STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **Consumers Energy Company** for reconciliation of its 2018 demand response program costs.	))))	Case No. U-20563

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on August 11, 2020.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before September 1, 2020, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before September 15, 2020.

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Kandra K. Robbins
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Date: 2020.08.11 09:16:39 -04'00'

August 11, 2020
Lansing, Michigan

Kandra K. Robbins
Administrative Law Judge

STATE OF MICHIGAN

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter of the application of **Consumers Energy Company** for reconciliation of its 2018 demand response program costs.	))))	Case No. U-20563

PROPOSAL FOR DECISION

I.

PROCEDURAL HISTORY

On May 31, 2019, Consumers Energy Company (CECo or Company) filed its Application for reconciliation of its Demand Response program capital expenditures incurred in 2018. In its filing, the Company requested the Michigan Public Service Commission: (i) approve the recovery of all incremental Demand Response ("DR") Program capital expenditures incurred by the Company in 2018 beyond the amounts previously approved by the Commission in Case No. U-18322; (ii) approve deferred regulatory accounting treatment of the actual revenue requirement for DR Program capital expenditures and Operating and Maintenance ("O&M") expenses incurred in 2018 compared to the authorized revenue requirement resulting in the creation of a regulatory liability of $1,635,407 which will be reflected in a future electric general rate case; (iii) approve the Company's requested financial compensation mechanism for DR and financial incentive of $2,026,943; and (iv) approve recovery of the financial incentive through a surcharge to be implemented beginning with the January 2020 billing cycle for a period of 12 months. The Company's filing was accompanied by the testimony of witnesses Patrick E. Ennis, Laura M. Collins, Rachel L. Dziewiatkowski, David B. Hays. Derek D. Kirchner, Svitlana Lykhytska, Emily A. McGraw, and Richard A. Morgan.

At the July 23, 2019 prehearing conference, the Company and Staff appeared, and intervention was granted to the Residential Customer Group (RCG), and the Association of Businesses advocating Tariff Equity (ABATE).

In accordance with the schedule established at the prehearing conference held on August 13, 2019, Staff filed the testimony of Sarah Mullkoff, Michelle Edelyn and Katie Smith; ABATE filed testimony of Amanda M. Alderson; RCG did not file any testimony. On May 6, 2020, CECo filed rebuttal testimony of Steven Q. McLean and ABATE filed rebuttal testimony of Amanda M. Alderson.

II.

OVERVIEW OF THE RECORD AND POSITIONS OF THE PARTIES

The evidentiary record is contained in two volumes of transcripts, and 23 exhibits. On overview of the testimony presented by each party is reviewed in the following sections.

A. CECo Testimony

CECo presented four witnesses. The first, Mr. Patrick C. Ennis, is Executive Director of Industrial Products for CECo. Mr. Ennis presented testimony to (i) provide a description of the Company's filing in this case and its overall DR portfolio; (ii) submit the reconciliation of anticipated capital expenditures and O&M expenses approved in the general electric rate case proceeding, Case No. U-18322, to actual capital expenditures and O&M expenses for the 2018 DR Program year; (iii) request approval of the 2018 performance incentive; and (iv) request approval of DR pilots planned through 2020.[1]

He testified that this 2018 DR reconciliation is being filed with the Commission to: (i) reconcile projected capital expenditures and O&M expenses from Case No. U-18322 to actual costs for the 2018 DR program year; (ii) request approval from the Commission for regulatory accounting treatment of the actual revenue requirement for DR capital and O&M spend compared to the authorized revenue requirement, resulting in the creation of a regulatory liability of $1,635,407, and to defer refund of this liability to a future electric rate case; (iii) request approval of the DR Financial Incentive of $2,026,943 to be collected through a 12-month surcharge to be implemented beginning with the January 2020 billing cycle; and (iv) approve the DR pilots planned through 2020 to meet the aggressive DR glide path as presented in the Company's IRP in Case No. U-20165, with the projected costs of the pilots to be included the Company's next general electric rate case.[2]

Mr. Ennis testified that the Company offers a DR portfolio comprising both business and residential programs. This portfolio acts as a virtual power plant that can be used during times of peak electricity demand to mitigate system constraints, ensure adequate power is available, and ultimately reduce costs paid by customers. The reduction in peak load resulting from the DR portfolio is intended to relieve stress on the electric system in a more cost-effective manner than purchasing capacity from the market or building additional generation resources to meet peak demand.[3]

1 Tr. Vol. II, pg. 23

2 Tr. Vol. II, pg. 24

3 Tr. Vol. II, pg. 26

He stated that the capital spending for the 2018 DR portfolio totaled $6,734,741, as shown on Exhibit A-1 16, page 1, line 4, column (a), and O&M spending for the DR portfolio, including DR residential customer incentive payments of $1,501,318 and business DR customer incentive payments of $1,827,1501 for 2018 totaled $10,365,843, as shown on Exhibit 19 A-1, page 1, line 3, column (a). Based on amounts approved in Case No. U-18322, the Company's actual 2018 DR spending was, in total, $6,108,741 higher in capital spending as shown on Exhibit A-1, line 4, column (c), and $2,281,144 lower than approved amounts for O&M spending as shown on Exhibit A-1, 2 line 3, column (c).[4] He testified the Company prudently incurred these capital expenditures and O&M expenses.[5] The 2018 Business DR customer incentive payments recovered as part of the Company's 2018 Power Supply Cost Recovery are included in this case for both the calculation of the DR performance incentive as well as the Business DR Program and DR portfolio cost-effectiveness analysis presented in the direct testimony of Company witness Morgan.

Mr. Ennis testified that the variance of the DR revenue requirement is the difference between the actual revenue requirement and the approved revenue requirement for the DR Program portfolio, which is $1,635,407. This variance is shown on Exhibit A-1, line 7, column (c). The Company proposes to record the difference in actual versus approved revenue requirements in a regulatory liability account to be reflected in a future electric general rate case.[6]

4 Tr. Vol. II, pgs. 26-27

5 Tr. Vol. II, pg. 29

6 Tr. Vol. II, pg. 27

Mr. Ennis testified that the Company is requesting a 2018 performance incentive based on its proposed financial incentive mechanism in Case No. U-20164, still pending before the Commission at the time he filed his testimony. The Company is requesting that it earn the 2018 DR financial incentive of $2,026,943 shown on Exhibit A-2, line 22. The Company proposes to recover the DR financial incentive of $2,026,943 through a 12-month surcharge to be implemented beginning with the January 2020 billing cycle.[7]

Mr. Ennis testified that the Company achieved a DR portfolio of 320.8 MW as of June 1, 2018 , 306.7 MW of which was registered with the Midcontinent Independent System Operator, Inc. ("MISO") as a Load Modifying Resource ("LMR") available to support grid reliability during the summer peak season should MISO have called a summer LMR emergency event. Further, the Company achieved a 2018 year-end DR portfolio of 355.4 MW. In addition, the Company had a portfolio of DR assets that were used up to 10 times on an economic basis during the 2018 DR season to reduce load during system peak events. The approximate market value of the DR programs was $20,872,469 based on 75% of the MISO 2018 Cost of New Entry for Michigan.

