of opposing all stakeholders. Using the process we recommend, IOUs transition from the role of an opponent to the role of a consultant. Utilities will have an opportunity to become trusted partners and collaborators in a paradigm that respects their expertise and responsibility to assure safety and reliability, while seeking a reasonable return on investment for shareholders. Finally, when IOUs are in sole control of distribution investment decisions in conditions of uncertainty, they run the very real risk, if not certainty, of making investments which will be proven errant with the benefit of hindsight. With the benefit of stakeholder input, IOUs are less likely to make poor decisions. Furthermore, even poor decisions can be cast as stakeholder-wide choices, not IOU choices, when such choices are made with the support of engaged stakeholders. This significantly reduces the pressure on IOUs to accurately predict future states.

Finally, ABATE's recommended process provides non-utility stakeholders with some of the same benefits our recommendations offer to regulators. For instance, the recommendations offer more transparency to stakeholders, and more objective and understandable information about the impacts and trade-offs of various grid investments. Over time, we believe a stakeholder-engaged distribution planning process will produce stakeholders who are more educated and informed regarding technical distribution issues and distribution technologies, leading to more valuable regulatory processes. This has happened in integrated resource planning over the last few decades, and we anticipate similar benefits ahead for stakeholders regarding distribution planning.

III. CONCLUSION

While the Commission may not have expected ABATE to present detailed recommendations for a transparent, stakeholder-engaged distribution planning process in these comments, we respectfully request the Commission strongly and thoroughly consider them. Of the customer advocates in Michigan, none has brought to this proceeding the national expertise and perspective ABATE has brought. While Staff is to be commended for going out of its way to bring national experts into this conversation, we note that some of the most prominent, like EPRI and ICF, are guided by, if not exclusively driven by, utility interests. Furthermore, of the distribution planning efforts currently being conducted or implemented by state regulators, none has yet considered the value of applying a transparent, stakeholder-engaged process, reminiscent of integrated resource planning, to the distribution business in the end-to-end manner ABATE recommends here.

We suggest the Commission consider these comments in the manner in which they are intended: as a well-considered, innovative call to action with a sense of urgency. Michigan IOUs are poised to invest billions of dollars in their distribution grids in coming years. Michigan electric customers and citizens expect, and deserve, the greatest possible service and policy benefits for the smallest possible distribution rate increases. The ABATE distribution planning process is designed specifically to deliver this outcome.

Respectfully submitted,

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