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April 13, 2018

Ms. Kavita Kale
Executive Secretary
Michigan Public Service Commission
7109 West Saginaw Highway
Post Office Box 30221
Lansing, MI 48909

Re: Case No. U-17990 - In the matter of the application of Consumers Energy Company for authority to increase its rates for the generation and distribution of electricity and for other relief.

Dear Ms. Kale:

Enclosed for electronic filing in the above-captioned case, please find the redacted version of Consumers Energy Company's Electric Distribution Infrastructure Investment Plan.

Please note that the Electric Distribution Infrastructure Investment Plan contains material which has been designated as confidential. This confidential material is being filed under seal with the Michigan Public Service Commission. This is a paperless filing and is therefore being filed only in a PDF format.

Thank you,

Anne M. Uitvlugt



Consumers Energy

Electric Distribution
Infrastructure Investment Plan
(2018-22)

March 1, 2018

Table of Contents

- I. Executive Summary.....1**
- II. Vision for the Consumers Energy Electric Distribution System7**
 - A. A Customer-Driven Future 7
 - B. Objectives 8
 - C. Metrics 10
- III. Description of CE Distribution System.....15**
 - A. Overview of Service Territory and System Components 15
 - B. Age of Assets..... 19
- IV. Overview of System Performance.....23**
 - A. Approach to Assessing System Performance..... 23
 - B. System-wide Performance and External Benchmarking 23
 - C. Regional Performance by Service Regions..... 30
 - D. Circuit-Level Performance 37
 - E. Electric Reliability Rally Room..... 42
- V. Grid Capabilities45**
 - A. Overview of our Future Modernized Grid and Advanced Capabilities 45
 - B. Summary of Investments for Advanced Grid Capabilities 49
 - C. Demand Response and Energy Efficiency 67
- VI. Approach to Investment Planning71**
 - A. Description of the Planning Process Today 71
 - B. Evolution of the Planning Process 75
 - C. Design Standards 77
- VII. Summary of Plan and Projected Impact86**
 - A. Five-Year Capital and O&M Plan..... 86
 - B. Cost to Replace Aging Infrastructure..... 87
 - C. Summary of Impact on EDIIP Objectives 89
 - D. Rate Recovery 96
- VIII. Capital Programs.....98**
 - A. 1.0 New Business 100
 - B. 2.0 Demand Failures 116
 - C. 3.0 Asset Relocations 149
 - D. 4.0 Reliability 159
 - E. 5.0 Capacity..... 203
 - F. 6.0 Tools and Technology 220
 - G. 7.0 Costs of Removals 223
- IX. O&M Programs.....226**
 - A. 1.0 O&M Associated with Capital Investments 228
 - B. 2.0 Reliability O&M..... 228
 - C. 3.0 Operations, Meter Services, Meter Readings, and Service Restoration..... 249
 - D. 4.0 Field Operations..... 261

E.	5.0 Grid Management and SEOC	262
F.	6.0 Planning and Scheduling	263
G.	7.0 Operations Performance	264
H.	8.0 Operations Management.....	265
I.	9.0 Engineering and Operations Support	265
J.	10.0 Engineering and System Planning.....	267
K.	11.0 Joint Pole Rental	272
X.	Conclusion	274
	Appendix A – List of Acronyms and Abbreviations.....	275
	Appendix B – Public Safety During Storms and Outages	278
	Appendix C – Consumers Energy Service Center List	280
	Appendix D – Energy Efficiency and Demand Response	281
	Appendix E – Selected Distribution Work Order Lists.....	284
	Appendix F – Decision Support and Planning Tools.....	303
A.	Reliability Analytics Engine (RAE)	303
B.	Restoration Management Systems.....	304
	Appendix G – Pole Inspection History	306

Table of Figures

Figure 1 – Vision for the Consumers Energy Electric Distribution Grid	9
Figure 2 – Consumers Energy Service Territory	15
Figure 3 – Illustration of Electric Distribution System	16
Figure 4 – Service Territory Voltage Map	18
Figure 5 – HVD Wood Pole Ages	19
Figure 6 – HVD Pole Characteristics.....	20
Figure 7 – HVD Substation Equipment.....	21
Figure 8 – LVD Substation Equipment	21
Figure 9 – LVD Pole Inspection Failure Rate	22
Figure 10 – SAIDI: Comparison of Consumers Energy to IEEE Reliability Survey (2007-2017)	24
Figure 11 – SAIFI: Comparison of Consumers Energy to IEEE Reliability Survey (2007-2017).....	25
Figure 12 – Service Regions and Service Centers.....	30
Figure 13 – Service Region Average SAIDI Excluding MED (2013-2017).....	31
Figure 14 – Service Region Average SAIFI Excluding MED (2013-2017)	32
Figure 15 – Service Region Average CAIDI Excluding MED (2013-2017)	32
Figure 16– Service Region SAIFI vs. CAIDI.....	34
Figure 17 – Service Region Average Percent of Customers with ≥ 3 Interruptions per Year	35
Figure 18 – Service Region Average Percent of Customers with One or More ≥ 5 Hour Interruption	35
Figure 19 – Service Region Average Percent of Customer MED interruption Restored within 24 Hours .	36
Figure 20 – Service Region SAIFI Contribution by Incident Cause (2013-2013 Average, Excluding MED) .	37
Figure 21 – Circuit-Level SAIDI Performance Distribution (2013-2017)	38
Figure 22 – Circuit-Level SAIFI Performance Distribution (2013-2017)	38
Figure 23 – Circuit Distribution of Percent of Customers with ≥ 3 Interruptions per Year	41
Figure 24 – Circuit Distribution of Percent of Customers with One or More ≥ 5 Hour Outage per Year	41
Figure 25 – Grid Modernization Capability Schematic	46
Figure 26 – Fault Location, Isolation, and Service Restoration Schematic	47
Figure 27 – Energy Efficiency and System Optimization Schematic	48
Figure 28 – DER Integration	49
Figure 29 – Deployment Timeline of Grid Capability investments	50
Figure 30 – Grid Modernization Technology Elements.....	53
Figure 31 – DSCADA Operational Visibility Illustration	54
Figure 32 – Installed Automatic Transfer Recloser	55
Figure 33 – Distribution Automation Loop Functionality Model	56
Figure 34 – Electric System Model Enhancement	58
Figure 35 – ADMS Overview	59
Figure 36 – Conceptual Data Lake Visual	61
Figure 37 – Example of Battery Energy Storage System	63
Figure 38 – Rendering of WMU Parkview Solar Farm BESS.....	64
Figure 39 – Circuit West Community Overview.....	65
Figure 40 – Rendering of Circuit West BESS	66
Figure 41 – Forecasted EV Adoption in Michigan	67
Figure 42 – Electric Distribution Financial and Engineering Planning Process	72
Figure 43 – Shielded LVD Tree Wire Construction.....	78
Figure 44 – ASC Construction by a Roadside	79
Figure 45 – Close-Up of an ASC Bundle.....	79

Figure 46 – ASC Supporting a Fallen Tree	80
Figure 47 – Horizontal HVD Polymer Post Design.....	81
Figure 48 – Illustration of MOAB Impact on HVD Line.....	83
Figure 49 – Path to Achieve 2022 SAIDI Target	91
Figure 50 – Historical Electric New Business Services Installed.....	102
Figure 51 – Homebuilders Association of Michigan Forecast.....	103
Figure 52 – New Business Project Example	104
Figure 53 – LVD New Business Project Example	104
Figure 54 – LVD New Business Planning Process	106
Figure 55 – Replacement of the Duct Bank in Alley for the New Service	112
Figure 56 – Artist Rendering of the New Mott CC Culinary Arts Institute in Downtown Flint	113
Figure 57 – Area Requiring Installation of new Conduit.....	113
Figure 58 – LVD Demand Failures Planning Process.....	124
Figure 59 – AC Transformer Failure at Gladwin Substation.....	128
Figure 60 – Infrared photo of Failed Transformer at Gladwin.....	129
Figure 61 – Failed Transformer at Shanty Creek Substation	129
Figure 62 – Screenshot From Corona Camera Showing Insulator With Corona Signature	134
Figure 63 – Typical 46 kV MOAB Switch	135
Figure 64 – Damaged Cable	143
Figure 65 – Damaged / Crushed Duct Banks.....	144
Figure 66 – Deteriorated Manhole/Vault Roofs	144
Figure 67 – Sunken/Deteriorated Manhole Access	145
Figure 68 – Rusted/Deteriorated Vault Hatches and Vents	145
Figure 69 – Vault or Manhole Roof Replacement.....	146
Figure 70 – Installation of New Manholes or Vaults.....	146
Figure 71 – Installing New Concrete Encased Duct Bank.....	147
Figure 72 – LVD Pole and Light Relocation Diagram for Municipality Road Widening.....	151
Figure 73 – LVD Traffic Signal Relocation Diagram for Municipality Road Widening.....	152
Figure 74 – LVD Asset Relocation for Private Landowner	152
Figure 75 – Underbuilt LVD on HVD System Awaiting Transfer to New Pole	153
Figure 76 – Direct Bury System (Left), Vault with Structural Damage (Right)	154
Figure 77 – New Duct Bank Built in Sidewalk Area	158
Figure 78 – Installation of New Duct Bank and Manhole	158
Figure 79 – Installation of Manhole Roof	159
Figure 80 – Illustration of First Zone Interruption Reduction.....	162
Figure 81 – RAE ranking Formula	164
Figure 82 – LVD Reliability Planning Process	165
Figure 83 – Diagram of System Protection Zones.....	166
Figure 84 – Deterioration of HVD Pole Top From Helicopter Inspection	170
Figure 85 – Age of HVD Wood Poles.....	171
Figure 86 – Mobile Substation	177
Figure 87 – Screenshot Example of the Repetitive Outage Report	185
Figure 88 – Repetitive Outage Customers vs. SAIFI (2008-2017)	187
Figure 89 – Old Robinson Vault Equipment Before Reliability Project	191
Figure 90 – New Robinson Vault Equipment	192
Figure 91 – Transformer Analytics Example	202
Figure 92 – LVD Lines Capacity Load Review Process.....	206
Figure 93 – Distribution Line Conductor Peak Loading.....	207

Figure 94 – LVD Capacity Planning Process 208

Figure 95 – Ranking of Proposed Capacity Projects..... 209

Figure 96 – Geographic HVD Planning Areas 214

Figure 97 – Blown Capacitor Fuses 231

Figure 98 – Sagged Wires on Pierson Feeder 232

Figure 99 – System SAIFI Improvement Post Clearing 238

Figure 100 – System SAIDI Improvement Post Clearing..... 239

Figure 101 – CNUC Benchmark Study – 5 year Annual Average Tree Related Outages per system pole Mile (2011-2015)..... 240

Figure 102 – Secondary Pole with Broken Guy 255

Figure 103 – Primary Pole with Broken Guy 256

Figure 104 – Helicopter Inspection 271

Figure 105 – Reliability Analytics Engine (RAE) Data Sources..... 304

List of Tables

Table 1 – Summary of Five-Year Electric Distribution Investment Plan	4
Table 2 – Historical Performance on Metrics and Targets.....	13
Table 3 – Distribution System Lines Overview.....	16
Table 4 – Distribution System Substations Overview	17
Table 5 – SAIDI and SAIFI Indices	25
Table 6 – Customers Experiencing Multiple Interruptions by Year	26
Table 7 – Customers Experiencing Long Interruption Duration	26
Table 8 – Time to Restore After MED Interruption.....	27
Table 9 – Service Quality and Reliability Standards for Electric Distribution Systems (U-12270)	27
Table 10 – Low Voltage Distribution Outage Incident Summary	28
Table 11 – High Voltage Distribution Outage Incident Summary	29
Table 12 – Ten Poorest-Performing SAIDI Circuits.....	39
Table 13 – Ten Poorest-Performing SAIFI Circuits.....	39
Table 14 – Battery Storage Benefits.....	63
Table 15 – HVD NESC Pole Design Standards	82
Table 16 – CE Participation in EPRI Grid Programs	84
Table 17 – Five-Year Capital Plan.....	86
Table 18 – Five-Year O&M Plan	87
Table 19 – Estimated Replacement Cost for Assets Past Expected Life	88
Table 20 – Five-Year Capital Plan for Unplanned Programs	99
Table 21 – Five-Year Capital Plan for Planned Programs	100
Table 22 – Capital: LVD Lines New Business	101
Table 23 – Capital: HVD Strategic Customers New Business	107
Table 24 – Capital: Metro New Business	110
Table 25 – Capital: Distribution Metering.....	115
Table 26 – Capital: Distribution Transformers.....	116
Table 27 – Capital: LVD Demand Failures	118
Table 28 – Service Restoration Activities (Demand) 3-Year Capital History.....	119
Table 29 – Service Restoration Repair Prioritization	119
Table 30 – Street Light Failures 3-Year Capital History.....	120
Table 31 – Underground Rehabilitation Estimated Miles.....	121
Table 32 – LVD Security Assessment Hazard Codes	123
Table 33 – Capital: LVD Substation Demand Failures	127
Table 34 – Capital: HVD Lines Demand Failures	131
Table 35 – HVD System Patrol Findings Criteria	132
Table 36 – Bore Test Criteria to Identify Wood Pole Replacement Candidates	133
Table 37 – Capital: HVD Substations Failures	136
Table 38 – HVD Substation Failures Projects (2017).....	137
Table 39 – HVD Substation Inspection Cadence	138
Table 40 – Capital: Street Lighting	141
Table 41 – Capital: Metro Demand Failures	142
Table 42 – Capital: LVD Lines Reliability	160
Table 43 – Capital: HVD Lines Reliability.....	167
Table 44 – HVD Outages Sorted by Number of Incidents Over the Period of 1/1/2015 – 12/31/2017 ..	169
Table 45 – HVD Outages Sorted by Cumulative Customer Minutes.....	169

Table 46 – Impact of Line Rebuilds on Outages.....	173
Table 47 – HVD Lines Reliability Approved Project List	174
Table 48 – Capital: LVD Substation Reliability	175
Table 49 – Capital: HVD Substation Reliability.....	178
Table 50 – Capital: Substation Communication Upgrades	181
Table 51 – Capital: HVD System Protection	182
Table 52 – Capital: LVD Repetitive Outages.....	184
Table 53 – Capital: Metro Reliability.....	188
Table 54 – Capital: Advanced Capabilities Infrastructure: Automation	193
Table 55 – Capital: Advanced Capabilities Infrastructure: Advanced Technology	199
Table 56 – Grid Operational Analytics Key Data	201
Table 57 – Capital: LVD Lines Capacity.....	204
Table 58 – Capital: HVD Lines and Substations Capacity	211
Table 59 – Capital: LVD Substation Capacity	217
Table 60 – Capital: Tools and Technology.....	220
Table 61 – Capital: System Control Projects	221
Table 62 – Historical Capital: Cost of Removals – LVD.....	224
Table 63 – 2017 Sample Retirement-Only Work Orders: Cost of Removals – LVD	224
Table 64 – Historical Capital: Cost of Removals – HVD.....	225
Table 65 – Five-Year O&M Plan	227
Table 66 – O&M: O&M Associated with Capital Investments.....	228
Table 67 – O&M: Reliability	229
Table 68 – O&M: HVD Lines Reliability	233
Table 69 – Substation Inspection Cadence	236
Table 70 – O&M: Forestry.....	237
Table 71 – LVD Clearing Schedule for Seven-Year Effective Cycle	241
Table 72 – O&M: LVD Line Clearing Five-Year Plan	242
Table 73 – HVD Clearing Schedule	244
Table 74 – O&M: Specimen Trees in Maintained Landscapes.....	246
Table 75 – ROW Width and Clearing for Non-Specimen Trees	247
Table 76 – O&M: Service Restoration.....	250
Table 77 – Historical Incidents.....	250
Table 78 – O&M: Demand Maintenance	251
Table 79 – O&M: Staking, Street light and Service Call	257
Table 80 – O&M: Meter Services	258
Table 81 – O&M: Smart Energy MTC – Electric	259
Table 82 – Communications Backhaul Charge calculation	260
Table 83 – O&M: Other Operations and Metering.....	260
Table 84 – O&M: Field Operations	261
Table 85 – O&M: Smart Energy Operations Center.....	262
Table 86 – O&M: Grid Management.....	263
Table 87 – O&M: Planning and Scheduling.....	264
Table 88 – O&M: Engineering and Operations Support	265
Table 89 – O&M: Engineering and System Planning	267
Table 90 – Helicopter Patrol Inspection Types	272
Table 91 – List of Acronyms and Abbreviations.....	275
Table 92 – Consumers Energy Service Center List	280
Table 93 – 2018-2022 Demand Response Enrollment Forecast	281

Table 94 — 2018-2022 Demand Response Financial Forecast	282
Table 95 — 2018-2022 Energy Efficiency Forecast	283
Table 96 — 2018-2022 Energy Efficiency Financial Forecast	283
Table 97 — Summary of Work Orders, as of February 2018.....	284
Table 98 — 1.1 Lines New Business – LVD – 20 Largest Work Orders by Year	284
Table 99 — 1.2 HVD Lines Strategic Customers – 20 Largest Work Orders by Year	285
Table 100 — 1.3 Metro New Business – 20 Largest Work Orders by Year	285
Table 101 — 2.1 LVD Lines Failures – 20 Largest Work Orders by Year.....	286
Table 102 — 2.2 LVD Substations Failures – 20 Largest Work Orders by Year	287
Table 103 — 2.3 HVD Lines and Subs Failures – 20 Largest Work Orders by Year	288
Table 104 — 2.7 Metro Failures – 20 Largest Work Orders by Year	289
Table 105 — 3.1 LVD Lines Relocations – 20 Largest Work Orders by Year.....	289
Table 106 — 3.2 HVD Lines Relocations – 20 Largest Work Orders by Year.....	290
Table 107 — 3.3 Metro Relocations – 20 Largest Work Orders by Year.....	290
Table 108 — 4.1 LVD Lines Reliability – 20 Largest Work Orders by Year.....	291
Table 109 — 4.2 HVD Lines Reliability – 20 Largest Work Orders by Year.....	292
Table 110 — 4.3 LVD Substations Reliability – 20 Largest Work Orders by Year	293
Table 111 — 4.4 HVD Substations Reliability – 20 Largest Work Orders by Year	294
Table 112 — 4.5 Substations Communications Upgrades – 20 Largest Work Orders by Year	295
Table 113 — 4.6 System Protection – 20 Largest Work Orders by Year	296
Table 114 — 4.7 LVD Repetitive Outages – 20 Largest Work Orders by Year.....	297
Table 115 — 4.8 Metro Reliability – 20 Largest Work Orders by Year.....	297
Table 116 — 4.9 Grid Capabilities: Automation – 20 Largest Work Orders by Year	298
Table 117 — 5.1 LVD Lines Capacity – 20 Largest Work Orders by Year.....	300
Table 118 — 5.2 HVD Lines and Subs Capacity – 20 Largest Work Orders by Year	300
Table 119 — 5.3 LVD Substations Capacity – 20 Largest Work Orders by Year	301
Table 120 — HVD and LVD Pole Inspections	307

I. Executive Summary

Consumers Energy Company (Consumers Energy or the Company) has proudly served Michigan families and businesses for over 130 years, with nearly 1.8 million electric customers across the state today. We are committed to providing an electric distribution system that delivers safe, reliable, and affordable electricity to our customers today and in the future. We must address challenges that exist with our infrastructure in the near-term, while adapting to meet evolving customer expectations. Our long-term ambition for the distribution system centers on five primary customer-driven objectives:

- **Safety and Security:** Improve overall safety, physical and cyber security for our customers and employees;
- **Reliability:** Improve reliability of the system under normal operating conditions and resiliency under extreme conditions;
- **Sustainability:** Continue to look for opportunities to explore sustainable options and reduce waste in the system;
- **Control:** Provide customers with the data, technology and tools to take greater control over their energy supply and consumption; and
- **System Cost:** Deliver the objectives above at an optimal, long-term system cost for all customers.

Over the past 10 years, we have invested nearly five billion dollars into our electric distribution system to maintain and upgrade our infrastructure. We have made strides towards our long-term ambition through deployments like our distribution automation loop installations (2010-2017) and Advanced Metering Infrastructure (AMI¹) rollout (2012-2017), though there is much more to accomplish in order to reach our vision.

In its Order in Michigan Public Service Commission (MPSC or the Commission) Case No. U-17990, dated February 28, 2017, the MPSC directed us to submit a five-year electric distribution investment plan to provide the Commission, MPSC Staff, and other parties a more thorough understanding of anticipated needs, priorities, and distribution spending outside of the contested rate case process. This five-year plan would include a detailed description of distribution system and asset condition, investment, and maintenance strategies, system goals, and performance metrics and assessments used to drive prioritization of investments².

This report, *Consumers Energy Electric Distribution Infrastructure Investment Plan (EDIIP)*, is our response to the Commission's Order and opportunity to share our grid strategy – specifically, the purpose, scope, and investments of our plan over the next five years as steps towards our long-term

¹ See Appendix A for full list of all acronyms and abbreviations.

² Full requirements and other supporting information in MPSC Case No. U-17990 docket including original Order on February 28, 2017; draft submission on August 1, 2017; public comments received through September 6, 2017; Order with further guidance on October 11, 2017; Order on November 21, 2017 with submission date for final report (this document).

vision. This path forward aligns with Governor Snyder's 2013 reliability goals to reduce both frequency and duration of customer outages³ and encompasses a broadened set of customer-driven objectives.

Highlights of our five-year EDIIP include:

- **Vision for the Consumers Energy Electric Distribution System:** The future of the electric distribution system is customer-driven and requires a dynamic electric distribution system that integrates cleaner, more modular sources of electric supply with grid enhancements engineered for customer value.
 - **Near-term Objectives:** We will continue our strong focus over the next five years to maintain and optimize the system through investments to rehabilitate, replace and rebuild existing infrastructure while also responding to emergent and customer-driven work. We will also lay the foundation for advanced grid capabilities and test out new technologies to increase our understanding of their role in the Consumers Energy distribution system.
 - **Long-term Objectives:** We will transform and modernize the grid by developing new capabilities and approaches to grid investment to maximize customer benefits across all five of our customer-driven objectives.
 - **Metrics:** We have developed a set of 14 metrics in order to track and manage our performance against each of our five objectives. The combination of these customer-driven metrics and our five objectives creates a balanced framework that underpins our investment decisions. Over time, we will continue to evaluate and evolve our metrics as more granular and local data becomes available, and as the needs and priorities of our customers change.
- **CE Distribution System and Overview of System Performance:** Benchmarked against our peers, our system performance consistently ranks well in the number of interruptions experienced by our customers (nearing first quartile System Average Interruption Frequency Index (SAIFI) in 2017), and we have seen significant improvement in our outage duration (approximately 25% reduction in System Average Interruption Duration Index (SAIDI) over the past five years). In 2017, we achieved our best SAIDI performance in 17 years and best ever SAIFI performance – evidence of our dedication to improve the state of our system and reliability for customers.
- **Grid Capabilities:** We will continue to advance our grid modernization strategy and build capabilities that will greatly enhance our distribution system performance and ability to deliver value to our customers in the long term. Over the next five years, we will build three critical grid capabilities: Fault Location, Isolation, and Service Restoration (FLISR) for reduced outages and faster restoration time, energy efficiency and system optimization (Volt-Var Optimization (VVO) and Conservation Voltage Reduction (CVR)), and distributed energy resource integration and

³ The Governor's guidance is for utilities to be operating in the first quartile among peers within the SAIFI and top half among peers within the SAIDI as well as SAIFI of 1.00 and SAIDI of 150 minutes. "21st Century Infrastructure Commission Report," pages 54 through 55.

http://www.michigan.gov/documents/snyder/21st_Century_Infrastructure_Commission_Report_555079_7.pdf

optimization. To build these capabilities, we will invest in foundational upgrades in infrastructure and telecommunications, as well as deployment of modern grid devices to improve system automation (Supervisory Control and Data Acquisition (SCADA) and Distribution Supervisory Control and Data Acquisition (DSCADA), line sensors, etc.) and advanced applications and analytics such as an Advanced Distribution Management System (ADMS) and our Electric System Model Enhancement (ESME) initiative.

- **New Technologies and Non-Wires Alternatives:** We believe Distributed Energy Resources (DERs) and Non-Wires Alternatives (NWA) will be critical parts of the future distribution network. We are committed to growing our capabilities and experience using NWA to defer or replace the need for traditional distribution equipment upgrades. We will incorporate NWA such as Energy Efficiency (EE), Demand Response (DR), DERs, and battery storage into our planning solutions pool. Through a combination of targeted piloting and analytics, we will make the right investments in the right place and at the right time.
- **Approach to Investment Planning:** The five-year plan outlined in this report is a result of a planning process designed to prioritize and sequence investments to meet system needs and achieve our customer-driven goals and objectives for the electric distribution grid.
 - **Planning Process Today:** We first determine and dedicate the pool of capital investment dollars needed to respond to customer requests and emergent needs. We then conduct a thorough analysis of the state of our system and customer needs to determine how to best allocate our funds to our “planned” programs, using a variety of investment prioritization methodologies and a robust set of design standards. We use a rigorous approach to the ongoing review and management of our operational performance, with a focus on continuous improvement.
 - **Evolution of the Planning Process:** As alternatives to traditional grid solutions become increasingly accessible (e.g., DR, battery storage, etc.), we will continue to evolve our planning process to take advantage of the benefits and opportunities of these new technologies. Increasing use of advanced data and analytics and greater cross-functional integration in our electric supply and distribution planning processes will be critical enablers to accelerated use of non-wires alternatives in our system.
- **Summary of Five-Year Plan (Capital and O&M programs):** Over the next five years, we plan to invest approximately \$3 billion of capital in our infrastructure to ensure safe and reliable electric service to our customers. In addition, our plan includes on average \$200 million annually for critical operations and maintenance activities, such as vegetation management, service restoration, field operations, and grid management. Table 1 is a summary of the capital investment and Operations and Maintenance (O&M) expense plan over the next five years. While the need for continued investment in our infrastructure is great, we limit our spending by customer affordability – striving to keep rate increases at or below the cost of inflation.

TABLE 1 – SUMMARY OF FIVE-YEAR ELECTRIC DISTRIBUTION INVESTMENT PLAN

5-Year Plan									
All values in \$ millions		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
Capital Programs									
Cap-ital	New Business	73	88	97	95	98	103	105	108
	Demand Failures	123	119	156	145	152	150	151	153
	Asset Relocations	28	20	28	27	24	26	26	26
	Total Unplanned	223	226	281	267	274	280	281	287
	Reliability	83	133	111	184	232	193	194	186
	Capacity	44	57	53	51	57	58	59	63
	Tools and Technology	3	4	3	10	11	11	11	11
	Total Planned	129	193	167	245	300	262	264	260
	Cost of Removals	40	42	70	60	62	59	58	57
	Capital Plan	392	461	518	572	635	601	603	605
Demand Response	0	1	7	9	9	9	8	8	
O&M Programs									
O&M	Reliability	40	54	53	55	56	59	63	67
	Ops, Metering, Service Restoration	89	76	83	69	77	77	78	79
	Field Operations	23	19	22	20	20	20	21	22
	Other O&M (i.e. Ops Support, Grid Management, Planning)	28	30	31	36	37	38	39	39
	O&M Plan	180	180	189	179	190	196	201	207
	Energy Efficiency & Demand Response	78	79	121	128	127	130	134	135

- **Unplanned Programs:** We expect to deploy between \$267 million and \$287 million per year towards unplanned programs in response to customer requests and emergent needs, a total of \$1.4 billion over the five-year plan. This level of investment is consistent with recent trends in these programs. Unplanned programs cover new business connections (roughly 10,000 new connections per year), response to emergent system needs (840,000 service restoration orders per year in Low-Voltage Distribution (LVD) lines), and the relocation of assets due to customer requests.
- **Planned Programs:** We expect to deploy between \$245 million and \$300 million per year towards planned programs, a total of \$1.3 billion over the five-year plan. Approximately half of this funding will be on infrastructure investments to reduce outages and improve reliability, including replacement of 6,000 to 8,000 poles per year and rebuilding four to five LVD substations each year, as part of our holistic reliability programs. We will also invest between \$50 million and \$63 million per year in upgrading and rebuilding targeted areas on the grid to ensure we are able to service the expected future system needs. Finally, our planned programs include investing approximately \$40 million to \$60 million per year on the infrastructure, telecommunications, and grid devices that will enable the advanced grid capabilities needed to modernize our grid and better serve customers.

- **Operations and Maintenance:** Over the next five years, we expect to spend approximately \$200 million per year for critical operations and maintenance activities. This includes a plan to increase spending on our forestry program in order to reduce the number of tree-caused outages on our system. It also includes spending on service restoration and critical support functions that will help to achieve our objectives.
- **Summary of Projected Impact of Plan:** Based on the five-year investment and maintenance plan outlined above, we will deliver on the vision, goals, and targets outlined above. The benefits to our customers across our five objectives include:
 - **Safety and Security:** We commit to providing a safe environment for employees, contractors, customers, and the public. We also recognize that safety and security extends beyond physical infrastructure to cybersecurity. We design our investment prioritization methodology to ensure a safe environment. Every time we upgrade failing or aging infrastructure beyond its expected life, there is an implicit safety benefit to employees and the public with the new infrastructure (which is hardened, resilient and modernized). In addition, there are specific programs and investments planned to ensure compliance with safety standards, such as those prescribed by the National Electrical Safety Code (NESC).
 - **Reliability:** We track reliability and resiliency through both a traditional engineering lens (with SAIDI, SAIFI) as well as a customer lens (e.g., number of customers with more than three outages per year) to ensure that we are accurately tracking both system-wide and individual customer experiences. Our investments in traditional infrastructure and grid modernization along with operational improvements are expected to deliver SAIDI and SAIFI benefits to meet the Governor’s goals: achieving a SAIFI in the first quartile of peers (less than 1.0) and a SAIDI in second quartile (target for 2022 of 120 minutes; second quartile today is less than 124 minutes). Reaching this level of performance will be the lowest SAIDI in our Company’s history, and will avoid 216 million minutes of customer outages and result in 200,000 and 300,000 fewer customer outages annually.
 - **Sustainability:** We aim to reduce the overall waste and carbon footprint driven by our operations by reducing energy usage and losses. Our five-year plan includes growing our demand response and energy efficiency programs. For example, we plan to increase our Commercial and Industrial (C&I) demand response portfolio from 50 MW in 2017 to 270 MW by 2022. In addition, we plan to continue early deployment and pilots of NWA investments.
 - **Control:** We aim to provide customers greater control over their power across a variety of dimensions, including providing information, technology, programs, and services to support customers in managing their usage. Our investments in grid automation and advanced system analytics will be critical to achieving this objective, increasing our situational awareness and enabling faster identification and resolution of system performance issues.
 - **System Cost:** We will meet all of our objectives in a manner that is most cost-effective and equitable for our entire customer base over the long term. Some of our investments have benefits in reducing costs, for example: replacing electromechanical (EM) relays

with newer digital devices that require less periodic maintenance and introducing grid automation devices that will allow operators to remotely operate substation equipment and reduce the number of truck rolls. In addition, we continuously look for productivity opportunities to improve the cost effectiveness of our investments. For example, we are improving our line clearing cycle to reduce the cost per line-mile of forestry work.

- **Regulatory approach and rate recovery:** Our five-year plan presents capital investment and O&M spending needed to support and improve our distribution system while providing the most value to our customers. In an effort to ensure a timely and customer-focused implementation of this investment strategy, we will work with the MPSC Staff on potential rate recovery mechanisms such as investment recovery and “shared savings” mechanisms. With the latter, we believe this type of innovative regulatory approach is intriguing in its potential application to non-wires alternatives and other aspects of utility operations designed to optimize the energy system.

Through our EDIIP, we present our future vision for the electric distribution system, compare and contrast that with the current state of the system, and outline our investment plan to bridge between the current state and the future. We look forward to working with the MPSC and the broader set of stakeholders as we execute and evolve this plan over time.

II. Vision for the Consumers Energy Electric Distribution System

A. A Customer-Driven Future

Over the past century, the electric distribution system has undergone a number of changes affecting system requirements and the investments needed to meet those requirements. Today, the electric grid is evolving ever-faster as technological advances and financial innovations allow customers to change their electricity usage in new, meaningful, and sometimes unexpected ways. Customer expectations are becoming more varied and complex, which requires the system to become increasingly adaptable. For the residential segment, one customer may want to install distributed solar, while another may desire greater certainty in his/her monthly bill. For the C&I segment, customers are expressing greater demand for a variety of options from lowering cost (e.g., demand response for peak shaving), to creating a brand that is more environmentally conscious (e.g., 100% renewable energy). More broadly, customers want some combination of the following objectives: enhanced security and safety, lower cost, improved reliability and resiliency, sustainable solutions, and more control over energy supply and consumption.

Additionally, there is a renewed focus on the critical state of the United States infrastructure in general, from water to transportation to electricity, as the infrastructure ages. The American Society of Civil Engineering's 2017 Infrastructure Report Card⁴ gives United States energy infrastructure a D+ grade, saying "the U.S. energy sector faces significant challenges as a result of aging infrastructure, including supply, security and reliability, and resiliency issues in the face of severe weather events, all posing a threat to public safety and the national economy." These acute infrastructure needs affect Michigan. Governor Snyder's 21st Century Infrastructure Commission Report⁵ identified a modern and dependable electric grid as a priority area for infrastructure improvement. The statewide storm events in March of 2017 further highlighted the need for increased reliability and resiliency.

Over the coming decades, five trends in customer expectations will meaningfully affect the attributes of the electric distribution system and thus the assets and capabilities required to operate it successfully:

- **Reliability and resiliency:** Outage events are extremely costly, both to the utility when we respond, and to our customers via lost productivity and damage. Following outage events across the country, from Hurricane Sandy in 2012 to the recent March 2017 storms in Michigan, customers increasingly focus on reliability and resiliency in their assessments of utility service.
- **Security:** Customers, governments, and utility executives are increasingly focusing on security threats, especially cybersecurity, as one of the most important issues facing utilities today, reflected through increasing security spending. Recent events, including the December 2015 hacking of several Ukrainian electric distribution centers and the April 2013 sniper assault on a Pacific Gas and Electric transmission substation, have highlighted the real security threats present today. In fact, in Utility Dive's "2017 State of the Electric Utility Survey"⁶ of utility executives, physical and cyber security threats topped the list as the most important concern for utility executives today.

⁴ <https://www.infrastructurereportcard.org/>.

⁵ http://www.michigan.gov/documents/snyder/21st_Century_Infrastructure_Commission_Report_555079_7.pdf.

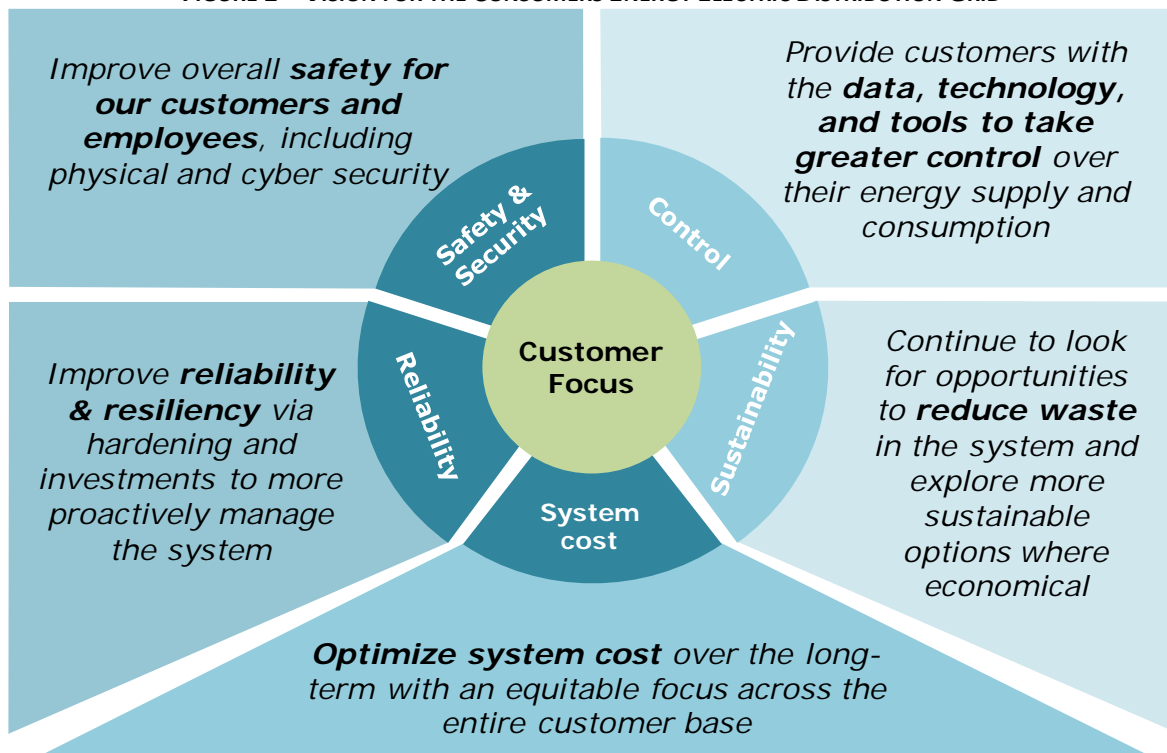
⁶ <http://www.utilitydive.com/library/2017-state-of-the-electric-utility-survey-report/>.

- **Distributed energy resources (DERs):** Customers will continue to pursue adoption of DERs (e.g., Distributed Generation (DG), battery storage, and Electric Vehicles (EV)). Adoption will accelerate as underlying costs continue to fall along normal experience curves.
- **Renewable generation:** C&I customers across the country and within Michigan will continue to desire expanded renewable generation, driven by falling costs of renewable energy and increasing demand by end use customers for stronger corporate commitment to sustainability and environmental responsibility. Projections for wind energy costs suggest it could be competitive with traditional generation on an unsubsidized basis in Michigan over the next decade. In addition, four of Michigan’s largest corporations have recently publicly stated a desire for a greater percentage of their electricity to be renewable, with more coming forward each year.
- **Data proliferation:** Our customers have a growing amount of data at their fingertips and increasingly leverage that data to make new, ever more impactful, real-time decisions. Customers can change the thermostat, monitor their homes, unlock the doors, and even do the laundry remotely. This new reality is evident in the electric sector as well. Customers can actively engage with the system via energy efficiency and demand response programs, and have the potential to control DG and energy storage devices. Further into the future, this could unlock the potential for a more interactive relationship between utilities and their customers, supported by expanded data and the analytics to drive new insights and decision-making. Just as past technological innovations rapidly penetrated the market over the course of a single generation, these “grid edge” data-driven technologies are expected to become deeply integrated in the electric distribution system over the next two decades.

B. Objectives

In our five-year EDIIP, we commit to building a more modern electric distribution system that integrates cleaner, more distributed sources of electric supply with grid enhancements that are engineered for customer value. More specifically, the plan focuses on solving for five primary objectives through the lens of the customer:

FIGURE 1 – VISION FOR THE CONSUMERS ENERGY ELECTRIC DISTRIBUTION GRID



- **Enhance cybersecurity, physical security, and safety** – Our plan will introduce new technologies and new work processes to support the deployment and operation of those technologies. We will design the system to ensure that the security and safety of our customers – and our employees – are maintained and ultimately enhanced.
- **Improve reliability and resiliency** – We will harden the system, where necessary; improve visibility in order to more proactively operate the system; minimize outage occurrences; respond with speed and effectiveness to minimize outage duration; and better manage frequency and voltage.
- **Optimize system cost over the long term** – We will meet all of our objectives in a manner that is most cost-effective and equitable for our entire customer base over the long term. We will not optimize costs for some customers in a manner that unfairly impacts other customers, and will not be short-sighted by minimizing cost in the short term only to bear a multiple of that cost in later years.
- **Increase sustainability and reduce waste in the system** – We will continue to look for opportunities to reduce waste in the system by building “at the right size and at the right time” (e.g., smaller, more modular, and more targeted investments) and exploring opportunities to promote lower carbon resources where economical (e.g., non-wires alternatives that integrate distributed generation).
- **Enable greater control** – We will continue to configure the system providing customers with the data, technology, and tools to take greater control over their energy supply and consumption. This will require a more robust communications network to facilitate two-way flows of

information and further improve our own systems to gather more data and translate that data into information useful to our customers, our regulators, and ourselves.

Over the next five years, we will focus on maintaining and optimizing our core system with an emphasis on safety and security, reliability and resiliency, and system cost while developing capabilities to improve sustainability and control. Our plan focuses on meeting the expectations of customers while continuing to develop rate constructs, in conjunction with the MPSC, that reflect the value of our services and provide sustainable returns.

C. Metrics

i. Description of Metrics

We have developed a set of metrics to track and manage our performance against each of our five objectives. These metrics are customer-focused, and are a mix of leading indicators and outcome measures. We will continue to evaluate and refine these metrics over time. In addition to tracking our performance against our EDIIP metrics, we regularly track and report our performance against MPSC-defined performance standards for electric power reliability and quality through annual filings and semi-annual updates with the MPSC Staff.

Enhance cybersecurity, physical security, and safety

We commit to safe operations for all stakeholders, including employees, contractors, customers, and the public. We work with various regulatory agencies to ensure safe and secure operations of our distribution system.

- **Recordable incident rate** – Ensuring all employees are operating safely, as part of our broader corporate security and safety mandate.
- **Wire down relief factor** – Ensuring we are minimizing risk by relieving police/fire-guarded wire downs in four hours or less within Michigan Metropolitan Statistical Areas (MMSAs) and six hours or less outside MMSAs, per MPSC performance standards.

We recognize that safety and security extends beyond physical boundaries to cybersecurity. Protecting our critical infrastructure and customer data are our top priorities for Consumers Energy. The Company has developed an industry-leading security program and has invested heavily in its development and maintenance. Security will be a key pillar of success for the EDIIP effort and will be fully embedded into the program. Security requirements will be implemented and new technologies will be assessed to ensure vulnerabilities are not introduced into the grid.