Mr. Ennis sponsored Exhibits A-1, A-2 and A-3. Exhibit A-1 provides 2018 DR Program planned and actual costs and revenue requirements. Exhibit A-2 is the 2018 DR Performance Incentive calculation. Exhibit A-3 is the 2018 DR Annual Report designed to provide an overview of the Company's 2018 DR Portfolio and to share achievements and key learnings of the Company's 2018 DR programs. Cross-examination of Mr. Ennis was waived.

7 Tr. Vol. II, pg. 27

Next, the Company presented the testimony of Laura M. Collins, Principal Rate Analyst, Lead in the Pricing section of the Rates and Regulation Department with CECo. She testified regarding the proposed recovery of the Demand Response Financial Incentive earned in 2018 and to introduce the proposed tariff sheet for the surcharges.[8] She testified that the Company proposes to collect the DR incentive through a 12-month surcharge to be implemented beginning with the January 2020 billing cycle for a period of 12 months. She explained how the surcharge was calculated. She testified that Company witness Ennis identifies the DR related operating expenses as residential or business. The Company separated the financial incentive between the residential and business customer classes based on the level of operating expenses for each class. For instance, the $1,155,449 residential portion of the DR financial incentive – shown on Exhibit A-4, line 1, column (a), – was calculated as the product of the total DR financial incentive on Company witness Ennis' Exhibit A-2, line 22, and the ratio of residential DR program operating expenses ($4,011,622) to total DR program operating expenses ($7,037,375). The business portion of the DR financial incentive shown on Exhibit A-4 (LMC-1), line 2, column (a), was calculated using the same approach. From there, the Company divided the residential portion of the DR financial incentive by the total residential bundled energy sales forecasted for 2020 to develop a monthly per kWh residential surcharge, as shown on Exhibit A-4, line 1, column (c). To calculate the business surcharge, the business-related financial incentive was divided by the total

8 Tr. Vol. II, pg. 33

secondary and primary bundled energy sales forecasted for 2020. The business surcharge is shown on Exhibit A-4, line 2, column (c).[9]

Ms. Collins sponsored exhibits A-4 and A-5. Cross-examination of Ms. Collins was waived.

Ms. Dziewiatkowski, Senior Rate Analyst II in the Revenue Requirement and Analysis section of the Rates and Regulation Department, testified concerning the revenue requirement for the Company's Residential and Business Demand Response Programs for the 2018 reconciliation period.[10]

She sponsored Exhibit A-6, which provides the revenue requirement calculation for capital spending associated with the DR program for calendar year 2018. Exhibit A-6, columns (b) through (d), provide the revenue requirement calculation for the approved capital spending or the revenue requirement included in rates for calendar year 2018 and columns (e) through (g) provide the revenue requirement calculation for 2018, incorporating actual DR capital spending. Exhibit A-6, line 6, provides the difference between the actual revenue requirement and the approved revenue requirement.[11]

Cross-examination of Ms. Dziewiatkowski was waived.

David B. Hays, Senior Business Support Consultant II for CECo, testified concerning the procedure used by the Company to identify and call peak events, along with the results realized during the DR period June 1, 2018 through September 30, 2018 (DR Event Season).[12]

9 Tr. Vol. II, pg. 34

10 Tr. Vol II, pg. 38

11 Tr. Vol. II, pg. 39

12 Tr. Vol. II, pg. 44

Mr. Hays testified that the Company deploys DR resources in either the Day-Ahead or Real-Time Energy markets. DR resources were deployed by the Company in the Day-Ahead market when market prices and electric loads were expected to exceed a trigger condition. The Company typically deploys DR resources in the Real-Time Energy Market only during a MISO Maximum Generation Emergency Event Step 2b.

Mr. Hays testified that the Company had a total of 306.7 MW of DR registered as an LMR in 2018, which comprised Rate GI (136.7 MW), C&I Emergency DR (74.1 MW), Rate EIP (77.4 MW), and ACPC (18.5 MW). The value of the Company's 2018 DR portfolio registered as an LMR was $20,872,469 based on 75% of the MISO 2018 Cost of New Entry ("CONE") for Michigan.[13] He stated that based on the Company and Cadmus evaluations, the Company believes that 0.48 kW is a reasonable estimate of the average load reduction per customer for DPP for the 2019/2020 planning year. Similarly, for ACPC, the Company concluded that the average 0.70 kW per customer will be used as the 2019/2020 per customer demand savings factor.[14]

Mr. Hays sponsored Exhibit A-7. Cross-examination of Mr. Hays was waived.

Derek D. Kirchner, Director of Demand Response, Commercial and Industrial Products for CECo, testified to (i) provide an overview of the Company's 2018 Business DR programs; (ii) describe program achievements and investments associated with these programs; and (iii) describe the Business DR pilots proposed for 2019 and 2020[15].

Mr. Kirchner testified that the Business DR Program is targeted toward business customers that have the ability to curtail at least 100 kW and are not currently on an

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13 Tr. Vol. II, pg. 47

14 Tr. Vol. II, pg. 50

15 Tr. Vol. II, pg. 53

interruptible or retail open access rate. Each business customer that signs up for the program is contracted for a specified load (kW) reduction during events for the program year of June 1 through September 30. The contract sets forth the program parameters, including the program period, timing and frequency of events, mandatory versus voluntary events, minimum advanced notification time, primary contacts to receive event notifications, how performance will be calculated, rules regarding non-performance, and the compensation the customer will receive for the capacity provided. The Company's Business DR Program offers an emergency program along with an economic option. In addition to agreeing to curtail per the customer agreement if an emergency DR event is called, customers participating in the economic program agree to curtail load if market conditions warrant an economic DR event day. The Company may call up to 10 economic events during the DR season.