Furthermore, we are strongly committed to measures that will improve public safety through our investments to replace aging infrastructure, activities to limit the impact of wire downs and upgrades of our facilities, and equipment to up-to-date safety standards. We have a number of public safety programs and initiatives underway to improve how we inform and protect the public when incidents do occur. These programs are described in more detail in Appendix B.

Improve reliability and resiliency

We track reliability and resiliency through both a traditional engineering lens (e.g., with SAIDI, SAIFI metrics) and also a customer lens to ensure that we are accurately representing both overall and individual customer experiences. As noted in the 21st Century Infrastructure Commission Report⁷, “although SAIDI and SAIFI measure average customer reliability in Michigan, often the individual customer experiences can be disguised by these statistics. In order to ensure no customers are left behind with electric reliability goals, it is critical that measures are in place to ensure each individual customer has an expectation of high reliability.”

- **SAIDI** – As an overall measure of operating and engineering performance tracking both the frequency of interruptions and speed of service restoration. SAIDI is influenced by a number of factors, including system design and standards, system condition, and workforce and restoration processes.
- **SAIFI** – As an overall measure of frequency of interruptions experienced by our customers.
- **Percentage of customers experiencing three or more interruptions (greater than five minutes)** – Understanding how many customers are experiencing multiple interruptions. This is related to the MPSC’s standard for Same-Circuit Repetitive Interruption Factor, defined as the percentage of customers with five or more interruptions in a 12-month period.
- **Percentage of customers experiencing a single interruption greater than five hours:** Understanding how many customers are experiencing interruptions with long durations. This is related to the MPSC’s standards for Service Restoration Factor for All Conditions and Normal Conditions, defined as percentage of customers restored in 36 hours or less (all conditions) and eight hours or less (normal conditions).
- **Percentage of customers whose power is restored within 24 hours after a major interruption (a Major Event Day (MED))** – Ensuring we are quickly restoring all customers following a major storm. This is related to the MPSC’s standard for Service Restoration Factor for Catastrophic Conditions defined as the percentage of customers restored in 60 hours or less during ‘catastrophic conditions.’

The reliability indices are calculated using the equations below:

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of customers served}} = \frac{\text{SAIDI}}{\text{CAIDI}}$$

$$\text{CAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customer interruptions}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

⁷ http://www.michigan.gov/documents/snyder/21st_Century_Infrastructure_Commission_Report_555079_7.pdf.

$$\text{SAIDI} = \frac{\text{Sum of all customer interruption durations}}{\text{Total number of customers served}} = \text{SAIFI} \times \text{CAIDI}$$

Optimize system cost over the long term

We track several measures of system cost and investment to ensure that we are delivering cost-effective and equitable performance across our entire customer base. These metrics track system cost and investment at a high-level and enable us to identify trends and then review underlying line-items, programs and projects to ensure each is prudent and delivering customer value.

- **Service restoration O&M cost per incident (three-year rolling average; including MEDs)** – Monitoring and tracking productivity of our service restoration operations. This metric captures both outage and non-outage based incidents.
- **Forestry cost per line-mile cleared** – Monitoring and tracking productivity of our forestry programs to ensure that we are delivering the benefits of line clearing in the most cost-efficient manner possible.

Increase sustainability and reduce waste in the system

We aim to reduce the overall waste and carbon footprint driven by our operations and our customers through reduction in energy usage. We target both average and peak load as ways to reduce both the emissions caused day-to-day as well as limiting the investment in new capacity to support peak load. Additionally, reduction in usage supports the broader goal of maintaining lower electricity bills for customers.

- **Energy savings through Energy Efficiency programs** – Ensuring we help our customers reduce their usage through various energy efficiency programs.
- **System load factor** – Ensuring we are efficiently utilizing our system with the goal of reducing peak load to limit investments in additional capacity; defined as average system load divided by peak load.
- **Total system losses and energy loss reduction** – Monitoring and tracking of network losses and targeted savings in energy losses to reduce waste in the system.

Enable greater control

We aim to provide customers greater control over their power across a variety of dimensions, including providing information, technology, programs, and services to support customers in managing their usage. Our metrics track multiple facets including overall customer sentiment and active engagement with existing tools.

- **Residential customer rating on a survey question: “how would you rate Consumers Energy on helping you manage your monthly electric usage”** – Ensuring customers feel we are supporting greater empowerment, engagement, technology options, and information, in order to meet their supply and consumption needs. We regularly conduct research into the underlying drivers of customer expectations to enable us to deliver the services desired.
- **Residential customers enrolled in the Peak Power Savers® programs** – Number of residential customers that are voluntarily enrolled in peak reduction programs, such as our AC Cycling and Time of Use (TOU) programs.

Customer adoption of DERs and advanced or emerging technologies (e.g., DG, battery storage, and EV) is also an important part of enabling greater control. Refer to Section V for details on our DER strategy and approach as well as an overview of our operational demonstrations and pilot applications introduced to date.

ii. Historical Performance & Metric Targets

Our EDIIP strives for continuous improvement over five years on all five of our objectives: safety and security, reliability and resiliency, cost, sustainability, and control. The table below summarizes historical performance and 2022 target performance for all of our EDIIP metrics.

TABLE 2 – HISTORICAL PERFORMANCE ON METRICS AND TARGETS

Historical Performance on Metrics and Targets					
	Metric	2013-2017	2017	2022 Target	Rationale for Target
Safety & Security	Recordable incident rate (for work in electric operations)	2.47 (2014-17)	1.02	0.58	Electric operations portion of defined corporate targets
	Wire down relief factor (% of police/fire-guarded wire downs relieved in 4 hours inside MMSAs, 6 hours outside MMSAs)	93% (inside MMSA)	87% (inside MMSA)	>90%	Compliance level set in MPSC Electric Distribution Performance Standards MPSC Case No. U-12270
		94% (outside MMSA)	93% (outside MMSA)		
Reliability	SAIDI (excluding MED)	186	161	120	Per Section VII
	SAIFI (excluding MED)	0.96	0.89	0.8	
	% of customers with ≥3 interruptions	16%	16%	14%	Improvements in line with SAIDI and SAIFI reliability targets
	% of customers with one or more interruption of ≥5 hours	28%	31%	20%	
	% of customers restored within 24 hours of a MED interruption	72%	71%	80%	
System Cost	Service restoration O&M cost per incident (three-year rolling average; including MED)	\$532 (2015-17) ⁸	\$519	\$475	Improvements in line with cost and incident reduction targets. Work currently in progress to refine metric to breakdown outage vs. non-outage incident costs.

⁸ Metric history provided for 2015-17 only, due to change in service restoration capital and O&M split in 2015.

	Forestry cost per line-mile cleared	\$9.1K	\$11.0K	\$10.6K	Per O&M program 2.2 Forestry
Sustainability	Energy savings through Energy Efficiency programs	430 GWh	560 GWh	536 GWh	Consistent with the levels committed to in the 2018 – 2021 EE Plan as defined in MPSC Case No. U-18261
	System load factor	58%	60%	60%	2% improvement from 5-year historic average. Includes impact of increasing EE and DR programs
	% system loss	3,000K MWh <i>(2013-16)</i>	3,010K MWh <i>(2016)</i>	65K MWh <i>(2% savings)</i>	2% improvement or ~65k MWh loss savings based on 2013-16 historic average
Control	% residential survey respondents rating 9/10 on CE’s efforts to help control usage (JDP)	20% <i>(2014-17)</i>	25%	First quartile	Ambition is to be top performer relative to comparable Large Midwestern utilities
	Number of residential customers enrolled in the Peak Power Savers® programs	25K <i>(2016-17)</i>	48K	225K	Long-term ambition for residential demand response enrollment

iii. Evolution of Metrics over Time

As part of our continuous improvement processes, we evaluate our metrics regularly to ensure they continue to adequately measure success against our key objectives. The metric definitions are designed to evolve over time as increasingly granular, local data is available and analytics capabilities mature. Over time, our metrics will evolve to become:

- A higher proportion of leading versus lagging indicators to allow us to proactively address issues and limit impacts on our customers.
- Increasingly granular to measure the specific, individualized experiences of customers as well as localized circuit-level performance to allow us to more surgically identify and address issues.

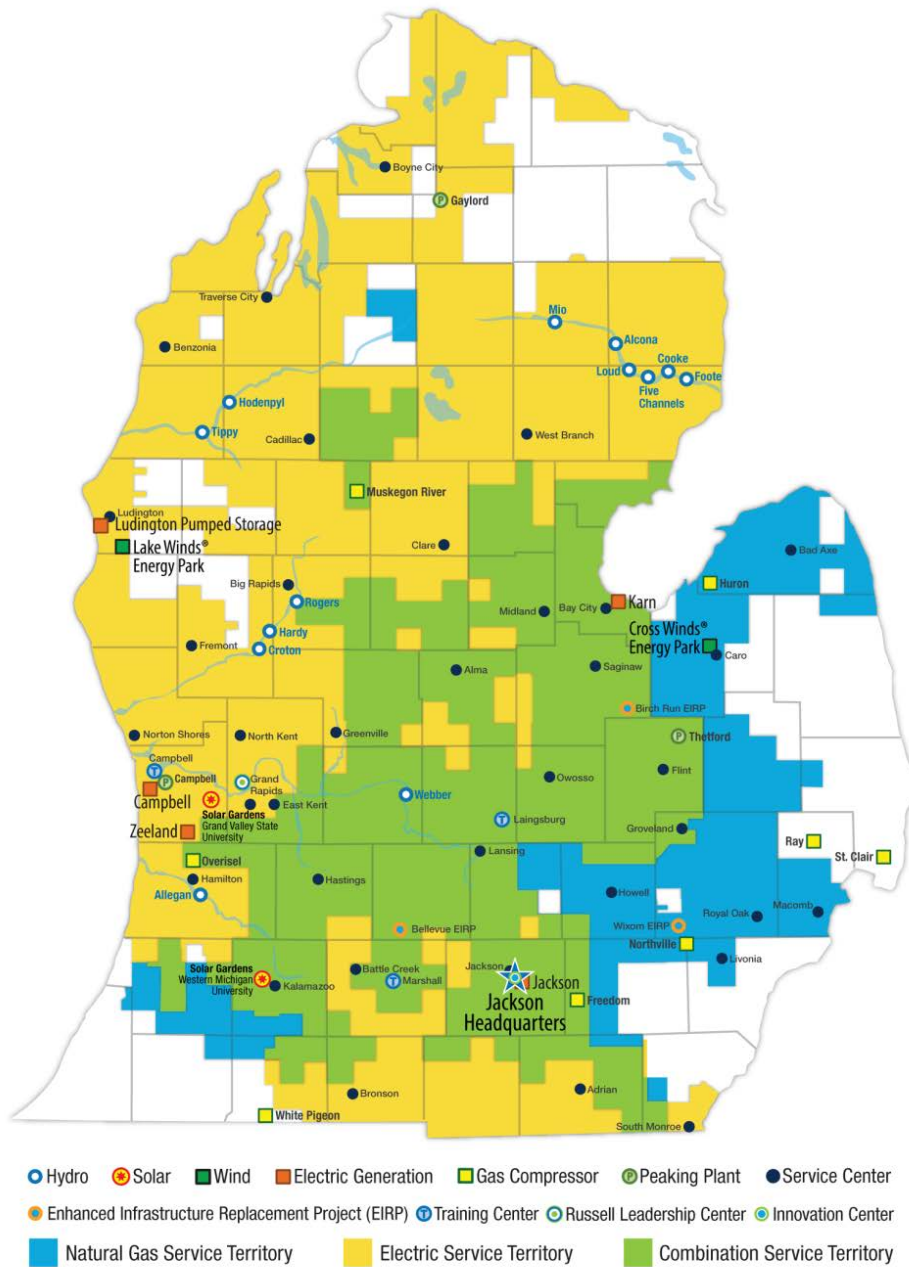
One metric in particular that we are actively in the process of updating is Service Restoration Cost per Incident. Our objective is to further define this metric into two components: Service Restoration Cost per Incident in Storm Conditions and Service Restoration Cost per Incident in Normal Conditions. In doing so, we anticipate we will be able to better isolate the driving factors of service restoration costs under different system conditions. We see a significant delineation in the cost of restoration in storm conditions relative to normal conditions and believe that defining the metric into two components will position us to better target improvements. We are currently conducting the necessary analytics in order to isolate service restoration costs in both scenarios. The evolution of metrics over time will be enabled by our longer-term data analysis strategy (see Section V).

III. Description of CE Distribution System

A. Overview of Service Territory and System Components

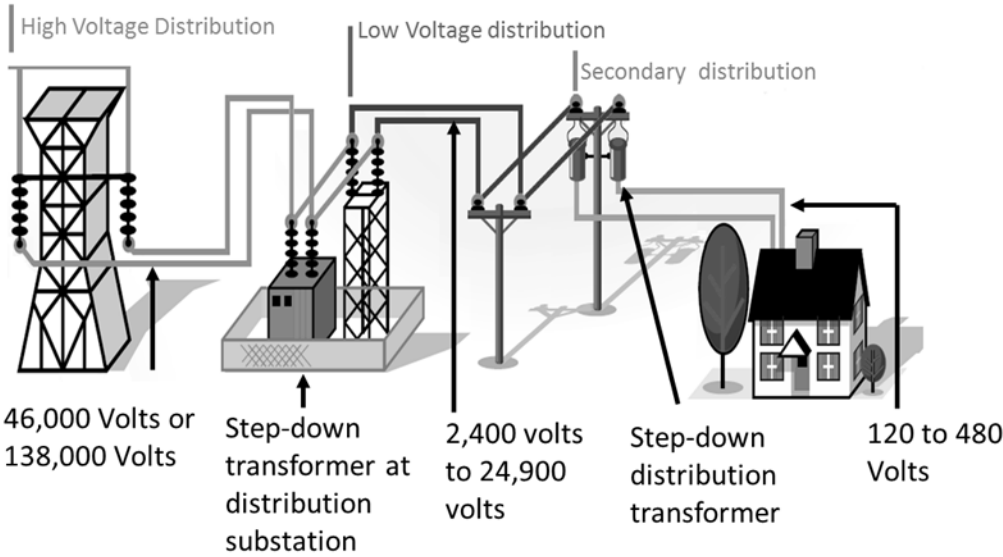
Our electric distribution system is an essential part of Michigan’s infrastructure, serving 1.8 million customers across approximately 70,000 miles of distribution lines and 1,200 substations in the north, central, and western portions of Michigan from Monroe County to Mackinaw City (See Figure 2 below).

FIGURE 2 – CONSUMERS ENERGY SERVICE TERRITORY



Our distribution system consists of wires on High-Voltage Distribution (HVD) and LVD systems, providing service to residential, commercial and industrial customers. The Consumers Energy HVD system consists nearly entirely of 46,000 volt lines (96% of the total), but also includes radial 138,000 volt and 69,000 volt lines (4% and <1% respectively). The HVD voltage is stepped down, or reduced, at LVD substation transformers to primary voltages between 2,400 and 24,900 volts (grounded-wye and delta). LVD voltage is then further stepped down at the distribution transformer to a secondary voltage, serving businesses and residences at between 120 and 480 volts. The LVD system consists of 13 different voltages, because we acquired distribution systems operating at different voltages from several smaller distribution companies over our Company history, a situation discussed further in Section VIII.D. The primary distribution system begins at the distribution substation and ends at the distribution transformer. The secondary distribution system begins at the distribution transformer and ends at the customer, as shown in Figure 3 below.

FIGURE 3 – ILLUSTRATION OF ELECTRIC DISTRIBUTION SYSTEM



Our distribution lines and substations assets are summarized in Table 3 and Table 4 below.

TABLE 3 – DISTRIBUTION SYSTEM LINES OVERVIEW

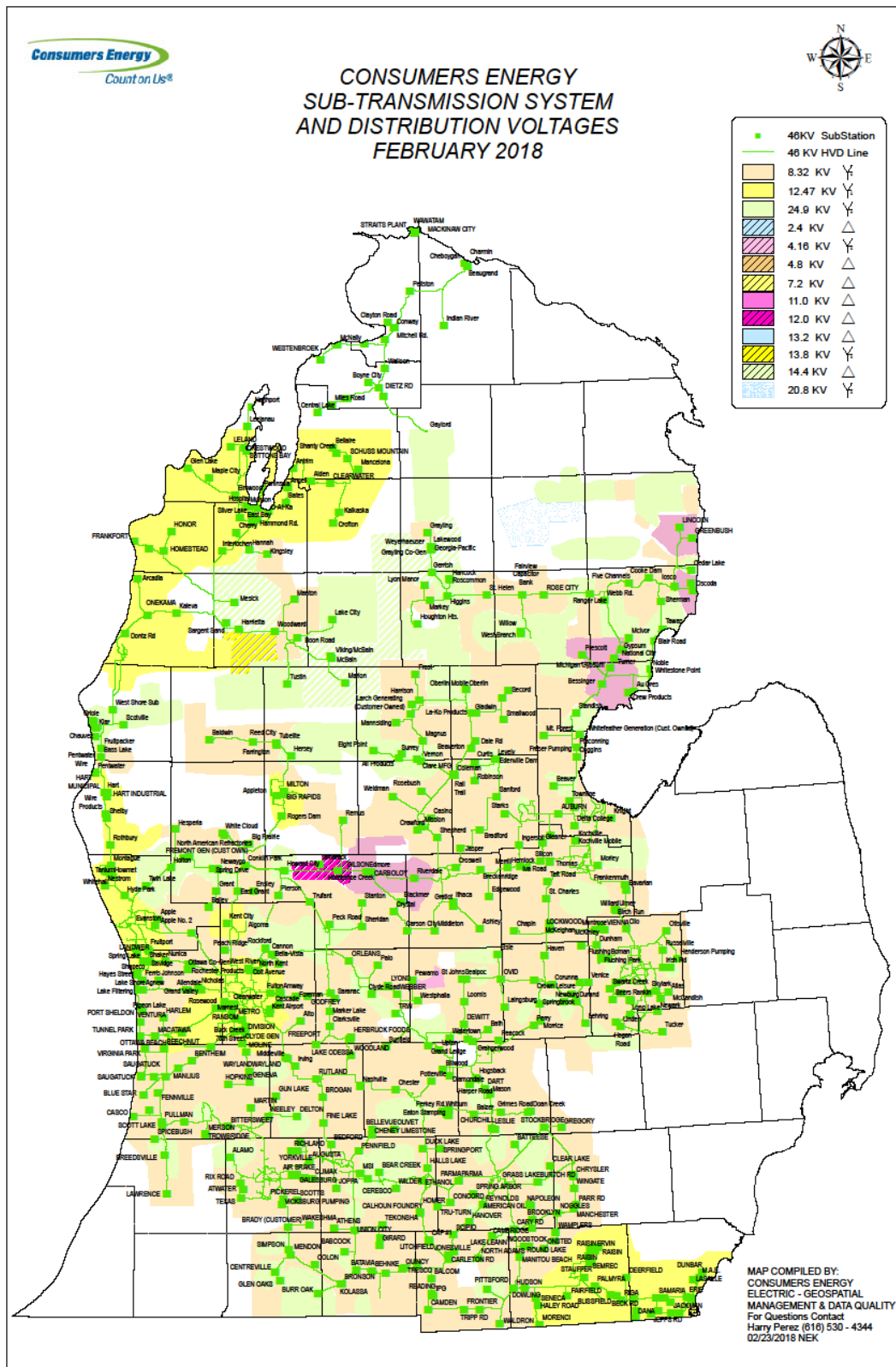
Distribution System Lines Overview			
Distribution System	Total Miles	Overhead Miles	Underground Miles
Low Voltage	66,763	56,098	10,665
High Voltage	4,642	4,431 Miles 46 kV and 69 kV 188 Miles 138 kV	19 Miles 46 kV 4 Miles 138 kV

TABLE 4 – DISTRIBUTION SYSTEM SUBSTATIONS OVERVIEW

Distribution System Substations Overview		
Distribution System	Total	Type(s)
Low Voltage	1,083	783 general distribution 230 Consumers Energy-owned dedicated customer substations 35 customer-owned dedicated substations 5 Consumers Energy-owned substations providing wholesale distribution service to rural co-op and municipal systems 30 customer-owned substations providing wholesale distribution service to rural co-op and municipal systems
High Voltage	121	138/46 kV Substations

Our system’s voltages are shown in the map in Figure 4.

FIGURE 4 – SERVICE TERRITORY VOLTAGE MAP

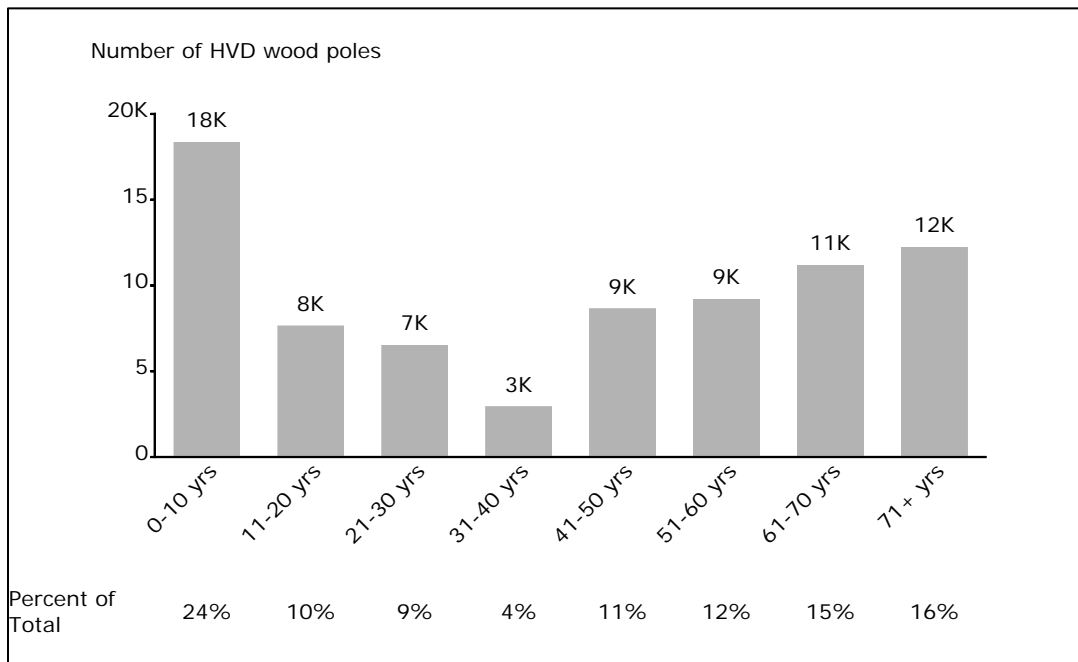


B. Age of Assets

Throughout more than a century of distributing electricity, our service area has expanded to serve many new communities and businesses in Michigan. Much of this timeworn infrastructure – lines, pole top equipment, and substations, among other assets – is in need of replacement. However, the age of our network is not an emergency, as we are not at a point where the age of our assets creates critical reliability and resiliency issues. Our inspection and repair programs, discussed in greater detail later in the report, diligently examine asset conditions to uncover deterioration, and programs are in place to reduce the risk of failure.

Figure 5 below shows that approximately 30% of the 77,400 wood poles supporting the HVD system are older than the expected life of 60 years. This example helps illustrate the age of some of our assets on our system.

FIGURE 5 – HVD WOOD POLE AGES



Age is not the only indicator of system health. We think about asset life not solely in terms of age, but holistically in terms of its ability to continue to reliably serve customers. This way of thinking is particularly important regarding LVD lines, as those assets are managed through mass property accounting where we have less certainty on the exact age of each asset. The deterioration and health of assets vary based on field conditions (e.g., soil, weather, grade/slope, wind patterns, etc.), location, and materials used by the manufacturer (e.g., wood type, porcelain, polymer, interrupting media, etc.). For example, poles deteriorate at a faster rate in wet soil conditions than in dry non-acidic soil conditions, and porcelain is more susceptible to freeze/thaw conditions than polymer. Retirements are processed statistically using curves that model when a particular asset is available to be retired.

We constantly strive to optimize the reliability and resiliency of our network while ensuring we meet our other objectives including offering affordable service to our customers. We are proactively evaluating how to best allocate spending to support our aging network. Over the next decade, significant rehabilitation and replacement of the oldest and most at-risk assets in the distribution network will be required to maintain system reliability.

Other components of our system have similar distributions to the above example of HVD poles, with many assets near or past the expected service life. The following figures present the average age and expected life of the assets on our HVD and LVD system. These figures are generated from our accounting records, which are determined statistically.

FIGURE 6 – HVD POLE CHARACTERISTICS

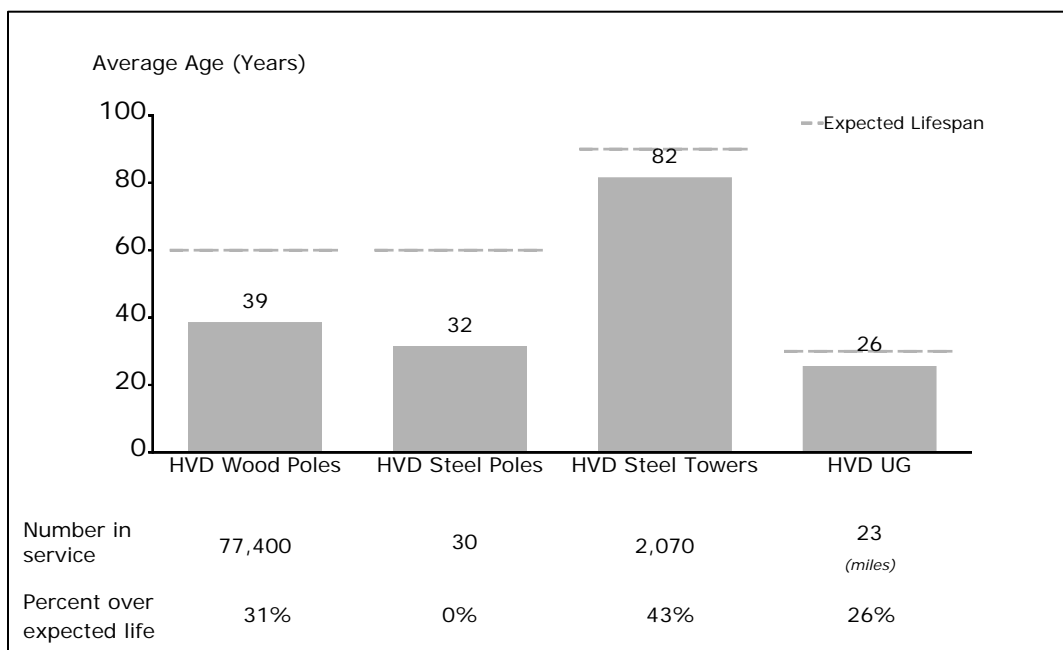


FIGURE 7 – HVD SUBSTATION EQUIPMENT

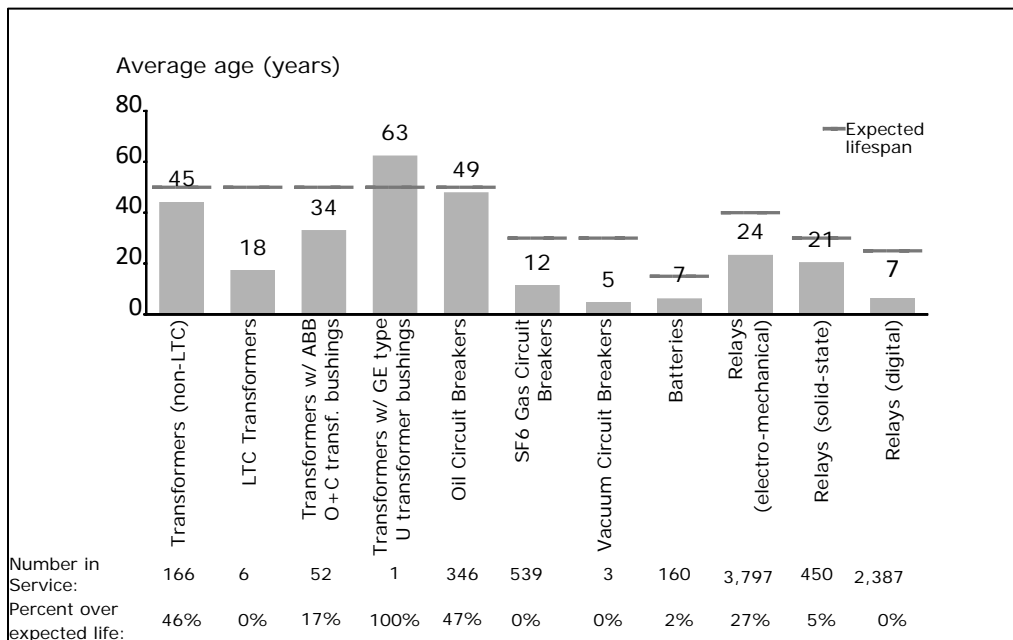
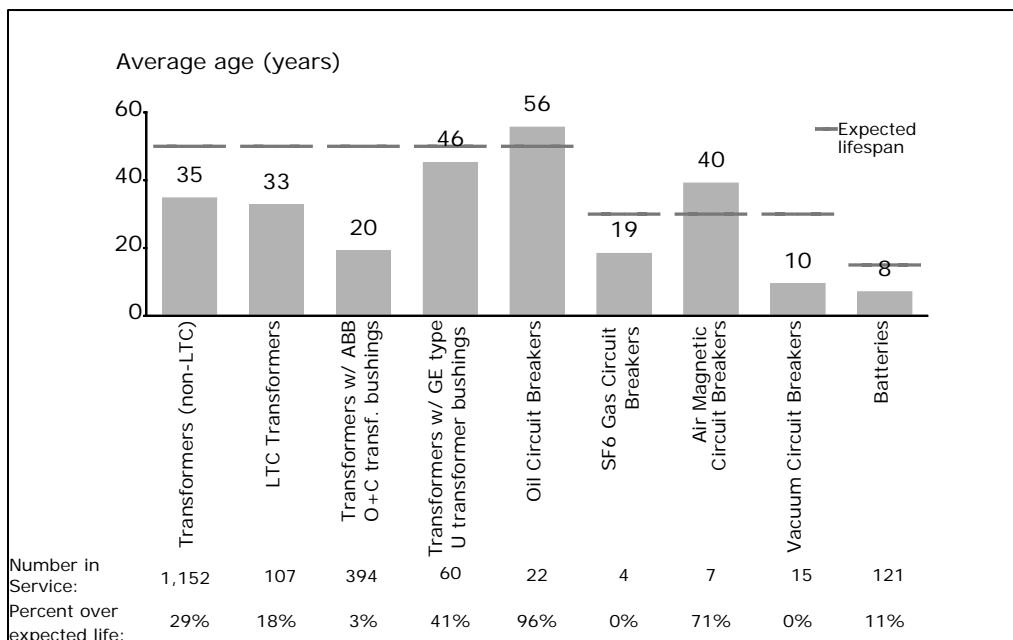


FIGURE 8 – LVD SUBSTATION EQUIPMENT

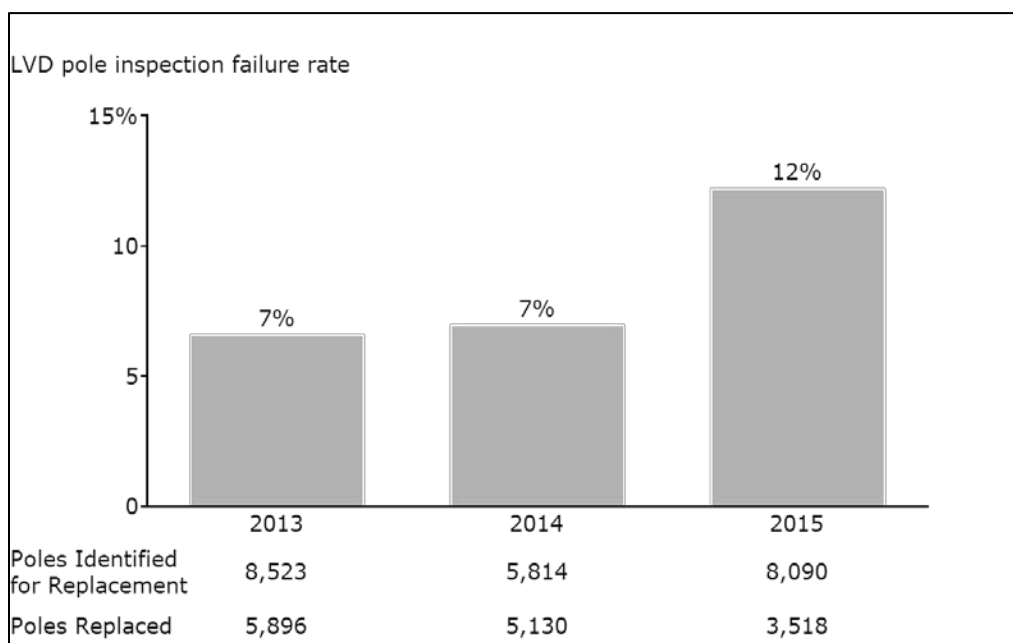


Because we account for LVD assets on a mass property basis, we have less age of asset detail for the LVD network than for the HVD network. Therefore, it is particularly important to have inspection programs in

place that monitor the health of our system. We utilize findings from these programs to approximate the overall system condition.

Between 2013 and 2015, we inspected approximately 20% of our LVD poles, which had a failure rate of 7-12% (with an average of 8% of poles), meaning there is a significant portion of poles on the LVD system that should be proactively replaced. Since these poles are outside their expected life, we anticipate the failure rate will increase in the interim. Of the approximately 22,000 poles identified for replacement during those inspections, we have replaced roughly 14,500 of them to date, leaving around 8,000 remaining for replacement. We also replace poles as part of our security, demand failures, and other programs. Over the past five years, we have replaced approximately 18,000 total poles per year through all of these programs (a little over 1% of our total poles per year). Based on similarities in failure rates between the HVD and LVD systems (i.e., 8-12% for HVD and 7-12% for LVD), it is believed that the age distribution of our LVD poles is similar to what can be observed above in Figure 5.

FIGURE 9 – LVD POLE INSPECTION FAILURE RATE



We are in the process of collecting data for our ESME initiative, the foundation needed to start developing an asset management system, which is discussed in detail later in this report. The ESME initiative will provide better insight and clarity into the current system configuration and our assets, which will enhance our ability to conduct load flow studies and develop infrastructure replacement plans.

IV. Overview of System Performance

A. Approach to Assessing System Performance

As mentioned in Section II, we assess our performance using industry standards and metrics (e.g., from the Institute of Electrical and Electronics Engineers (IEEE)), as well as metrics that we have defined to inform meeting our customer-centric EDIIP objectives. These measures are analyzed in many different ways across our organization as we continuously work to improve the reliability and resiliency of our network to provide better service for our customers. In this section of the report, we will discuss how we analyze the performance of our system, as well as major trends in recent performance. We have also highlighted a number of specific investments that will take place in 2018 to target improving customer experience. The analysis highlighted in this section is fundamental to identifying the infrastructure investments we make on the system to improve the reliability and resiliency of our network.

We think about diagnosing the performance of our system in three ways:

- **System-wide performance and external benchmarking** – Comparing system-wide performance to historic levels to understand opportunities to improve the electric distribution system as a whole, as well as where we perform relative to our peers. System-wide measures are also used by our organization to set long-term goals (as outlined previously).
- **Regional performance and internal benchmarking** – Analyzing system metrics at a more granular level across our 29 service regions, to “de-average” our system and understand the service experience, outage causes and more detailed opportunities for improvement across the state.
- **Circuit-level performance** – Determining which circuits within our network face the most severe performance challenges, to pin-point the highest priority locations for system investment.

Our multi-prong reliability improvement strategy is monitored and managed through our **Electric Reliability Rally Room**, a physical collaboration area that promotes improved visibility and accountability of performance, discussed later in this section.

B. System-wide Performance and External Benchmarking

System-wide performance metrics are at the center of our reliability focus. Our ongoing efforts to improve system reliability for our customers are based on a holistic approach to reduce the duration and frequency of interruptions to customers. There are several standard industry metrics commonly used to measure this performance:

- **SAIDI** – The primary overall electric system reliability indicator. SAIDI measures the annual number of minutes the average customer is without power across the entire electric system.
- **SAIFI** – The average number of interruptions per customer per year (outage frequency).

In addition, we track specific measures of customer reliability experience (see also Section II):

- **Customers Experiencing Multiple Interruptions (CEMI)** – The percentage (%) of customers that are experiencing multiple interruptions.
- **Customers Experiencing Long Interruption Duration (CELID)** – The percentage (%) of customers experiencing interruptions with durations longer than a specified number of hours.

- Time to restore power to customers after a MED interruption.

As seen in Figure 10 and Figure 11 below outlining our performance relative to peers, we consistently rank well in SAIFI excluding MEDs. We achieved our best ever SAIFI with 0.89 interruptions per customer in 2017. This represents first quartile performance based on 2016 IEEE figures. Furthermore, we have seen significant improvement in SAIDI over the past number of years. In 2017, we achieved our best SAIDI performance in 17 years. Our recent SAIFI and SAIDI performance is evidence of our continued dedication to improve the state of our system and reliability for customers.

Summary Statistics

FIGURE 10 – SAIDI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007-2017)

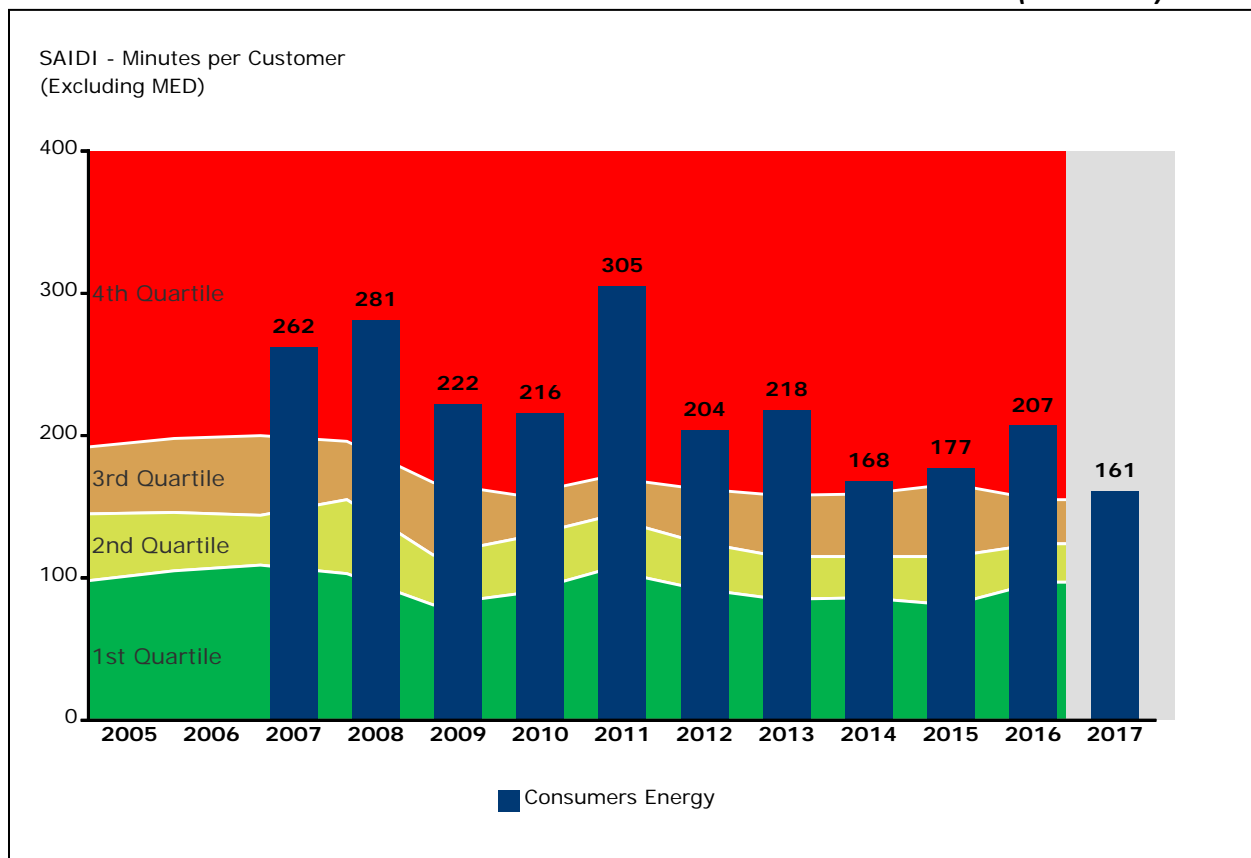


FIGURE 11 – SAIFI: COMPARISON OF CONSUMERS ENERGY TO IEEE RELIABILITY SURVEY (2007-2017)

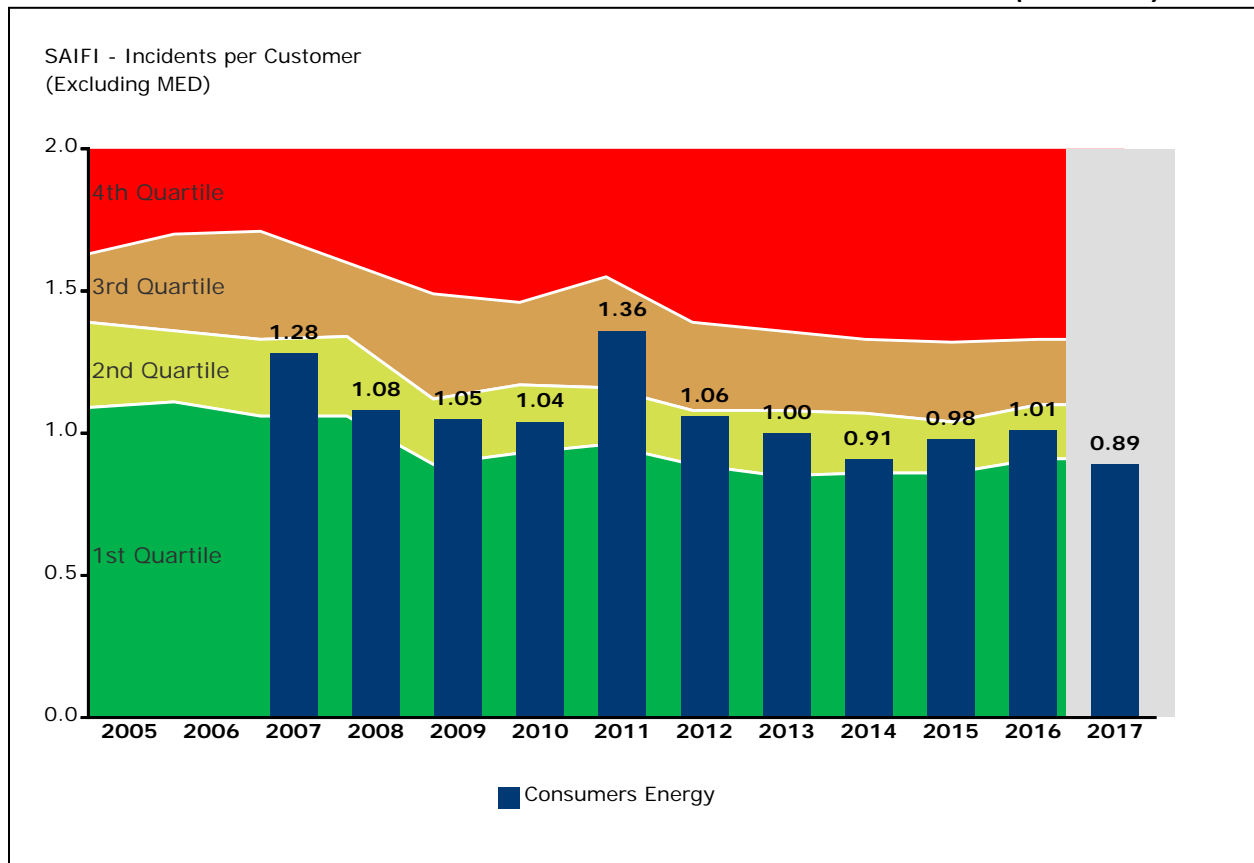


TABLE 5 – SAIDI AND SAIFI INDICES

SAIDI and SAIFI Indices (Five-Year Rolling Average)								
Year	All Conditions				Excluding Major Event Days			
	SAIDI		SAIFI		SAIDI		SAIFI	
	Annual	5 Yr. Avg.	Annual	5 Yr. Avg.	Annual	5 Yr. Avg.	Annual	5 Yr. Avg.
2013	1108	619	1.50	1.43	218	233	1.00	1.10
2014	377	625	1.10	1.40	168	222	0.91	1.08
2015	441	620	1.18	1.36	177	214	0.98	1.06
2016	284	544	1.15	1.26	207	194	1.01	0.99
2017	606	563	1.31	1.25	161	186	0.89	0.96

Table 5 above further outlines the rolling five-year average SAIDI and SAIFI indices. These indices were calculated for all conditions, and to exclude MEDs using the methodology in IEEE Standard 1366-2012, which defines MEDs based on five sequential years of daily outage minutes to set a threshold for extraordinary weather events. When the MED threshold is exceeded in a 24-hour period from midnight to midnight, all reliability metrics from outages initiated in that time frame are excluded. We experienced the following numbers MEDs in recent years: 2013 (10), 2014 (4), 2015 (3), 2016 (5), and 2017 (8). The average customer interruption count for the 30 MEDs over the previous five years was 88,000.

We most commonly observe and analyze SAIDI excluding MEDs, to ensure that we are comparing performance across time while excluding significant weather events and the impact that those anomalies have on our system. With that said, we are well aware that customers are severely impacted by and sensitive to interruptions during MEDs, so our efforts to improve system resiliency consider the ability of our infrastructure to withstand severe weather events.

Additional Measures of Customer Reliability Experience

Our CEMI data is provided in Table 6 below, with number of interruptions by year. The data is representative of all the interruptions on the system, except for momentaries, as defined by IEEE; it does not exclude MEDs or other accommodations for hazards on the system.

TABLE 6 – CUSTOMERS EXPERIENCING MULTIPLE INTERRUPTIONS BY YEAR

CEMI by Year											
	% of Customers experiencing X interruptions										
Year	0	1	2	3	4	5	6	7	8	9	10+
2013	30%	30%	19%	11%	6%	2%	1%	1%	0%	0%	0%
2014	38%	32%	18%	7%	3%	1%	0%	0%	0%	0%	0%
2015	40%	30%	15%	8%	4%	2%	1%	0%	0%	0%	0%
2016	40%	30%	15%	7%	4%	2%	1%	0%	0%	0%	0%
2017	37%	29%	17%	8%	4%	2%	1%	1%	0%	0%	0%

CELID data for various time durations is provided in Table 7 below for the last five years. The data is representative of all the interruptions on the system; it does not exclude MEDs or other accommodations for hazards on the system.

TABLE 7 – CUSTOMERS EXPERIENCING LONG INTERRUPTION DURATION

CELID by Year									
	% of Customers experiencing interruptions less than or equal to...								
Year	8 Hrs	24 Hrs	36 Hrs	48 Hrs	60 Hrs	72 Hrs	96 Hrs	120 Hrs	
2013	71%	86%	90%	93%	95%	96%	98%	99%	
2014	84%	95%	97%	99%	100%	100%	100%	100%	
2015	85%	94%	96%	98%	99%	99%	100%	100%	
2016	88%	99%	100%	100%	100%	100%	100%	100%	
2017	79%	90%	96%	97%	99%	99%	100%	100%	

Table 8 below highlights the recent trend in performance for service restoration after MED occurrences. In 2017, we restored 48% of customers within eight hours of all MED interruptions. This is an approximately 17% improvement over our 2013 performance and our second highest level in five years (following 2016).

TABLE 8 – TIME TO RESTORE AFTER MED INTERRUPTION

Time to Restore Customers after a Major Event Day Interruption					
Year	% of Customers restored in less than or equal to...				
	8 Hrs	12 Hrs	16 Hrs	20 Hrs	24 Hrs
2013	31%	37%	45%	52%	60%
2014	34%	42%	50%	61%	72%
2015	37%	45%	52%	58%	64%
2016	62%	72%	80%	86%	93%
2017	48%	58%	63%	67%	71%

Along with the metrics noted above, we actively monitor system performance and track our ability to meet the standards outlined by the MPSC as part of the Electric Distribution System Performance Standards MPSC Case No. U-12270. In 2017, we were compliant with all the reliability-focused standards.

TABLE 9 – SERVICE QUALITY AND RELIABILITY STANDARDS FOR ELECTRIC DISTRIBUTION SYSTEMS (U-12270)

Service Quality and Reliability Standards for Electric Distribution Systems						
Standard Definition	Standard	Yearly Performance				
		2013	2014	2015	2016	2017
Service Restoration Factors for All Conditions % of customers restored in 36 hours or less	> 90%	90%	97%	96%	100%	96%
Service Restoration Factors for Normal Conditions % of customers restored in 8 hours or less	> 90%	88%	86%	94%	88%	91%
Service Restoration Factors for Catastrophic Conditions % of customers restored in 60 hours or less	> 90%	83%	98%	93%	No events	93%
Same Circuit Repetitive Interruption Factor % of customers with 5 or more interruption in a 12- month period	< 5%	4.3%	1.5%	3.0%	2.8%	4.2%

Cause of Outage Incidents

Along with monitoring and analyzing trends in our system-wide SAIDI, SAIFI, and customer-centric metrics, we also assess the causes of the outage incidents impacting our system. In doing so, we better understand the major drivers of system performance and determine how specific causes are trending over time. This data is critical to our assessment of the highest priority areas to improve reliability.

Table 10 and Table 11 show the average number of outage incidents, customer interruptions, and customer interruption minutes from 2013 to 2017 for the LVD and HVD systems, including all conditions (i.e., not excluding MEDs), to reflect overall customer experience.

TABLE 10 — LOW VOLTAGE DISTRIBUTION OUTAGE INCIDENT SUMMARY

Low Voltage Distribution Outage Incident Summary				
Average of years 2013—2017				
Cause	Outage Incidents	Customer Interruptions	Interruption Minutes	2013-2017 LVD Incidents (Average; Including MED)
Trees	13,287	671.7K	395.4M	<p>41,635</p>
Weather	7,550	375.5K	347.0M	
Equipment Failure	6,844	241.7K	49.0M	
Wildlife	3,590	41.8K	4.8M	
Planned Scheduled	1,345	62.6K	9.3M	
Lightning	1,117	40.8K	9.4M	
Transmission or Generation	282	8.7K	2.0M	
Other	7,620	299.3K	72.2M	
Total	41,635	1,742.2K	888.9M	
2017				
Cause	Outage Incidents	Customer Interruptions	Interruption Minutes	2017 LVD Incidents (Including MED)
Trees	16,969	867.3K	548.1M	<p>43,174</p>
Equipment Failure	7,452	254.7K	60.6M	
Weather	4,440	228.0K	238.2M	
Wildlife	3,068	39.7K	5.2M	
Planned Scheduled	1,962	51.8K	5.1M	
Lightning	1,028	28.1K	7.5M	
Transmission or Generation	34	2.0K	0.3M	
Other	8,221	413.2K	99.0M	
Total	43,174	1,884.9K	964.0M	

Note: For Table 9 and Table 10 other includes: Car pole accidents, Public damage, Trees from outside right of way, other unique incidents and when no specific cause was found; Lightning category includes all incidents caused by lightning (direct stroke, contacting the wires, etc.); Trees category includes incidents caused by falling trees or limbs, growth of trees, vines, and roots, and weather category incidents due directly to a weather phenomenon including: wind, snow, ice, hail and rain where the weather itself caused the incident and exceeded the system design limits. Note: if any part of a tree is involved, the incident would go under the Trees category.

TABLE 11 — HIGH VOLTAGE DISTRIBUTION OUTAGE INCIDENT SUMMARY

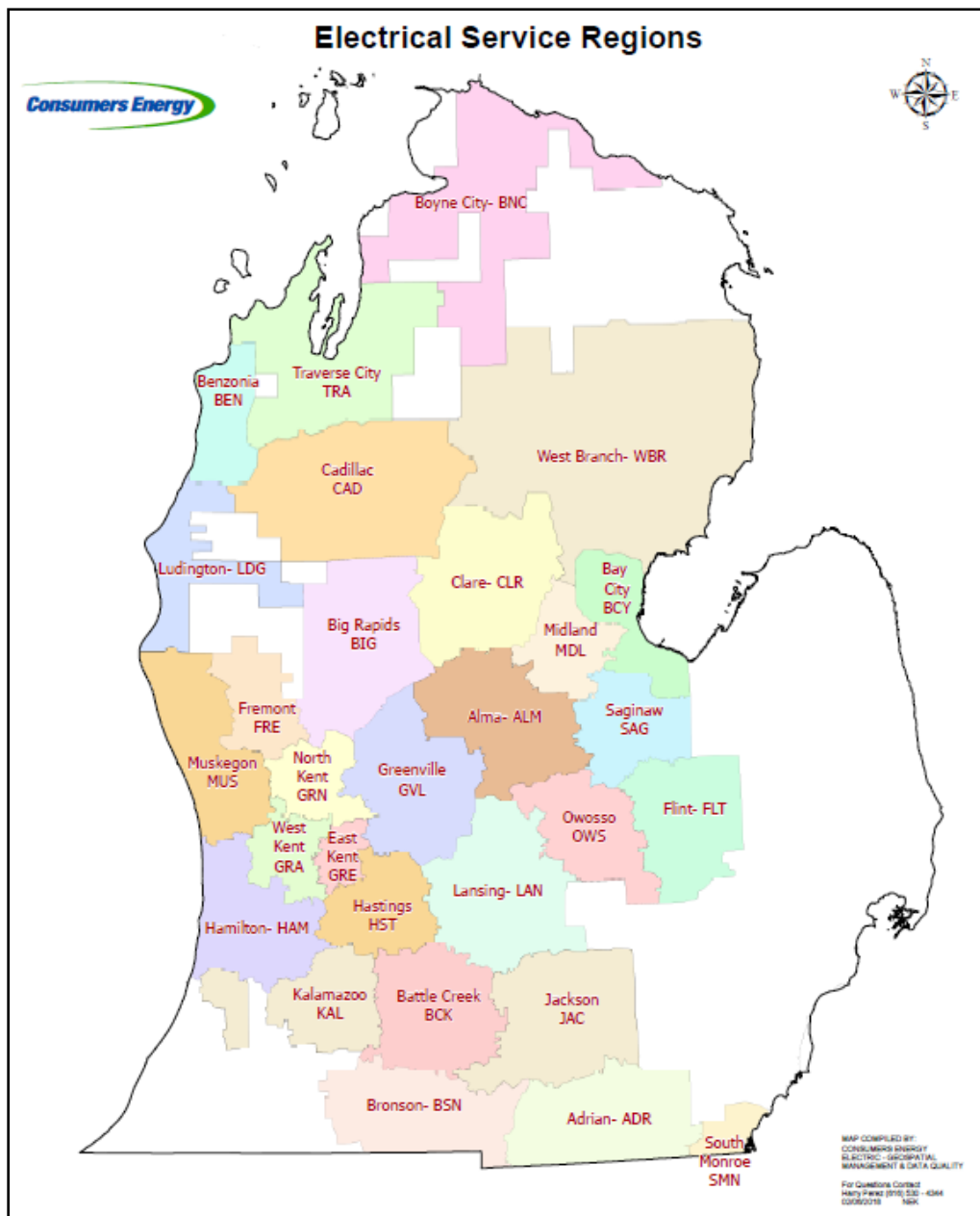
High Voltage Distribution Outage Incident Summary				
Average of years 2013—2017				
Cause	Outage Incidents	Customer Interruptions	Interruption Minutes	2013-2017 HVD Incidents (Average; Including MED)
Equipment Failure	200	153.7K	29.4M	<p>2013-2017 HVD Incidents (Average; Including MED) 602</p>
Weather	122	92.8K	38.2M	
Wildlife	59	53.7K	9.7M	
Trees	52	41.6K	17.5M	
Planned Scheduled	32	29.2K	5.4M	
Transmission or Generation	29	22.0K	5.2M	
Lightning	11	10.6K	3.0M	
Other	97	78.8K	11.2M	
Total	602	482.5K	119.5M	
2017				
Cause	Outage Incidents	Customer Interruptions	Interruption Minutes	2017 HVD Incidents (Including MED)
Equipment Failure	279	210.8K	43.7M	<p>2017 HVD Incidents (Including MED) 612</p>
Weather	90	72.2K	32.2M	
Trees	62	48.8K	26.0M	
Transmission or Generation	36	26.7K	11.6M	
Wildlife	25	26.6K	7.5M	
Planned Scheduled	24	26.4K	5.3M	
Lightning	8	7.7K	0.9M	
Other	88	68.2K	8.5M	
Total	612	487.4K	135.7M	

Note: For Table 9 and Table 10 other includes: Car pole accidents, Public damage, Trees from outside right of way, other unique incidents and when no specific cause was found; Lightning category includes all incidents caused by lightning (direct stroke, contacting the wires, etc.); Trees category includes incidents caused by falling trees or limbs, growth of trees, vines, and roots, and weather category incidents due directly to a weather phenomenon including: wind, snow, ice, hail and rain where the weather itself caused the incident and exceeded the system design limits. Note: if any part of a tree is involved, the incident would go under the Trees category.

C. Regional Performance by Service Regions

In addition to monitoring performance at a system-wide level, we commonly utilize the data from our Outage Management System (OMS) to conduct more detailed analysis at the service region level. Our network is divided into 29 service regions, each with its own dedicated service center:

FIGURE 12 – SERVICE REGIONS AND SERVICE CENTERS



When defining boundaries, we consider the location of the service center relative to locations of potential interruptions on our system that could be serviced from that location. Boundaries are used as the basis for assigning work to operational resources and are reviewed annually to ensure an optimal design is maintained to best service our customers.

The same measures that we monitor on a system-wide level can be analyzed at a service region level to reveal varying performance across our system. By observing the industry standard metrics (e.g., SAIDI, SAIFI), customer experience measures (e.g., CEMI), and the causes of outage incidents at the service region level, we can “de-average” the system and develop a detailed understanding of system performance at a more localized level. This granular approach allows us to target our infrastructure upgrades and ensure that we approach reliability and resiliency challenges while considering the diverse operational realities of our service territory.

Summary Statistics

Below is a summary of SAIDI, SAIFI, and Customer Average Interruption Duration Index (CAIDI) statistics across our service regions. These graphs illustrate the experience of an average customer within each service region. See Appendix C for all the service region/center abbreviations.

FIGURE 13 – SERVICE REGION AVERAGE SAIDI EXCLUDING MED (2013-2017)

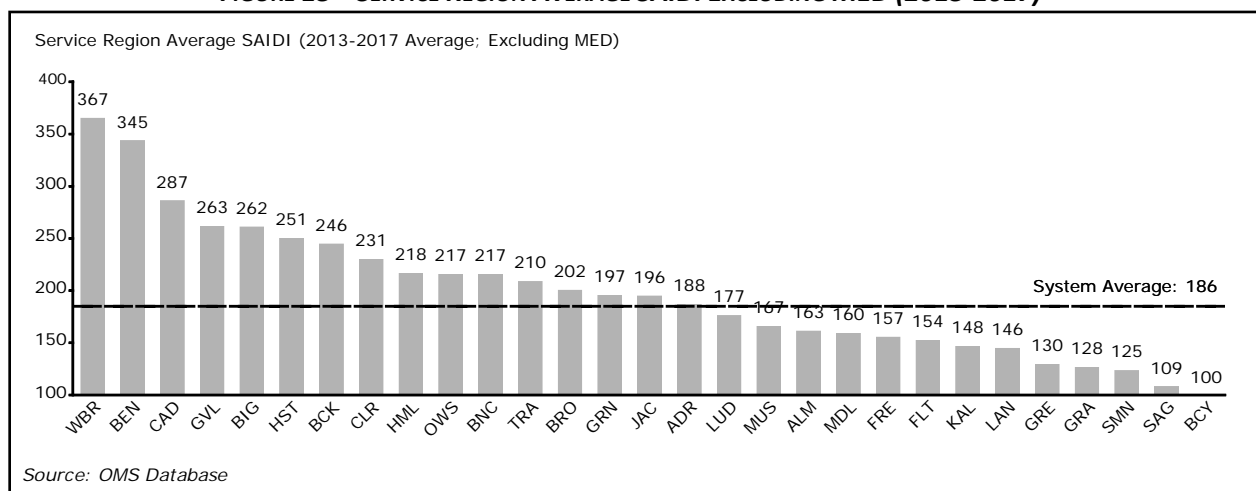


Figure 13 shows the average SAIDI by service region, excluding MED, from 2013 through 2017. The system-wide average for this period was 186 minutes. The data points on top of each of the bars detail the average customer interruption duration experienced by customers served by each service center. The three service regions with the highest average outage durations over this time period were West Branch (‘WBR’), Benzonia (‘BEN’) and Cadillac (‘CAD’) with an average SAIDI of 367, 345, and 287 minutes respectively. In contrast, the three service regions with the lowest interruption durations were South Monroe (‘SMN’), Saginaw (‘SAG’) and Bay City (‘BCY’) with an average SAIDI of 125, 109, and 100 minutes respectively.

FIGURE 14 – SERVICE REGION AVERAGE SAIFI EXCLUDING MED (2013-2017)

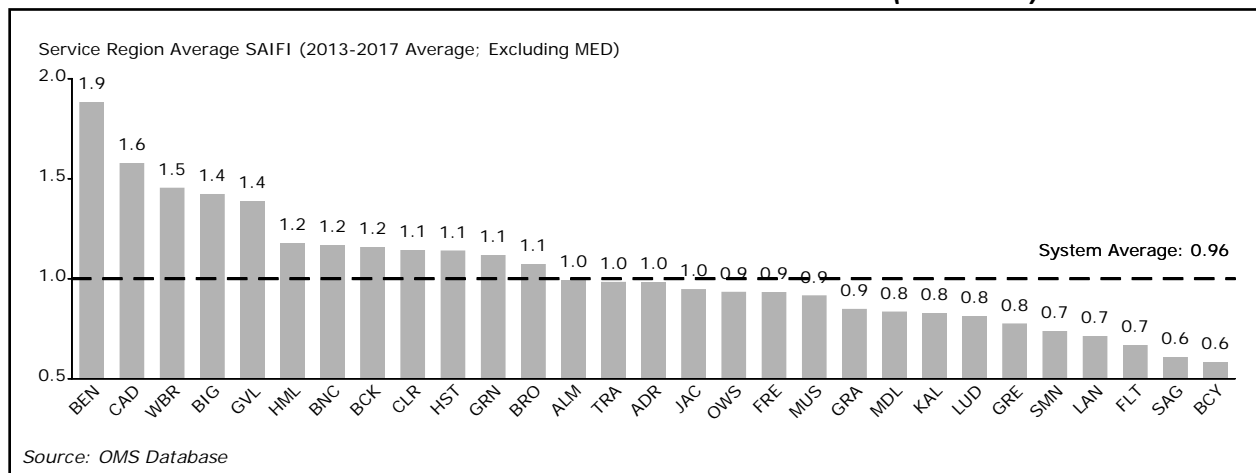


Figure 14 shows the average SAIFI by service region, excluding MED, from 2013 through 2017. The system-wide average for this period was 0.96 interruptions per customer. The three service regions with the highest interruption frequency were Benzonia ('BEN'), Cadillac ('CAD') and West Branch ('WBR') with an average SAIFI of 1.9, 1.6, and 1.5 interruptions respectively. The service regions with the lowest outage interruption frequency were Flint ('FLT'), Saginaw ('SAG') and Bay City ('BCY') with an average SAIFI of 0.7, 0.6, and 0.6 interruptions respectively.

FIGURE 15 – SERVICE REGION AVERAGE CAIDI EXCLUDING MED (2013-2017)

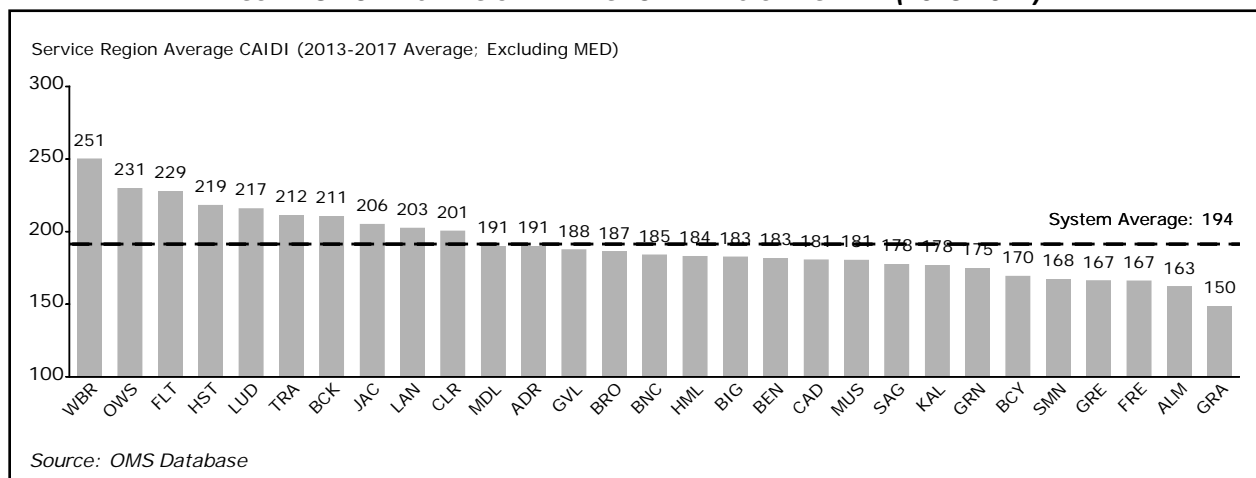


Figure 15 shows the average CAIDI by service region, excluding MED, from 2013 through 2017. The system-wide average interruption duration for this period was 194 minutes. The three service regions with the longest interruption durations were West Branch ('WBR'), Owosso ('OWS') and Flint ('FLT') and with an average CAIDI of 251, 231, and 229 minutes respectively. The service regions with the shortest interruption durations were Fremont ('FRE'), Alma ('ALM') and Grand Rapids ('GRA') with an average CAIDI of 167, 163, and 150 minutes respectively.

The analysis above allows us to further understand the underlying dynamics of customer-experienced interruption durations across our service territory by breaking down SAIDI into its component parts – the number of interruptions (SAIFI) and average interruption duration (CAIDI). Observing Cadillac's

(‘CAD’) statistics can help demonstrate how we translate service region-specific analysis into action. Cadillac has the third-highest SAIDI across our 29 service regions, despite having a CAIDI below the system average. It is clear that from the positioning in Figure 14 that Cadillac experiences a significantly above-average number of interruptions with the second highest SAIFI across our system. Therefore, when planning reliability investments for the LVD system, our focus for the Cadillac service region is to reduce the number of interruptions. In order to improve customer experience in the Cadillac service region in 2018, we are investing in the Stittsville circuit on the Lake City substation, which has a segment of customers that have had an average of four interruptions per year over the past four years. Our investment includes relocating a section of the line out of an inaccessible area, and adding additional fuses and aerial spacer cable, all of which are expected to support better reliability and fewer interruptions for customers served by this circuit. Alternatively, regions such as Flint (‘FLT’) will benefit most from initiatives that target shortening outage durations. In order to improve outage durations in the Flint service region, we are investing in replacing two underground substation exits that have previously contributed to lengthy outage interruptions.

Although service region SAIDI, SAIFI and CAIDI performance can be compared and used for internal benchmarking, we ensure we always consider service territory diversity when doing so. As demonstrated in the figures above, the West Branch (‘WBR’) service region experiences the longest outage durations. This is in part due to West Branch serving a rural component of our network, with lower customer density per line mile than many other service regions (in other words, many circuits that cover long distances). West Branch has the most overhead line miles in comparison to other service regions, making this region more susceptible to outages. Furthermore, when outages do occur, this region is more challenging to service, because (on average) it takes more time for line workers to reach outages given the large service region.

Reliability performance of a service region does not always correlate with its contribution to overall system metrics, given different populations served by each service region. Figure 16 below breaks down service region SAIFI and CAIDI while also mapping the overall contribution of each of our service regions to system SAIDI. The larger the size of the circle associated with a service region, the more minutes that service region contributes to the overall system SAIDI. A reference circle in the bottom right of the graphic shows the size of a circle that would contribute 40 minutes to the system SAIDI total (e.g., since the Flint (‘FLT’) circle is about half the size of the reference bubble, Flint contributed about 20 minutes to the 186 minute average between 2013 and 2017).

FIGURE 16— SERVICE REGION SAIFI VS. CAIDI

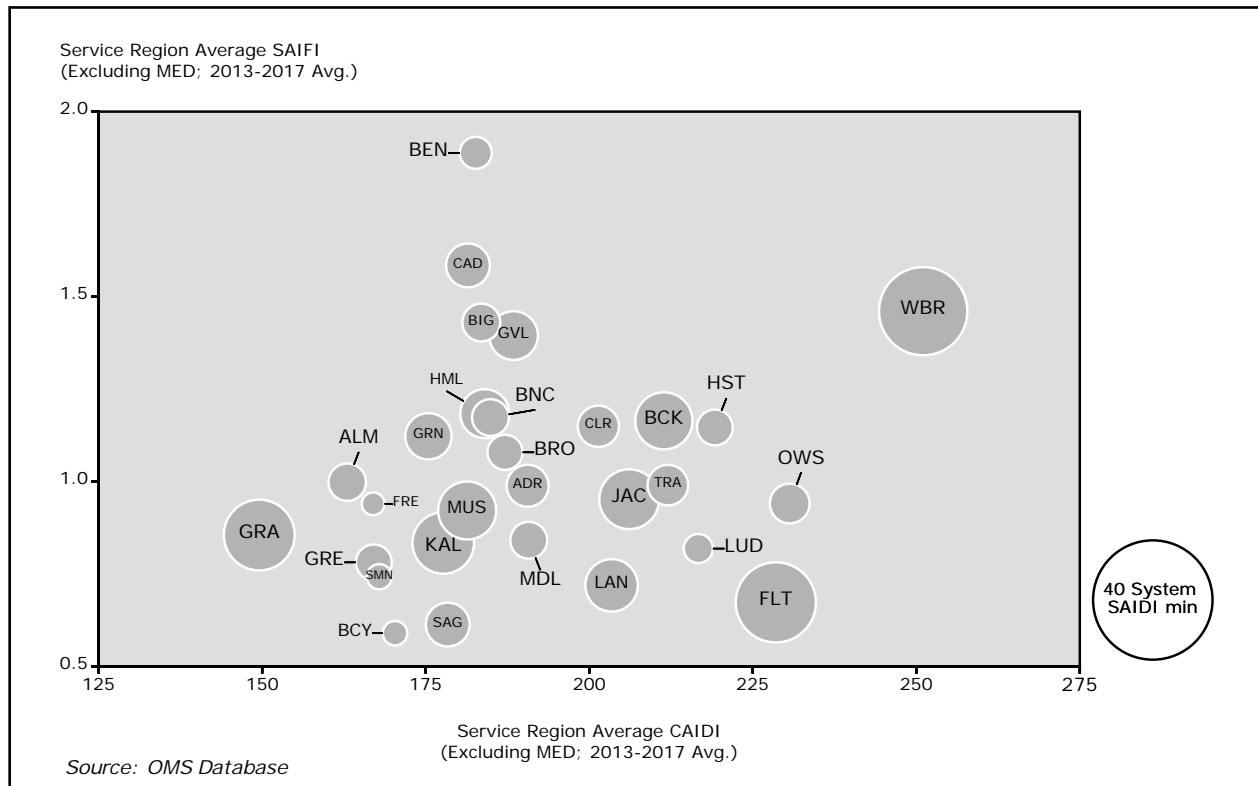


Figure 16 shows that Grand Rapids ('GRA') had a CAIDI of 150 minutes and a SAIFI of approximately 0.9, which are both below the system average across all of our service regions. Grand Rapids ('GRA') is the fourth-best performing service region at a regional level with regards to service region SAIDI. However, the large circle size indicates that GRA has the third highest contribution to overall system SAIDI. This is because Grand Rapids contains a significant proportion of the system's total population, at just over 10% of customers. Therefore, when we think about investing in our system to reduce the total number of outage minutes experienced by customers, we must also consider which components of our system are highly populated.

Together with the knowledge of our system-wide metric performance, these regional performance assessments help us to better target our reliability investments to achieve the greatest benefit for customers.

Additional Measures of Customer Reliability Experience

As discussed in Section II.C, customer satisfaction is closely linked to several key outage metrics. Analyzing these metrics at a service region level allows us to develop more granular insights into customer experience, and determine the varying levels of service experienced across our network.

FIGURE 17 – SERVICE REGION AVERAGE PERCENT OF CUSTOMERS WITH ≥3 INTERRUPTIONS PER YEAR

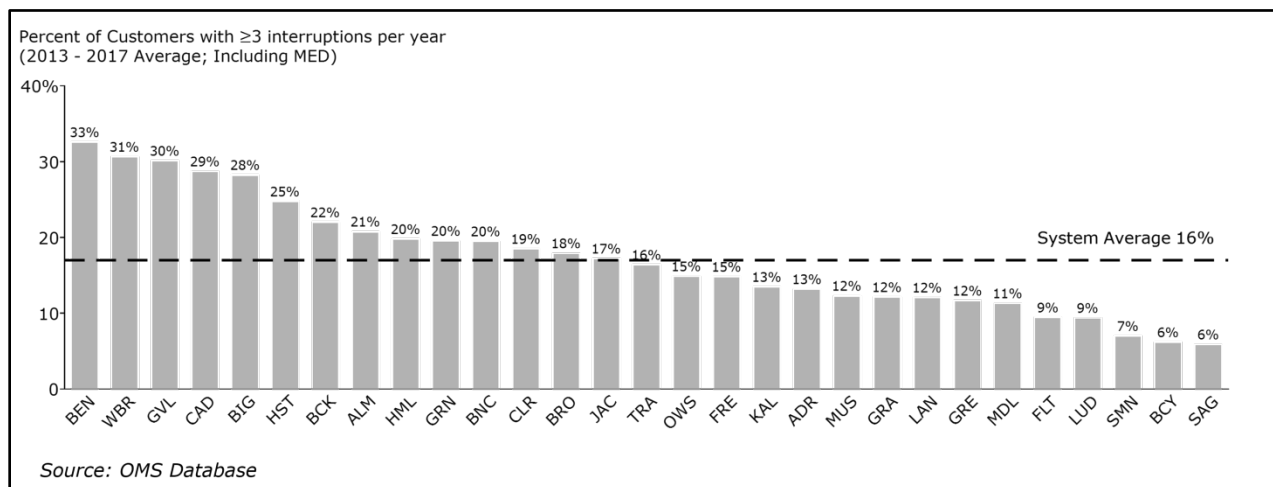


Figure 17 shows the average percent of customers served from a service center that experienced three or more interruptions in a year, including MED, from 2013 through 2017. The system-wide average for this period was 16% of customers. The service regions that had the highest proportion of customers with three or more interruptions were Benzonia ('BEN'), West Branch ('WBR'), and Greenville ('GVL') with an average of 33%, 31%, and 30% of customers respectively. The service regions that had the lowest proportion of customers with three or more interruptions were South Monroe ('SMN'), Bay City ('BCY') and Saginaw ('SAG') with an average of 7%, 6%, and 6% of customers respectively.

FIGURE 18 – SERVICE REGION AVERAGE PERCENT OF CUSTOMERS WITH ONE OR MORE ≥5 HOUR INTERRUPTION

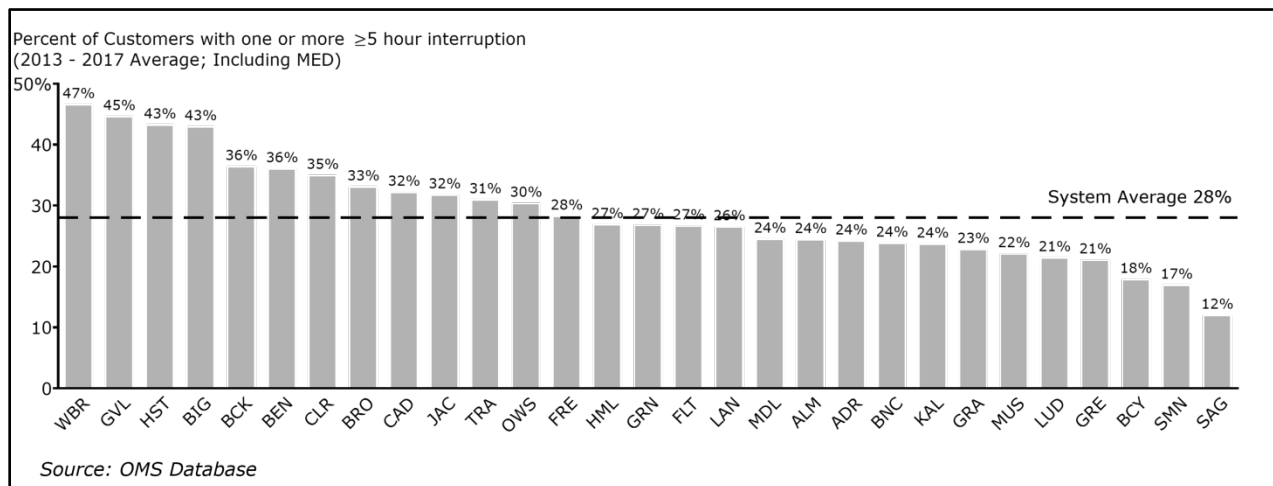


Figure 18 shows the average percent of customers experiencing at least one interruption of five or more hours, including MED, from 2013 through 2017. The system-wide average for this period was 28% of customers. The service regions with the highest proportion of customers experiencing a five or more hour interruption were West Branch ('WBR'), Big Rapids ('BIG') and Hastings ('HST') with an average of 47%, 45% and 43% of customers respectively. The three service regions with the lowest proportion of customers experiencing a five or more hour interruption were Bay City ('BCY'), South Monroe ('SMN') and Saginaw ('SAG') with an average of 18%, 17%, and 12% of customers respectively.

FIGURE 19 – SERVICE REGION AVERAGE PERCENT OF CUSTOMER MED INTERRUPTION RESTORED WITHIN 24 HOURS

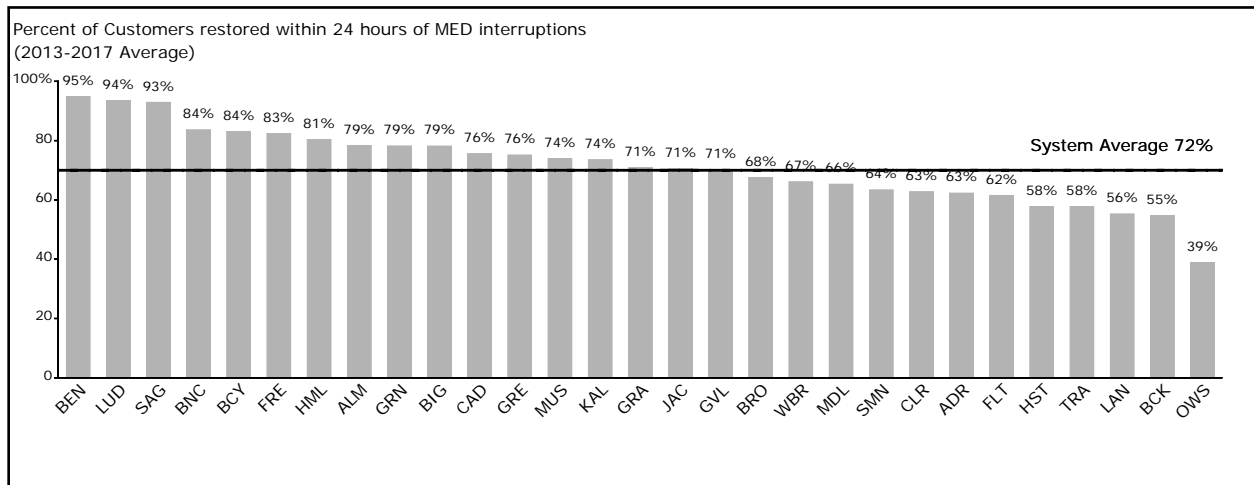
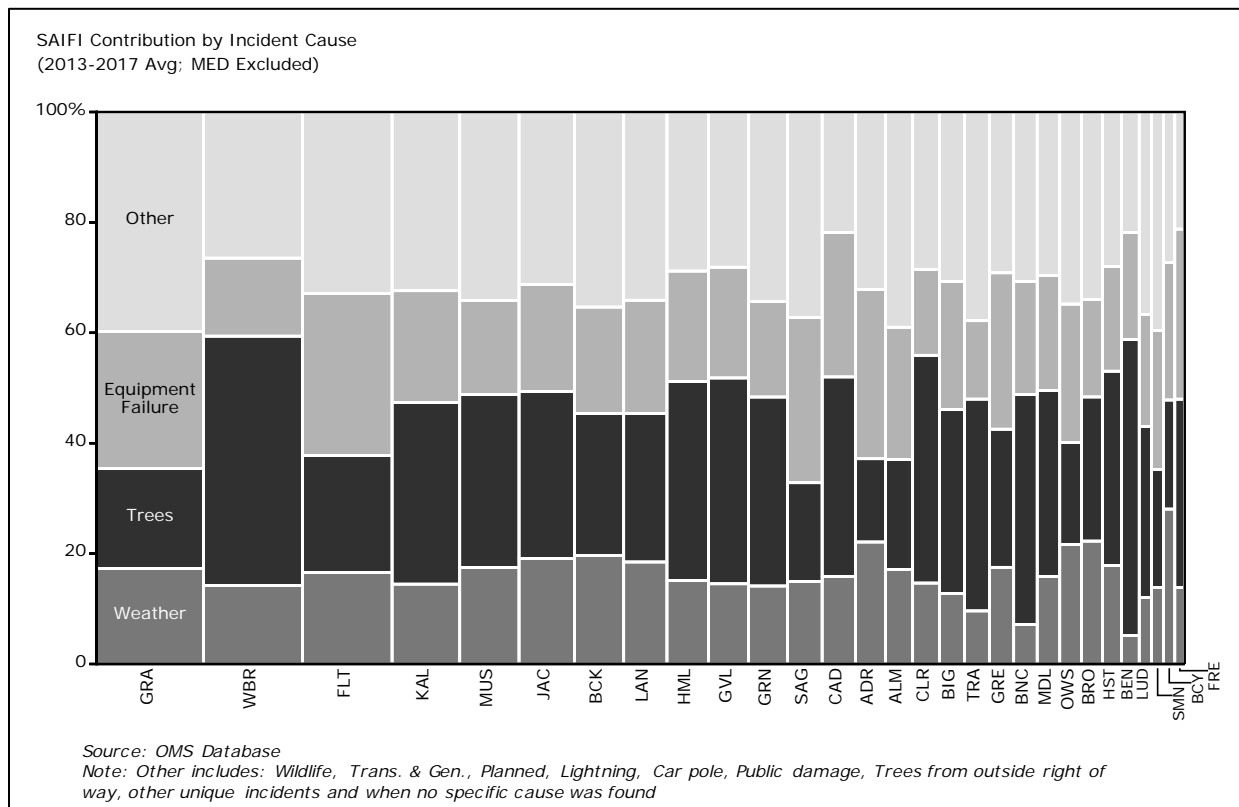


Figure 19 shows the average percent of customers restored within 24 hours of MED interruption, from 2013 through 2017. For each individual year, this is calculated as the sum of customer MED interruptions lasting less than 24 hours, divided by the sum of customer MED interruptions. We then average 2013 through 2017 data to observe a five-year period. The system-wide average for this period was 72% of customers. The service regions with the highest proportion of customers restored within 24 hours of MED interruptions were Benzonia ('BEN'), Ludington ('LUD') and Saginaw ('SAG') with an average of 95%, 94% and 93% of customers respectively. The three service regions with the lowest proportion of customers restored within 24 hours of MED interruptions were Lansing ('LAN'), Battle Creek ('BCK') and Owosso ('OWS') with an average of 56%, 55%, and 39% of customers respectively.