Mr. Kirchner testified the Emergency DR Program enrolled a total of 136 customer facilities representing 73.1 MW under contract as confirmed in Exhibit A-9 for the 2018 DR season. Throughout 2018, the Company enrolled a total of 189 customer facilities representing 96.9 MW for the 2019 DR season. In 2018, the Company enrolled a total of 17.8 MW in the Economic DR Program, 11.7 for the 2018 and 6.1 for the 2019 DR seasons.[16]

Mr. Kirchner testified that the capital variance for the Business DR Program was $108,688 less than the overall annual budget of $626,000, which is approximately 17%. See Exhibit A-8, page 1, line 4, column (c). This is based on fewer customer telemetry device installations than originally forecasted. O&M costs were $363,247 lower than the

16 Tr. Vol. II, pg. 57

2018 budget forecast of $3,389,000, which is approximately 10%. See Exhibit A-8, page 1, line 1, column (c). The lower overall O&M cost for the Business DR Program is the result of lower labor impacts and timing issues related to hiring processes.[17]

Concerning future DR pilot programs, Mr. Kirchner testified that the Company is planning a Small Business Customer Pilot targeted at 500 customers during the 2019 DR season. This pilot plans to target business customers with smaller usage profiles who may not be able to enroll 100 kW of demand to be curtailed during peak events. The pilot is expected to include two events, one in late July and one in late August, while following the same operational notifications to the customer as described in the Business DR Program. The pilot intends to provide the same incentive payment to the customer, based on performance during the events, as the Business DR Program. In addition to the incentive, the Company will compensate participants with a gift card for their efforts at the end of the DR season. The expected cost of the pilot is approximately $300,000.[18] Currently, the Company is evaluating a number of potential rate design programs, Bring Your Own Device initiatives, and other best-in-class DR options for implementation in 2020. While no pilots are definitive at this time, the pilots will be implemented to assist the Company in meeting the DR goals set forth in its IRP. The Company expects 2020 pilot costs in the range of $1,000,000 for 2020.[19]

Mr. Kirchner sponsored Exhibits A-8 and A-9. Cross-examination of Mr. Kirchner was waived.

17 Tr. Vol. II. pg. 58

18 Tr. Vol. II., pg. 58

19 Tr. Vol. II, pg. 59

Ms. Svitlana Lykhytska, Principal Accounting Analyst in the General Accounting Department of CECo, testified concerning the 2018 Demand Response regulatory balance as reflected in the Company General Ledger and the collection period for the 2018 DR financial incentive as required under Generally Accepted Accounting Principles.[20]

Ms. Lykhytska testified that per the September 15, 2017 Order in Case No. U-18369, "costs associated with DR should follow deferred regulatory accounting with return." However, the Commission stated that "deferred regulatory accounting for capital expenditures and O&M is not permitted for items that have been previously approved and already included in rates."[21] She testified that Company will record carrying costs on over/under recovery balances starting from the date of the Commission's approval of its annual DR reconciliation case until the regulatory balances are fully collected or refunded in rates in future general electric rate cases. The carrying cost rate used for both over and under recovery balances will be the Company's short-term borrowing rate. This process is consistent with the application of carrying costs in the Company's EWR Program.[22]

Ms. Lykhytska testified that the DR incentive revenue is categorized as an alternative revenue program according to the Accounting Standards Codification. She stated that alternative revenue is generally segregated into two programs. The first program adjusts billings for the effects of abnormal weather patterns, energy conservation efforts, or from broad external factors such as a general recession. Revenue recorded through decoupling falls under this program. The second program provides for additional

20 Tr. Vol. II, pg. 62

21 Tr. Vol. II, pg. 62

22 Tr. Vol. II, pg. 62

billings if the utility achieves certain objectives, such as reducing costs, reaching specified milestones, or improving customer service. Revenue recorded through the DR financial incentive falls under this latter program.[23]

Next, Ms. Lykhytska testified regarding the collection period. She stated that once the incentive mechanism is established, the annual DR financial incentive revenue will be recognized on Consumers Energy's books at the end of a calendar year it pertains to. In order to comply with the 24-month collection requirement it needs to be certain that the annual incentive will be fully collected within 24 months from the date it is recorded in the Company's financial statements. If the DR incentive is not fully collected within 24 months from the end of its incentive year, GAAP would require a determination that the revenue was recorded out of period and should have been recognized when actually billed to the customer. The requirements of ASC 980-605-25 stipulate that the revenue must be collected within 24 months and allows no flexibility. Failing to collect within 24 months from the end of its incentive year would then require a reversal of the DR incentive revenue that was already recognized by the Company.[24]

Ms. Lykhytska did not sponsor any exhibits and cross-examination was waived.

Emily A. McGraw, Director of Residential Demand Response and Demand-Side Customer Pilot Programs on behalf of CECo, testified to (i) provide an overview of the Company's Residential DR programs; (ii) describe program achievements and investments associated with these programs; and (iii) request approval of Residential DR pilots proposed for 13 2020 and 2021.[25]

23 Tr. Vol. II, pg. 63

24 Tr. Vol. II, pg. 65

25 Tr. Vol. II, pg. 68

In describing CECo's 2018, residential DR programs, Ms. McGraw testified that in 2017, the Company launched two residential DR programs, approved by the Commission ,as part of its Peak Power Savers Program: Air Conditioning ("AC") Peak Cycling ("ACPC") and Dynamic Peak Pricing ("DPP"). These programs have been deployed and utilized by the Company over the last two years. Similar to business DR programs, the residential DR programs are designed to give the Company a flexible demand-side resource that can be used during times of peak electricity demand to reduce power supply costs that directly impact all of the Company's customers.[26]

Ms. McGraw testified that ACPC is a direct load control program in which the Company installs a load control switch on the outside of a customer's home on or near their central AC unit. During peak event days the Company activates the switch to cycle the output of the central AC unit by 50% to reduce load during the event. The central AC unit cooling system returns to normal once the cycling event ends. The load control peak demand reduction is achieved using the Automated Metering Infrastructure and ZigBee two-way communication technology. Load management may occur any weekday (excluding holidays) between 7 a.m. and 8 p.m. for no more than an eight-hour period in any one day and may be implemented to maintain system integrity, for economic reasons, or when there is insufficient system generation available to meet anticipated system load. Load management may also occur outside of the hours of 7 a.m. to 8 p.m. during a declared Midcontinent Independent System Operator, Inc. emergency.[27]

26 Tr. Vol. II, pg. 69

27 Tr. Vol. II, pg. 70

Ms. McGraw explained that capital costs for the ACPC Program include: (i) management labor costs for the call center, scheduling, and route planning; (ii) switch installation, removals, and materials; (iii) permits and processing costs; and (iv) other direct costs such as warehousing, equipment, and taxes. O&M cost components for the ACPC Program include: (i) project management, Information Technology (“IT”), field inspection, and service call expenditures; (ii) customer acquisition expenses including website development, direct mail, bill inserts, and other customer communications and program materials; (iii) customer incentives and associated processing activities; and (iv) other direct costs such as software licensing and taxes.[28]