Cause of Outage Incidents

In addition to outage performance metrics, outage root-cause analysis can inform investment decisions at a regional level. Figure 20 shows the outage incident cause breakdown by service region, highlighting the three most prevalent causes of outages on our system – weather, trees, and equipment failure. The width of each bar indicates the percent of system SAIFI contributed by each service territory, while the stacked bar height shows the relative percentage of each outage incident cause within a territory. To illustrate an example, Grand Rapids contributes approximately 10% of system-wide SAIFI (more than any other service region), and has approximately 17% of its outage incidents caused by weather, 18% from trees, 25% from equipment failures, and 40% from other causes.

FIGURE 20 – SERVICE REGION SAIFI CONTRIBUTION BY INCIDENT CAUSE (2013-2013 AVERAGE, EXCLUDING MED)



It is important to analyze outage incident information while considering the operational traits of each of the service regions within our system. For example, we can see from the above data that West Branch ('WBR') has a high percentage of outage incidents caused by trees. That said, when we normalize for the amount of overhead line miles within each service territory, West Branch performs similarly to peers, given it has a significant amount of exposed line miles (34% more overhead line miles than 'FLT', for example).

The graphics above demonstrate an example of how our system varies in historical performance, operational realities, and customer needs across our many service territories. These differences require tailored solutions to solve the most critical reliability challenges experienced by our customers within each region.

D. Circuit-Level Performance

In addition to system-wide and regional analysis, observing the performance of our network at a circuit level allows us to target the most vulnerable and challenged components of our network.

A circuit is defined as a device, or a system of devices, that allows electrical current to flow through it and allows voltage to occur across positive and negative terminals. LVD circuits are individual portions of the LVD system served from a dedicated distribution substation exit. Across our system, we have over 2,000 LVD circuits serving our 1.8 million customers.

The following summarizes the analysis we conduct at a circuit level for the LVD system. Similar analysis is completed on HVD line segments.

Summary Statistics

Below is a summary of SAIDI and SAIFI distributions of the circuits within our system.

FIGURE 21 – CIRCUIT-LEVEL SAIDI PERFORMANCE DISTRIBUTION (2013-2017)

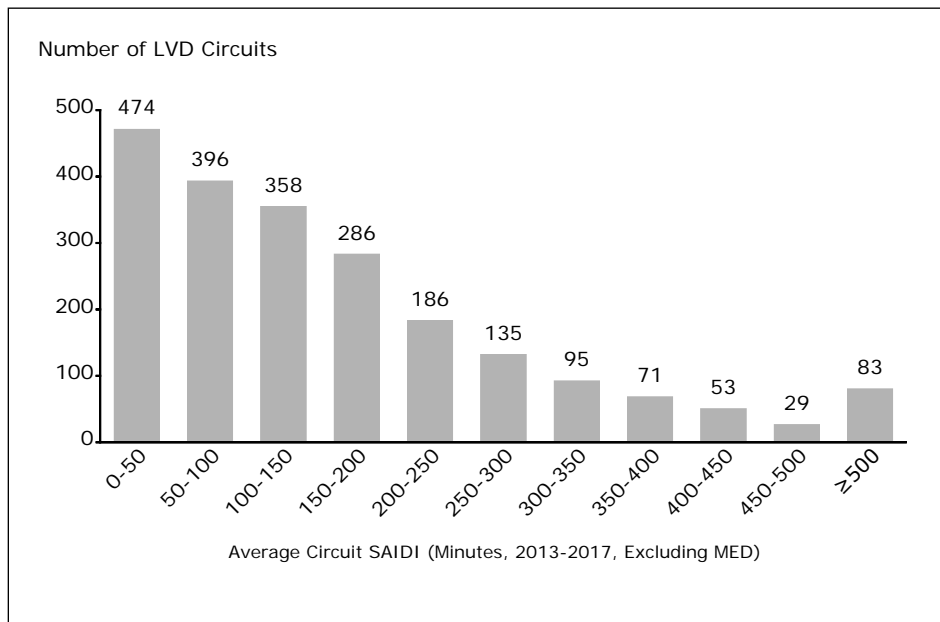
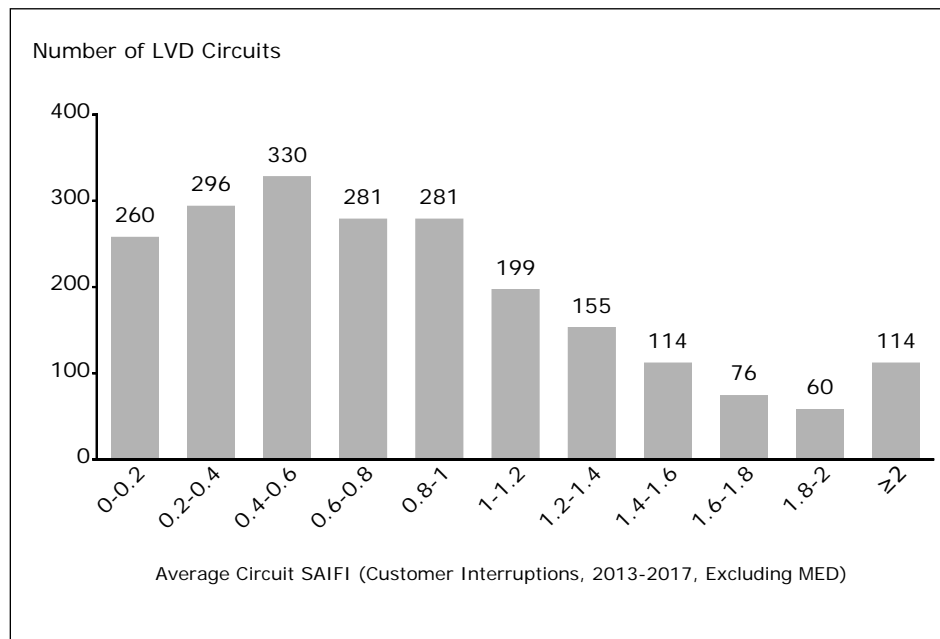


FIGURE 22 – CIRCUIT-LEVEL SAIFI PERFORMANCE DISTRIBUTION (2013-2017)



As seen in Figure 21 and Figure 22, circuits have varying degrees of reliability. The majority of our circuits (approximately 57%) achieved an average SAIDI of less than 150 minutes per customer between

2013 and 2017, with more than 20% achieving a circuit SAIDI of 50 minutes or lower. Similarly, the majority of our circuits achieved very reliable SAIFI, with approximately 70% of our circuits having less than one interruption per customer on average from 2013 through 2017.

The following tables show performance from 2017 for the 10 poorest-performing circuits as ranked by our SAIDI and SAIFI metrics, excluding MED. The circuit performance is driven by the outage incident types listed in Section IV. Each circuit is reviewed in detail to develop a specific corrective action plan targeted at drastically improving reliability.

TABLE 12— TEN POOREST-PERFORMING SAIDI CIRCUITS

Ten Poorest-Performing SAIDI Circuits					
Substation-Circuit	Service Center	Circuit Length (miles)	Customer Count	Customer Interruptions	Circuit SAIDI
Lyon Manor-Treasure	West Branch	20	923	6,574	2,151
Pittsford-Church Road	Adrian	98	791	5,156	2,011
Hubbard Lake-Miller Road	West Branch	63	623	2,460	1,820
Rogers Hydro-Stanwood	Big Rapids	44	456	2,081	1,720
Pittsford-Bird Lake	Adrian	86	1,620	9,382	1,702
Delton-Cloverdale	Hastings	59	1,389	8,430	1,651
Webb Road-Plainfield	West Branch	18	498	951	1,571
Peach Ridge-Kenowa	North Kent	28	416	3,443	1,547
Delton-Delton	Kalamazoo	40	1,079	6,329	1,518
Gerrish-Golf Club	West Branch	34	702	856	1,437

TABLE 13 — TEN POOREST-PERFORMING SAIFI CIRCUITS

Ten Poorest-Performing SAIFI Circuits					
Substation-Circuit	Service Center	Circuit Length (miles)	Customer Count	Customer Interruptions	Circuit SAIFI
Peach Ridge-Kenowa	North Kent	28	416	3,443	8.3
Frontier-Ransom	Adrian	69	831	6,749	8.1
Mccandlish-Bush Creek	Flint	25	393	2,853	7.3
Lyon Manor-Treasure	West Branch	20	923	6,574	7.1
Peck Road-M-91	Greenville	25	583	4,061	7.0
Pittsford-Church Road	Adrian	98	791	5,156	6.5
Delton-Cloverdale	Hastings	59	1,389	8,430	6.1
Watkins-Christy	Battle Creek	11	800	4,816	6.0
Delton-Delton	Kalamazoo	40	1,079	6,329	5.9
Pittsford-Bird Lake	Adrian	86	1,620	9,382	5.8

Many of the poorest-performing circuits listed above will receive investments in 2018 to improve reliability on the most challenged components of our system. For example, we are investing in the Treasure circuit on the Lyon Manor substation, which was the poorest-performing circuit on our system when ranked by circuit SAIDI in 2017. Some of the interruptions on the Treasure circuit were caused by tree contacts, others were caused by weather events, and the circuit also had an interruption caused by the upstream HVD component of the system. In an effort to improve the reliability and resiliency of this circuit and better serve our customers, we are performing a full circuit clearing and rebuilding approximately 1.6 miles of the Markey-Houghton Heights 066E line (the upstream HVD line of Lyon Manor – Treasure) in 2018. We are also investing in the Church Road circuit on the Pittsford substation in an effort to reduce outage frequency. This circuit had the majority of its interruptions caused by trees and the upstream HVD system. To address the poor performance, we are upgrading two HVD lines that feed this circuit including pole top rehabilitation, structure replacement, and adding line sensors.

Additional Measures of Customer Reliability Experience

Our customer experience metrics are analyzed at the most granular level to identify specific circuits where we can focus our efforts to improve the reliability and resiliency of our network. The distributions below in Figure 23 and Figure 24 highlight the number of circuits that fall within different performance bands for the percent of customers experiencing three or more interruptions and the percent of customers experiencing one or more interruptions that last five hours or longer.

FIGURE 23 – CIRCUIT DISTRIBUTION OF PERCENT OF CUSTOMERS WITH ≥3 INTERRUPTIONS PER YEAR

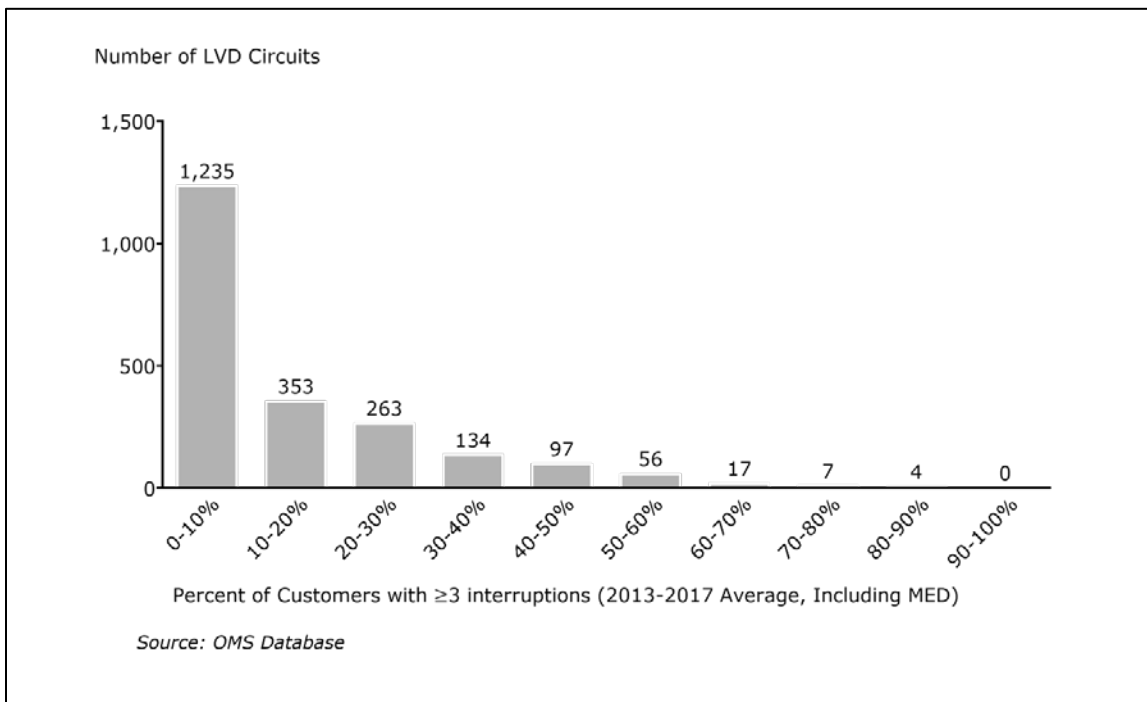
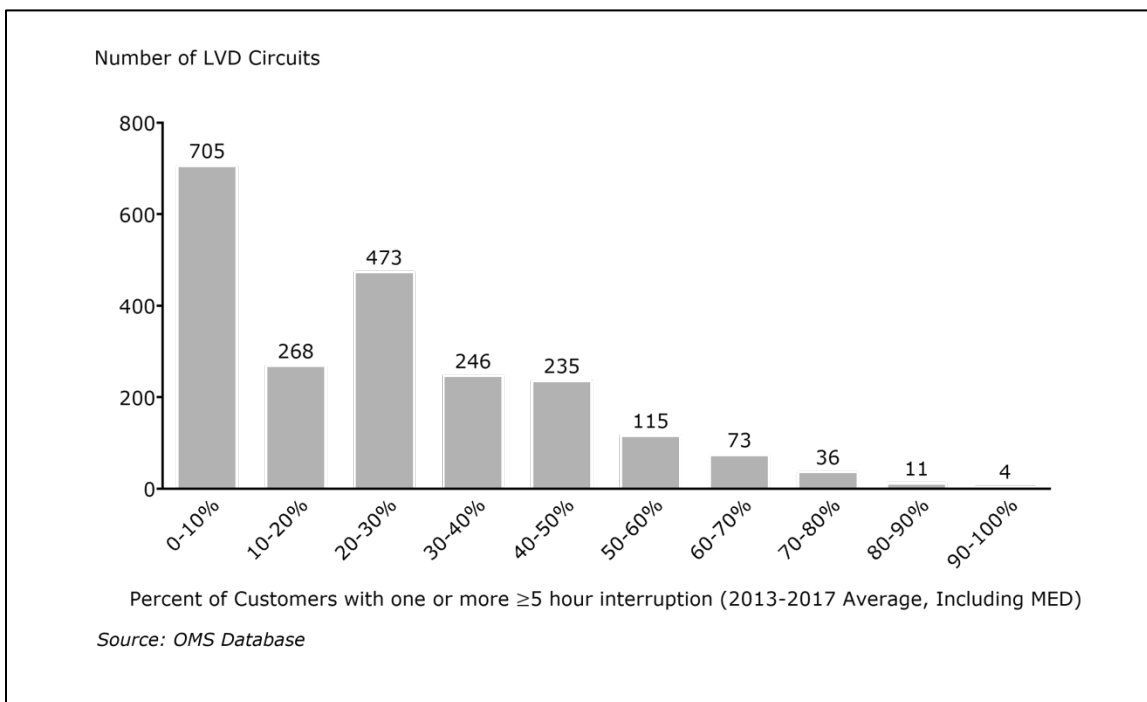


FIGURE 24 – CIRCUIT DISTRIBUTION OF PERCENT OF CUSTOMERS WITH ONE OR MORE ≥5 HOUR OUTAGE PER YEAR



As shown, we track customer reliability experience metrics at a circuit level and have programs to specifically improve the reliability and resiliency of circuits that perform poorly against these metrics. For example, the Delton circuit on the Delton substation had 100% of customers experience three or more interruptions in 2017. This circuit is receiving HVD investment to rebuild approximately 1.8 miles of line, LVD line relocation work, pole replacements, and had full line clearing in 2017 to reduce the frequency of tree related events. Additionally, the Legion circuit on the Gerrish substation is receiving LVD line upgrades and is transferring customer load to an adjacent circuit to reduce the number of customers impacted when outages occur, due to its history of long interruptions (100% of customers had more than one five-hour outage in 2017).

E. Electric Reliability Rally Room

Our multi-prong reliability improvement strategy is monitored and managed through our Company's use of Rally Rooms – dedicated collaboration spaces and forums for coordination and problem solving that minimize organizational barriers and promote improved visibility and accountability. This Rally Room concept is not unique to Consumers Energy; it is a key element of the lean system that has been used across manufacturing industries to implement continuous improvement initiatives. Key elements of this concept are identifying a dedicated purpose or goal, visual management, practical problem solving, and daily and Weekly Operating Reviews (WOR) with a cross-functional team of key personnel. The process makes information accessible at the local level and enhances the overall decision-making process. All of this analysis connects to efforts undertaken by the stakeholders that work together on a daily basis in the Rally Room.

In the Rally Room, we bring together two key elements of our Company culture: breakthrough thinking – the willingness to set performance targets beyond the scope of historical performance; and lean tools adapted from outside of our industry – including visual management, operating reviews, problem solving, and standardization. The Rally Room is utilized by cross-functional teams to come together to analyze the gap between current state and the breakthrough stretch objectives, develop plans to drive improvement, execute the plans, monitor performance through trend charts and Pareto analyses, conduct structured problem solving to address root causes of problems, and implement countermeasures.

Over the past 10 years, our emphasis on improving the customer experience has renewed our focus on reliability as a key driver of not only system performance, but also of customer satisfaction. Data supports our premise that there is a high correlation between customer satisfaction and reliability; customer satisfaction data indicates customers who experience three or more interruptions within 12 months, or interruptions lasting longer than five hours, have reduced satisfaction.

While reliability has been important for many years, and our SAIDI performance trend line has been improving, we realized that we needed to do even more, and that we could achieve even greater benefits by applying lean principles to our reliability processes. Therefore, in October 2016 we established our Electric Reliability Rally Room, a place to collaboratively define reliability problems, align on performance improvement plans, and monitor the progress and SAIDI benefits of projects so adjustments can be made when necessary. Developing this collaboration space involved creating detailed visual management to facilitate problem definition and highlight performance gaps to help guide decisions and actions. This visual management system displays the expected outcome of a process and the standard or target, while simultaneously highlighting any performance gap(s) between the expected and actual outcome. This makes it immediately obvious when something is wrong, allows for

quick action on countermeasures, and promotes accountability, while facilitating cross-functional communication and open challenging of assumptions based on data. As a result, we can ensure that our employees at all levels are engaged in identifying the next steps by making analysis and data visible to everyone.

To build the Rally Room, we began by displaying existing data and breaking out top reliability drivers. We then analyzed the data, seeking to isolate the root causes of our worst reliability issues. In particular, we used Pareto charts to graphically quantify key performance gap drivers. These Pareto charts illustrate where outages are occurring; the causes of those outages; and which substations, circuits, or HVD lines are impacted. As part of continuous improvement, the team has developed a key performance indicator tree that shows the connection between processes and SAIDI performance, which will help identify additional process improvement opportunities.

The Rally Room has evolved with an expedited Plan, Do, Check, Act (PDCA) cycle. This four-step method identifies detailed action plans with timelines, required resources, and owners. SAIDI performance is measured against those plans to evaluate results, and the plan is adjusted as we determine needed countermeasures and operationalize them.

The Rally Room has a set cadence and a majority of reliability-related meetings take place in the shared working area, open at all times to allow cross-functional collaboration. The core team includes members from Distribution Operations, Forestry Operations, HVD Engineering, LVD Engineering, and Planning and Scheduling. This team meets for working sessions multiple times weekly to check performance and apply the lean tools identified above to the key drivers of SAIDI. Each metric has a team member assigned who updates the metric every week. Teams conduct Daily Operating Reviews (DOR) with individual team member check-ins, providing insights to incorporate into daily plans. Any barriers to solving those issues get escalated into the Weekly Operating Review (WOR), which includes the core team, subject matter experts, and executive leadership from the Engineering and Operations organizations. Monthly Operating Reviews (MOR) with cross-functional senior management, and periodic reviews with the Company-wide Officer team, occur throughout the year. See Section VI.A for additional detail on operating review cadence.

This regular cadence provides frequent routine checkpoints to compare performance to the plan and allows us to quickly adjust when key performance indicators are off target. Key changes driven by the WOR cadence include the addition and relocation of forestry crews to address poor-performing circuits and the institution of overtime for design and field resources to close a gap in work plan completion.

As part of the governance structure, we have also established a Reliability Steering Committee comprised of leadership from the Engineering and Operations organizations. The Reliability Steering Committee provides a unified and cross-functional approach to coordinating, prioritizing, resourcing for implementation, and approving various reliability, restoration, and customer communication improvement efforts. Program managers evaluate the SAIDI benefit of projects in each category of work, and recommend investments to maximize the reliability benefit for their respective programs. The Reliability Steering Committee reviews this input from multiple program managers and allocates capital resources to ensure that customers receive the greatest SAIDI benefit across the electric distribution system.

By using visual management, we have had success in several electric reliability areas. We have made holistic investments on the worst SAIDI performing circuits by finishing forestry and engineering work as

part of a single project, because these worst performing circuits were a major contributor to customer interruptions and complaints. We first tested this concept in 2016 with very successful results on the Lost Lake circuit on the Lincoln substation, yielding a reduction of 13 LVD line incidents and avoiding 317,000 customer interruption minutes (approximately 0.2 minutes of system SAIDI) from the first half to the second half of the year. We also changed our approach to line clearing. Previously, we made line clearing decisions based on the number of customers that could be impacted on the circuit. Through data analysis in the Rally Room, we determined that rural circuits with fewer customers were a predominant driver affecting system reliability performance. These customers would experience several lengthy interruptions per year, heavily impacting overall reliability. By focusing on the goal of reducing SAIDI and maintaining a degree of flexibility in the work plan, we shifted line clearing resources to areas with repetitive customer interruptions.

The Rally Room focuses not only on infrastructure investment, but also on work processes. We analyzed the time between weather events and mobilization of needed field resources. The variance between events helped identify the need for specific employee guidelines. These guidelines have been implemented, communicated, and practiced in a tabletop exercise and during actual restoration events. Each time, the guidelines have been refined to continuously improve the process to reach standardization across the state. Compared to 2016, we achieved an average reduction of 80 minutes in 2017 executing this process, improving electric reliability by two SAIDI minutes.

In 2018, the team is focusing on improving planning processes and continuing to focus on practical problem solving. As part of these efforts, we are making our processes as visible as possible to quickly identify and mitigate any bottlenecks. Based on the knowledge we have developed, we are making the Rally Room more proactive, laying out our holistic SAIDI reduction plans, and using our data to continuously check our progress and identify specific corrective actions that are needed.

V. Grid Capabilities

A. Overview of our Future Modernized Grid and Advanced Capabilities

Customer expectations of the grid are becoming more varied and complex, which requires the system to become more adaptable as technological advances and financial innovations allow customers to change how they use electricity and interact with the system. As the requirements of the grid change, we are becoming more dependent on networked field devices and control systems to maximize efficiency, reliability, and system performance – all without compromising safety or distribution asset protection.

Our distribution grid modernization strategy leverages automation and invests in advanced technology to support the objectives of our customer-driven electric distribution plan. These advanced capabilities will have a significant impact across all five of our objectives and goals, as outlined in Section II of this report: safety and security, reliability, cost, sustainability, and control.

Our plan for grid modernization is outlined over several sections in this report, as follows:

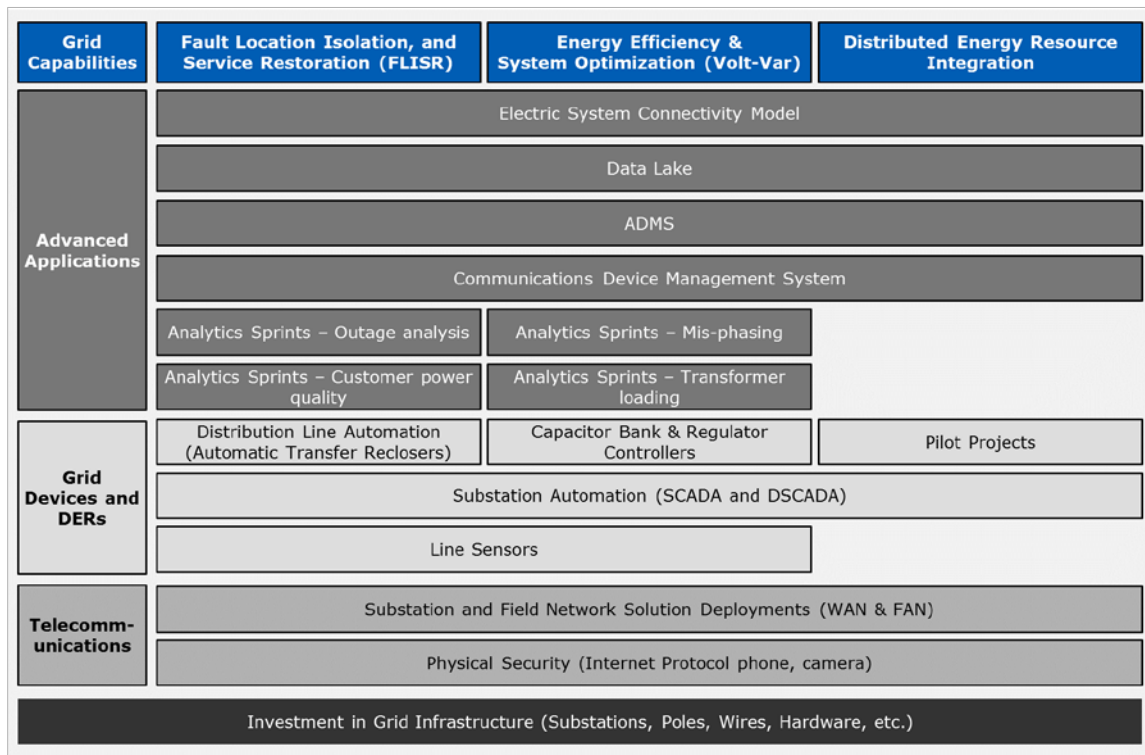
- This section (Section V) outlines the grid capabilities that we plan to build (FLISR, energy efficiency, and DER integration) and describes how investments across grid infrastructure, telecommunications, grid devices, and advanced infrastructure will enable those capabilities. Section V focuses on the overall logic of our grid modernization plan and how the different technologies and investments fit together over a multi-year roadmap.
- The specific details of the five-year investment plan can be found in Section VIII (budget line items 4.5, 4.9, and 4.10), including the annual capital investments, number of devices deployed, prioritization methodology, and specific benefits of each technology.
- Section VI includes a discussion of the role of non-wires alternatives and the increasing role of data and analytics in the evolution of the planning process.
- Section VII outlines the benefits of our EDIIP investments, including benefits from grid capabilities investments.

Over the next five years, we will focus on building three primary capabilities:

- Reliability related – Automated re-routing of power flows around an outage and restoration following an outage, commonly known as Fault Location, Isolation, and Service Restoration (FLISR).
- Sustainability and cost related – Energy efficiency gains and peak reduction through VVO.
- Control related – Enabling increased utility- and customer-owned DERs such as DG and energy storage systems.

These early capabilities will be enabled by investments in physical infrastructure and devices, telecommunications upgrades, and advanced applications, as outlined in Figure 25 below.

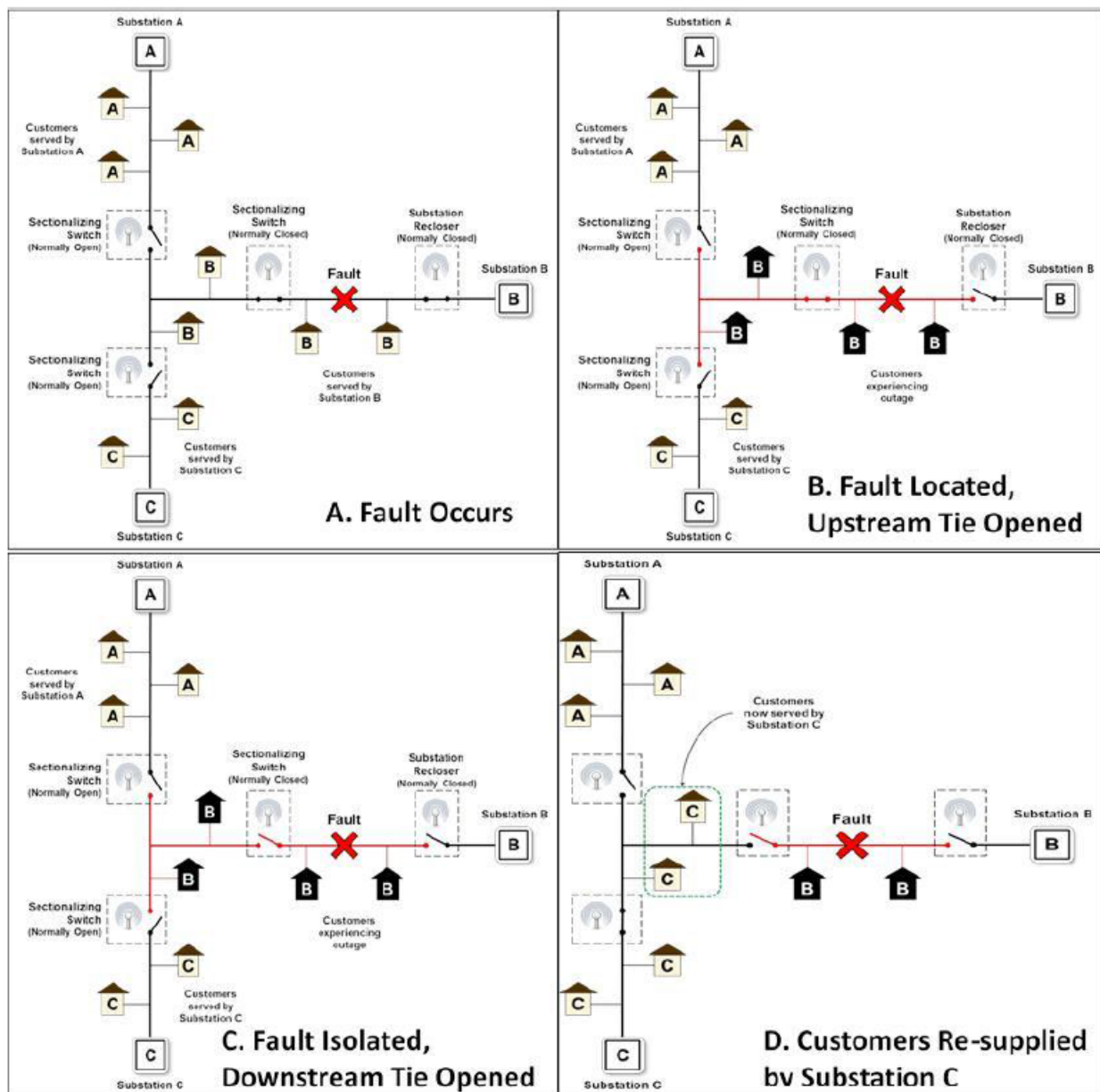
FIGURE 25 – GRID MODERNIZATION CAPABILITY SCHEMATIC



Fault Location, Isolation, and Service Restoration (FLISR)

One of our core objectives in the five-year distribution plan is to improve system reliability and resiliency. The FLISR capability will be critical to achieving this objective. A FLISR system will quickly and automatically restore power to as many customers as possible when faults occur, without requiring intervention by operators or crews. Automating fault location will reduce outage duration, decrease service costs associated with outages by reducing crew patrol time, and improve safety. Figure 26 shows an example from the United States Department of Energy (DOE) on how FLISR can reduce outage impact and duration. Over the next five years, we will invest in a number of critical enablers necessary to support a FLISR system. These include line sensors, DSCADA, and advanced applications, discussed in more detail later in this section.

FIGURE 26 – FAULT LOCATION, ISOLATION, AND SERVICE RESTORATION SCHEMATIC



Source: United States Department of Energy (DOE), https://www.smartgrid.gov/files/B5_draft_report-12-18-2014.pdf

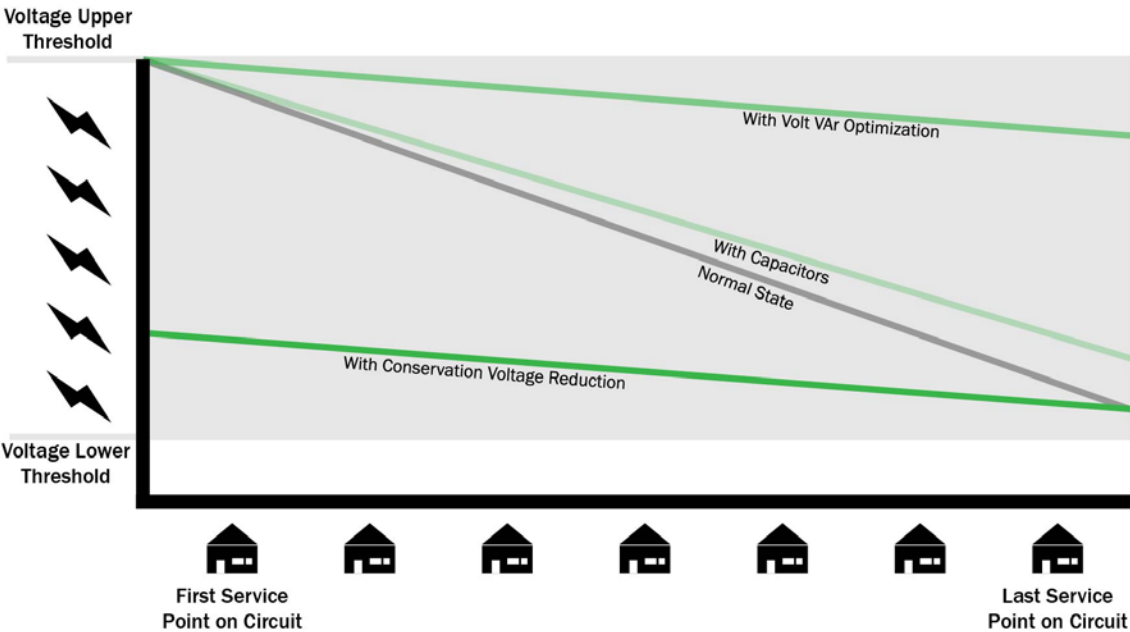
Energy Efficiency and System Optimization

VVO will enable coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste. VVO will also allow us to implement a CVR Program to optimize end-point voltages to reduce demand and the carbon footprint of our system, without requiring investment by customers (e.g., in high-efficiency appliances for their homes). The specific investments to enable this capability include regulator controllers, capacitor controllers, DSCADA, and advanced applications, which are outlined in more detail as part of our five-year capital plan in Section VIII.

The schematic below (Figure 27) illustrates the benefits of VVO and CVR. The “Normal State” represents the status of our distribution system prior to the capacitor controller replacement project. In our current

state, we must maintain upper threshold voltage at the substation relative to MPSC standards, but due to line losses, our end of line customers see a significant voltage drop. With distribution capacitors fully functional, we can slightly raise that end of line voltage as seen in the “With Capacitors” line of the chart. However, we will not see significant loss reduction and voltage improvement until we operationalize the VVO project. This project flattens the voltage profile by reducing system losses and improving voltage to our customers. With this step complete, we will then be able to reduce substation output voltage to the lower threshold of the MPSC voltage requirements. This reduction in voltage leads directly to lower energy usage by our customers. By first flattening the voltage with VVO, we are ensuring that all customers receive quality voltage with our CVR implementation. These projects concurrently provide large benefits to us and our customers through energy efficiency and energy reduction.

FIGURE 27 – ENERGY EFFICIENCY AND SYSTEM OPTIMIZATION SCHEMATIC



Distributed Energy Resource (DER) Integration

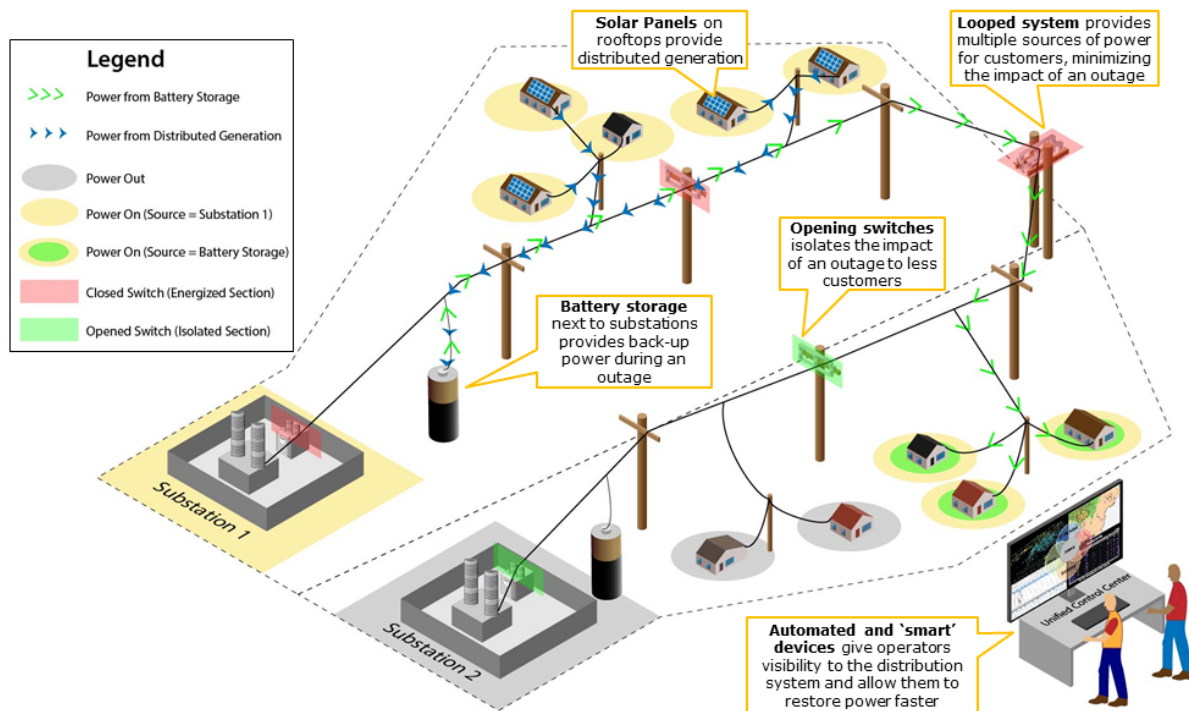
We are exploring ways to more fully integrate DERs in our grid planning and operations strategy. Some examples of DERs include utility and customer-owned battery storage, solar power, wind power, and backup generators. Based on current trends, we believe customers will continue to adopt DERs, and these adoption rates will accelerate as underlying costs fall. Developing our DG experience plays a key part in planning to meet our sustainability and control objectives. With this experience, we will be able to better integrate DG resources, enabling greater customer control and providing opportunities to use these resources as NWAs to address system overload issues.

It is important that our system is prepared to support the growth of DERs for both real-time operation and future system planning. This will require the capability to continuously monitor and control DER deployments through two-way power flow while making other foundational investments (e.g., developing an accurate system model, telemetry from substations and line devices, and ability to

optimize voltage levels). These elements need to be in place prior to utilizing new software-based tools, analysis methods, and models with circuit-level granularity.

The schematic in Figure 28 illustrates the management of DERs on a distribution system optimized for improved system hosting capacity allowing for two-way power flows.

FIGURE 28 – DER INTEGRATION



B. Summary of Investments for Advanced Grid Capabilities

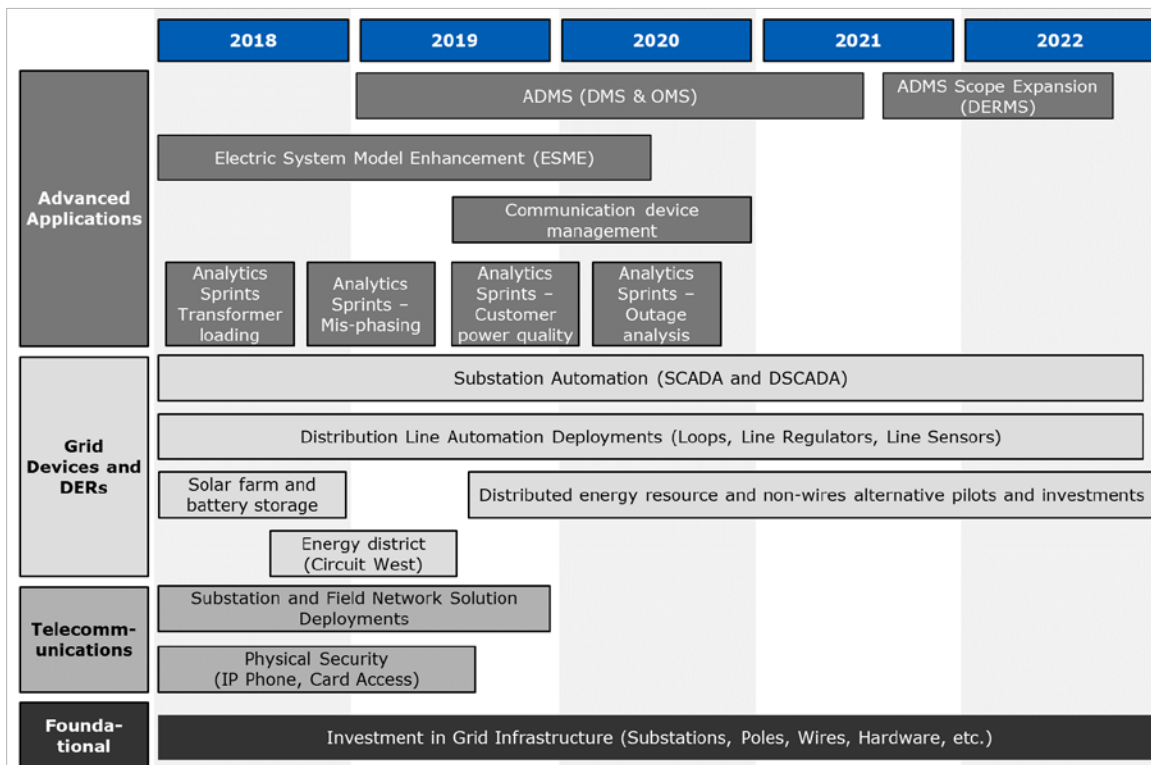
Modernizing our distribution system is a significant undertaking. The investments will span over several years and require complex sequencing, engineering, and close coordination with physical infrastructure upgrades. Over the past few years, we have made considerable progress towards laying the foundation for the future grid capabilities described above. We have invested in grid device deployments, implemented applications, and will be launching two Battery Energy Storage Systems (BESS) later this year. Over the next five years, we will continue to deploy foundational technologies to improve the reliable delivery of energy to our customers and enable the integration of DERs, all with a continued focus on safety.

In order to achieve this, we plan to deploy technologies across three categories: Telecommunications, Grid Devices, and Advanced Applications.

There are many factors at play to determine the best sequencing of grid modernization investments for customer benefit. First, we need to make simultaneous, coordinated investments across all three categories to achieve the greatest benefits for our customers. In other words, the full potential benefits from these technologies are only realized when all three are in place: automated grid devices at an appropriate minimum scale that communicate over telecommunications infrastructure, with advanced applications to optimize control and visibility. For this reason, our rollout strategy involves scaling groups of grid modernization technologies on the highest benefit areas of the grid over time (as opposed to, for example, deploying all Automatic Transfer Reclosers (ATRs) before moving on to the next grid device). Second, we consider the maturity of technologies in our rollout plan, focusing on scaling deployment of technologies with known and proven benefits first, while having pilots or smaller-scale deployment of technologies that we are testing. Third, our deployments are limited by the available funding for these programs, which we balance across a variety of needs on the distribution system, as described in Section VI.

Our grid modernization deployment roadmap is shown in Figure 29.

FIGURE 29 – DEPLOYMENT TIMELINE OF GRID CAPABILITY INVESTMENTS



Foundational Infrastructure

The investments in physical grid infrastructure (poles, wires, relays, transformers, etc.) discussed elsewhere in this report provide the necessary foundation for our ability to upgrade grid capabilities. We will not meet our grid modernization goals if we deploy the new technology on our existing aging infrastructure, so we must coordinate these deployments with physical grid infrastructure upgrades.

Telecommunications

Advanced grid capabilities require secure and reliable telecommunications infrastructure. Today, we use existing cellular communications infrastructure from cellular network carriers. This set-up (as opposed to having a communications network that we maintain) allows us to deploy future grid devices and technology without needing to upgrade an internal communications network. Our telecommunications plan is focused on two primary investments. First, we will prioritize upgrading facilities where service carriers are retiring our existing aging analog services. Second, we will find opportunities where upgrades can best support the deployments of our future grid devices and pilot applications.

Grid Devices

As described above, our strategy for grid devices focuses on deploying technologies with known benefits at scale while testing or piloting newer technologies. SCADA, DSCADA, and ATRs provide proven customer reliability benefits, and they are foundational components that will enable other grid capabilities in the future. As we expand these programs to full scale over time, we will continue to target deployment on specific grid locations and circuits where we can maximize reliability and energy efficiency benefits. We are in an earlier stage of deployment of line sensors and line regulators. Over the next five years, we will increase the penetration of these devices on the grid as we learn more about the technologies and their impact on improving grid capabilities.

Advanced Applications

As our monitoring and automation deployments grow, we will implement advanced applications that will allow for centralized management of these technologies and enable enhanced decision support and operational efficiency. As we achieve operational scale in our deployments of devices and applications, changes to our processes, our people, and our technological skillsets will be required to achieve the full benefits of these technologies. The way that we operate and manage the distribution system will change as we have greater visibility and control over devices in the field. These changes, coupled with our investments, will allow us to unlock additional capabilities and provide greater benefits across all of our objectives.

i. Foundational Infrastructure

The investments in physical grid infrastructure (poles, wires, relays, transformers, etc.) discussed elsewhere in this report provide the necessary foundation for our ability to upgrade grid capabilities. We will not meet our grid modernization goals if we deploy the new technology on our existing aging infrastructure, so we must coordinate these deployments with physical grid infrastructure upgrades. If we do this, the advanced communications and intelligent applications can manage the electrical grid as a fully integrated system, allowing for a mix of generation and delivery of energy at any point, rather than treating it as a unidirectional distribution system.

Our plan to enhance grid capabilities is linked to our ongoing maintenance programs and traditional infrastructure upgrades. For example, improvements performed at each capacitor location address not only the immediate needs of the capacitor control replacement program, but also the future needs of all capacitor-dependent programs. Our system conditioning efforts include the replacement of obsolete or failing equipment such as rusty meter sockets, oil switches, capacitor cans, junction boxes, cabling, lightning arresters and more. As part of our infrastructure upgrades, we also incorporate the addition of neutral current sensors. These sensors are brand new to the system and provide valuable information on capacitor health and status. If a capacitor were to have a blown fuse, it would result in a step change

in neutral current which would be detected by the sensor and relayed back to our SCADA application in real-time. This data can be used to detect circuit load imbalance, informing the need for repairs, and is a key indicator of future problems. These sensors and the enablement of two-way communication have allowed Consumers Energy to start predictive maintenance at capacitor locations. These tools and enablers are critical for achieving ongoing success in VVO or CVR deployment.

ii. Telecommunications

Grid modernization puts new demands on network connectivity and communications, driven by the growing number of grid devices, added sensors, and increased computation capabilities at the edge of the system. The communications architecture is built on a network design that enables reliable wired and wireless communications to generating facilities, substations and pole top devices. The communications architecture will continue to evolve and will require upgrades to support the growing functional and security requirements as deployments ramp-up. The value of this communications architecture is to enable a more connected modern distribution system, improving our goals of safety and security, reliability, cost, sustainability, and control.

There are two main drivers for grid communications investments. First, telecommunication carriers are quickly retiring aging analog services that currently provide SCADA and circuit protection functionality for our electric grid. Second, the complexity is only growing as more devices are deployed and more networking infrastructure is used for the connected grid. To support and manage the growing system, automation deployments and existing pilot applications, a high-speed communications network is required. To achieve this, we have developed and deployed a communications architecture solution, as described below.

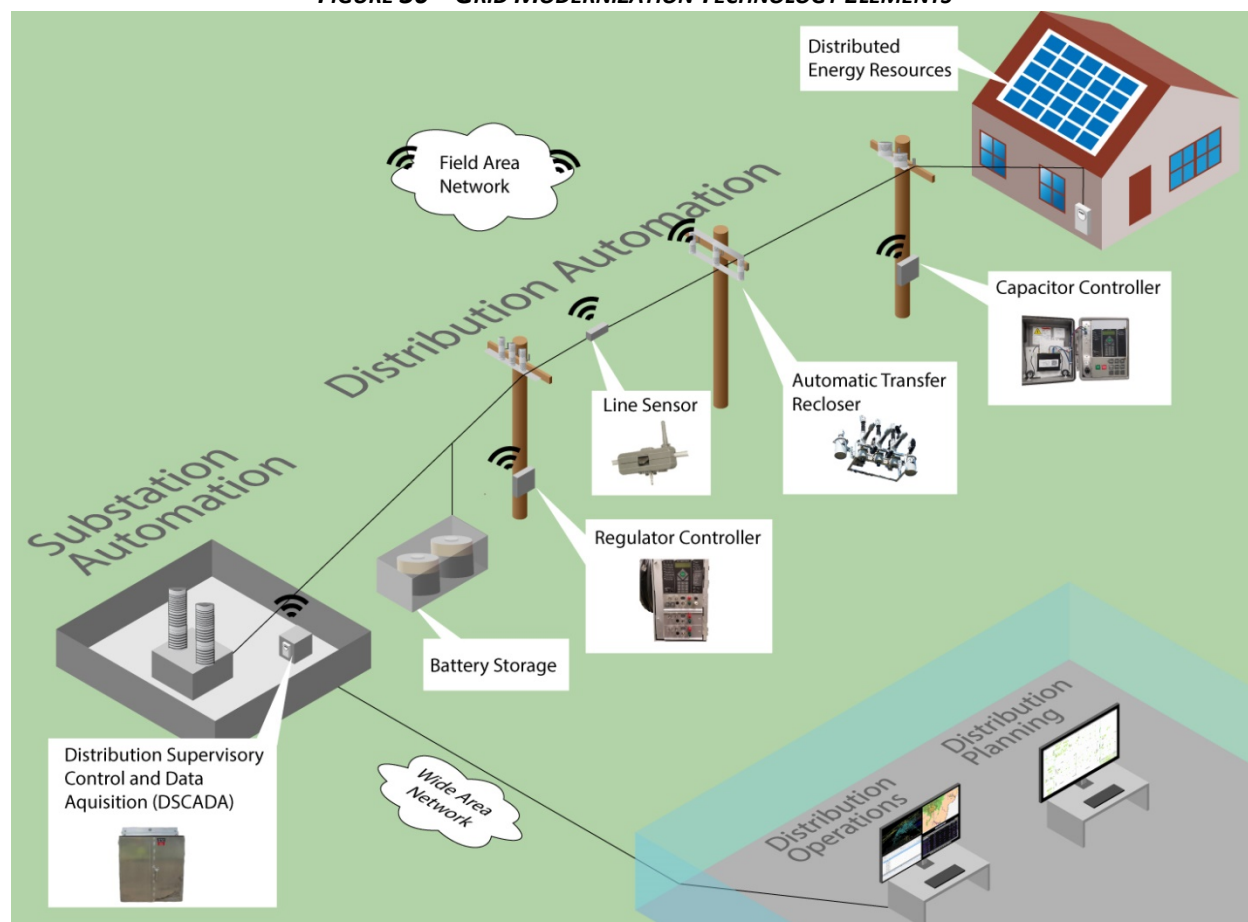
- **The Wide Area Network (WAN)** architecture being deployed at our high voltage substations and generation facilities has been engineered as a converged network solution (the coexistence of telephone, video, and data communication within a single network). The focus on convergence has allowed us to reduce the number of purpose-built networks provisioned at our facilities, better utilizing increased bandwidth for services like Voice-Over Internet Protocol and physical security. We are implementing standards-based, flexible and scalable technologies with additional focus on redundancy and reliability.
- **The Field Area Network (FAN)** architecture deployed supports multiple distribution grid devices, and is standards-based, flexible and scalable. The architecture utilizes well-established carrier based cellular networks, allowing us to accelerate deployments by eliminating the need to build out and support a custom wireless network. Reliability, cost, and security are fundamental design elements that have been addressed by using multiple carrier-based cellular networks with private Internet Protocol (IP) and data encryption. There are currently over 4,000 line and substation automation devices communicating using this FAN architecture.

iii. Grid Devices

Grid devices are the primary technology components that allow for automation at substations and on distribution lines. This automation is foundational to enable the grid capabilities outlined in Section V.A of this report. Figure 30 represents the grid devices within our five-year plan for grid modernization deployments. This conceptual diagram shows an illustration of a distribution system with grid devices

that include DSCADA, ATRs, capacitor controllers, regulator controllers, and line sensors. Today, these devices are largely used to achieve reliability goals. As deployments of regulator controllers and DER begin to increase on our system, our grid devices can expand to support more energy efficiency and DER integration capabilities. Further, we can use data from these devices to help provide a more strategic asset management approach by collecting advanced warning of equipment problems and proactively addressing the issue. This approach reduces outages, minimizes repair time, and reduces cost for distribution equipment. Throughout the lifecycle of these field deployments, we will continue to enhance future deployments to support the rapid change in technology. This includes adding more remote management, real-time diagnostic of equipment, and support for a more distributed peer-to-peer computing architecture.

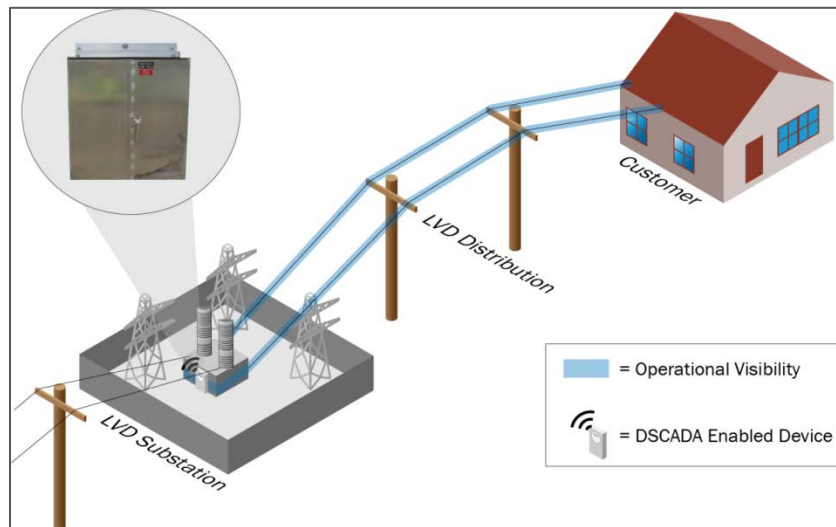
FIGURE 30 – GRID MODERNIZATION TECHNOLOGY ELEMENTS



Distribution Supervisory Control and Data Acquisition (DSCADA)

DSCADA is the primary component that will enable substation automation. The technology expands the existing HVD SCADA system to LVD substations, to enhance operational visibility between the existing HVD SCADA in the bulk power substations and our AMI at our service delivery points. This enhanced visibility will allow us to more quickly and effectively address system outages, improve real-time system operation, and enable programs such as VVO, CVR, and FLISR.

FIGURE 31 – DSCADA OPERATIONAL VISIBILITY ILLUSTRATION



We have been upgrading distribution substations with DSCADA communications for several years. To date, over 260 distribution substations are DSCADA-enabled, providing monitoring and control capabilities to over 33% of our electric system. DSCADA enables efficiency savings from VVO and CVR, reliability and productivity benefits from distribution automation loop operations (see below), and switching operations in a future ADMS (see below). DSCADA, on its own, provides significant reliability benefits through immediate visibility into system problems and remote control capabilities. DSCADA saves customer outage minutes by enabling real-time information to diagnose fault locations, instead of relying on customers to report outages. System controllers can remotely operate substation equipment and get notified in real-time when substation reclosers are locked out causing an outage. Without this capability, when a circuit locks out, system controllers dispatch a substation area operator to the substation and contact the appropriate work management center to dispatch a crew to investigate the cause. In 2017, we documented five million customer minutes saved (including MEDs) and 185 avoided truck rolls as a result of our DSCADA communications.

In addition, our LVD planners and circuit engineers benefit greatly from improved system visibility, as they can more quickly and accurately perform their job functions. The following examples illustrate some of the benefits DSCADA provides for LVD planning activities:

- **Annual circuit load flow studies** – Currently, we prepare load flow studies using applicable regulator peak readings (available every one to two months), matching them with the corresponding peak meter reading data for that approximate month. Studies prepared in this manner only provide a rough “maximum peak” loading level, do not reflect how long that loading level lasted, and leave planners with no insight into the normal conditions on the circuit. With real-time DSCADA data available, any communicating device can provide the applicable readings for the time of year in question, including previous-day smart meter readings. There is great value in this to enable additional load transfer capabilities based on real load rather than the often-restricting maximum peak. Load flow studies based on DSCADA can be dynamic, based on time of year (or day), and enable planners to make improved capacity investment decisions for the LVD system.

- **Customer issue resolutions** – DSCADA information can greatly improve the customer experience that LVD planners deliver. Planners frequently handle customer issues and complaints. Regardless of the nature of the complaint (e.g., outages, voltage variation, and power disturbances), we have historically had limited data to explore the issue, making resolution often difficult, lengthy, and unsatisfactory for customers. Current methods to deduce these issues include hanging load recording devices (no voltage data, requiring deployments to and data reads from the field), installing voltage metering at the customer (only captures a few day snapshot to troubleshoot), or sending a service worker to retrieve an instantaneous current reading at a line location. Data coming in from exactly when and where capacitors operate via VVO/CVR, smart meter reading history, real-time and historic data from active devices like regulators and reclosers, and/or fault data from reclosers and line sensors can all provide immense insight into the nature of elusive power quality and outage complaints. The added visibility provided by DSCADA enables faster resolution of issues with increased success, providing value to our customers.

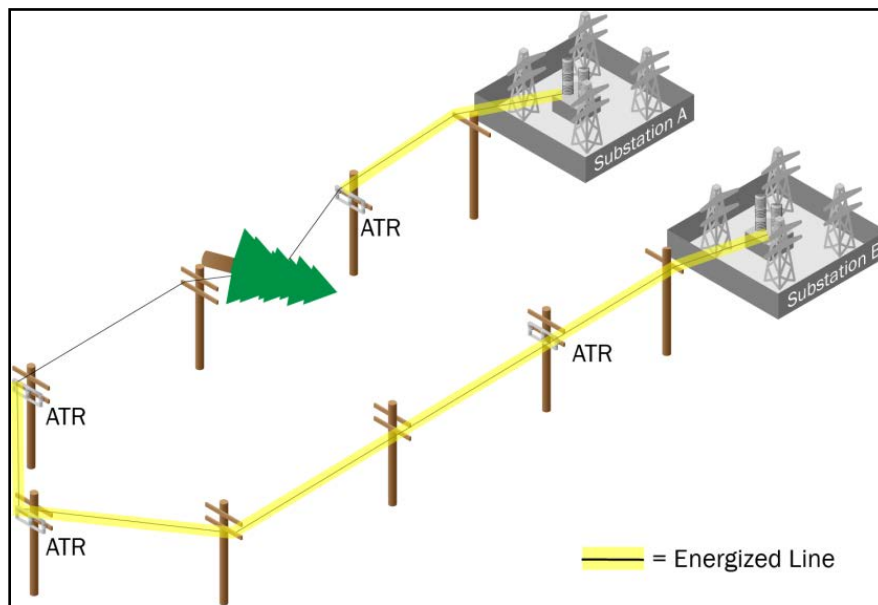
Automatic Transfer Recloser (ATR)

ATRs are a key component for enabling distribution automation loops on our system. This technology is installed as sets on the system between two LVD feeders creating an automation loop. ATRs transfer load automatically in the event of an outage, reducing customer outages, and improving system reliability by isolating a faulted section of a feeder. The “Loop Scheme” software on these devices is designed to operate even when communications are down on the device. This ensures the systems provide the greatest benefit, even in catastrophic storms.

ATRs shown below are specially programmed reclosers with voltage sensing, and are installed at key locations between two feeders. In the event of an outage on looped circuits, the ATRs will perform an automatic transfer to isolate the faulted section, restoring the maximum number of customers possible from the other source.

FIGURE 32 – INSTALLED AUTOMATIC TRANSFER RECLOSER



FIGURE 33 – DISTRIBUTION AUTOMATION LOOP FUNCTIONALITY MODEL

Individual ATR projects are prioritized based on circuit reliability metrics (SAIFI, SAIDI, and CAIDI), historic outage data, electric system model information, and historic loading information from various sources. These selection criteria are used to identify advantageous locations for future automation and to prioritize funding to candidate locations.

ATR projects typically include some amount of system infrastructure upgrades such as replacing conductors, protective device modifications, line regulator upgrades, or minor substation upgrades. All projects include the installation of ATRs equipped with two-way communication to HVD and LVD SCADA systems. ATRs are capable of fault interruption in addition to the voltage monitoring necessary to perform their designed load transfers.

Capacitor Controllers

Distribution capacitors are a source of reactive power with the purpose of reducing system losses and maintaining the distribution system voltage profile. When in service, the three-phase capacitor bank injects reactive power onto the primary distribution lines. A capacitor controller operates the switches that take the capacitor bank into and out of service. The capacitor controller replacement project was completed over a two-year period and replaced nearly 4,000 controllers statewide. The new capacitor controllers utilize 4G cellular technology for two-way communication, providing real-time data and status through DSCADA.

Regulator Controllers

Distribution line regulators are essentially a tap changing transformer utilized to increase or decrease voltage on the primary distribution system based on changing load conditions. The goal of the regulator controller replacement project is to enable two-way communication between the regulator controller and our DSCADA application. There are nearly 4,000 line regulator controllers statewide, which will be replaced or upgraded as a part of the project. Modernized regulator controllers with two-way communication allow distribution line regulators to be part of an optimized distribution system that is both adaptable and rapidly reconfigurable. With remote monitoring and control, we can provide

customers with optimum voltage regardless of the system conditions, monitor their performance, and identify new ways to improve system efficiency. This upgrade allows for enhanced distribution planning activities that will focus on energy efficiency and system optimization. Lastly, the upgraded controllers with two-way communication are a prerequisite to the CVR program.

Line Sensors

Line sensors are an integral part of FLISR to detect faults, determine the faulted section and the probable location of fault. Line sensors also provide information such as feeder loading, fault current data, momentary outages, permanent faults, line disturbances and high current alarms. This, in-turn, significantly reduces our customer outage minutes along with reducing the miles we travel for fault resolution. Line sensors also enhance our ability to accurately respond and resolve customer complaints. These devices facilitate the VVO and FLISR capabilities and provide accurate information in substations that do not have all phases being metered or where we currently only possess hydraulic reclosers.

iv. Advanced Applications

Advanced applications planned for grid modernization will require an accurate distribution model, near real-time data from connected grid devices, and an integration strategy for connecting real-time operational and enterprise systems. The planned applications will enable advanced analysis, visualization, and control capabilities to manage distribution system resources and networked devices that operate and monitor the system.

Evolution of Data Analytics

Expanding data and analytics capabilities are critical enablers in our distribution system plan, allowing us to more effectively target investments to the areas of highest benefit on the grid by having greater visibility and situational awareness. The volume and complexity of distribution grid data available will expand over time with continued deployment of grid technologies like DSCADA and line sensors.

The evolving data capabilities of the organization can be broadly divided into four key themes:

- **Collecting new data** – facilitated by the rollout of “smart” devices that have communications capabilities.
- **Improving access to data** – integrating multiple systems for real-time feedback, development of a common organizational data platform (“The Data Lake”).
- **Improving organizational analytics capabilities** – specific analytic “sprints” and use of additional analytics tools propagating through the organization.
- **Operationalizing data** – using new capabilities to optimize both real-time and future operation of the grid.

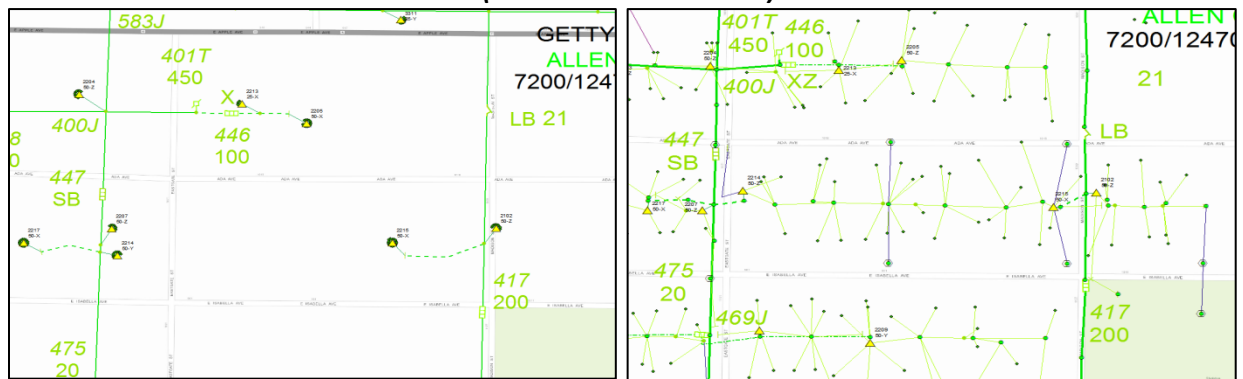
These four themes span across our current technologies and systems as well as future capabilities that we are focused on developing. Further details on the current and future capabilities are embedded through this section (Section V), Section VI.B, and the investment prioritization logic in Section VIII.

Electric System Connectivity Model

Nearly every modern distribution application, including line power flows, VVO, and FLISR require an accurate three-phase electrical model of the distribution system that represents its exact physical and load characteristics. Our current electric distribution system model is stored in our Geographical Information System (GIS) and, like many other utilities, some of the information contained in GIS is

inaccurate. Many of the errors are because the original data was from old paper maps that have not been kept up to date. In 2016, we began a project to enhance the electric system model data with greater connectivity and spatial accuracy of the connected assets. This project, called the ESME, also enhances our business process for maintaining the integrity and quality of the data. The project has corrected about one-third of the circuits, finding that the existing system model is about 85% correct. In other words, 15% of the assets are not properly modeled in the present GIS system (e.g., phasing, customers, transformers).

**FIGURE 34 – ELECTRIC SYSTEM MODEL ENHANCEMENT
(BEFORE AND AFTER ESME)**



Advanced Distribution Management System (ADMS)

ADMS is the integration of four key software application components that include SCADA, Distribution Management System (DMS), OMS, and Distributed Energy Resource Management System (DERMS) on a single platform.

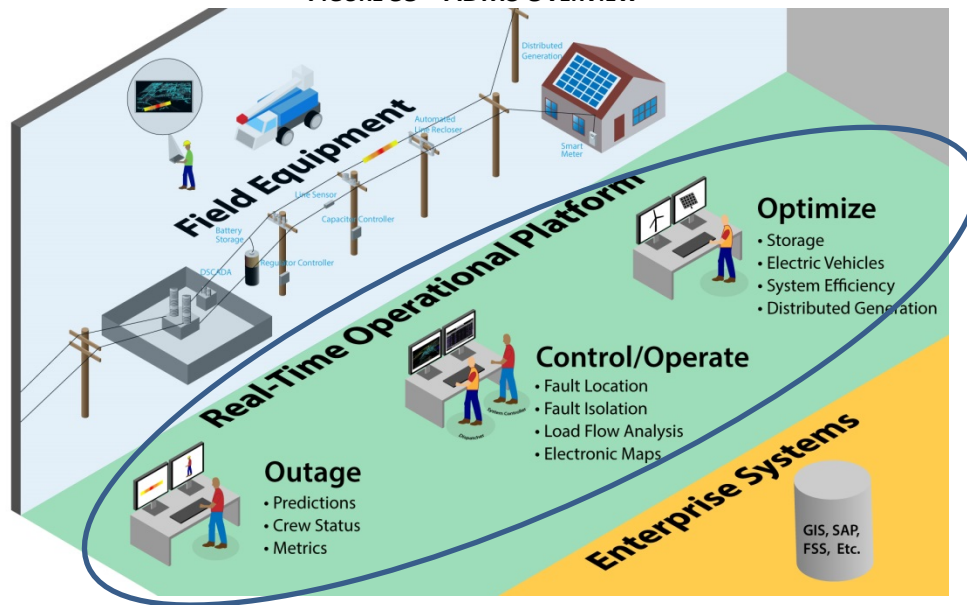
ADMS is popular due to having a single “as operated” connectivity model and platform for supporting multiple operational applications. ADMS enables full integration of Grid Management applications that work as a comprehensive solution to improve reliability, cost, and grid performance. Common industry reasons for investing in ADMS include⁹:

- **Resilience and Reliability** – Creates ability to withstand or recover quickly from outage events including natural disasters.
- **Distributed Resources** – Allows for the accommodation and management of larger quantities of DERs.
- **Replacement** – Updates old Information Technology (IT) systems that can no longer be maintained or do not have the ability to integrate with new technologies.
- **Regulatory** – Meets specific requests to accommodate efficiency and reliability requirements.

Figure 35 below illustrates how ADMS provides improved line of sight, from the substation to the customer.

⁹ DOE “Insights into Advanced Distribution Management Systems,” February 2015.

FIGURE 35 – ADMS OVERVIEW



Communications Device Management System

Grid devices have a diverse set of requirements for optimal performance, often demanding multiple communication platforms. We are working to deploy a device management system that can integrate with multiple device-specific software systems, permitting links to telecommunications carrier-based web applications and vendor-specific telecommunication platforms like Cisco and RedLion, and will position us for future integration with cloud-based service providers. This will provide real-time operational visibility across our communications fleet independent of the hardware manufacturer. With operational visibility focused on start-of-day monitoring, issue prioritization/tracking, device health, and long-term trending, we will improve overall grid performance.

Data Integration and Advanced Analytics

The ADMS and other operational platforms will require a well-developed integration strategy, placing an emphasis on common data objects to define standard interfaces that can be implemented with various vendors’ applications and existing Company systems. The data integration approach takes a strategic view for the management of information from an enterprise perspective (across business units) and will implement processes to manage information as an enterprise-wide shared strategic asset. The approach implements best practices for information management and leverages industry data standards. This includes the International Electrotechnical Commission System Interfaces for Distribution Management series of standards. This standard consists of various application interfaces for the utility to manage the electrical distribution system that includes monitoring and control of equipment for reliability, voltage management, customer management, outage management, work management, and electric system model management. The planned advanced applications (e.g., ADMS) are large and complex and following this approach will help reduce implementation risk.

With the deployment of smart meters and automation technologies, we are collecting more information than we have ever collected. Handling the data volume and velocity is important. To support this, we have implemented data historians for operational data storage and analysis. In addition, we have implemented an analytics platform that lets us model and visualize connected sources of both operational and enterprise data with consistent meaning and quality.

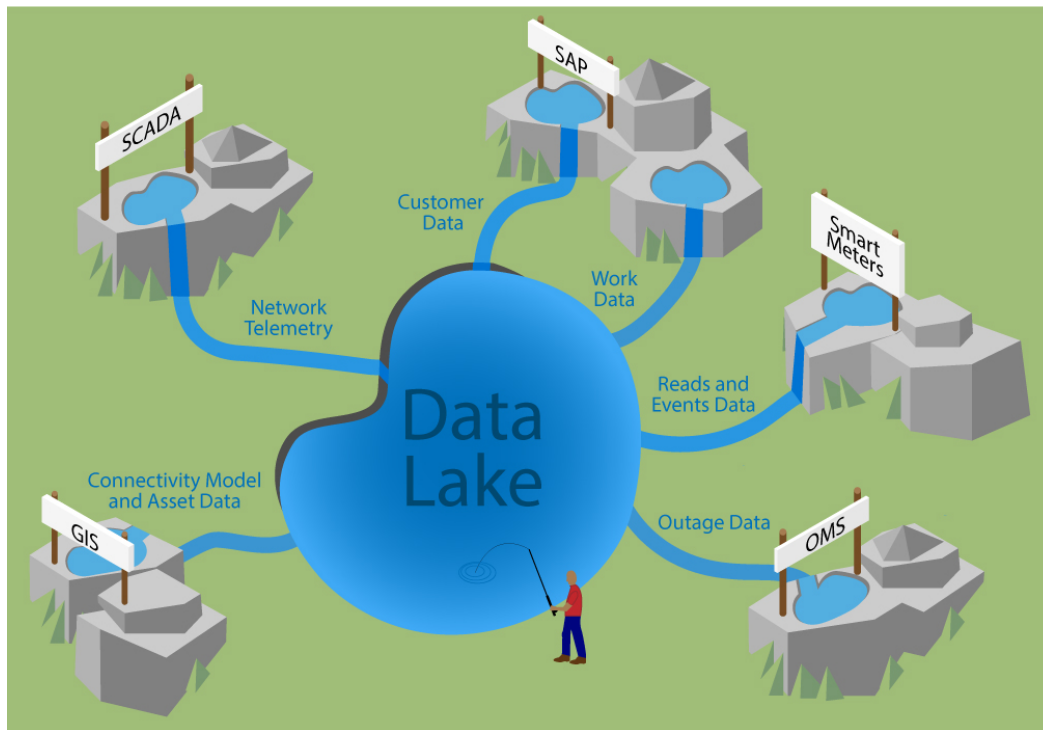
Data Lake

Our traditional database systems are not suited to the volume, variety, and velocity of the data sets that are provided by smart meters and grid devices. A “Data Lake” centralizes disparate data sources (asset, customer, outage, smart meter, DSCADA, etc.) into a single location. The raw data from content sources are combined into analytical data models to be processed using advanced data processing and analytical techniques. Planners, designers, and system operators can retain flexible access to the Data Lake and its content from both enterprise and operational data sources.

We have constructed a data repository, referred to as the “Data Lake,” capable of storing, retrieving, and processing large amounts of data that can be turned into meaningful information to improve decision-making. There are four key benefits that the data lake provides. First, it provides a system capable of handling high-volume queries, taking the processing load off critical operational systems. Second, part of the value of the Data Lake is in its integration of data from disparate systems. As data is ingested into the Data Lake, it is transformed and stored in a standardized manner. This provides a consistent and common framework for the analytics that will be done in the Data Lake. Third, like other corporate systems, the security model provides strict controls for who can access what data. However, the Data Lake also provides a secure space for users to create and explore for relationships in the data without exposing the information to other users or having to offload the data. Finally, the Data Lake is designed to be independent of any particular reporting or data visualization application. This allows users the freedom to turn the raw data into information and to present that information in a manner that is most meaningful to the decision-maker.

In 2017, we completed the first major load into the Data Lake, which included two years of historical smart meter reading and event data comprising more than two hundred billion records. Going forward, smart meter data will be updated in the Data Lake on a daily basis. For 2018, planned additions to the Data Lake include outage incident data and work order data. Additional data sources such as GIS and weather history will be added going forward, compounding the value of the data in the Data Lake and the analytics that can be derived from it. Figure 36 below illustrates the types of data loaded into and stored in the lake.

FIGURE 36 – CONCEPTUAL DATA LAKE VISUAL



Grid Analytics Sets

We have started an initial grid analytics program focused on transformer-based operational insight. The transformer data analytics aligns transformer loading, voltage, and geographic data for our existing 670,000 distribution transformers. Expected outcomes include determining overloaded and underloaded conditions to fine-tune service quality, identifying assets with abnormal voltage patterns due to transformer damage or excessive load, and correct modeling of meter-to-transformer installations.

The second set of analytics development will focus on mis-phasing issues related to individual circuits. This will identify areas with imbalance or model discrepancies based on meter data and events associated with each phase of individual circuits. Expected outcomes include corrections to the circuit model for modeling errors and identification of circuits that need corrective actions.

The third set of analytics development will focus on power quality issues. This will identify circuits that display unbalanced load and voltage profiles and extend voltage and load monitoring across the entire circuit. Expected outcomes include identification of circuits that need corrective actions to provide better service quality.

The fourth set of analytics development will focus on outage analytics. This will look at outage and momentary trends and history to determine systemic issues with electric reliability. Expected outcomes include identification of repetitive outages and determination of root cause and corrective actions.

v. Distributed Energy Resources

We believe DERs and other NWA will be critical parts of the future distribution network. We are committed to expanding our capabilities in this area, such as using NWA to defer or replace the need for traditional distribution equipment upgrades. In the future, we will more fully incorporate NWA, such as EE, DR, DERs, and BESSs into our planning solutions pool (also see Section VI.B on planning process). Through a combination of targeted piloting and analytics, we will deploy the right investments in the right place and at the right time.

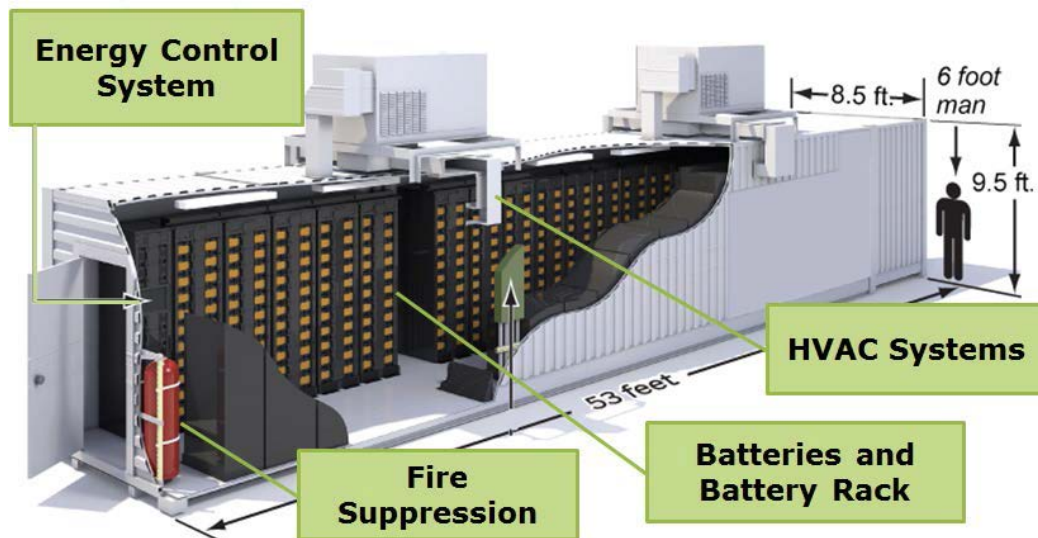
Increased adoption of DER on our system will require new interconnection rules, new grid devices, major system enhancements, and new processes for planning and operating these new sources, with an emphasis on ensuring safe and reliable integration. To prepare for these new distributed resources and validate their intended value, we are continuing to establish small deployments. As our grid modernization deployments mature over time, we will be in a position to integrate these resources into our grid (not just connect them), allowing for improved planning and operation of the new modern distribution system.

DER management relies on data inputs from other grid devices. DERs also impact the operation of other grid devices. Much like the relationship between BESSs and other grid devices, DERs cannot be managed as independent resources without considering the impact to our system and connected automation devices. When DERs are utilized with BESSs and existing grid devices, new possibilities are available for energy optimization such as solar smoothing, frequency regulation, and micro-grid management.

Utilization of a BESS for grid modernization is an effort being undertaken by industry-leading utilities to improve upon the EE programs enabled by DSCADA, upgraded capacitor controls, upgraded regulator controls, ATRs, and line sensors. With utility-scale batteries attached to the distribution system, new capabilities such as peak shaving and solar smoothing are enabled and existing capabilities such as VVO, CVR, and distribution automation with ATRs are improved upon.

BESSs are becoming an integral part of a national strategy to modernize the electric system. They can take many shapes and sizes depending on the specifications of the battery and the chosen application. Batteries under 10 MW generally are built in containers up to the size of a semi-trailer. Batteries that are 10 MW and larger are typically housed in a building that is configured similarly to a data center. Inside, racks are filled with batteries and large Heating, Ventilation, and Air Conditioning (HVAC) systems for climate control.

FIGURE 37 – EXAMPLE OF BATTERY ENERGY STORAGE SYSTEM



Source: GE

Additionally, BESSs are flexible energy supplements with multiple use cases and benefits as detailed in Table 14 below.

TABLE 14 — BATTERY STORAGE BENEFITS

Battery Storage Benefits	
Benefit	Description
Upgrade Deferrals	Batteries can be used to delay or avoid investments that would otherwise be necessary to maintain capacity to serve all load requirements. For example: when a transformer is replaced, the new transformer is sized to accommodate future load growth, and thus a large portion of the investment may be underutilized for some of the new equipment’s life. Rather than replacing the transformer, a battery can be installed to offload it during peak periods, thus potentially extending its operational life by several years.
Peak Shaving	Rather than designing the grid to meet the load on the one peak day in the summer, we may be able to use batteries in areas with large load swings to reduce the impact to distribution feeders where the load can be supported by the BESS during peak hours.
Outage Mitigation	A BESS that is “islanded” can support customer loads for a period of time when there is a loss of power. Locations with less reliable power supply could be augmented by a BESS to impact reliability performance.
Integration with Renewables	A BESS can be used to store the excess energy from intermittent distribution generation and discharge it when the generation is insufficient. This can reduce variability and firm up renewable capacity, therefore enabling more penetration of renewables on the system.
Frequency Regulation	Batteries can provide frequency response in areas where there is a significant amount of integrated variable generation (renewables). The pairing of batteries with these sources mitigates distribution system frequency fluctuations resulting

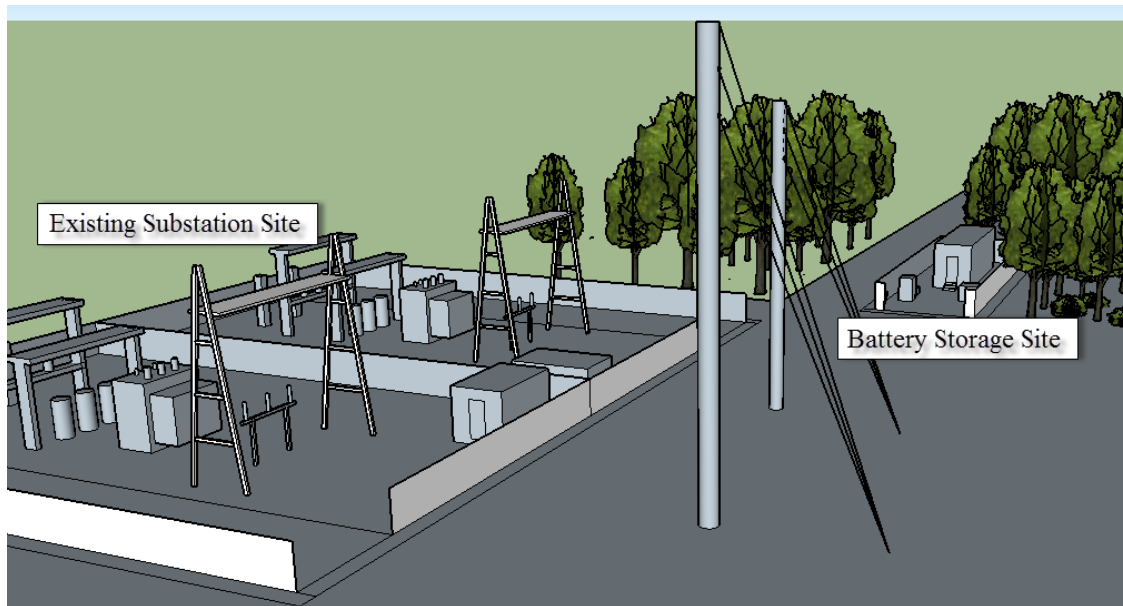
from unexpected cloud cover or variations in wind speed.
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We are determining how to best use BESS to benefit our customers. We recently partnered with Michigan State University (MSU) to research the present state of BESS and its applications, vendors, engineering, and materials. The partnership has focused on state-of-the-science applications of utility-scale distribution systems. The MSU research, in part, helped us develop BESS projects that will be installed on our system in 2018, to test battery capabilities, provide benefits to the circuit, and learn about how to integrate batteries into the grid at the distribution level. We are planning two installations in 2018, in Kalamazoo ('Parkview') and Grand Rapids ('Circuit West'), detailed below. These installations will help understand the interactions between the grid devices, our electric system and understanding how they can be optimized to leverage their full capability. These smaller deployments will enable us to better plan for these new energy resources and improve our abilities to integrate and manage them on our system.