Ms. McGraw testified a total of 27,060 (gross) switches were installed in 2018; however, the Company experienced higher than expected attrition of 4,489 switches, bringing net installations to 22,571. ACPC Program attrition included 3,241 customers who moved out of the premise and 1,248 customers who de-enrolled from the program. The Company is developing a strategy to market to customers who move into a home that already has a switch installed to mitigate attrition due to move-outs, the top reason for ACPC Program losses. In August of 2018, the Company experienced a provisioning loss of 8,000 ACPC switches in its DR Management System. The Company informed the Commission Staff of this issue in September 2018 and expects all 8,000 impacted switches to be re-provisioned by June 2019.[29]

In describing the Dynamic Peak Pricing Program, Ms. McGraw testified that the DPP Program was designed to encourage customers to move energy consumption to off-

28 Tr. Vol. II, pg. 71

29 Tr. Vol. II, pg. 71

peak hours by providing less expensive rates at these times. In addition, the program provides incentives for customers to reduce their energy use during DR events. The more energy usage participants shift from peak hours, the more they can save. In 2018, the Company offered two DPP programs: Critical Peak Pricing ("CPP") and Peak Time Rewards ("PTR"). The goals of the two pricing options are identical, but the approach to achieve them is different. The CPP option replaces the standard on-peak energy charge participants pay with a much higher critical peak energy charge. This is generally referred to as a "stick" incentive to encourage customers to shift demand. Alternatively, the PTR option offers customers an incentive payment of $0.95 in bill credits for every kWh of energy they save during the event, compared to their typical use during those same hours. This is generally referred to as a "carrot" incentive.[30]

She testified that the DPP Program is comprised of O&M costs including (i) project management, IT, Evaluation Measurement and Verification; (ii) customer acquisition expenses including website development, direct mail, bill inserts, and other customer communications and program materials; and (iii) other direct costs such as software licensing and taxes.[31]

Ms. McGraw stated that the Company enrolled 4,515 customers in the DPP Program in 2018. Although, DPP experienced higher than expected attrition of 5,398 customers comprised of 2,372 customers who moved out of the premise and 3,026 (1,445 CPP; 1,472 PTR) customers who de-enrolled. As a result, although the Company enrolled 9,913 (gross) customers in 2018, net enrollments were 4,515.[32]

30 Tr. Vol. II, pg. 73

31 Tr. Vol. II, pgs. 73 and 74

32 Tr. Vol. II, pg. 74

Ms. McGraw testified that the costs for the 2018 Residential DR portfolio are capital expenditures in the amount of $6,217,430 and O&M expenses in the amount of $5,512,940 as shown on Exhibit A-10. Approved costs for the Residential DR Program for capital expenditures in Case No. U-18322 were $0, which is $6,217,430 lower than actual costs. Approved costs for O&M expenses were $7,430,837, which is $1,917,897 lower than actual cost. The Company spent $1,917,897 less than expected because the Company was able to reach the projected DR portfolio levels for 2018, which were developed after filing Case No. U-18322 as part of the Company's Integrated Resource Plan ("IRP") in Case No. U-20165.[33]

Regarding the higher capital costs, Ms. McGraw testified that in its March 29, 2018 Order in Case No. U-18322, the Commission did not approve the Company's capital request for the ACPC Program. The Company continues to value ACPC as a DR resource, and continued to invest in installing switches to meet the increased DR portfolio goals outlined in the Company's IRP presented in Case No. U-20165.[34]

Ms. McGraw testified the Company recognizes the need for additional residential DR resources in pursuit of the DR levels proposed in the IRP. To that end, the Company seeks approval to plan and implement two pilots in 2020 and 2021, with projected costs of $4,332,000 in O&M and $770,000 in capital. These pilots were selected based on their potential demand savings. These pilots will test the demand savings achieved from new load control devices as described below. Additionally, the Company will continue to implement its Bring Your Own Device ("BYOD") pilot. For the BYOD pilot in 2019, the

33 Tr. Vol. II, pg. 76

34 Tr. Vol. II, pg. 77

Company is testing the per customer demand savings achieved with day ahead pre-cooling optimization. In 2020, the Company intends to test market potential energy efficiency benefits and tactics for further optimizing demand savings. Finally, the Company will continue to investigate DR as a Non-Wires Alternative by studying the feasibility of using DR to reduce or defer investments for distribution circuits.[35]

Ms. McGraw sponsored Exhibit A-10, A-11, A-12, A-13 and A-14. Exhibit A-10 identifies residential DR enrollments and expenditures. Exhibit A-11 is a certification of residential DR program enrollments conducted by Cadmus. Exhibits A-12 and A-13 are 2018 Residential DR Program evaluations conducted by Cadmus. Exhibit A-14 identifies and provides projected costs for proposed 2020-2021 DR pilots. Cross-examination of Ms. McGraw was waived.

Richard A. Morgan, President of Morgan Marketing Partners, LLC (MMP), testified on behalf of CECo to (i) describe how MMP helped Consumers Energy model the cost-effectiveness of its 2018 DR programs; (ii) describe the cost-effectiveness modeling for the DR programs; and (iii) provide the results demonstrating that the DR portfolio is cost-effective using the Utility System Resource Cost Test ("UCT").

Mr. Morgan testified that MMP provided cost-effectiveness modeling services utilizing the DSMore modeling tool to calculate and report cost-effectiveness of the Company's DR programs. The DSMore cost analysis tool was used to calculate and report cost-effectiveness for the Company's DR programs using the UCT (also known as the USRCT), as defined by 2008 PA 295, as amended in 2016 PA 342. The DSMore tool is an award-winning modeling software that is nationally recognized and used in many

35 Tr. Vol. II, pg. 78

states across the country to determine cost-effectiveness of energy efficiency and DR programs. Developed and licensed by Integral Analytics based in Cincinnati, Ohio, the DSMore cost-effectiveness modeling tool takes hourly prices and hourly energy savings from the specific measures/technologies being considered for each program, and then correlates both to weather. The algorithm used by the modeling software looks at over 30 years of historic weather variability to fully capture the weather variances. In turn, this allows the model to capture the low probability, but high consequence weather events and apply appropriate value to them. Thus, a more accurate view of the value of the DR can be captured in comparison to other alternative supply options.[36]

Mr. Morgan testified that all CECo's programs are cost-effective with the Electric DR Program Portfolio UCT score of 1.31. This means that the energy demand benefits are 31% greater than the DR program cost. Each program was analyzed individually and then aggregated to the portfolio score above. The AC Peak Cycling program has a UCT score of 1.04, the Dynamic Peak Pricing program has a UCT score of 1.86, and the Business DR program has a UCT score of 2.22.[37]

Mr. Morgan did not sponsor any exhibits and cross-examination was waived.