Western Michigan University Parkview Solar Farm BESS (Kalamazoo)

We are developing a BESS installation on the circuit that serves our Parkview Solar Gardens facility near the campus of Western Michigan University (WMU). This circuit also has residential, C&I customers connected to it. The 1 MW/1 MWh battery, large enough to power 1,000 homes for one hour, has been developed in conjunction with research at Michigan State University and will be in service in third quarter 2018. The footprint of the BESS will be approximately 25'x75' and will consist of a packaged set of equipment including battery, battery charger, battery management controls, inverter, and other hardware. This BESS will provide storage capabilities to support outage mitigation, DR, and other use cases. Figure 38 shows a rendering of the BESS in relation to our Colony Farm Substation and WMU Bronco Substation.

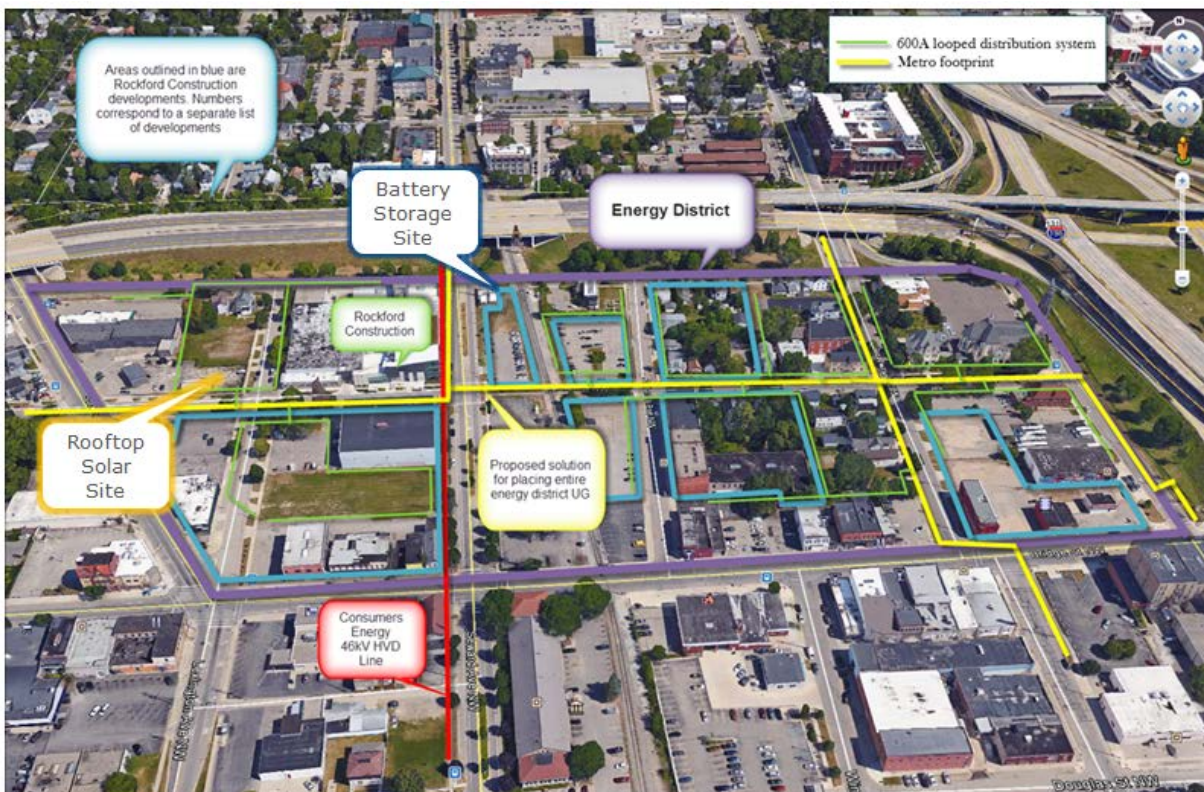
FIGURE 38 – RENDERING OF WMU PARKVIEW SOLAR FARM BESS



Circuit West Project (Grand Rapids)

The Circuit West project is a joint effort that we are undertaking with Rockford Construction. The purpose of Circuit West is to develop an energy district for testing and implementing sustainable and renewable energy for businesses and residents. The project covers portions of approximately nine city blocks in Grand Rapids, immediately southwest of the interchange between Interstate 196 and United States Highway 131, as shown in Figure 39 below:

FIGURE 39 – CIRCUIT WEST COMMUNITY OVERVIEW



The area will offer mixed-use development for residents of all ages and income levels. There is an emphasis of the concept “the neighborhood you work in is the neighborhood where you shop, dine, entertain and live.” Our plans for the area will focus on cutting-edge technology for solar, battery storage, electric grid modernization, and innovative ways to deliver electricity to densely populated areas. Plans include interactive technology to inform the public of the demonstration work underway in the District and look at ways to expand the concept to all Consumers Energy customers.

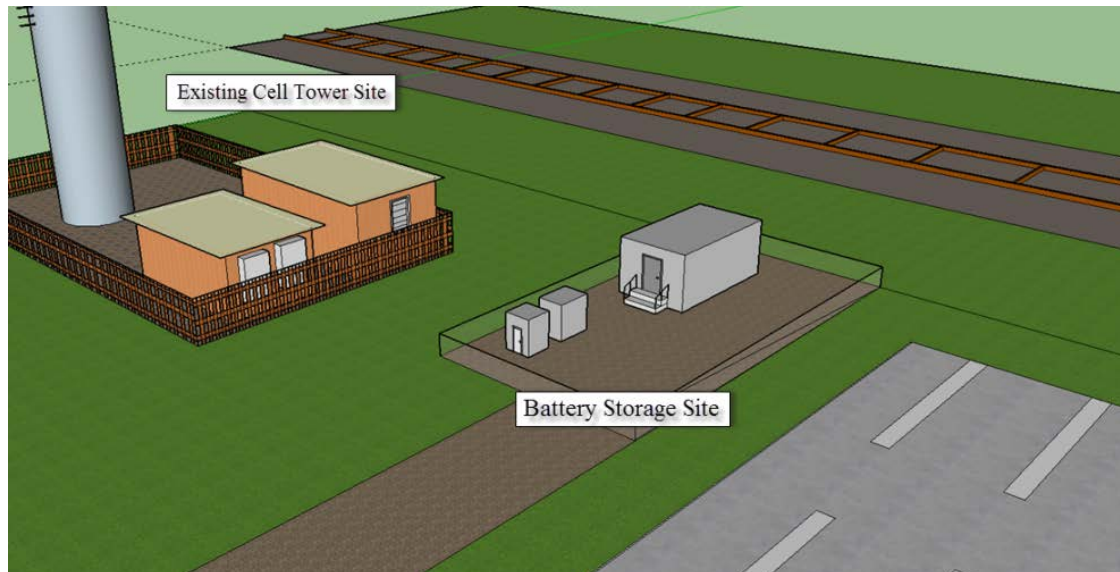
In terms of infrastructure investments, the Circuit West project combines various components:

- A hybrid metro/underground distribution system;
- Substation communication;
- A rooftop solar installation;
- Distribution automation; and
- Battery storage.

The battery storage system at Circuit West will be sized between 0.25 and 0.75 MW, with a footprint of approximately 30’x60’. It will be connected to the grid on a circuit with commercial and residential

customers, along with distributed rooftop solar. Figure 40 is a rendering of what the BESS may look like in the Circuit West development.

FIGURE 40 – RENDERING OF CIRCUIT WEST BESS



We will go live with the automation of Circuit West in fourth quarter 2018, and begin leveraging the lessons learned for our 2019 planning cycle. It is important to note that, although Circuit West is experimental in the sense that we will glean lessons learned, it goes beyond a typical pilot because it will be a permanent part of our system. The Circuit West project focuses on integrating advanced technology for advanced-use cases, and using what we learn to develop the necessary processes, procedures, and methodology to apply this technology to our entire service territory.

The combination of distribution automation and battery storage will give us the ability to develop a microgrid at Circuit West in the future if we so choose. In addition, the battery at Circuit West will allow us to pursue peak load shaving, VVO, and the smoothing out of the production of the rooftop solar installation. It also could be used to provide frequency regulation to the Midcontinent Independent System Operator (MISO) market. The battery at Circuit West will be able to supply 0.5 MWh of energy, enough to power 500 homes for 1 hour.

The substation communication at Circuit West relies on high-speed fiber optic technology, which enables decentralized control, advanced protection schemes, and advanced automation. It also makes use of dead-front switchgear and SCADA monitoring to allow faster and safer restoration switching to address underground failures.

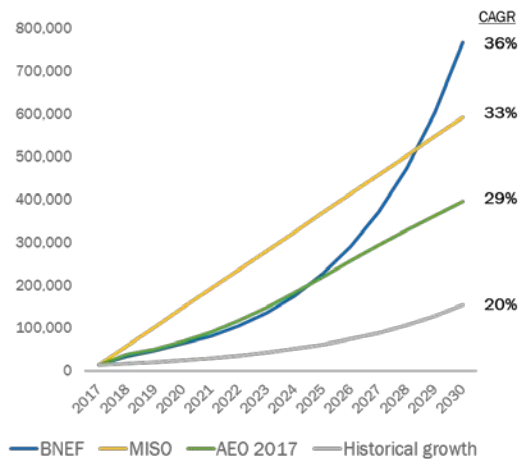
The Circuit West project offers us reliability benefits beyond the borders of the project. For example, we estimate that the project could reduce our SAIDI by up to 0.13 minutes per year due to the enabled automation.

By 2020, as we apply the project’s initial lessons learned, we will be exploring additional possibilities at the site, such as underground and metro automation and advanced monitoring.

Electric Vehicles

EVs will increasingly become part of the grid load between now and well into the future. EV growth forecasts vary, but all point to rapid growth from a relatively small base today. Primary factors of growth include falling battery costs, faster charging speeds for vehicles and chargers, industry investment and public policy, and parallel trends in autonomy, connectivity, and ride-sharing. We will continue to monitor the expansion of EVs in case adoption increases more than expected. In particular, the parallel trends of electric, autonomous, and shared vehicles could dramatically increase adoption rates by shifting vehicle ownership models and driving down costs to make an automated ride from a fleet vehicle more inexpensive than using one’s own vehicle.

FIGURE 41 – FORECASTED EV ADOPTION IN MICHIGAN¹⁰



Our grid is robust and can handle the anticipated adoption rates in the near-term, particularly if we encourage customers to charge EVs off-peak with TOU rates. For example, a DTE study found that if 30% of all vehicles were Plug-in Electric Vehicles (PEV), charging during off-peak times at home, just 6% of distribution transformers would be overloaded.¹¹ While there are a wide range of EV market forecasts, many indicate that it will not be until sometime between 2030 and 2035 that PEVs will start to significantly increase the electric load (by 10-15%). When adoption does increase, capacity constraints will be felt first at transformer-level, localized areas (e.g., 10 electric vehicles in one neighborhood pulling from the same transformer). For the longer term, we will plan to perform localized analyses to proactively identify areas that will require upgrades.

C. Demand Response and Energy Efficiency

DR programs are an environment friendly “Michigan first” resource, because they manage capacity without needing additional electricity generation infrastructure or expensive capacity contracts. Utilizing these demand-side resources as NWA’s will be an increasingly important part of our grid planning process (see Section VI.B).

¹⁰ Bloomberg New Energy Finance, MISO data through M.J. Bradley, AEO, Consumers Energy analysis.

¹¹ PHEV Pilot Program Final Report, 2011.

i. Demand Response Programs

We use DR programs to manage loads and stresses on the electrical system under emergency conditions, reducing peak demand, and saving our customers money in avoided capacity or system constraints-related expenses. However, these programs do more than help solve capacity needs. They also compensate customers that participate and provide economic benefits for Michigan. Peak demand reduction is reached with programs targeting residential and C&I customer classes.

DR resources that are registered with the MISO can qualify as Load Modifying Resources (LMRs) if they can reduce demand with no more than 12 hours advance notice and sustain reduction for a minimum of four consecutive hours. The resources must be capable of being interrupted at least the first five times during the summer season when directed by MISO to do so for emergency purposes. The capability to reduce demand to a targeted reduction level and measurement and verification protocol must be documented and approved by MISO. DR programs curtail on-peak loads or shift load from peak periods to off-peak periods, either by controlling the load directly, such as with Air Conditioning (AC) cycling, or by motivating and incentivizing customers to take action to modify their load on their own to contracted levels.

Residential

We launched an AC cycling pilot with 1,754 customers in 2016. In 2017, we applied our learnings from the prior year pilot to enroll more than 30,000 customers in the AC Peak Cycling program. Throughout 2017, we also continued to learn and experiment with the program as peak demand events were implemented. These learnings not only helped inform us of potential program enhancements, but also gave us a better understanding of how to leverage the program to maximize system performance.

We also launched two peak TOU pilots to a group of 37 employees in 2016. Similar to the AC Peak Cycling Program, the TOU pilots transitioned to programs in 2017. The Critical Peak TOU and Peak Rewards TOU programs provide over 17,000 customers with two additional pricing options that combine daily TOU rate structures with an extra price incentive to reduce consumption during summer hours of peak system demand.

In 2017, we also began shifting our marketing approach for residential DR from individual programs to a portfolio approach, called Peak Power Savers®. The portfolio offers customers these direct control and behavioral DR programs:

- AC Peak Cycling;
- Critical Peak TOU; and
- Peak Rewards TOU.

Commercial and Industrial

Our C&I DR program provides a flexible energy resource that can reduce power supply costs for all customers. Each business customer that signs up for the program is contracted for a specified load reduction. We work with individual customers at their facility to set up an energy reduction plan that will be implemented when a DR event is called. When customers in the portfolio initiate their plan, it reduces stress on the grid.

Over the next five years, we are planning for approximately \$22 million of spending in our C&I DR program, increasing our C&I DR portfolio from 50 MW in 2017 to 270 MW by 2022. See Appendix D for additional details of our programs including enrollments and five-year spending plan.

ii. Energy Efficiency Programs

EE programs focus on improving customers' overall energy usage by reducing energy waste, helping stabilize volatile energy prices, and solidifying energy security. It also helps customers save money, providing a boost for Michigan's economy. Since 2009, our EE programs have saved customers more than \$1 billion on their energy bills and helped avoid over five million tons of carbon dioxide greenhouse gas emissions.

We offer a comprehensive portfolio of electric and natural gas EE programs and incentives to customers. In particular, we offer programs and incentives to residential customers who install more efficient lighting, appliances, insulation, air-conditioning, and windows. Similarly, we offer programs and incentives to business customers that improve production processes and reduce energy waste — such as agriculture initiatives, building operator certification, and smart buildings retro-commissioning. Over the next five years, we plan to continue investing in cost-effective EE programs to help its customers further reduce electric and gas energy waste. See Appendix D for additional details of our EE programs including energy savings and five-year spending plan.

Swartz Creek Non-Wires Alternatives Pilot

Improvements in the efficiency of energy use in homes and businesses can provide substantial benefits to the consumers who own, live in, and work in those buildings. They can also reduce the need for capital investments in electric and gas utility systems — benefits that accrue to all consumers whether or not they participate in EE programs. Launched in October 2017, the Energy Savers Club is a pilot program designed to reduce the energy load on our Swartz Creek substation. This NWA pilot focuses on the role efficiency can play in deferring utility infrastructure investments. In particular, it addresses the role that intentional targeting of EE and DR programs to specific capacity-constrained geographies can play in managing load and deferring capacity-related investments.

Early discussions to develop this pilot began in 2014, in coordination with the Natural Resources Defense Council and targeted areas where EE and/or DR could be investigated as lower-cost solutions for potential distribution capacity upgrades. The Swartz Creek substation was selected as the targeted location due to its observed potential need for capacity upgrades in future years (not immediate). The substation transformer at Swartz Creek had experienced peak loadings of 92%, 94%, 80%, 79%, and 85% from 2012 through 2016. The load appeared to be highly dependent upon the weather as no system changes (large transfers or large, new customers) had been observed. A traditional substation capacity increase would be implemented after an observed overload. Swartz Creek substation was chosen due to the fact that historical loads had been observed close to capacity, but never over. Piloting an NWA at this location was an opportunity to test an NWA solution's feasibility without risking the equipment or customer reliability due to an observed overload the prior year.

Our NWA pilot at Swartz Creek substation relies heavily on the existing EE and DR programs in place. The area included in this project is mainly suburban/rural and includes a little less than 4,000 residential and 300 commercial accounts. Through this pilot program, we employ a uniquely branded marketing campaign within the target area to enable customers to connect to existing EE and DR programs and

incentives. A community-based Energy Ambassador program will be utilized to enable increased education and awareness, program participation, behavior change, and customer satisfaction. The Company is currently working with an implementation contractor and third-party evaluators to analyze the benefits of deferral from the pilot. While we are focused on one specific location at this time, we will investigate the possibility of expansion in the future. It is through these types of demonstration projects that we will continue to grow our capabilities using non-wires alternatives as effective grid planning solutions.

VI. Approach to Investment Planning

A. Description of the Planning Process Today

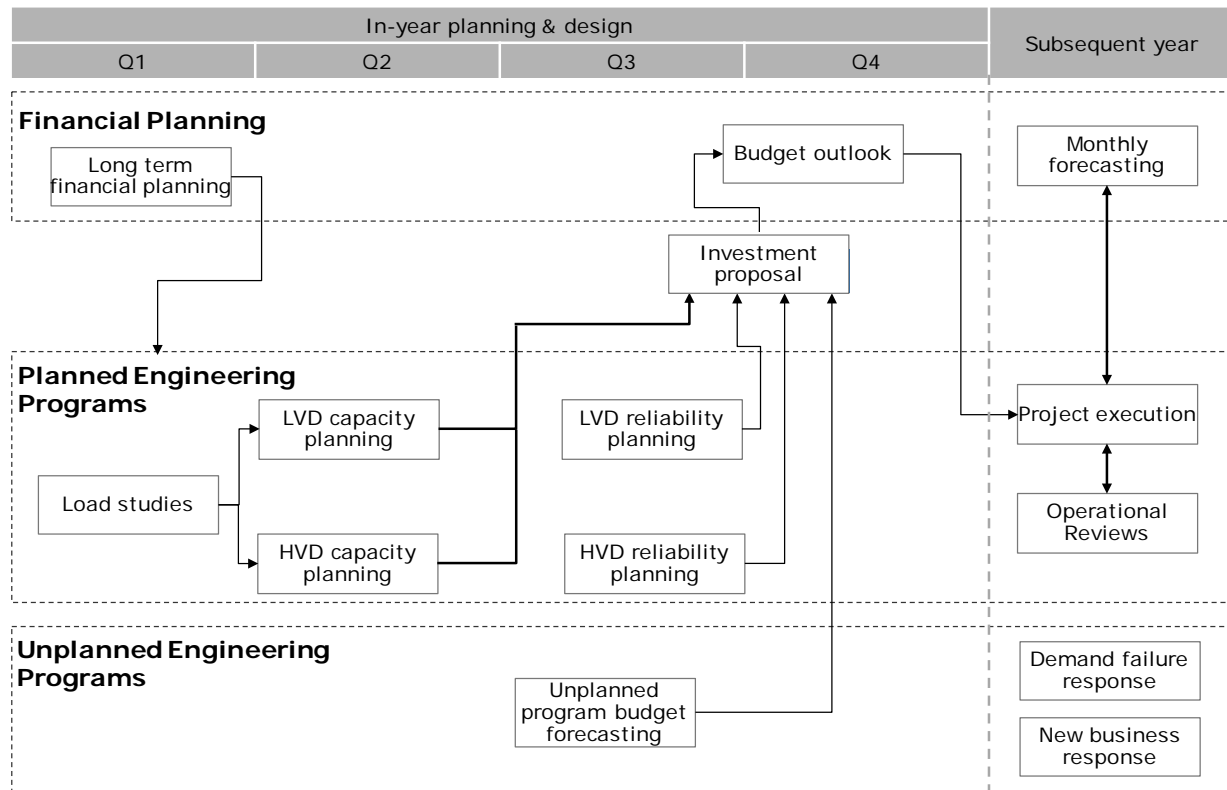
Our electric distribution grid investment planning process is part of an integrated utility-wide financial and strategic planning process. Multi-year financial plans are developed through an iterative process that involves both “top-down” financial planning to set strategic direction and budget guidance, as well as “bottom-up” engineering planning to meet system needs and achieve our goals and objectives for the electric distribution grid (see Section II).

Running the financial and engineering processes in parallel ensures that our long-term investment plans balance the operational and resourcing realities in electric distribution. Cross-functional data inputs and analyses guide our planners as they develop investment proposals and make decisions on how best to allocate funds across system needs. The result of this year-long investment planning process is a five-year plan for the electric distribution organizations, based on expected customer demand and emergent replacements, as well as for planned maintenance and improvements to the grid.

In addition to our annual planning activities, monthly forecasting and regular operational reviews track our progress and ensure alignment of our financial and operational plans across the organization. These ongoing planning activities allow us to respond swiftly and effectively to changes as required, by re-allocating resources and capital to where they will have the greatest benefit for our customers.

Figure 42 shows how these planning activities connect over the course of the year, and this section contains further details on each of the most important elements of the planning process.

FIGURE 42 – ELECTRIC DISTRIBUTION FINANCIAL AND ENGINEERING PLANNING PROCESS



i. Financial Planning Process

At Consumers Energy, the financial planning process consists of two budget cycles: a five-year plan for long-term strategic and financial planning, and a more detailed two-year operational budget. Both planning cycles focus on allocating the funding needed to deliver on our long-term objectives for the grid (see Section II) and the goals for the organization as a whole around people, planet, and prosperity. The goals and objectives inform operational and engineering plans for the electric distribution system.

Throughout the year, program planners conduct thorough analyses of the state of the system to assess customer needs. They use this to scope the work required for the following year(s) and develop investment proposals geared around individual program objectives such as improving reliability, upgrading capacity, and responding to new business requests. See Sections VIII and IX for further details of these analyses and assessments by program.

During the budget outlook cycle (in the third and fourth quarters of each year), we build the detailed budget plan for the subsequent two years, and refine our long-term financial outlook. We use an integrated planning process that develops financial plans tied to operational activity, anticipated system needs, and customer demand. The financial planning process is managed utility-wide so that investment trade-offs are made across the various organizational groups (i.e., electric generation, gas, customer operations, etc.) to ensure that the overall strategic priorities of the organization are met. To make effective investment decisions across the organization, we prioritize investment programs based on the type of work and the impact that the work has to customers. We must complete critical programs, e.g., those that involve the safety of our customers or workers, or those mandated by the MPSC or other

external bodies. Leaders prioritize and make trade-offs across the remaining projects to optimize for our goals and objectives, improving customer outcomes.

ii. Engineering Planning Process

The electric distribution engineering planning process runs throughout the year and involves many engineers, planners, designers, operators, and business leaders. This ongoing planning work informs our design and execution, resource planning, and budgeting processes.

Sections VIII and IX of this report describe the engineering planning process for each of our major investment and O&M spending programs. For each program, we plan our engineering work to address a set of specific objectives. The investment and prioritization logic used to make decisions depends on the type of work, the type of customer, and the attributes of the individual system (e.g., HVD, LVD, substations).

We take different approaches to investment planning based on whether the investment is “unplanned” (customer requested or emergent replacements) or “planned” (improvements to reliability or other customer needs).

Capital investments in our “unplanned” programs respond to customer requests or emergent system needs, such as demand for new business connections, restoration of service after a storm, or requests for asset relocations. Although we plan our overall investments in these programs based on anticipated needs, we are usually unable to plan our specific project work until after a storm occurs or a request comes in from the customer. We use a variety of external economic and industry indicators, as well as detailed analyses of the state of our system, to develop a multi-year spending plan based on our forecasts for these programs. We also consider the impact that our long-term investments will have on emergent demand. For example, we use data from the Home Builders Association of Michigan to estimate net load growth from new housing starts to help forecast future spending on new lines and substations; we combine that housing start information with our planned commercial capacity upgrades to develop a complete picture of where investment in the grid will be needed. Our engineering planners analyze trends by reviewing historical circuit performance and incorporate new data to help inform our short- and long-term forecasts.

Our proactive “planned” programs improve reliability and address capacity constraints. We prioritize investments in these programs to maximize customer benefit of every dollar that we spend. For each program, we have a set of specific objectives and goals tied to the long-term objectives for our grid. For every potential investment that we consider, our engineering teams determine the benefits that each project will provide, considering customer reliability, safety, control, sustainability, and cost. Our program planners assess options for investment with a set of criteria developed through years of experiential insights, analysis, industry knowledge, and customer feedback.

Investment planning for our planned programs broadly follows three stages:

1. **Reviewing system needs** – Engineering planners review overall system needs, circuit-by-circuit, to identify critical areas to target at a circuit, zone, substation, or line level, using a variety of inputs and analytics tools. Some of this real-time data comes from our System Control Center

(SCC) for Transmission and HVD and the Distribution Control Center (DCC) for LVD. This information provides planners with insight on the state of the grid and any critical issues.

2. **Determining required actions and developing projects** – Once a customer or system need is identified, our regional engineering planners determine the required actions and develop project plans. See Appendix E for examples of work orders for our capital programs.
3. **Prioritizing and sequencing work** – Program planners work to balance financial and operational resources across investment programs to optimize results against our goals. They prioritize and sequence projects based on required timelines for completing the project, the benefits to customers based on our long-term objectives, and available funding. The specific prioritization method depends on the program (as described in Sections VIII and IX).

Details on the inputs, investment logic, and prioritization methodologies for each program are described in Sections VIII and IX.

iii. Monthly Forecasting Process

We manage our overall level of capital investments and O&M expenses across the utility portfolio. Due to factors both inside and outside the organization, spending can fluctuate throughout the year and over multiple years. On a monthly basis, we assess actual spending on our capital and O&M programs and compare them to our monthly financial forecasts and budgets. This allows us to identify spending fluctuations, react to changes in the forecast and emerging demands, and identify risks and opportunities in the amount that we are spending to ensure that we are effectively managing our resources.

For example, we may have unforeseen issues obtaining easements needed to complete a project. As a result, we might move a different project ahead in the work plan while we obtain the easement for the original project. Although actions like these change our short-term plan and performance, we continue to work towards achieving our long-term commitments and goals.

Often our forecast will change when unplanned spending fluctuates due to customer requests or emergent needs. Service restorations, demand failures, and corrective maintenance are difficult to predict accurately due to the impact of weather events such as storms and extreme temperatures. We ensure adequate funding for critical restoration and storm response, as well as new business needs, by diligently reviewing the operational and financial forecast on a monthly basis to balance needs using the prioritization method described above. We re-allocate funding as required to ensure that we address critical customer needs. Operators and planners take into account any changes to our operational and financial plans and reprioritize on an ongoing basis.

This process ensures that we can react quickly to the most critical customer needs (e.g., restoring service after a storm) while having flexibility for less urgent work. These dynamics can result in a difference between the plan for the year and the specific projects completed at the end of the year.

iv. Operational Reviews

We use a rigorous approach to the ongoing review and management of our operational performance, with a focus on continuous improvement.

In our Operating Reviews, business leaders and operators come together at regular intervals with standardized agendas to review performance data and trends against targets, identify opportunities for improvement, and problem solve to ensure timely resolution of any issues. The cadence of these meetings includes daily, weekly, and monthly reviews.

- Daily Operating Reviews (DORs) review the previous day's performance and actions identified to improve the expected performance in the current day.
- Weekly Operating Reviews (WORs) review trends of daily performance over the week, along with analysis of top issues and formal problem solving sessions to drive longer-term improvement.
- Monthly Operating Reviews (MORs) review long-term performance trends and analysis, noting top drivers of performance. There is a focus on forward planning to ensure there are sufficient resources assigned and actions planned to deliver on the monthly glide path toward annual improvement targets.

This execution system is standardized and present throughout the business from the front-line supervisors in customer, operations, engineering, and support teams all the way to the officer level. In addition, there are standard times when cross-functional teams come together in the same cadence (daily, weekly, monthly) to review performance metrics that require multi-disciplinary teams to address problems effectively across boundaries and between functions.

As described in Section IV.C, we also use the Electric Reliability Rally Room to monitor the progress and specifically the SAIDI benefit of our ongoing projects. The Rally Room provides an area for various groups within the organization to collaborate as well as identify and solve critical reliability issues. This process incorporates lessons from daily and weekly operating reviews, providing frequent checkpoints and flexibility.

B. Evolution of the Planning Process

Historically, our approach to capital planning largely revolved around making investments in traditional infrastructure solutions (poles, wires, etc.) to upgrade and replace existing grid infrastructure. This need to upgrade and maintain our grid infrastructure will continue to be a priority due to the age and state of the system (as described in Section III and IV). As alternatives to traditional solutions (like demand response, battery storage, etc.) become increasingly accessible, we are evolving our distribution planning approach to assess the costs and benefits of these technologies. As described throughout this report (Sections V, VIII, IX), we are already deploying some of these solutions today to optimize outcomes for our customers.

We expect that the penetration and use of these new technologies and grid solutions will continue to increase in the future, and therefore our planning processes and approaches will continue to evolve to take advantage of the full benefits and opportunities of these technologies. Increasing use of advanced data and analytics and greater cross-functional integration in our planning processes will be critical enablers to accelerating use of non-wires alternatives in our system.

i. Integration of Non-Wires Alternatives

NWAs are already an integral part of the electric supply planning process, and are becoming increasingly feasible as both supply and distribution capacity solutions due to technology advancements and cost

reductions over time. Today, EE and DR programs are already part of our annual load monitoring and forecasting process, and are assessed as economic demand-side solutions within our electric supply resource planning process. More recently, as our supply and distribution planning functions are becoming more integrated, we are maturing our capabilities in considering the full suite of NWA solutions – EE, DR, DG such as BESS – to avoid or defer traditional distribution investments. For example, we are piloting an EE project at the Swartz Creek substation to test the viability of deferring a potential capacity upgrade. We will use this pilot to learn more about NWA integration so we can plan for future, larger-scale deployments (see further detail on Swartz Creek in Section V).

In addition, we continue to track the growth of EE and DR on our electric system, as well as DG penetration through our Net Metering program and Generator Interconnection Application process. We are upgrading our grid capabilities, to consider NWAs and advanced applications alongside traditional infrastructure upgrades, as discussed in Section V. Section VIII and Appendix D describe the detail behind our NWA investments planned for the five-year period.

In Michigan, utilities receive an incentive to engage in Energy Waste Reduction (EWR) and demand response programs. The form of this incentive is a “shared savings” mechanism whereby the cost savings generated by the program is shared between customers and the utility. Michigan’s implementation of an energy waste reduction shared savings incentive mechanism has been quite successful in achieving the policy goal of eliminating energy waste, delivering savings to customers, and providing an appropriate incentive for utilities to make non-capital investments in energy waste reduction. This type of innovative regulatory approach is intriguing in its potential application to non-wires alternatives and other aspects of utility operations designed to optimize the energy system.

ii. Increasing Role of Data and Analytics in Planning

As we invest in grid capabilities that lay the foundation for our vision of the grid as described in Section V, we will be able to better leverage advanced analytics and data to respond to the needs of our customers. A more detailed understanding of our distribution grid across customer needs and other characteristics will allow us to improve how we plan our investments. We will enhance our ability to directly target our infrastructure improvements to the specific needs of our customers across the grid and can invest in specific pilots and test opportunities where they make the most sense.

A customer-driven data analytics approach will allow us to better prioritize and select investments based on multi-dimensional criteria that align with our five objectives. As we evolve over time, we will be able to enable more algorithm-based and automated decision making to help guide our investment spending.

iii. Improved Integration of People and Processes

We will continue to integrate cross-functional data into our planning process to inform how we make decisions on our grid investments. With greater availability of complex data over time, we will continue to evolve our planning processes as needed to ensure that we are taking full advantage of the richness of customer data available, and continue to align our people and processes around delivering against our five objectives for the distribution grid. Overall, we are working towards a future where our people continue to use the best possible data and decision-making tools and processes to better prioritize

investments and deliver on our objectives (safety and security, reliability, cost, control, and sustainability).

C. Design Standards

As we move forward with our distribution plan, we will leverage our robust distribution design standards while continuing to explore additional design advancements to ensure infrastructure resiliency and serve our customers in a reliable and cost-effective manner. Our distribution standards manuals are currently going through an overhaul process to eliminate redundancy, improve adherence to the standards, and update language to be more compatible with current technology. This will provide an improved governance structure to make future updates as needed to ensure consistent standards, and will allow relevant employees to more efficiently access the standards.

We have developed many of our design standards in order to shorten the time it takes to restore power to our customers and improve the resilience of our system after storms. In the aftermath of major events, broken poles, crossarms, and other support structures contribute to lengthy delays for restoring service to customers. Over the years, we have learned a number of lessons from storms and other events and adapted our design standards to help our system better cope with the impact of wind, downed trees, storm effects, and animals. We describe a number of these specific design standards in more detail below.

i. Tree Wires and Aerial Spacer Cables (ASC)

Trees are the primary cause of outages on our LVD system today and mitigating the impact of falling trees is a critical part of improving the reliability of our system. The two best design methods for improving LVD line resiliency in heavily wooded areas are to use Tree Wire and ASC construction. Over the last four years, we have installed between 170,000 and 300,000 feet of cable per year on our LVD system using these design standards. Each of these construction types uses conductor(s) coated in a semi-conducting polyethylene material that reduces the probability of an electrical fault due to objects coming into contact with the line. This is particularly effective in densely forested areas where tree contact with the line is highly probable. Both ASC and Tree Wire construction require stouter poles and shorter spans to support the heavier conductor and higher tension wire utilized. The two types of construction differ in how they are constructed and where they can best be deployed, as explained below.

Tree Wires

In order to improve the reliability of our system, we prefer to relocate a line from a deep Right of Way (ROW) to the roadside to increase the accessibility of the line. However, this is not always feasible and one alternative is for the line to be re-conducted in place with Tree Wire. Tree Wire is a coated conductor strung on the crossarms that reduces the chance of falling limbs and trees from causing an outage. Tree Wire can be constructed with or without a high tension wire at the top of the pole with the phase wires on crossarms below. In the “shield wire” approach, the high tension line at the top of the pole above the Tree Wire aids in deflecting falling branches and trees, or even supporting a fallen tree until it can be removed. Tree Wire construction can also be done in an “unshielded” manner, used when vertical clearances need to be respected while crossing under other electric lines. Shielded Tree Wire construction is the preferred method of construction and can be seen in Figure 43 (highest wire on the pole, mounted 5’-7’ above the crossarm to provide proper deflection angles).

FIGURE 43 – SHIELDED LVD TREE WIRE CONSTRUCTION



Aerial Spacer Cables (ASC)

When we are able to relocate a line to the roadside, but still have vegetation issues, ASC can be used to provide similar benefits to those of Tree Wire, while reducing the amount of trees that need to be removed or trimmed. ASC is strung in a bundle about one foot in diameter and hung on a high tension wire to keep the line from sagging as can be seen in Figure 44 and Figure 45 below. The high tension wire is able to deflect fallen branches and temporarily support the weight of a fallen tree, preventing an outage.

FIGURE 44 – ASC CONSTRUCTION BY A ROADSIDE



FIGURE 45 – CLOSE-UP OF AN ASC BUNDLE



FIGURE 46 – ASC SUPPORTING A FALLEN TREE



In Figure 46 above, the line remained energized during a storm despite the impact of a fallen tree, preventing an outage until crews could address the issue.

ii. New Materials

Expanded Use of Fiberglass Materials on LVD System

We are expanding our use of fiberglass crossarms in place of wooden ones. Fiberglass crossarms have a longer life expectancy and can better withstand sudden forces like tree impacts. While wooden crossarms have an approximate life expectancy of 20 to 35 years, the equivalent fiberglass arms would have an approximate projected life expectancy of 40 to 50 years. Fiberglass crossarms are specifically engineered to have a more uniform structural integrity than wood while maintaining the same loading (weight bearing) capabilities of the largest wooden ones. While wooden crossarms are rated strictly based on their breaking point, fiberglass crossarms are rated based on the point at which deflection or flexing of the arm is not acceptable. This difference allows the fiberglass crossarms to absorb a significant amount of force and return or flex back to a normal operating function very easily whereas a wooden crossarm would simply break.

We are also increasing our use of fiberglass standoff brackets to insulate the LVD conductor from the pole. This will help to mitigate pole top fires and provide enhanced avian protection. Fiberglass brackets almost completely eliminate the phase-to-ground opportunities for birds and other wildlife that land on the bracket. Because the end is insulated from the pole, the path to ground is much more difficult to complete, compared to a metal bracket connected to the pole. The fiberglass brackets are also more difficult for birds to perch on in the first place as they have an upwards angle instead of a flat landing spot, as found on our existing metal brackets.

In addition to these operational benefits, lightweight fiberglass materials provide ergonomic and safety benefits to the installation crews that routinely physically lift and adjust components during installation.

Polymer Insulators on LVD and HVD Systems

We are working to replace our existing porcelain insulators with a more modern polymer version that is much more impact-resistant. The physical impacts incurred by insulators can range from a tree impact

to simply those which occur during shipping. Due to its material makeup, porcelain is breakable and vulnerable to damage (cracking or chipping) when struck by an external force or object. The polymers used in the new insulators are more similar in makeup to rubber, and this flexibility allows them to be more resistant to an external force or impact. In addition to the straightforward structural failure issues that can present themselves when a porcelain insulator is severely damaged, even minor damage to porcelain such as that of a hairline crack can lead to electrical tracking, eventually causing a pole fire as electricity gradually breaches the properties of the insulator.

Readily available polymers still do not have as high of a resistance to heat as traditional porcelain, meaning that polymer insulators can become subject to melting if the conductor is loaded to its emergency ratings. We are collaborating with manufacturers to develop new high-temperature polymer insulators that will resolve this issue. Our partners are planning to test a new product in 2018. If successful, we will perform a field pilot to test the new material on our system.

HVD Horizontal Polymer Post Design

We have incorporated horizontal polymer post design in approximately 85%, or nearly 440 miles, of our new or rebuilt HVD line miles since 2010. This style of post is fairly new, and one benefit is that it uses less material for the crossarms and crossarm braces, reducing the potential for future failures. This horizontal post design can also be constructed quickly, because the time to frame a pole is reduced. Additionally, this style of construction is inherently NESC Class B construction, whereas many of the poles replaced are NESC Class C construction. Class B is a higher standard than Class C, so utilizing horizontal post designs during replacement naturally increases the resiliency of the HVD lines. Horizontal polymer post construction can be seen in Figure 47 below.

FIGURE 47 – HORIZONTAL HVD POLYMER POST DESIGN



iii. Pole Design Standards

LVD Pole Class

We have hardened our LVD distribution system by moving up one pole class on our three smallest and most utilized pole sizes. We are working to completely phase out our three smallest pole size classes. This will improve the overall strength of each pole replaced and reduce the number of broken poles.

We are no longer carrying 35-foot Class 6, 40-foot Class 6, or 45-foot Class 5 poles; we are replacing them, respectively, with 35-foot Class 5, 40-foot Class 5, and 45-foot Class 4, installing the higher classes as the poles are replaced. Increasing these pole classes increases the amount of force that each pole is able to withstand. The quantitative improvement is specific from pole to pole, based on calculations involving pole height and other factors. However, we estimate that by replacing the lower class poles as noted above to date, we have averaged a 15 to 25% increase in the ability of those poles to withstand an external force. As part of our design standards process, we will continue to assess the viability of higher pole classes to improve system resiliency.

HVD Pole Class

We apply the standards contained in NESC Rule 250B, 250C, and 250D to our HVD poles, and all of our pole designs must meet these standards.

TABLE 15 – HVD NESC POLE DESIGN STANDARDS

HVD NESC Pole Design Standards			
NESC Rule	Wind (mph)	Ice (in.)	Transverse Load on 3/0 Pigeon (lb/ft)
250B	40	0.50"	1.3
250C	90	--	1.0
250D			
North	50	0.50"	1.1
Central	40	0.75"	0.89
Southeast	40	1.00"	1.1

For example, to be in compliance with Rule 250B, a pole must be able to withstand 40 mph wind with a half inch of ice on the wire. While all three standards must be met, typically Rule 250B (bolded above) is the ruling or highest standard and drives the specifics in most of our pole designs. In North America, bird names are used to identify different sizes or gauges of conductor; 3/0 Pigeon is a particular size of conductor (about one half inch in diameter) that we use on these HVD poles.

iv. Animal Mitigation – LVD and HVD Substations

Animal-caused customer outages, particularly related to squirrels and raccoons, continue to be an issue at our LVD and HVD Substations. LVD substation animal contacts typically result in customer interruptions while HVD substation animal contacts typically result in equipment damage and failure.

Our current animal mitigation standards were developed based on research conducted at MSU, experiments conducted at our Marshall Training Center, and experience gained from previous animal mitigation projects. Based on this, we pursue two methods to prevent animal-caused outages:

- Keeping animals out of substations by creating a barrier around the perimeter; and
- Maintaining a clearance of all energized components to ground that is sufficient to prevent an animal from short-circuiting the system if it does make contact.