B. Staff Testimony

Three witnesses testified on behalf of Staff.

Sarah A. Mullkoff, Departmental Analyst in the Generation and Certificate of Need Section of the Energy Resource Division, testified concerning the Staff's recommendations for the reconciliation.

36 Tr. Vol. II, pg. 84

37 Tr. Vol. II, pg. 87

Ms. Mullkoff testified that the Commission's Final Order in the IRP Settlement Agreement, June 14, 2019 established approval of new investments of 607 megawatts (MW) of demand response programs.[38]

Ms. Mullkoff testified that Staff had some concerns over technical flaws of the ACPC switch program. In August of 2018, the Company experienced an accidental provisioning loss of 8,000 ACPC switches in its DR Management System. Unfortunately, this resulted in a significant number of ACPC customers being ineligible for DR events called during the end of the summer, thereby missing out on potential MW savings. The Company informed Commission Staff in a timely manner following the issue and relayed a plan to complete re-provisioning of all switches by June 2019. Through a data request as shown in Exhibit S-1.1, Staff learned that the Company took both short-term and long-term measures to help ensure that such a mechanical error does not occur again. Its short-term countermeasure was deploying into production a fix that removed the functionality of Mass Provisioning, which allowed the Company to have greater monitoring over the system. The Company described the long-term fix that upgrades the Demand Response Management System, with new features that automate and enhance the switch communication troubleshooting process. This upgrade is scheduled to go into production by May 2020. Staff intends to continue to monitor this fix until the new DRMS system is fully intact in advance of the 2020 ACPC DR season.[39]

Ms. Mullkoff testified that Staff requested that the Company provide expenditures for each of the Company's DR programs, specified by total capital spend, total operations

38 Tr. Vol. II, pg. 105

39 Tr. Vol. II, pg. 107

and maintenance (O&M) spend, monthly projected O&M spend per program, and monthly capital spend per program. This is shown in Exhibit S-1.3, "Monthly DR Spend, Enrollment & Savings." This data provided a detailed picture comparing the actual expenditures to the projected expenditures per each program throughout calendar year 2018. Staff reviewed and compared the projected expenses to actual expenses for capital and O&M spending for each DR program and also reviewed the monthly enrollment breakdown in each program. Exhibit S-1.3 also shows the demand savings per each program showing the amount of enrolled MW into each MISO Planning Year (PY) since the program's PY 2015/2016. Staff compared these numbers to those submitted in the 2018-2021 Capacity Demonstration filing, confirming these amounts of registered load modifying resources (LMRs) are consistent. In addition, through a data request, Staff requested a spreadsheet requesting the Net Present Value of the Revenue Requirement (NPVRR) and levelized cost of each program, as shown in Exhibit S-1.4, and discussed later in this testimony.[40]

Ms. Mullkoff testified that Staff recommends that the Company work towards more consistency and defined parameters when assessing the viability of proposed pilot programs. Staff requests that in future DR reconciliation filings, the Company present results and lessons learned of the prior year's pilot programs. For instance, the results of its 2019 pilot programs should be detailed in its 2019 DR reconciliation case, which is likely to be filed in May of 2020. [41]

40 Tr. Vol. II, pgs. 111 and 112

41 Tr. Vol. II, pg. 112

Ms. Mullkoff testified that the Company's Demand Response programs and pilots are reasonable for the requested cost recovery. The MW achievements are appropriate for meeting the targeted projections presently, though Staff will continue to monitor as the Company makes further progress towards the increased targets identified in the IRP. Staff recommends the Commission order further guidance on the appropriate approval process for Demand Response Pilots at the conclusion of the MI Power Grid Workgroup report.[42]

Ms. Mullkoff sponsored Exhibit S-1.0, S-1.1, S-1.2, S-1.3, S-1.3 and S-1.5. Cross-examination was waived of Ms. Mullkoff.

Michelle L. Edelyn, auditor in the Revenue Requirements Section of the Regulated Energy Division, testified regarding the Staff's capital expenditure and O&M expense reconciliation.

Ms. Edelyn testified Staff's audit did not reveal any indication that the Company's $6,108,741overspend was incorrect. The Company filed an O&M underspend of $2,281,144, however it was revealed through Staff's audit that the Company had errored in providing this figure; the correct actual underspend for O&M should be $2,404,595, an increase of $123,451. [43]

Ms. Edelyn testified that Staff recommends a net amount of $1,758,858 be deferred as a regulatory liability. After correcting the O&M error, the 2018 actual O&M expense amount is reduced from $10,365,843 to $10,242,392. The derivation of the regulatory liability is illustrated on Exhibit S-2.1.[44]

42 Tr. Vol. II, pg. 119

43 Tr. Vol. II, pg. 123

44 Tr. Vol. II, pg. 124

Ms. Edelyn sponsored Exhibits S-2.0 and S-2.1. Cross-examination of Ms. Edelyn was waived.

Katie J. Smith, Economic Specialist in the Resource Adequacy and Retail Choice Section of the Energy Resource Division, testified regarding the Staff's recommendations for the Company's DR reconciliation of its 2018 program costs, collection of regulatory liability and to address the Financial Incentive Mechanism (FIM).[45]

Ms. Smith testified that in Case No. U-18322, the Commission approved capital spending of $626,000 and O&M spending of $12,646,987 for DR programs. She stated that the Company spent a total of $6,108,741 above the approved amount of capital in of $626,000. The Company spent a total of $2,404,595 less than the approved $12,646,987 in O&M. In total the Company spent $6,734,741 in capital expenditures and $10,242,392 in O&M expenditures.[46]

Ms. Smith testified that Staff is concerned that the Company could take advantage of the DR reconciliation process as a way to recover unapproved capital spending on DR programming that has not been fully examined for prudency by Staff. In this instance, the Company chose to continue to install switches beyond the target identified by the Commission, once re-calculated using actual enrolled participant savings, without notifying Staff and without a prudency review of the program.[47]

Ms. Smith testified that Staff recommends the Commission order the Company to conduct a meeting with Staff if the DR program spending exceeds 10% of the approved

45 Tr. Vol. II, pg. 129

46 TR. Vol. II, pg. 130

47 Tr. Vol. II, pg. 130

expenditures.[48] Although the prudency review was successful in this instance, the Company is not always guaranteed recovery of DR expenditures beyond approved amounts. If Staff finds future overspending to be imprudent, Staff has the ability to recommend denial of the recovery of DR expenditures.[49]

Ms. Smith stated that Staff recommends the Commission approve the Company's 2018 DR reconciliation program costs, which are comprised of all incremental capital expenditures incurred by the Company in 2018 beyond the amounts previous approved by the Commission in Case No. U-18322. Staff recommends that the Company include the regulatory liability in its next general rate case. This recommendation follows the Commission-approved three phase DR framework approved in Case No. U-18369.[50]

Ms. Smith testified that Staff recommends the Commission deny approval of the Company's requested FIM and incentive amount. The Commission has issued an order in Case No. U-20164 that approved a specific FIM that is different in scale and scope to what the Company has requested in this case.[51]

Ms. Smith did not sponsor any exhibits and cross-examination was waived.

C. ABATE Testimony

Amanda M. Alderson, consultant in the field of public utility regulation with the firm of Brubaker and Associates, Inc., testified on behalf of ABATE regarding the requested approval of a FIM.

48 Tr. Vol. II, pg. 130

49 Tr. Vol. II, pg. 131

50 Tr. Vol. II, pg. 131

51 Tr. Vol. II, pg. 132

Ms. Alderson testified that Case No. U-20164 is the recently concluded proceeding to reconcile Consumers' 2017 DR spending amounts. In the Commission's July 18, 2019 Order, it rejected the Company's proposed FIM formula in favor of the FIM formula proposed by the National Resources Defense Council ("NRDC") in that proceeding. It further ordered that the FIM be applied only prospectively beginning with Consumers' DR spending in calendar year 2019.[52]

She stated CECo's FIM proposal in the instant proceeding is identical to the one it proposed, and the Commission rejected, in Case No. U-20164. The Commission found the Company's proposed formula to be "overly generous, lacks consideration of NWAs [non-wires alternatives], includes an 'incentive to use' that lacks justification, and is insufficiently tied to performance."[53]

Ms. Alderson recommended that the Commission deny the Company's requested recovery of $2.0 million for the FIM, based on the fact that the Commission recently rejected CECo's identical FIM proposal in Case No. U-20164 and ordered that the FIM be applied prospectively beginning in 2019. She also recommends that the Commission order that the just-approved work group for DR FIM established in Case No. U-20521 be expanded to include all interested parties in the instant proceeding as well.[54]

Ms. Alderson testified that the Commission ultimately concluded in its October 7, 2019 order in Case No. U-20164 that because Consumers had not been put on notice that its first DR reconciliation proceeding could include the 2015-2016 period, "on that basis" it declined to extend the reconciliation proceeding to 2015 and 2016. If the

52 Tr. Vol. II, pg. 142

53 Tr. Vol. II, pg. 142

54 Tr. Vol. II, pg. 144

Commission determines that it is prudent to revisit this issue in the instant proceeding, it should require a full reconciliation of the 2015-2018 period as recommended by Staff in Case No. U-20164.[55]

Ms. Alderson sponsored Exhibit AB-1. Cross-examination of Ms. Alderson was waived.

D. Rebuttal Testimony

In rebuttal, the Company presented testimony Steven Q. McLean. ABATE presented the testimony of Ms. Alderson.

Mr. McLean, Director of Customer Experience Regulatory Strategy, Reporting and Quality, testified to rebut the testimony of Ms. Mullkoff, Ms. Smith, and Ms. Alderson. In response to Ms. Mullkoff's testimony, Mr. McLean testified that DR pilots are utilized by the Company to assess the viability of emerging DR technology, new program designs, and customer acquisition techniques. This process requires agility and flexibility in order to test and implement new DR initiatives in a timely manner. The Company understands Staff's concerns and is willing to work towards more consistent and defined parameters for DR pilots so long as they allow for the necessary agility and flexibility to implement new DR initiatives in a timely manner.[56]

To rebut Ms. Smith's testimony, Mr. McLean stated that the three-step process established in Case No. U-18369 included the reconciliation process for the purpose of comparing actual DR spending to that approved in general rate cases and IRP proceedings. The cost of implementing DR programs, including capital investment, may

55 Tr. Vol. II, pg. 147

56 Tr. Vol. II, pg. 92

increase or decrease from the amounts forecasted in general rate cases and IRP proceedings. The DR reconciliation process allows for the review of both increasing and decreasing DR costs. DR is quickly evolving, which requires the Company to continually review and potentially adopt new strategies more frequently than can be addressed in IRP proceedings or general rate cases. The annual DR reconciliation process allows for frequent reviews of the prudency of DR spending related to programs that may shift between IRP proceedings. While the exact structure of the programs may change outside of the IRP proceeding, DR reconciliations are an appropriate setting to review such changes. However, the Company understands Staff's concerns and is willing to update Staff anytime that the Company expects that the DR program capital spending will exceed 10% of the approved expenditures.[57]

In addition, Mr. McLean testified that the Company agrees that it would not be appropriate to receive double incentive on specific NWA programs. To achieve its full incentive approved in Case No. U-20164, the Company has completed significant work to meet the approved NWA requirements. The Company recommends that as NWA programs are shifted away from DR, careful consideration be given to the work already completed to assure any FIM associated with current and future NWA programs be handled fairly and appropriately.[58]

In response to Ms. Alderson's testimony, Mr. McLean stated that Consumers Energy was not a party to Case No. U-20521 or the settlement agreement, and thus the work group associated with that proceeding does not apply to Consumers Energy. In

57 Tr. Vol. II, pg. 93

58 Tr. Vol. II, pg. 93

addition, the settlement agreement in Case No. U-20521 indicates that the workgroup is for the purpose of creating an FIM proposal for DTE Electric, not Consumers Energy. More importantly, it is not necessary to establish a work group to develop a DR FIM for Consumers Energy. In Case No. U-20164, the Commission approved a DR FIM for Consumers Energy beginning with the 2019 reconciliation, which the Company will file in 2020. The Commission stated in that proceeding, “Like DR reconciliations in general, DR FIMs may need to undergo some refinement and will be subject to revision in future DR reconciliations.” Case No. U-20164, July 18, 2019 Order, page 12. The Company agrees with the Commission that DR reconciliations are an appropriate venue to establish and modify a DR FIM. Intervening parties will have the opportunity to review and recommend changes to the FIM for Consumers Energy in the DR reconciliations.[59]