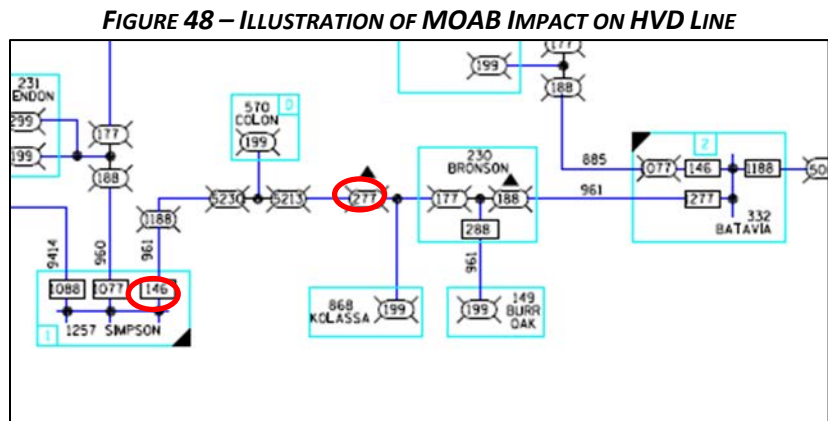
As we evaluate new techniques and materials to address animal mitigation, one new approach we are exploring is a technology that covers energized parts in a substation so an animal cannot bridge the gap to the ground, using custom fitting covers and conductor insulation to allow the animal to climb on equipment without causing a flashover. Among the specific benefits of this technology are:

- Covers are custom-made to fit very tightly over equipment;
- Covers and the appropriate tools are designed with the capability for energized installation; and
- The manufacturer works with the designer and station layout to create a custom plan to identify what is needed for effective coverage.

v. Line Automation

In addition to our broader LVD distribution line automation efforts, which allow us to isolate outages and limit the number of affected customers, we are also increasing our deployment of Motor Operated Air Break (MOAB) switches on our HVD system.

Our combined outage isolation strategy will help to limit the impact of storms. MOABs are installed to automatically sectionalize the faulted portion of an HVD line which keeps the un-faulted sections energized and able to continue to service our customers. MOABs are coordinated with the line breakers which are typically located in substations at each end of the line. For example, on the Bronson 46 kV line, illustrated in Figure 48 below, if an electrical fault occurred between the Simpson 146 breaker and the 277 MOAB at Kolassa Junction, the line would automatically sectionalize with the Simpson 146 and 277 MOAB at Kolassa Junction automatically opening. The Colon substation would be the only one interrupted, leaving Kolassa, Bronson, and Burr Oak substations in service. Without the MOABs on this line, the same electrical fault would have caused interruptions on the Colon, Kolassa, Bronson, and Burr Oak Substations.



vi. Design Standards Innovation Opportunities

Our LVD and HVD design groups have been expanding their participation in the Electric Power Research Institute (EPRI) programs and activities. Through our participation in EPRI, we are active in many programs that aim to improve the overall health of our electric grid. In 2018, we will be focused on identifying best practices for improving and maintaining distribution system reliability and resiliency. A brief description of the EPRI programs in which we participate is below.

TABLE 16 – CE PARTICIPATION IN EPRI GRID PROGRAMS

EPRI Program	Goal
35-Overhead Transmission	This program’s approach is to improve efficiency of transmission line design and management of aging transmission line components as well as provide knowledge on approaches to selecting, applying, inspecting and assessing insulators.
37-Substations	This program has projects focused on the assessments of substation assets. Consumers Energy is expressly interested in the substation breaker life management focus of this program.
174-Integration of Distributed Energy Resources	This program provides resources that keep members up to date on technology integration issues, standards, activities, and changes in technology. They provide updates on the latest software tools, guides, standards, and procedures for managing distributed generation.
180-Distribution Systems	This program delivers a portfolio of tools and technologies to increase overall distribution systems reliability and resiliency; understand the expected performance for specific components throughout its lifecycle; assess methods for evaluating the condition of system components; and develop and test new technologies.
200-Distribution Operations and Planning	This program includes research that supports grid modernization and provides tools for planners, operators, and analysis experts of the modern distribution system.

One specific area of potential innovation that we are exploring is cable injection. We are studying this cable rejuvenation method to address some of our oldest underground cables on our LVD system. Cable injection works by injecting a dielectric fluid into existing cable to restore the cable to like-new condition, effectively doubling its 30-year lifespan. The cost for doing cable injection averages about 40% of the cost of full replacement of the cable.

Additionally, we continue to pursue opportunities to use Unmanned Aerial Vehicles ((UAV) better known as “drones”) to inspect our lines. Currently the Federal Aviation Administration (FAA) restricts the use of drones to flights within the visual line of sight of the remote pilot. We are seeking a waiver from the FAA to allow us to use drones to inspect lines beyond the visual line of sight of the operator.

Lastly, Consumers Energy is also involved with the Edison Electric Institute (EEI) as another source of industry experts to help us benchmark existing practices with other utilities. We participate in many areas of EEI including rates and regulatory affairs, transmission committee, distribution committee, NESC working group, and National Electric Code working group just to name a few. From a standards perspective, we participate heavily in the discussion on NESC code changes as they have a large impact on our standards. Our participation includes scrutinizing new code proposals for the NESC clearances section and voting within EEI to help establish new NESC codes. In doing so, Consumers Energy is

working on the ground level of new issues that arise from new technology that could impact our clearances and allows us to be ready for changes when they occur.

VII. Summary of Plan and Projected Impact

A. Five-Year Capital and O&M Plan

Our five-year EDIIP focuses on delivering customer value across our five objectives of safety and security, reliability, control, sustainability, and optimizing system costs. Our specific investment and spending plans are summarized in Table 17 and Table 18 below.

Over the next five years, we plan on investing over \$3 billion in capital into our electric distribution grid. We expect to deploy between \$267 million and \$287 million dollars in capital per year towards responding to the immediate needs of our customers through new business connections, relocation of assets, and response to emergent system needs. Additionally, we plan to invest between \$245 million and \$300 million per year in planned programs to improve the overall reliability of our electric distribution system by enhancing and replacing infrastructure, upgrading equipment capacity, and laying the foundation for advanced grid capabilities. We also plan to spend approximately \$60 million per year in capital on the removal of infrastructure as we make these system investments.

Additionally, we have an O&M plan that calls for between \$179 million and \$207 million per year in expenses. This plan includes spending between \$55 million and \$67 million per year on our O&M reliability programs, which includes spending on forestry and vegetation management to reduce tree-related service interruptions for our customers. Our O&M plan also includes spending to directly support our long-term investments, restore service to our customers, and maintain our grid infrastructure.

Sections VIII and IX of this report include details for each of the capital and O&M programs and describe the objectives of each program, how we prioritize our spending or investments, and what the benefits are for our customers.

TABLE 17 – FIVE-YEAR CAPITAL PLAN

5-Year Plan – Capital Programs									
All values in \$ millions		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
1.0	New Business	73	88	97	95	98	103	105	108
2.0	Demand Failures	123	119	156	145	152	150	151	153
3.0	Asset Relocations	28	20	28	27	24	26	26	26
	Total Unplanned	223	226	281	267	274	280	281	287
4.0	Reliability	83	133	111	184	232	193	194	186
5.0	Capacity	44	57	53	51	57	58	59	63
6.0	Tools and Technology	3	4	3	10	11	11	11	11
	Total Planned	129	193	167	245	300	262	264	260
7.0	Cost of Removals	40	42	70	60	62	59	58	57
	Capital Plan	392	461	518	572	635	601	603	605
8.0	Demand Response	0	1	7	9	9	9	8	8

TABLE 18 – FIVE-YEAR O&M PLAN

5-Year Plan – O&M Programs									
All values in \$ millions		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
1.0	Net O&M Assoc. with Construction	-2	1	-3	0	0	0	0	0
2.0	Reliability	40	54	53	55	56	59	63	67
3.0	Ops, Metering, Service Restoration	89	76	83	69	77	77	78	79
4.0	Field Operations	23	19	22	20	20	20	21	22
5.0	Grid Management & SEOC	3	3	5	6	6	6	7	7
6.0	Planning & Scheduling	3	4	6	6	6	6	6	6
7.0	Operations Performance	0	1	2	2	2	2	2	2
8.0	Operations Management	7	8	6	7	7	7	7	7
9.0	Engineering & Ops Support	2	2	3	4	4	5	4	4
10.0	Engineering & System Planning	12	10	9	9	10	11	11	11
11.0	Joint Pole Rental	2	2	2	2	2	2	2	2
O&M Plan		180	180	189	179	190	196	201	207
12.0	Energy Efficiency & Demand Response	78	79	121	128	127	130	134	135

B. Cost to Replace Aging Infrastructure

The five-year investment plan outlined above is designed to meet our objectives while maintaining customer affordability. As our grid infrastructure continues to age past its expected service life, we see an increasing need to replace a large part of our existing electric grid asset base over the coming years. Our current five-year plan includes spending approximately \$330 million per year to replace, upgrade, and rehabilitate our assets. This spending includes all of our traditional infrastructure investment and maintenance programs within our capacity, demand failures, and reliability categories. We use a targeted approach to deploy these capital dollars towards the parts of the system that are at the greatest risk of failure or that will have the greatest customer impact, informed by regular inspection and maintenance of our assets and condition assessments. Through this targeted approach, we ensure that we invest our capital dollars to maintain the resiliency of our system infrastructure, ensure timely and effective replacement of our most at risk assets, and have the greatest impact on improving customer reliability.

Our current five-year plan includes replacing some of our most at-risk infrastructure, but substantial components of our system are well past their expected service life, as described in Section III of this report. Therefore, over the coming years we will need to replace or upgrade much of this infrastructure to reduce the risk of equipment failures and interruptions to customers. Although age itself does not always mandate replacement, older assets have been shown to exhibit a higher amount of physical degradation and were built with now-outdated construction standards, making them more prone to experience failures.

We estimate that the total cost to replace the entire portion of our system past its expected service life would be between \$4 billion and \$5 billion. Table 19 shows the breakdown of this cost by asset across our HVD and LVD systems. These estimates rely on a number of assumptions, due to limited detail in our tracking of individual assets or costs.

The estimated age of our system and the percentage of assets past their service life are described in more detail in Section III of this report. The estimated unit cost to replace each type of equipment is based on the historical average cost to proactively replace and install the asset. In reality, the investment required to replace an individual asset varies considerably depending on the type of work, location, and other external cost drivers. For example, a pole replaced during a storm or emergency will have a significantly higher cost than one replaced as part of a planned reliability program.

TABLE 19 – ESTIMATED REPLACEMENT COST FOR ASSETS PAST EXPECTED LIFE

Capital Replacement Costs						
	Asset	Average Age (Years)	Number in Service (thousands)	Estimated Cost per Unit (\$ thousands)	% Over Expected Life	Replacement Spend (\$ millions)
LVD lines	LVD Wood Poles	39	1,490	5.3	30%	2,300
	Lines Equipment (isolators, reclosers, etc.)	25	35	10-20	30%	180
	Cutouts / Fuses	25	700	1.2	30%	250
	Overhead Conductor (miles)	51	138	0.1	30%	0
	Underground (miles)	30	11	300	20%	640
Total LVD lines						3,400
LVD subs	Transformers (non-LTC)	35	1.2	700	29%	240
	Transformers (LTC)	35	0.1	750	10%	10
	Regulators	N/A	5.4	30	28%	45
	Other Equipment	N/A	0.3	various	24%	25
Total LVD Substations						320
HVD lines	Wood Poles	39	77	18	31%	430
	Steel Poles	32	0	45	0%	0
	Steel Towers	82	2	75	43%	70
	Underground (miles)	26	0.02	1,500	26%	10
Total HVD Lines						510
HVD subs	Transformers	N/A	0.2	1,500	49%	150
	Oil Circuit Breakers	49	0.3	135	47%	20
	EM Relays	24	4	113	27%	110
	Other HVD Subs Equipment	N/A	5	various	2%	10
Total HVD Substations						300
Total Replacement Cost						4,500

As described above, our current plan involves spending \$330 million per year, or approximately \$1.6 billion over the next five years, on replacement, upgrading, and rehabilitation of our existing assets, a significant shortfall from the \$4 to \$5 billion estimates to rehabilitate the portion of the system that is past its expected life.

Since replacing every asset that is beyond its expected life is not feasible in the short term, we plan our investments to target assets at greatest risk of failure or with greatest customer benefit. We inspect our

distribution system to identify our most at-risk assets and have a number of programs in place to prioritize our investments, as described in further detail throughout Section VIII and IX of this report. Furthermore, we are making investments in hardening our grid by constantly re-evaluating our design standards and building in redundancies as appropriate. Lastly, we are making considerable investments in upgrading our grid capabilities, as described in Section V of this report, to help us improve the reliability of our existing infrastructure through capabilities such as FLISR and VVO.

C. Summary of Impact on EDIIP Objectives

The five-year financial plan summarized above will deliver on the vision, goals, and targets outlined in Section II. Sections VIII and IX include descriptions of the impact of individual programs and investments on the five objectives – safety and security, reliability, system cost, sustainability, and control. A summary of these benefits is included below.

i. Safety and Security

We commit to providing a safe environment for employees, contractors, customers, and the public. We also recognize that safety and security extends beyond physical boundaries to cybersecurity. A number of investments in the five-year plan will have specific safety and security benefits on our distribution grid, contributing to improvements in employee safety, public safety, and security. Examples include:

- **Employee safety** – Circuit Exit Enhancements, in the LVD Lines Reliability program (See capital program 4.1 LVD Lines Reliability): The circuit exit switches installed on each phase outside the substation fence provide additional safety by creating an isolation point for line workers in the event the substation becomes energized. The plan will install circuit exit switches on approximately 175 circuits over the next five years. This investment will help impact our recordable incident rate metric.
- **Employee safety** – Substation control houses, in NESC/North American Electric Reliability Corporation (NERC) compliance (See capital program 6.3 NESC/NERC Compliance): We plan investments to address working space issues that exist in some of our substation control houses and ensure that they comply with workspace clearance standards, as outlined in the NESC. Actions include minor facility modifications, or relocation of control equipment to new or expanded control house facilities. This investment will help impact our recordable incident rate metric.
- **Public safety** – Reduced frequency of outage and wire down incidents through infrastructure investments (See Section VIII): Hardening and maintaining our grid infrastructure will improve the safety of our employees and the public. Our design standards and our investment planning processes are geared towards preventing equipment failures and wire downs. Through our planning and prioritization process, we prioritize work on our grid infrastructure when we see that a potential failure may result in a public safety risk.
- **Public safety** – Improved processes during storms and outages (See Appendix B – Public Safety During Storms and Outages): When incidents do occur, we operate a number of safety programs that focus on ensuring the safety of the public and our employees. We are implementing an Incident Command System (ICS) that will provide a common response mechanism to ensure that we respond to, communicate, and mitigate issues that result in a safety risk to our customers. By improving our processes, we are able to target the wire down relief factor metric.

- **Security** – Physical security at substations (See capital program 2.3B HVD Substation Failures): Installing or replacing substation fences helps ensure that members of the public cannot enter our substations. In addition, it helps prevent wildlife from interfering with substation operations.
- **Security** – Cybersecurity through communication upgrades (See capital program 4.5 Substation Communications Upgrades): Upgrading our communications infrastructure will provide additional control over cybersecurity measures to ensure the safety of our systems. As we continue to invest in and deploy advanced grid devices and applications across our systems, we will implement advanced cybersecurity measures to ensure the stability and resiliency of our network.

ii. Reliability

We track reliability and resiliency through both a traditional engineering lens (e.g., with SAIDI and SAIFI metrics) and a customer lens (e.g., number of customers experiencing ≥ 3 outages per year) to ensure that we are accurately representing both the system-wide and individual customer experiences. This section summarizes the reliability impact of our investments (detailed in Sections VIII and IX) into a five-year integrated system forecast, ensuring the interdependency between benefits is captured.

As an example of these interdependencies, outage frequency on a circuit could be impacted through both pole replacement and vegetation management. Installing line sensors on the circuit will improve fault location capabilities. These fault location capabilities are most effective with an accurate system model and appropriate integration into the restoration process. Operational improvements will reduce CAIDI, and thus impact the SAIDI benefit provided by reducing outage duration. To account for these overlapping factors, we estimate SAIDI benefits holistically with a set of common assumptions that consider the impact of multiple actions on the system and changing state of the system.

The Governor has outlined a set of reliability targets for the number and length of outages experienced by Michigan residents. More specifically, the Governor’s goal is to reach a SAIFI of 1.00 and SAIDI of 150¹² minutes by 2025¹³ as well as first quartile among peers for SAIFI and top half among peers for SAIDI. We are confident we can reach and exceed this mark by 2022. We are targeting a SAIDI of approximately 120 minutes by 2022, which would place us in the second quartile of SAIDI for North American utilities based on current IEEE benchmarking,¹⁴ and the lowest SAIDI in our Company’s history.

Figure 49 below outlines our path to achieve this ambitious target. We expect to see benefits from three distinct areas: traditional infrastructure investment, grid modernization investment, and operational improvements. The graphic below contains a range of benefits within these three areas, to reflect the uncertainty of improvements from new technology and variability in weather events.

Reaching our SAIDI goal of approximately 120 minutes will avoid 216 million minutes of customer outages, and result in 200,000 to 300,000 fewer annual customer outages. Accomplishing these changes despite an aging system will be challenging, but we believe our targeted approach to investments,

¹² All reliability figures in this section refer to the Non MED statistics.

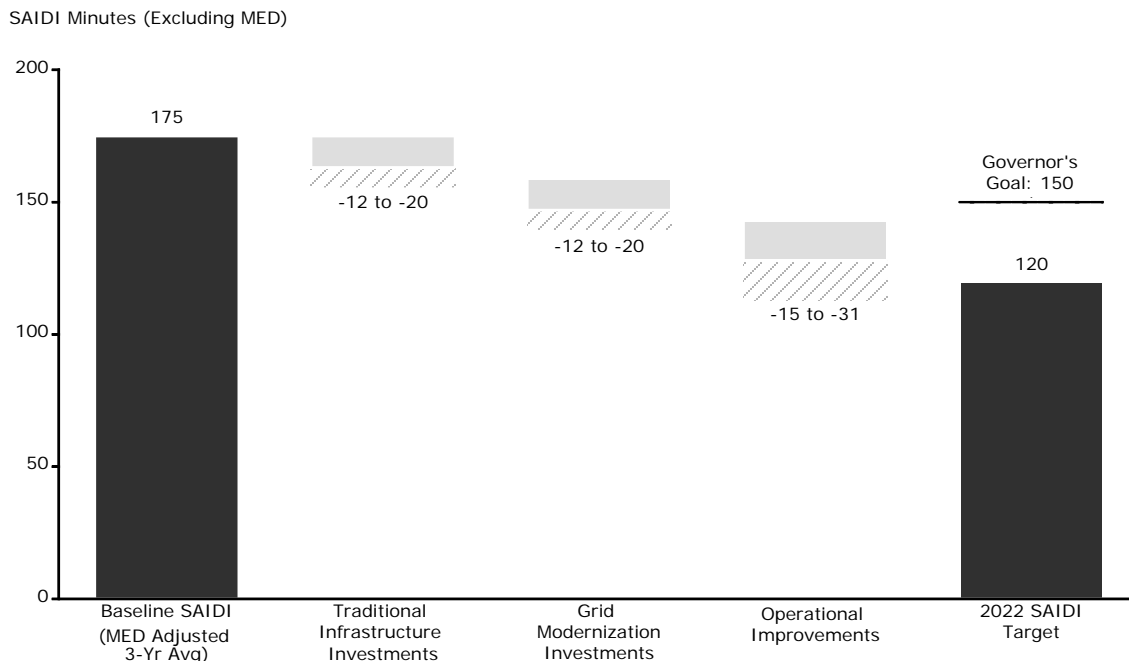
¹³ “21st Century Infrastructure Commission Report,” pages 54 through 55.

http://www.michigan.gov/documents/snyder/21st_Century_Infrastructure_Commission_Report_555079_7.pdf

¹⁴ IEEE Benchmark Year 2017 Results for 2016 Data.

increased use of technology, and culture of continuous improvement provide a strong platform to meet these challenges.

FIGURE 49 – PATH TO ACHIEVE 2022 SAIDI TARGET



The **starting point** for our SAIDI waterfall in Figure 49 is the adjusted 3-year SAIDI average (excluding MED). The three-year average was adjusted from 182 minutes to 175 minutes, by applying our 2018 MED threshold to the past three years. This accurately captures our recent historical performance and the current system state as described in Section IV.

Traditional infrastructure investments both offset the deterioration of the system due to the age and state of the system (see Section IV) and provide additional reliability benefits and improvements for customers. The traditional infrastructure investments bar in Figure 49 shows that the expected benefit (net offsetting deterioration) is between 12 to 20 SAIDI minutes. The largest contributor to uncertainty in this benefit is weather. Localized storms that are not MEDs may contribute up to eight SAIDI minutes during a single day (since our MED threshold for 2018 is just over eight minutes on a single day). Our investments aim to increase the resiliency of the system and to mitigate the effect these days have on our customers. When considering the impact of traditional investments, it is also important to note that we expect that natural aging, overloads, deterioration, and forestry growth would increase SAIDI by at least 50 minutes or more over the next five-years if there was no investment in the grid.

SAIDI improvement from traditional infrastructure investment results from several reliability programs:

- The largest incremental benefit is through the LVD and HVD Forestry programs. These programs are estimated to provide five to seven minutes of SAIDI improvement, as Forestry spending increases over the next five years. Further discussion of the Forestry impact can be found in O&M program 2.2 Forestry.

- The LVD and HVD Lines Reliability programs (See capital program 4.1 LVD Lines Reliability and capital program 4.2 HVD Lines Reliability) and associated Demand Failure spending are also expected to have a significant impact. In addition to offsetting the aging of our poles and wires, these programs are expected to provide four to six minutes of SAIDI improvement as spending increases over the next five years.
- The Repetitive Outages Program (see capital program 4.7 LVD Repetitive Outages), which targets the worst performing areas of the system, is expected to provide three to five minutes of SAIDI benefit, and drastically improve performance for customers in those areas.
- The remaining SAIDI benefit is spread across other Reliability, Capacity, and Demand Failure programs. Although these provide lower incremental SAIDI benefit, they are crucial to offset deterioration on the system.

Grid modernization investments enable new grid capabilities and meet the evolving needs and expectations of our customers for reliability, sustainability, cost, control, and safety. These investments are often interlinked, requiring a few devices or technologies to be in place in order to capture the range of benefits across our five objectives. The SAIDI improvement from grid modernization investments is estimated at 12 to 20 SAIDI minutes. Based on the uncertainty around new technology, a small range has been added to estimates for each component of the SAIDI improvement. For the technologies that we have already deployed (i.e., DSCADA, distribution automation loops), initial deployment results were used to forecast future SAIDI benefits. More detail on the investments and benefits can be found in capital program 4.9 Advanced Capabilities Infrastructure: Automation, and capital program 4.10 Advanced Capabilities Infrastructure: Advanced Technology on Grid Capabilities.

- The largest SAIDI benefit from grid modernization investments is from distribution automation loops, which provide the capability to automatically transfer load in the event of an outage. This capability is expected to provide between seven to ten minutes of SAIDI improvement.
- DSCADA deployment is estimated to provide two to four minutes of SAIDI improvement by enabling faster fault detection and remote operation capabilities for reclosers.
- Fault location capabilities enabled through line sensors and other connected devices are estimated to provide two to four minutes of SAIDI improvement.
- The remaining grid modernization capabilities, including automated switching orders and proactive fault location, are estimated to provide one to two minutes of SAIDI benefit.

It is important to note that many of these capabilities are either fully reliant on ADMS or receive incremental benefit from ADMS deployment. The ADMS benefit is embedded within the above numbers.

Operational improvements are expected to have a large impact on SAIDI by reducing the duration of outages (CAIDI). There are two key components that influence the duration of outages from an operational lens:

- Workforce – The number of employees and contractors, location of the workforce across our service territory, and work schedules of the field workforce all influence the duration of outages. Electric line crew and service worker schedules and the coverage period (e.g., 24/7) reduce interruption duration by increasing resources available to respond to outages.
- Restoration Process – The process for restoring customers includes weather monitoring and pre-planning, field execution, customer and governmental communications, and after-action reviews. A key component of the process is having a standardized field execution approach:

isolating damage, restoring all possible customers, making repairs, and clear communication among office and field employees. These standards are critical to safe, consistent, timely, and effective responses in storm and non-storm situations.

Our overall SAIDI improvement target summarized above includes a 15 to 31 minute reduction in SAIDI through operational improvements. We plan to improve outage duration by optimizing the restoration process and using the existing workforce more effectively. Over the next five years, we plan to improve outage duration through the following initiatives.

Process and Culture

Timely restoration critically depends on our processes and on employees executing safe and reliable work. We continuously evaluate and improve our restoration processes to provide faster service restoration for our customers.

Customers often experience long interruption durations during storm conditions, due to the concentration and complexity of outage incidents. To target improvement during storm events, we recently generated a detailed process map with a thorough assessment of our current storm processes, and are utilizing the map along with new key performance indicators to identify and streamline bottlenecks. In addition, we are implementing an ICS, which is part of the National Incident Management System. ICS is primarily a command and control system that delineates responsibilities for managing incident restoration operations. We are planning to complete a full rollout of ICS to our employees, including the required training, by the end of 2018. The ICS is expected to improve real-time planning processes and dispatch efficiency during restoration events.

In addition to storm-related initiatives, we have a number of process-based initiatives focused on improving CAIDI during normal conditions. This includes implementing best practices from our peer utilities, and refining field practices to better respond to underground outages. Furthermore, we are actively working to enhance the culture of timely restoration in the field by utilizing DORs and WORs and visual management in crew rooms, similar to the successful fundamentals of the Electric Reliability Rally Room (see Section IV for more details). We work side by side with our union partners to solve problems in real time, and deliver results for our customers each day.

Tools and Mobilization Improvements

The location of crews and materials relative to an outage location is important, because drive time to reach an outage adds to the total time to restore power to customers. For this reason, we are evaluating the locations of our service centers and other options to improve crew mobilization, particularly in areas like West Branch, where drive time is a significant factor in the time to restore power. As seen in Section IV, customers serviced by our service centers in northeast Michigan (e.g., West Branch) experience longer than average interruption durations.

In addition, we are evaluating new tools that will streamline the restoration process. We are working closely with suppliers to explore new tools and approaches that will enable our crews to restore power more safely and quickly, and focus on repairing the issue while minimizing impacts to customers.

Systems, Analytics, and Data Visualization

Integrated systems and the use of data analytics are critical components in meeting our overall CAIDI ambitions. In addition to the storm process changes described above, these integrated systems and analytics can have a large impact during storm operation. For example, we are exploring predictive

weather analytics tools to enhance pre-storm crew mobilization and staffing plans. Furthermore, as discussed in Section V, the ESME system modeling effort will provide a geographically precise model, which will enhance system analysis for outage locations and reduce unnecessary truck rolls that occupy crew time during restoration events.

We have also identified tools and analytics to reduce CAIDI during normal operation. The rollout of ADMS over the next few years will provide greater visibility into outage events for dispatchers, and help crews locate faults faster. In addition to our ADMS plans, we have recently put analytics in place to dissect outage performance across the service territory. By comparing the duration of each step in the restoration process (e.g., incident creation time, dispatch time, travel time, and repair time), we can implement service center-specific targets and benchmarks. By tracking this detail, we are better able to share best practices and impact our poorer-performing service centers. Finally, as mentioned in the previous sub-section, we are investigating new tools that will allow our restoration crews to more easily access real-time outage details while out in the field.

iii. Cost

We will meet all of our objectives in a manner that is the most cost-effective and equitable for all of our customers over the long term. We will not optimize costs for some customers in a manner that unfairly impacts other customers, and will not be short-sighted by minimizing costs in the short-term only to experience higher costs in later years. We plan to optimize system cost in two main ways. First, we will install newer equipment that reduces recurring O&M expenses and improves system operation. Second, we plan to find cost efficiencies in existing processes and operations. The following examples illustrate how these two approaches will optimize system cost:

- **System upgrades** – Investments in grid modernization line automation (see capital program 4.9 Advanced Capabilities Infrastructure: Automation): The implementation of SCADA, DSCADA and ATRs will give our operators better system visibility and the ability to remotely operate substation equipment. These capabilities will reduce the number of truck rolls and service dispatches. In addition, these capabilities will help reduce outage duration, reducing cost to restore power. As we continue to advance our capabilities to isolate and restore supply to our customers, we expect to realize additional cost efficiencies. The line automation investments are expected to directly impact our ‘service restoration O&M cost per incident’ metric.
- **System upgrades** – Replacing EM relays with digital devices, in the HVD System Protection Program (see capital program 4.6 HVD System Protection): Investments in this program are directed at replacing obsolete, high maintenance EM relays with digital devices. Many of the EM relays are either no longer manufactured or no longer have parts available. Those that do have available parts are no longer cost-effective to repair. Replacing end-of-life relays reduces O&M expenses, as older EM relays require more periodic maintenance than newer digital relays.
- **Cost efficiency improvements** – Reducing cost per line-mile cleared in the Forestry program (see O&M program 2.2 Forestry): Over the next five years, the cost to perform tree clearing activity on each mile of line on our system will continue to improve as we move our LVD line clearing program towards a seven-year effective clearing cycle. We will achieve cost efficiencies as we reduce the time between line clearing, giving trees less time to grow over the lines. With a stable multi-year funding plan, we will be able to better plan our line clearing activities and will need to perform less of the more costly demand or incident-driven work.

- **Cost efficiency improvements** – Data and operational visibility to optimize investments (See Section VI.B.ii Increasing Role of Data and Analytics in Planning): We constantly strive to maximize the benefit that our investments provide for our customers. As we gain additional visibility into system conditions, use data to better understand customer behavior, and are able to better segment our circuits along customer needs, we will be able to more effectively target our investments across the grid. Over time, we will be able to further reduce costs by enabling more algorithm-based decision making to help guide our investment spending.

iv. Sustainability

We have three metrics to measure our performance on sustainability: energy savings through energy efficiency programs, system load factor, and percent system loss. Through our investment decisions, we aim to impact these metrics and reduce the overall waste and carbon footprint from our operations and by our customers. In addition, we strive to mitigate environmental risks (e.g., oil spills and wildfires). Examples of investments and spending in the five-year plan that will improve sustainability include:

- **Reduce waste and carbon footprint** – Energy efficiency programs to reduce energy waste (see Section V.C): We offer a comprehensive portfolio of electric energy efficiency programs and incentives to customers. For example, incentives are offered to residential customers who install more efficient lighting, appliances, insulation, air-conditioning, or windows. Over the next five years, we plan to continue investing in cost-effective energy efficiency programs, to help customers further reduce energy waste.
- **Reduce waste and carbon footprint** – Improving overall system efficiency with VVO, enabled by investments in Advanced Capabilities (see Sections V.A and V.B): This capability will enable coordinated control of voltage regulators and switched capacitor banks to reduce system losses and eliminate waste, allowing us to implement a CVR Program, reducing demand and our carbon footprint without requiring additional investment by customers.
- **Reduce waste and carbon footprint** – Improving load forecasting via DSCADA (see capital program 4.9 Advanced Capabilities Infrastructure: Automation): Increased visibility into distribution system load will provide system planners with more granular load data, and greater understanding of the coincident peak load and duration of loads above equipment capacity on the distribution system. This improved forecasting will help reduce system losses, by targeting capacity investments to areas with sustained overload conditions and high losses.
- **Mitigate environmental risk** – Inspecting and proactively replacing underground padmount equipment (see capital program 2.1 LVD Lines Demand Failures): Underground padmount equipment is visually inspected annually to check for any signs of oil leaking or damage. If any issues are found, they are proactively fixed, mitigating the risk of an oil spill harming the nearby environment.
- **Mitigate environmental risk** – Replacing overloaded equipment (See capital programs in 5.0 Capacity): Overloaded equipment increases the risk of fires, which can cause devastation to the nearby environment. We proactively replace overloaded equipment and work to prioritize replacing equipment that will have the highest environmental and safety impact.

v. Control

We aim to provide customers greater control over their power across a variety of dimensions, including providing information, technology, programs and services to support customers in managing their

usage. In order to achieve this, we are focusing on two areas over the next five years. First, we will deploy a number of system enhancements and technologies to help enable improved control. Second, we are offering our customers a number of programs to help them take control of their energy needs. The following investments in the five-year plan are examples of how we will improve control:

- **Deploying technology** – Improved situational awareness via SCADA systems (see capital program 4.9 Advanced Capabilities Infrastructure: Automation): Better real-time visibility of the status of the electric system allows for quicker identification and resolution of system performance issues. Our investments in SCADA and other situational awareness investments will ultimately increase our ability to integrate DERs on the grid.
- **Deploying technology** – Our investments in advanced applications such as ADMS will integrate a number of our systems and data, bringing additional visibility to our grid (see capital Program 4.10 Advanced Capabilities Infrastructure: Advanced Technology). Integrating an ADMS platform will allow us to better utilize the investments we are making in telecommunications and grid devices. We will improve our operational visibility and provide our customers with faster recovery from outage events. Furthermore, we will have the ability to model and integrate two-way power flow, giving our customers greater control of their energy supply.
- **Customer programs** – Demand response programs (see Section V.C): Demand programs allow us to manage loads on the electrical system by reducing peak demand via registered LMRs. These programs compensate customers who use energy more efficiently and provide economic benefits to Michigan by reducing peak demand and the need for new capacity investments.
- **Customer programs** – Customer communications, in service restoration spending (see O&M Section IX.C): We continue to focus on spending on our two way communications systems and media costs during outages. These programs give customers and the public information about our progress in restoring their power and reminding them how to stay safe during an incident.

D. Rate Recovery

This report presents O&M spending and capital investment needed to support and improve our distribution system while providing the most value to customers. As has been presented, significant capital investment is required to sustain the distribution system. In an effort to ensure a timely and customer-focused implementation of this investment strategy, we will work with the MPSC Staff on potential rate recovery mechanisms.

i. Rate Mechanisms Currently in Place

The Company was recently approved an Investment Recovery Mechanism (IRM) for its gas business, allowing for recovery of certain transmission and distribution capital investments to ensure safe and reliable gas service for customers. In addition, the energy waste reduction (EWR) program includes an incentive mechanism and the demand response (DR) program has been designed to allow for an incentive mechanism, which encourage utility participation in the programs. The form of the EWR incentive is a “shared savings” mechanism whereby the cost savings generated by the program is shared between customers and the utility. Michigan’s implementation of an EWR shared savings incentive mechanism has been successful in achieving the policy goal of eliminating energy waste, delivering savings to customers, and providing an appropriate incentive for utilities to make non-capital investments. This innovative regulatory approach is intriguing in its potential application to non-wires alternatives and other aspects of utility operations designed to optimize the energy system.

ii. Use of Rate Mechanisms

Use of rate mechanisms will help facilitate the customer-driven objectives used as a base for our long-term ambitions for our distribution system. Specifically, they can help ensure safety and security, reliability, sustainability, customer control, and optimal system costs. Incentive mechanisms can be used to facilitate the design and implementation of the most cost-effective maintenance and capital investment programs. A multi-year IRM can be used to provide an avenue to ensure timely rate relief for these critical distribution related capital investment programs while creating a means to monitor program activity and spending. We will continue to work with the MPSC Staff on the appropriate programs to be included in an IRM as well as the potential for other mechanisms that could enhance the distribution system plan.

VIII. Capital Programs

Over the next five years, we plan to invest \$570 million to \$635 million per year in capital on our LVD and HVD systems. This total spending constitutes a 3.1% average annual increase between 2017 and 2022. The investments that we plan to make over the next five years will be tied to the objectives we have laid out in this report of reliability, safety and security, sustainability, control, and affordable cost. Our capital spending is managed utility-wide and therefore fluctuations in specific programs can be expected on an annual basis to deal with external factors such as incremental weather, customer restoration, unexpected equipment failures and other factors that may impact the utility as a whole. The current five-year plan presented in this document provides the best representation of our expected future capital investments into the distribution grid as of March 1st, 2018.

Our capital dollars are directed into two categories of investments: (1) spending on demand-driven, customer-driven, and emergent capital investments; and (2) planned proactive capital investments. Due to the emergent nature of the first category, they are more difficult to plan in advance; these "unplanned" investments, which make up roughly \$280 million in average annual spending, respond to immediate customer needs such as replacing failed equipment, relocated infrastructure, or adding new customer connections. The spending in these categories is expected to be in line with historical trends, growing at an average rate of 0.5% between 2017 and 2022. The capital plan takes into account expected impact of weather and storm activities, as well as external indicators, to come up with a reasonable forecast. Some of these costs are partially offset by customer contributions and the costs shown below are net of any expected contributions. While these investments are more difficult to plan in advance, we plan some investments in this program in anticipation of emergent or imminent customer needs, or for failures that do not require an immediate response. Further details for these programs are provided in the sections to come.

On average, we plan to spend \$270 million per year on planned capital investments to proactively improve our grid through reliability-targeting projects, capacity upgrades, and investments in updated tools and technology. We aim to invest in upgrading our grid infrastructure, rehabilitating our aging infrastructure, and growing our future capabilities. Due to these goals, our planned spending represents an increase from our historical capital spending levels, which has averaged \$160 million per year over the past three years. We expect these programs to grow at an average rate of 9% annually between 2017 and 2022, driven by necessary investments in reliability and grid modernization. The tables below show the current five-year plan broken out by each of our capital investment programs.

TABLE 20 – FIVE-YEAR CAPITAL PLAN FOR UNPLANNED PROGRAMS

5-Year Capital Plan – Unplanned Programs (All values in \$ millions)									
All values in \$ millions		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
	Unplanned programs								
1.1	Lines New Business – LVD	46	43	66	60	65	68	70	73
1.2	Lines Strategic Customers – HVD	7	28	7	14	10	10	10	10
1.3	Metro New Business	3	3	2	5	5	5	5	5
1.4	Metering New Business – LVD	5	5	8	6	7	7	7	8
1.5	Transformers New Business – LVD	12	9	13	10	12	12	12	12
1.0	New Business	73	88	97	95	98	103	105	108
2.1	Lines Failures – LVD	76	67	85	79	79	79	81	82
2.2	Substations Failures – LVD	8	9	15	14	14	14	15	15
2.3	Lines & Subs Failures – HVD	15	13	18	16	17	17	17	18
2.4	Metering Failures – LVD	6	7	12	11	13	13	13	14
2.5	Transformers Failures – LVD	14	15	21	16	19	20	19	20
2.6	Street Lighting	3	2	2	6	6	2	0	0
2.7	Metro Failures	2	5	4	4	5	5	5	5
2.0	Demand Failures	123	119	156	145	152	150	151	153
3.1	Lines Relocations – LVD	19	14	23	17	20	21	20	20
3.2	Lines Relocations – HVD	1	0	0	1	1	1	1	1
3.3	Metro Relocations	7	5	5	10	3	5	5	5
3.0	Asset Relocations	28	20	28	27	24	26	26	26
	Total Unplanned	223	226	281	267	274	280	281	287

TABLE 21 – FIVE-YEAR CAPITAL PLAN FOR PLANNED PROGRAMS

5-Year Capital Plan – Planned Programs (All values in \$ millions)									
All values in \$ millions		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
	Planned programs								
4.1	Lines Reliability – LVD	25	49	38	46	49	51	54	54
4.2	Lines Reliability – HVD	15	38	17	37	39	38	39	41
4.3	Substations Reliability – LVD	9	11	14	19	20	20	21	20
4.4	Substations Reliability – HVD	3	4	4	4	5	5	5	5
4.5	Substations Comms Upgrades	0	0	0	23	41	-	-	-
4.6	System Protection	2	2	4	2	2	2	2	2
4.7	Repetitive Outages – LVD	10	8	6	10	9	10	10	10
4.8	Metro Reliability	4	3	1	4	3	4	3	3
4.9	Grid Capabilities: Automation	14	19	26	24	31	39	43	44
4.10	Grid Capabilities: Advanced Tech	0	0	0	16	32	24	16	6
4.0	Reliability	83	133	111	184	232	193	194	186
5.1	Lines Capacity – LVD	17	15	18	18	17	18	19	19
5.2	Lines & Subs Capacity – HVD	16	21	17	18	22	22	22	25
5.3	Substations Capacity – LVD	7	18	14	12	13	14	14	14
5.4	Transformers Capacity – LVD	4	3	5	3	4	4	4	4
5.0	Capacity	44	57	53	51	57	58	59	63
6.0	Tools and Technology	3	4	3	10	11	11	11	11
	Total Planned	129	193	167	245	300	262	264	260
7.0	Cost of Removals	40	42	70	60	62	59	58	57
	Capital Plan	392	461	518	572	635	601	603	605
	Demand Response	0	1	7	9	9	9	8	8

The sections below summarize each of the capital programs that directly impact the electric distribution grid at Consumers Energy. Each program has a unique set of objectives and criteria which, together, help deliver on the five-year goals of the electric distribution plan. Through these programs, capital funding is allocated in a manner that allows for satisfying the needs of our system and the demands of our customers. For each program outlined below, we have provided a breakdown of our five-year capital plan, a summary of the types of investments and projects that will be funded through these programs, and a description of the investment logic and prioritization process that is used to ensure we are using our capital dollars in the most effective and productive manner for our customers.

A. 1.0 New Business

The New Business category consists of the capital cost of connecting new commercial, industrial, and residential customers to the electric system. The program costs include the cost of installing poles,

conductors, transformers and services, the cost of meters to service new customers, and the cost of installing new customer-requested street lights. These costs are partially offset by customer contributions.

Projects in the New Business programs are in response to customer requests for installation of new service which the Company must provide if the customer meets the requirements set forth in the applicable tariffs. Customers may be billed for service pursuant to the stipulations of the tariff sheets. In general, the Company does not have advanced knowledge of the projects in New Business as they are emergent in nature. Additional details for individual programs can be found in the following sections.

i. 1.1 LVD Lines New Business

Most Electric New Business projects fall under the LVD Lines New Business category. Our LVD Lines New Business program provides for the installation of low voltage distribution lines to connect new customers to the electric system. Investments include service installation, infrastructure installation, and upgrades needed to serve new customer load. Under this program, we complete over 10,000 projects annually, varying in size and scope.

Due to the large volume of projects and the emergent nature of the program, we do not forecast project work on an individual level. Instead, we estimate capital spending for this program based on historical program investments, with adjustments for anticipated increases or decreases in activity, costs, or customer credits. Due to this variability, we show our plans for this program below as wide ranges of expected activity over the next five years.