Additionally, Mr. McLean testified that in Case No. U-20164, the Commission already considered whether it is appropriate to reconcile the 2015 and 2016 DR costs. In its October 7, 2019 Order in that case, the Commission noted that its September Order in Case No. U-18369 had not made clear that the Company’s first DR reconciliation could encompass 2015 and 2016, and as a result determined that it was not appropriate to include the 2015-2016 period in the reconciliation. No party appealed that Commission determination, and it should not be revisited in this proceeding.[60]

Finally, Mr. McLean testified that including DR reconciliations in either general rate cases or IRP proceedings will only create unnecessary complications in already complex cases. Furthermore, annual DR reconciliations allow for more frequent and focused

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59 Tr. Vol. II, pg. 94

60 Tr. Vol. II, pg. 95

reviews of the DR costs and programs than could be achieved in general rate cases or IRP proceedings.[61]

Ms. Alderson provided rebuttal testimony in response to Ms. Smith's and Ms. Mullkoff's testimony concerning the $6.1 million excess capital spending on DR programs in 2018.

Ms. Alderson testified that CECo recovered costs from ratepayers in 2015 and 2016 through base rates for DR-related expenses that it did not incur, and CECo seeks recovery now for an additional $6.1 million in capital spending beyond the approved amounts for 2018. It is unjust to burden ratepayers for the same costs twice, and a full accounting of DR spending, beginning with the inception of DR spending in 2015, is necessary to avoid such double-recovery by Consumers.[62]

Ms. Alderson testified that as part of its review in CECo's just-filed base rate case, Case No. U-20697, the Commission should perform a full review of DR spending beginning in 2015 when considering whether to permit the 2017-2019 regulatory assets and/or liabilities stemming from the DR reconciliation proceedings to be included for recovery in rates. In its base rate case, Consumers proposes to recover the capital spending excesses identified in its 2017 and 2018 DR reconciliation proceedings through a new DR reconciliation surcharge. Consumers 2019 DR reconciliation filing is due in May 2020, and the data from that filing should inform the base rate case proceeding as well. She testified that she maintains her recommendation that the Commission consider the full DR spending period beginning with 2015 in order to ensure customers are not paying

61 Tr. Vol. II, pg. 96

62 Tr. Vol. II, pg. 155

twice for DR program costs. Consumers' just-filed base rate case is the appropriate proceeding to perform such a holistic review, and review a complete record of Consumers' successes and spending toward its DR enrollment and performance goals.[63]

III.

DISCUSSION

A. Position of the Parties

CECo is requesting the Commission to approve the reconciliation of the Company's 2018 DR program costs and savings; approve the recovery of all incremental capital expenditures incurred by the Company in 2018 beyond the amounts previously approved by the Commission in Case No. U-18322; approve deferred regulatory accounting treatment of the actual revenue requirement for DR program capital expenditures and O&M expenses incurred in 2018 compared to the authorized revenue requirement resulting in the creation of a regulatory liability of $1,758,858 to be reflected in a future electric general rate case; and approve the Company's proposed DR pilots.[64]

After a prudency review, Staff recommends that the Commission approve the Company's 2018 DR reconciliation. However, Staff recommends the Commission order the Company to conduct a meeting with Staff if the DR program spending exceeds 10% of the approved expenditures. Staff recommends acceptance of the Company's demand response capital expenditure overspend of $6,108,741 as included in the initial filing. Staff recommends approval of the revenue requirement related to O&M underspend of $2,404,595 totaling a net amount of $1,758,858. Staff agrees that the Company should

63 Tr. Vol. II, pg. 156

64 CECo's Initial brief, pg. 22

be approved for a $1,758,858 deferred regulatory liability and recommends the regulatory liability be included in the Company's next general rate case. Staff requests that the Commission deny the Company's request for a financial incentive mechanism (FIM) award of $2,026,943 because the Commission approved a specific FIM in Case No. U-20164.[65]

ABATE also requests that the FIM be denied as a result of the order in Case No. U-20164. In addition, ABATE requests that DR cost reconciliations should occur in the context of a general rate case or IRP proceeding and not in standalone reconciliation cases. ABATE also requests that the Commission reject Staff's recommendation to approve the recovery of CECo's excess DR capital spending in a subsequent base rate case. Finally, ABATE asks that the Commission ensure that any regulatory liability approved include a carrying charge equal to Consumers' authorized ROE as applied in Power Supply Cost Recovery proceedings. ABATE argues that requiring utilities to pay interest on their over-collections serves as an effective cost-control mechanism and discourages utilities from inflating their cost projections.[66]

In its reply, CECo agrees to update Staff when the Company expects that the DR program capital spending will exceed 10% of the approved expenditures. Additionally, CECo, does not object to the recommendation to deny approval of the Company's requested financial incentive mechanism and incentive amount for the 2018 DR program year pursuant to the Commission's determinations in Case. No. U-20164.[67] The Company

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65 Staff's Initial brief, pgs. 23-24

66 ABATE Initial brief, pg. 5

67 CECo Reply brief, pg. 3

argues against ABATE's proposed carrying charge and request to revisit the procedural framework approved in Case No. U-18369.[68]

As a result of the briefing, it appears that the remaining issues are limited to the proposed carrying charge and the framework for DR reconciliation. Section A will discuss the carrying charge. Section B will address the DR reconciliation process.

1. Section A: Carrying Charge

ABATE requests that the Commission approve a carrying charge for any regulatory liability approved in this matter. To support its argument, ABATE presented the testimony of Ms. Alderson.

Ms. Alderson testified that she recommends that the regulatory liability include a carrying charge equal to Consumers' authorized ROE, which is 10.0%, similar to the carrying charge currently and historically applied in the Michigan PSCR proceedings. In the PSCR process, regulatory liabilities, refunds owed to the customer, include a higher carrying charge at the authorized ROE to incent utilities to limit the pre-spending of ratepayer funds and limit the size of refunds due. In the PSCR process, regulatory assets, additional revenue owed to the utility from future ratepayers, include a lower carrying charge at the utility's short-term borrowing rate. This approach provides an incentive for the utility to limit the level of customer refunds owed, and should be used for DR reconciliation proceedings as well.[69]

The Company argues that the Commission should reject ABATE's request. To support its position, the Company presented the testimony of Mr. McLean. Mr. McLean

68 CECo Reply brief, pg. 4

69 Tr. Vol. II, pg. 148

testified that the PSCR interest rate is based on a statutory requirement that does not apply to DR reconciliation proceedings. Ms. Alderson's proposal is also contrary to how the Commission has historically approved the calculation of interest owed by the Company to its customers. In its residual balance cases, the Commission has consistently approved the use of the Company's actual known short-term borrowing rate to calculate interest. As another example, the Commission's February 22, 2018 Order in Case No. U-18494 adopted Staff's position which recommended applying the Company's short-term interest rate to the un-refunded balance of Credit B. Ms. Alderson's proposal is flawed in that it seeks to apply the Company's rate of return on common equity, which reflects the cost of financing long term assets, to the DR regulatory liabilities, which are short-term in nature. If the Commission does not approve the calculation of interest for DR regulatory liabilities based on the Company's short term borrowing rate, which Consumers Energy contends is appropriate given the short-term nature of the regulatory liabilities, the maximum rate that should be used is the Company's overall cost of capital currently set at 5.96% because the DR liability is in working capital, and net working capital is funded at the overall cost of capital.[70]

This PFD recommends that the Commission reject ABATE's proposal. MCL 460.6j(16) applies to Power Supply Cost Recovery and not Demand Response.

2. <u>Section B: DR Reconciliation Process</u>

ABATE contends that DR cost reconciliations should occur in the context of a general rate case or IRP proceeding rather than a standalone reconciliation case. ABATE

70 Tr. Vol. II, pg. 96

requests that the Commission revisit the procedural framework approved in Case No. U-18369. To support, its position, ABATE presented the testimony of Ms. Alderson.

Ms. Alderson testified that stand-alone proceedings conducted on a compressed time schedule create a heightened risk of saddling customers with rate increases to reflect higher DR costs without recognizing offsetting cost reductions in other components of the utility's overall costs. ABATE's point is exemplified in the instant proceeding, given that Consumers' ratepayers will be paying more than the Commission authorized for DR capital expenditures due to the requirement for annual stand-alone DR reconciliation proceedings. She recommended the Commission revisit the procedural framework it approved in Case No. U-18369 and require DR program cost reconciliation to occur in general rate cases or IRP proceedings.[71]

As noted above, Ms. Alderson testified that as part of its review in Consumers' just-filed base rate case, Case No. U-20697, the Commission should perform a full review of DR spending beginning in 2015 when considering whether to permit the 2017-2019 regulatory assets and/or liabilities stemming from the DR reconciliation proceedings to be included for recovery in rates. In its base rate case, Consumers proposes to recover the capital spending excesses identified in its 2017 and 2018 DR reconciliation proceedings through a new DR reconciliation surcharge. Consumers 2019 DR reconciliation filing is due in May 2020, and the data from that filing should inform the base rate case proceeding as well. She argues that the Commission consider the full DR spending period beginning with 2015 in order to ensure customers are not paying twice for DR program costs. Consumers' just-filed base rate case is the appropriate proceeding to perform such a

71 Tr. Vol. II, pg. 148

holistic review, and review a complete record of Consumers' successes and spending toward its DR enrollment and performance goals.[72]

In response, the Company argues that the Commission should reject this request. The Company argues that in the Commission's September 15, 2017 Order in Case No. U-18369 ("September 15 Order"), a proceeding which involved utilities and stakeholders, the Commission adopted a three-phase process, as proposed by Staff, for DR evaluation and cost recovery. This process was described as follows:

> The three-phase approach is a multi-step process where DR proposals, including program costs and benefits, are evaluated in the IRP. Once DR plans are approved as part of the IRP, the DR programs costs are considered approved and are included in rates in a utility's next general rate case. In between IRP proceedings, a provider may propose changes to DR programs or pilots, and these changes will be evaluated and approved in rate cases and must be included in the next IRP. The third phase involves a reconciliation of the DR program costs and customer participation rates (i.e., demand savings achieved) that will occur annually in a manner similar to that used in the provider's EWR reconciliation, with rates and participation reconciled against the levels approved in the IRP. [September 15 Order, page 5.][73]

The annual DR reconciliation that the Commission established in Case No. U-18369 as part of the three-phase DR reconciliation process allows for more frequent and focused reviews of DR costs or programs than is possible in general rate cases or IRP proceedings. Furthermore, it would be unreasonable to require Consumers Energy to use a different process for the review and approval of DR costs than is used by other utilities

72 Tr. Vol. II, pg. 156

73 Company Reply Brief, pg. 4

in Michigan. The Commission should reject ABATE's recommendation to alter the three phase DR review process in this proceeding.[74]

Staff also objects to ABATE proposal. Staff disagrees with the concern that ratepayers would pay more for DR capital expenditures. Staff approves of the three-phase framework as approved by the Commission in cast No. U-18369. This framework establishes that all capital costs associated with DR approved in IRPs will be considered for prudency in annual DR Reconciliation filings, but O&M costs will undergo review in the utility's general rate case. While in recent cases, the timing for the reconciliation period has sometimes been longer than one year, the intention is that the reconciliation "trues up" the spending from the previous year. As the Commission ruled, "The utility is able to recover the fixed investment required to implement successful DR programs, while allowing the Commission more regular oversight into the ongoing operation of these successful programs." Staff stands by the framework as a means to review DR spending on a regular basis and prevent risk of overcollection from customers.[75]

Based on the Commission Order in Case No. U-20164, this PFD recommends the Commission reject ABATE's proposal that DR reconciliation be included as part of the general rate case or an IRP proceeding.

IV.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission:

(1) Determine that the Company's DR programs are reasonable;

74 Company Reply Brief, pg. 5

75 Staff Initial Brief, pg. 21

(2) Approve the reconciliation of the Company's DR program costs and savings;

(3) Approve the incremental capital expenditures incurred by the Company in 2018 beyond the amounts previously approved by the Commission in Case No. U-18322;

(4) Approve deferred regulatory accounting treatment of the actual revenue requirement for DR program capital expenditures and O&M expenses incurred in 2018 compared to the authorized revenue requirement resulting in the creation of a regulatory liability of $1,758,858 to be reflected in a future electric general rate case;

(5) Approve the Company's proposed DR pilots;

(6) Deny ABATE's recommendation that DR reconciliation be included as part of the general rate case or an IRP proceeding;

(7) Reject the Company's proposed financial incentive mechanism; and

(8) Require the Company to confer with Staff when the DR program capital spending will exceed 10% of the approved expenditures.

MICHIGAN OFFICE OF ADMINISTRATIVE HEARINGS AND RULES
For the Michigan Public Service Commission

Kandra K. Robbins

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Kandra K. Robbins
Administrative Law Judge

August 11, 2020
Lansing, Michigan