The current five-year plan for LVD Lines New Business consists of between \$60 million and \$73 million per year, based on three factors used to estimate our anticipated spending: (1) forecasted service installation volumes; (2) expected cost per installation; and (3) anticipated customer credits.

TABLE 22 – CAPITAL: LVD LINES NEW BUSINESS

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Direct new business costs	71	77	80	83	86
Expected customer contributions	-12	-12	-12	-13	-13
Total	60	65	68	70	73
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
LVD service connections	9,273	9,736	9,736	9,736	9,736

Projections of Service Installation Volumes

Our new business spending typically rises and falls in correlation with Michigan’s overall economic health. Since recovering from the economic downturn in 2012, service installation volumes have

increased linearly. We have not seen significant variability beyond the 5-10% range, except for 2013 when growth was at 18%, shown in Figure 50 below.

Understanding the health and overall outlook of Michigan’s economy provides the first data point we use to begin our New Business planning process. Looking forward over the next five years, we assess that the overall Michigan economy will continue to grow, and Michigan housing starts will continue to grow incrementally with the economy. Additionally, historical analysis shows that Michigan’s economy has a long way to grow to reach historical connection volumes; for example, in 2005 we connected nearly 20,000 electric services.

FIGURE 50 – HISTORICAL ELECTRIC NEW BUSINESS SERVICES INSTALLED

Electric new business services installed

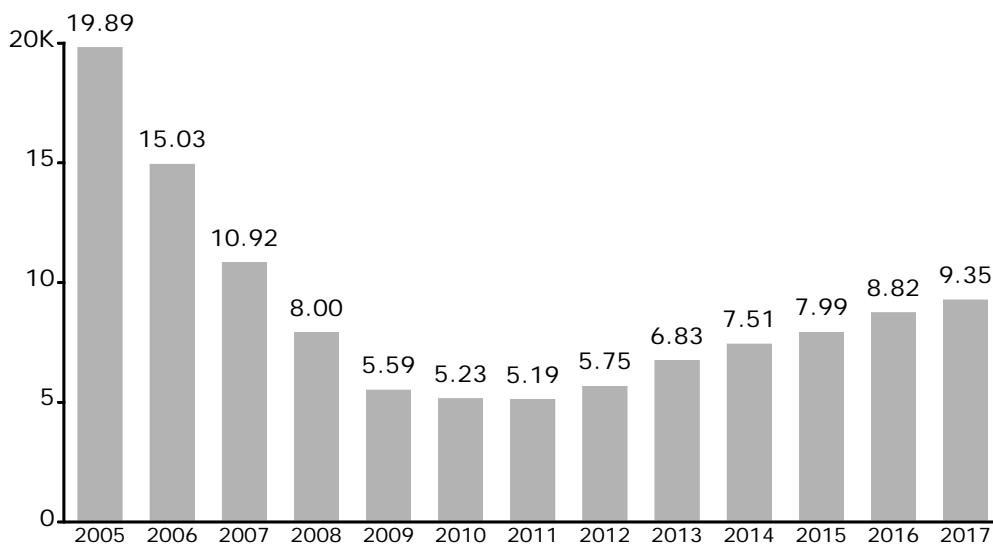
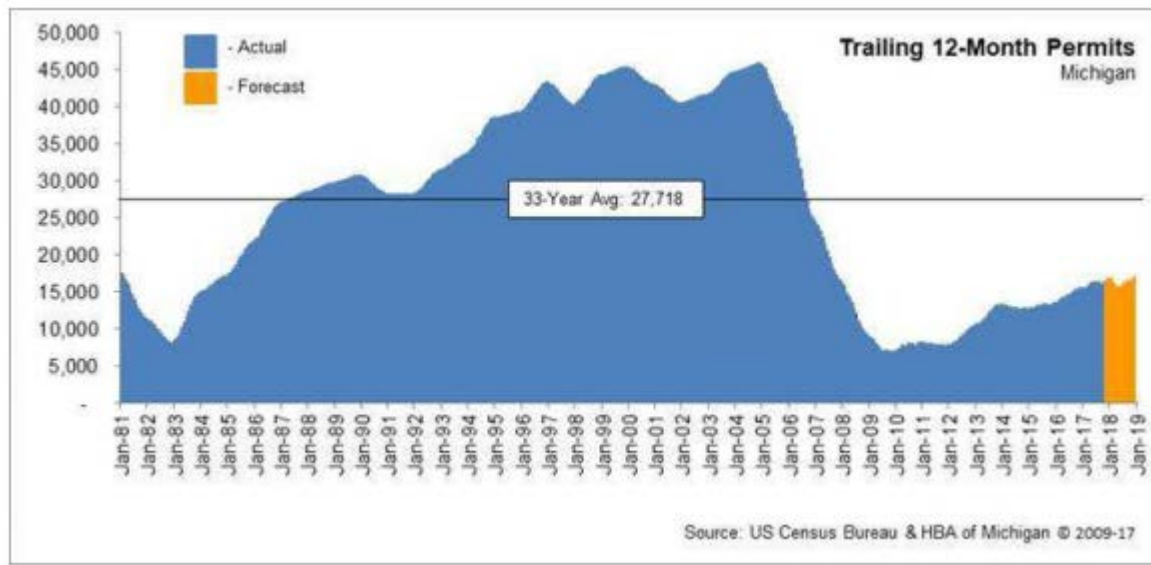


FIGURE 51 – HOMEBUILDERS ASSOCIATION OF MICHIGAN FORECAST



We currently build our financial forecast with the baseline assumption that Michigan's economy and housing market will continue to expand at a rate consistent with historical trends. Our three-year historical average growth has been between 5-10%. We forecast growth of 5% over the next 12 to 24 months. Beyond this, we temper our assumptions on growth or decline, due to economic uncertainty beyond a 12- to 24-month forecasting period. Our growth forecast is consistent with the National Association of Home Builders (NAHB), who forecasts a 5% increase in the single family housing market in 2018.¹⁵ The Home Builders Association of Michigan issued their 2018 forecast expecting modest growth of 1%, citing constraints on the labor market and North American vehicle sales¹⁶. We believe our growth will be closer to 5%, as much of our electric market is within West Michigan, a top-ranked metropolitan area for job growth in the United States.¹⁷

New Business Credits and Rate Applications

Section C6 of the Consumers Energy Rate Book for Electric Service authorizes service installation and prescribes their administration. Residential service connection rates described in C6.1 allow for 600 feet of distribution extension without a customer contribution. We also provide the overhead service connection without customer contribution. Residential underground service connections outside of subdivisions require *"a contribution in aid of construction to cover the difference in cost between overhead and direct burial underground facilities"* (C6.2B.b).

A recent project in West Michigan provides an example of rate application and collection of contributions. As shown in Figure 52 and Figure 53 below, the project included a short overhead primary extension, an underground primary distribution extension, and an underground service.

¹⁵ "Economic Panel Predicts Housing Will Continue to Gain Ground in 2018." NAHB, www.nahb.org/en/news-and-publications/press-releases/2018/01/economic-panel-predicts-housing-will-continue-to-gain-ground-in-2018.aspx.

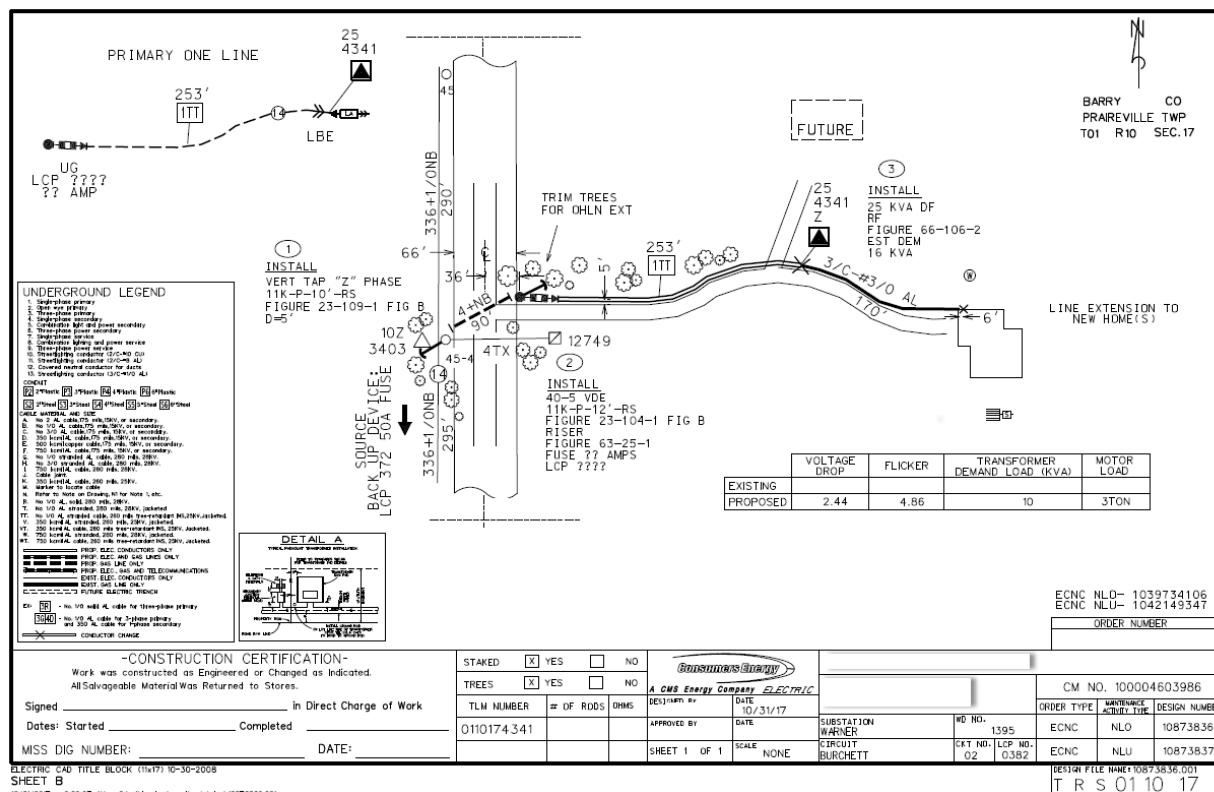
¹⁶ "Cautious Optimism about Homebuilding Industry at the Forefront of 2018 IBS." Home Builders Association of Michigan, 8 Jan. 2018, www.buildingmichigan.org/?page=Menu/HBA+News/Press+Releases.

¹⁷ Harger, Jim. "Grand Rapids Ranked No. 1 in U.S. for Job Growth." Mlive, 10 July 2017.

FIGURE 52 – NEW BUSINESS PROJECT EXAMPLE

Project # 001039734106				
	CE Cost	Customer Contribution	Description of Charge	Rule
Overhead Line Extension	\$2,486	N/A	Overhead allowance - No Cost	C6.1A
Underground Line Extension	\$4,970	\$2,419	Difference in cost between OH and UG	C6.2B(b)
Underground Service	\$667	\$440	\$350 Flat service rate. \$90 for excess footage	C6.2B.(3)
Total	\$8,122	\$2,859		
CE Cost for Service	\$5,263			

FIGURE 53 – LVD NEW BUSINESS PROJECT EXAMPLE



Our costing model for general service connections is prescribed by Section C.6 of our Electric Rate Book. The central costing principle applied to all general service connections is the total project cost less three times the customer's anticipated annual revenue. In effect, we apply a three-year anticipated revenue credit to offset the customer's contribution. For a project with no additional revenue, the contribution will be the full project cost.

Prior to 2017, we collected mandatory charges for the difference in cost between overhead and underground facilities as a contribution for all general service connections. In 2017, Rule 511 of the Michigan Administrative Code was changed so that we can no longer collect mandatory underground charges. This promotes the construction of underground facilities, which are less impacted by acts of nature, and enables us to be competitive with alternative providers in scenarios where our facilities are in similar proximity to other utilities prior to making an initial service connection. The net result was

approximately a \$240 credit per service reduction in 2017 compared to our three-year average. We used 2017 credits per service to forecast our five-year outlook.

As described above, LVD Lines New Business costs include the cost of service connections, residential and commercial, as well as line extensions and the installation of developments. In 2017, we completed 3,785 distribution extensions and alterations to support the installation of 9,353 service connections. Our cost per service connection, including all alterations and extensions in 2017, was \$7,044.

Planning Process, Prioritization, and Delivering On Time

Customer business needs drive customer service requests initiated through this program. We accept all customer projects for consideration and give them equal opportunity to proceed.

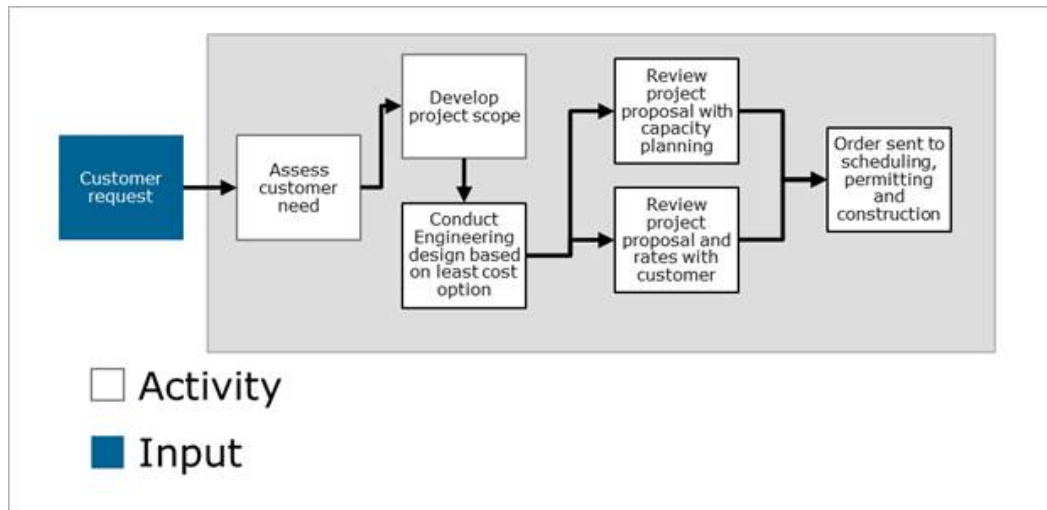
Delivering projects on-time for our customers is paramount. At the initiation of each project, independent of scope, we establish a Customer on Time Delivery (COTD) date. The initial COTD date is captured and recorded for each new service request. Our milestone-driven process provides deliverable targets throughout the project lifecycle, ensuring we remain on track to meet customer needs. COTD dates are only modified if mutually agreed upon or if requested by the customer. We record reasons for changing COTD dates, unless requested by the customer, to facilitate problem-solving and continuous improvement. COTD was first benchmarked in 2016. Our ability to deliver on the customer's committed date was 9% in 2016. In 2017, with our progressive continuous improvement cycle, we made 60% of our COTD commitments.

Once a COTD date is established after receiving the initial request, we send a member of our Project Coordination team to scope the project by working with the customer to identify project needs including capacity demands.

Our Design and System Planning teams receive scoping information and analyze our system and the facilities required to serve the customer's request. When appropriate, we offer the customer alternative design options such as the installation of overhead or underground distribution facilities. We design the project based on customer approval of project scope.

The design process includes the selection of Compatible Units (CU), which include labor reasonable expectancy or expected time to complete, and material requirements. We summarize the selected CUs to develop a total cost and bill of material. Final distribution project designs must then receive financial and design approval. The financial approval authorizes spending for the project and ensures appropriate billing recovery through our rates. The design approval validates the design meets our technical standards and can be constructed safely and efficiently at our least cost option. A schematic of the planning process can be found below.

FIGURE 54 – LVD NEW BUSINESS PLANNING PROCESS



Our design and system planning teams are integrated in our Grid Infrastructure organization, enabling us to plan for new business demand in our capacity planning models. Solutions developed for customers are therefore comprehensive and aligned with planned system improvements, benefiting connecting customers. Our robust scoping, planning, and approval process ensures our New Business distribution investment is prudent for our customers.

We leverage survey data and COTD results to continuously improve. Our goal is to deliver the best value for our customers to ensure we can continue to be their energy service provider of choice.

ii. 1.2 HVD Strategic Customers New Business

Our HVD Strategic Customers New Business program meets the needs of large commercial and industrial customer new business requirements that are too energy-intensive to be served by the area LVD system. Typical investments for this program include dedicated substations and interconnections of dedicated substations to the HVD system with poles and conductors. Recent examples include Brembo North America near Homer (2016), the Facility for Rare Isotope Beams at Michigan State University (2016-2017), General Motors in the Flint area (2016-2018), St Mary’s Cement near Petoskey (2016-2017), The Andersons near Albion (2017), and Arauco North America near Grayling (2017-2018).

We plan for and begin to develop these projects as we are made aware of needs, based on customer activity. The timeline from a customer request notification to final connection can vary from six months to two years. For 2018, we are planning two new substations, two substation modifications, and approximately 10.3 miles of HVD lines. Some projects in our current five-year plan include:

- HVD Line to Customer-Owned Substation – 8.5 miles of new 138 kV line and rights of way to connect a new customer-owned substation in mid-Michigan.
- Dedicated Customer Substation #1 – Final charges for a new 138 kV dedicated customer substation and 1 mile of new 138 kV line in northern Michigan for a project predominantly constructed in 2017.
- Dedicated Customer Substation #2 – New 138 kV dedicated customer substation and 0.2 miles of 138 kV line in southern Michigan.

- Dedicated Customer Substation #3 – New 46 kV dedicated customer substation and 0.1 miles of 46 kV line in southwest Michigan.
- Dedicated Customer Substation #4 – New 138 kV dedicated customer substation and 0.2 miles of 138 kV line in west Michigan.
- Dedicated Customer Substation #5 – New 138 kV dedicated customer substation and 0.6 miles of 138 kV line in west Michigan.
- Power Quality and Communications Upgrade – Power quality meter upgrades at dedicated customer substations.

The fully projected plan for 2018 through 2022 is as follows:

TABLE 23 – CAPITAL: HVD STRATEGIC CUSTOMERS NEW BUSINESS

5-Year Capital Plan (all values in \$ millions)					
Projects	2018	2019	2020	2021	2022
HVD Line to Customer Owned Substation	4	1	-	-	-
Dedicated Customer Substation #1	0.3	-	-	-	-
Dedicated Customer Substation #2	2	-	-	-	-
Dedicated Customer Substation #3	5	-	-	-	-
Dedicated Customer Substation #4	-	-	-	8	1
Dedicated Customer Substation #5	-	3	-	-	-
Power Quality & Comms. Upgrade	0.4	-	-	-	-
Other expected HVD new business	3	6	10	2	9
Total	14	10	10	10	10

While we know what our work will be in 2018, the projected values in years 2019 through 2022 are estimated based on current planned work as well as expected investment that will be required for other new business, based on historic spending levels. The five-year plan above is the level of investment we will need to support these types of customer projects. These costs are net of any contributions made to Consumers Energy by customers in support of their project.

Planning Process

Our investment requirements in this program are driven primarily by service inquiries in support of new HVD connections or increased load requirements from new or existing customers. Due to the magnitude of load and impact to the electric system, these inquiries typically involve our Business Customer Care team. These service inquiries can originate from existing customers or from proposed new customers looking to locate in Michigan.

An existing customer will typically contact their assigned Customer Account Manager (CAM) on the Business Customer Care team, who will then contact the appropriate HVD planning engineer for the geographic area of the customer’s location. The CAM will acquire data from the customer including the location, proposed new maximum demand (kW or MW), the customer’s proposed schedule for the new

load to come online, and any other specific details about the load type (furnace, manufacturing, large motors, etc.) that could affect the facilities required to serve the new load. The CAM will also work with the customer and the HVD planning engineer to determine a mutually acceptable timeframe to provide results of any studies and cost estimates of required facilities to serve the new load. The HVD planning engineer will then perform studies and develop conceptual cost estimates for any new or upgraded Consumers facilities required to serve the new load. The CAM and the HVD planning engineer will then populate a proposal with this information, including the proposed project schedule and any Contribution in Aid of Construction (CIAC) allowance available to offset costs. The CAM will deliver it to the customer for their review and approval. If approved, specific agreements are drafted and executed between Consumers and the customer, and the HVD planning engineer will open a work order for new facilities to be engineered and constructed according to the agreed upon schedule.

Customers may also initiate service inquiries through the Michigan Economic Development Corporation (or any of a number of local community economic development organizations). These groups then submit a Request for Proposal (RFP) to our Economic Development group (also part of our Business Customer Care team). These RFPs are very similar to a service inquiry, except that the customer information is typically confidential at these early stages, and there may be multiple alternative locations to review, instead of just one. Our Economic Development Manager will contact the appropriate HVD planning engineer, based on geographic location, and work to fill out the RFP in much the same manner as a service inquiry. The timeline for completing these RFPs is very short (several days or less), and very high-level conceptual costs and timeframes for proposed facilities are provided. The RFP is returned for review by the Economic Development Manager. If the prospective customer is interested in pursuing a particular location based on the information in the RFP, the same service inquiry process as described above begins for that location.

For new and expanding businesses considering Michigan, our Economic Development group offers an award-winning Energy Ready program that was created in collaboration with the Michigan Economic Development Corporation and several regional and local economic development organizations. The Energy Ready program offers two key tools – energy ready profiles and energy ready sites – to help state and local economic development allies confidently identify and market the best sites offering existing energy infrastructure and capacity suited to new and expanding commercial and industrial customers throughout Michigan.

- **Energy ready profiles** identify existing electric and natural gas infrastructure at specific sites. Profile highlights include maps and details about available low- and high-voltage electrical infrastructure and natural gas service. The profiles empower discussions between Consumers Energy, economic development allies and prospective customers. Consumers Energy has created more than 35 energy profiles and adds sites at the request of our economic development allies.
- **Energy ready sites** contain energy profile information and also identify “best-fit” business customers based on a range of energy needs. Site information includes competitive, customer-focused engineering service options and estimates.

Customer service inquiries in our HVD Strategic Customers New Business program are continuous and are driven by customer business needs. Unlike many of our other capital programs, this program and the timing of projects and investments are driven to meet the needs and expectations of these specific customers. In most cases, customer needs and expectations limit the amount of lead time available to

plan the project and typically result in a schedule that is more expedited than schedules for projects in other programs.

Project Prioritization and Selection

All customer service inquiries are evaluated, analyzed, and given an equal opportunity to proceed. We manage the projects generated in this program to meet the customers' needs, and individual projects are not promoted or deprioritized relative to other projects in this program.

Customers may have to make a contribution towards the infrastructure investments in this program under our CIAC tariff, and this can be a key consideration for some customers. We use this tariff to determine the level of contribution and to support the growth of business customers of all sizes. This tariff uses a growing customer's new revenue to offset a portion or all of the required upfront utility infrastructure costs to receive service. This approach insulates other customers from paying for the electric service requirements of a growing business while also lowering the specific business' upfront utility investment. Ultimately, it is the customer's decision to proceed.

Benefits

Increased new large customer connections and load additions provide benefits to our local communities and Michigan through development of jobs and other revenue streams associated with business expansions. Additionally, all of our customers will benefit from these customer additions – by increasing our energy load, as utility costs are spread across a larger customer base, benefiting overall rate competitiveness.

iii. 1.3 Metro New Business

The Metro New Business program promotes the long-term safe and reliable operation of the Metro electric distribution system. Metro work requires significant and, at times, multi-year pre-planning to ensure that the system can serve electric customer needs for years to come.

The investments in this program respond to electrical energy needs of new construction and existing metered locations served by our six Metro underground territories. We typically need to extend both the underground civil infrastructure, such as ductwork, and the electrical system to accommodate new business requests.

Our new business spending typically rises and falls in correlation with Michigan's overall economic health. Metro New Business is challenging to forecast, since it is contingent on (1) customers contacting us in advance of the desired date of service; and (2) customers following through with required information and their portion of work to coincide with that desired date. Analysis of historical trends and data has enabled us to stay within the range of our yearly spending projections and is used as a basis for future spending plans.

Table 24 below shows a number of projects that are already planned for 2018 (Refer to Appendix E for a more detailed project listing). We estimate that we will spend between \$4 million and \$6 million per year on new business for our Metro customers over the next five years. We expect an increase in spending over historical levels, driven by growth in our Metro regions, based on both external data sources and the number of formal requests that we are currently seeing. Specifically, we have observed an increased demand for mixed-use developments in our core urban areas by monitoring media releases

of upcoming developments. An example of this is a growth in the number of developers making multimillion dollar investments, such as buying surface parking lots to build new structures. In addition, we respond to approximately 10 to 15 new and upgraded service requests per year. Each service order costs \$15,000, on average. This equates to approximately \$200,000 of capital spending per year for this type of activity.

TABLE 24 – CAPITAL: METRO NEW BUSINESS

5-Year Capital Plan (all values in \$ millions)					
Projects	2018	2019	2020	2021	2022
GR - 150 Ottawa	0.4	-	-	-	-
GR- Arena South Elec	0.8	-	-	-	-
GR - 601 Bond St Civil & Elec	0.8	-	-	-	-
GR - GVSU 333 Michigan Ave	0.4	-	-	-	-
GR - 12 Weston	0.8	-	-	-	-
BCK - Heritage Tower Redevelopment	0.8	-	-	-	-
JAX - Commonwealth Development	0.8	-	-	-	-
New & upgrade service requests	0.2	0.2	0.2	0.2	0.2
Expected metro new business projects	-	5	5	5	5
Total	5	5	5	5	5

Metro New Business connections generally use the following guidelines:

- New business customers are connected to the system at no cost in accordance with rate administration and billing rules in our MPSC-approved tariffs. Customers commonly fall into two categories:
 - New construction – The new building is on either a vacant site or following a complete tear down of an existing structure.
 - Extensive remodel of existing building – The existing structure of the building is intact, but electrical systems and service from the utility are undersized, due to the new building usage or code requirements (e.g., fire pump, HVAC, etc.). Occasionally a customer with a significantly different load profile is intending to occupy an existing space, which will require upgrades to the system.
- New business meter location(s) also help determine the characteristics of service for the customer. We prefer to locate meters outside along the back façade of a building (in the alley way). On occasion, the metering can be located in an enclosure (primary metering) or inside the building itself. Depending on the characteristics of service for the customer (e.g., residential or general service), we may need to solicit an indemnity agreement from the customer for conductors between the utility load center and the metering bank(s).
- Some customers and developments require the use of the ‘high rise policy’ and separate rate administration and billing rules. A high rise is an energy dense, multi-story building that requires a vertical extension of Consumers Energy electrical assets. These investments require the customer to make a deposit, furnish and install conduits, provide an elevator of adequate

capacity to move electrical equipment, and rooms with adequate floor space and support per our standards.

Planning Process and Prioritization

We accommodate all Metro New Business requests, prioritizing them based on the customer's desired date of service. When a new request is received, we evaluate a number of inputs that impact the design of the system modification, including:

- Customer voltage required
- Customer anticipated load
- Potential future load from the customer
- Potential development of surrounding area (and potential loads)
- Existing system capacity
- Existing system condition in the area

In some cases, customers contact us well in advance, allowing for project costs to be planned for and included in longer range forecasts. When contacted in advance, these dates tend to be fluid, as developers and/or owners seek funding, and it is not uncommon for projects to take several years to come to fruition.

In other cases, customers contact us much later in the project planning process, with desired dates of service in the near future. In these cases, we cannot account for these costs in our longer-term planning forecasts. With the type of work that can be involved with providing Metro electric service (additional conduit/duct bank, possibly manholes, new and/or upgraded transformers and corresponding overcurrent protection), these amounts vary greatly and can be quite large.

Examples of Metro New Business Projects

1. Upgrades to Serve Existing Building in Year Requested

The following Metro New Business project took place in downtown Flint. The customer's contractor contacted us regarding an existing building that had been largely vacant for several years. The contractor inquired about three-phase electric service for planned HVAC, elevators, and fire pump loads. The customer requested service completed as soon as possible. Working with the customer's contractor, we obtained preliminary loads. The circuit engineer determined that the existing conduit system to the building would not provide adequate service. The completed design included upgrades to the conduit systems, transformers, system protection in the nearby vault, and increased cable size to feed customers.

Plans were submitted to the City of Flint for permits, and bids were sent out for civil infrastructure work, which took several months. We also coordinated with the contractor to maintain existing service during construction, and coordinated with adjacent businesses. This was an involved, complicated, and costly project. It was never included in our longer-term planning, due to the late request relative to the customer's desired date of service.

Figure 55 shows the final construction of the duct bank that was replaced in the alley for the new service.

FIGURE 55 – REPLACEMENT OF THE DUCT BANK IN ALLEY FOR THE NEW SERVICE



2. Upgrade to Serve Existing Building in Future Year

In another example, Mott Community College approached us well in advance about their planned renovation of a vacant downtown Flint building for their new culinary school. For this new project, we made contact with the owner/owner's contractor. Figure 56 below is a sample of an artist rendering that we received for this request as part of the information collected. Through conversations regarding the intended usage, we calculated estimated potential loads and completed preliminary cost estimates. Discussion on the developer's project timeline revealed that this project was approximately one year out from requiring electric service. With that in mind, we included this project in longer-term plans for the next year. However, delays in the developers funding pushed the desired service date to the following year.

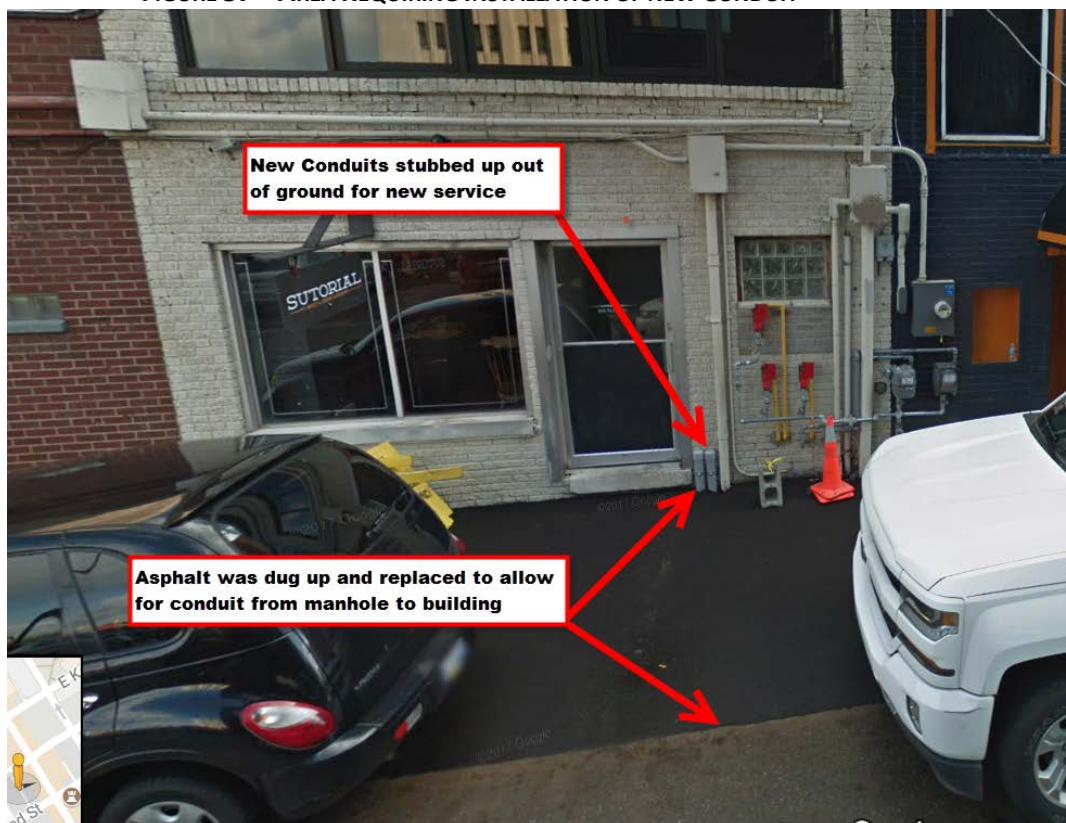
FIGURE 56 – ARTIST RENDERING OF THE NEW MOTT CC CULINARY ARTS INSTITUTE IN DOWNTOWN FLINT



3. Upgrade of Service Requiring Replacement of Deteriorated Conduit

As mentioned above, the scope of metropolitan new business requests can vary greatly depending on the type of work involved. Figure 57 below shows a location where a customer requested new service. In this case, the existing conduit was deteriorated so greatly that pulling new cable through existing conduit was not possible. The area was instead dug up and new conduit was installed to allow new service to be completed.

FIGURE 57 – AREA REQUIRING INSTALLATION OF NEW CONDUIT



Benefits

Metro new business projects are important not only for the customers impacted, but well-planned projects may decrease future outage time for neighboring customers when expansion of buildings occurs or surrounding areas are developed. Additionally, increased new customer connections and load additions provide benefits to our local communities and Michigan through development of jobs and other revenue streams associated with business expansions.

iv. 1.4 Distribution Metering New Business

Our Distribution Metering New Business program consists of capital expenditures for meters purchased that are allocated to the New Business Program based upon the projection of meters that will be utilized in the program (as opposed to those utilized in other programs).

As established by MPSC rules and regulations, our Metering Technology Center (MTC) is accountable on an annual basis for the accuracy, maintenance, and stability of our electric metering (including metering transformers) population, covering all 1.8 million of our electric customers. We track and maintain an accurate metering population through new technology evaluation, meter upgrades, new business, and verification of meter equipment accuracy for all customer classes (residential, commercial, and industrial), all according to our own guidelines and those of the MPSC.

The MTC is required to test a sample of each shipment of new electric meters and metering transformers prior to releasing the equipment for use in the field. Legacy meters are tested for accuracy while smart meters are tested for accuracy and communications functionality as part of shipment acceptance testing.

The proposed five-year plan for this program ensures that we maintain metering accuracy, regulatory compliance, and support for the demand for metering equipment created by customer generated work, including emergent and new business.

Depending on the meter type, each new meter purchase generates a first set credit, on purchase, that is an O&M credit to our Electric Meter Operations (EMO) department. This is reflected in our Meter Services O&M program.

Historically, the MTC has retired about 70% of the legacy meters returned from the field due to obsolescence. During and after our deployment of smart meters, a significantly higher percentage of the new smart meters returned from the field to the MTC will instead be recycled and returned to service, due to the overall reduced age of the metering population. This will create a decrease in the number of units purchased on an annual basis. However, the cost of a smart meter is three to five times greater than the cost of a legacy meter, which will net a higher capital cost for metering equipment overall.

In 2017, we saw an increase in the volume of “troubled” legacy meters that had to be returned to the factory for warranty repair, which has resulted in higher than expected spending in this category. Now that those meters are no longer being deployed, we expect the failure rate to improve and more meters will be recycled. In 2018, we will set new baseline assumptions now that smart meter deployment is complete.

Currently, new electric meter and metering transformer purchases are split between capital programs 1.4 Metering New Business and 2.4 Metering Failures. The 2018 split, which is based on historical levels, is 32% New Business and 68% Demand Failures. These are reviewed annually based on prior-year actuals. Totals can be found in Table 25 below.

TABLE 25 – CAPITAL: DISTRIBUTION METERING

5-Year Capital Plan (all values in \$ millions)								
Metering Programs (Net cost after credits)	Historical			Planned				
	2015	2016	2017 prelim	2018	2019	2020	2021	2022
New Business	5	5	8	6	7	7	7	8
Demand Failures	6	7	12	11	13	13	13	14
Total	11	13	20	17	19	21	20	22
Unit Forecast								
Meters and Metering transformers	Historical			Planned				
	2015	2016	2017	2018	2019	2020	2021	2022
New Business (32%)	4,123	7,631	11,372	11,439	11,766	12,104	12,451	12,809
Demand Failures (68%)	7,332	18,496	24,163	24,308	25,004	25,720	26,458	27,218

v. 1.5 Distribution Transformers New Business

Distribution transformers are part of many new business connections, providing the means to supply electricity to the customer at an acceptable voltage. Our Transformers program consists of the purchase costs of distribution transformers and the associated first set expense.

We build our five-year plan by first estimating the total number of transformers that will be needed across the grid based on historical requirements. We allocate the purchase costs across our various capital programs (New Business, Demand Failures, and Capacity) based on historical allocation of costs across these programs. The current allocation rates for 2018 and beyond are 34% New Business, 12% Capacity, and 54% Demand Failures. Our current five-year plan is based on an estimated 2% annual increase in the number of transformers that will need to be purchased each year.

We are currently redeveloping the budgeting process for our transformers business. Moving forward, we will evolve from using historical spending as the primary driver for our transformer budgets, to a more proactive approach based on the forecasted need for transformers. Our plan is for our Supply Chain organization to drive this budgeting process. Table 26 below was used to forecast capital expenses and the associated first set credits during the 2017 planning process. 2018 will be the baseline year for that budget change.

TABLE 26 – CAPITAL: DISTRIBUTION TRANSFORMERS

5-Year Capital Plan (all values in \$ millions)								
Transformer Programs (Net cost after credits)	Historical			Planned				
	2015	2016	2017 prelim	2018	2019	2020	2021	2022
New Business (34%)	12	9	13	10	12	12	12	12
Capacity (12%)	4	3	5	3	4	4	4	4
Demand Failures (54%)	14	15	21	16	19	20	19	20
Total	30	27	38	29	34	37	35	36
Unit Forecast								
	Historical			Planned				
	2015	2016	2017 prelim	2018	2019	2020	2021	2022
Number of transformers	10,775	10,569	10,780	10,996	11,216	11,440	11,669	11,902

B. 2.0 Demand Failures

The Demand Failures category includes expenditures incurred in connection with customer interruption restoration and the repair or replacement of equipment, including pole top rehabilitation, due to unanticipated or imminent failure. These investments provide both immediate customer benefit via service restoration and longer-term customer benefit due to having new equipment providing service.

Our current plan includes spending between \$145 million and \$153 million in annual capital investments for demand failures. The capital expenditures in this program will depend highly on external factors that result in outages and failures, including weather, falling trees, and equipment failure. For this reason, we must plan for a large range of potential spending needs and ensure that we have the required funding available for years with higher numbers of outages and failures.

In addition, this category includes projections to enhance the credit available for customers who request conversion of existing street lighting to Light Emitting Diode (LED) fixtures. The expenditures for this program support the upgrade of Company-owned luminaires with LED fixtures by reducing the customer up-front contribution in the following cases: (1) conversion and replacement of mercury vapor (MV) street lights, as part of the Company program that started in 2011; (2) replacement of failed High Pressure Sodium (HPS) and Metal Halide (MH) street lights; and (3) installation of new street lights.

Additional details for individual programs can be found in the subsections below.

i. 2.1 LVD Lines Demand Failures

The LVD Lines Demand Failures program includes capital expenditures incurred during customer interruption restoration, or during the repair or replacement of LVD equipment due to unanticipated or imminent failure, including pole top rehabilitation. We respond to failures on the LVD system throughout the state 24 hours a day, seven days a week, 365 days a year. This includes immediate

response to day-to-day failures, capitalization of projects during storm restoration, and response to underground cable failures.

This program also includes planned projects in response to areas on the LVD system that incur emergent reliability issues or material defects identified during inspection. We perform the following types of capital work as part of planned projects:

- Replacing equipment that has reached the end of its expected life such as poles, crossarms, switches (cutouts), and overhead and underground conductors.
- Sectionalizing in conjunction with replacing deteriorated assets, which refers to measures designed to segment the electric distribution system into smaller sections (with fuses, reclosers, or sectionalizers), thereby minimizing the number of customers that are affected by any individual outage (refer to capital program 4.1 LVD Lines Reliability for more information on sectionalizing).
- Relocating lines to more accessible areas, such as moving poles and conductors located behind homes, through trees or in a swampy area to the road side in conjunction with deteriorated assets.
- Upgrading conductors for additional tree protection to tree wire or aerial spacer cable in conjunction with deteriorated assets.

Within this program, we balance our work activity between planned and demand/emergent work. The project completion schedule needs to remain flexible to accommodate the demands of storm event and equipment failures. Table 27 below presents the five-year plan for our LVD Demand Failures program. This program contains investment categories of service restoration activities, street light failures, rehabilitation (including emergent, voltage improvement, and system protection) and security assessment repairs.

TABLE 27 – CAPITAL: LVD DEMAND FAILURES

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Service Restoration Activities (Demand)	38	38	38	39	39
Street Light Failures (Demand)	3	3	3	3	3
Emergent Rehabilitation (Demand)	8	8	8	8	8
Rehabilitation, Voltage Improvement, and System Protection (Planned)	25	25	25	26	27
Security Assessment Repairs (Planned)	5	5	5	5	5
Total	79	79	79	81	82
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Number of Service Restoration orders	840K	840K	840K	840K	840K
Number of Street Light Failures	2,200	2,200	2,200	2,200	2,200
Emergent Rehabilitation Projects	500	500	500	500	500
Rehabilitation, Voltage Improvement, and System Protection Projects	42	42	42	43	45
Security Assessment Repairs	65	65	65	65	65

As shown above, the LVD Demand Failures program has both immediate demand response and planned projects. We base our funding in the program on historical spending on failures and expected rehabilitation costs. Based on historical spending, we forecast that service restoration, street light failures and security assessment repairs will remain flat. Rehabilitation will have an increase to address additional underground cable and overhead conductor replacements.

The five major subprograms under the LVD Lines Demand Failures program are described below.

Service Restoration Activities

We expect an average annual cost of \$39 million for all capital restoration and demand failures activities. On average, we forecast roughly 840,000 service restoration orders per year. This forecast is based on our historical average service restoration activity and costs. Due to the highly emergent nature of this work and the challenges in forecasting, capital spending for this type of activity may fluctuate significantly over the next five years. If storm restoration activities are greater than forecasted, other planned rehabilitation work would need to be correspondingly scaled back.

TABLE 28 – SERVICE RESTORATION ACTIVITIES (DEMAND) 3-YEAR CAPITAL HISTORY

3-Year Capital History (all values in \$ millions)			
Investment Category	2015	2016	2017 prelim
Service Restoration Activities (Demand)	44	31	46

Once we have identified a failure or damage to the system, we must effectively prioritize our response. We do this by categorizing damage by severity as shown in Table 29 below:

TABLE 29 – SERVICE RESTORATION REPAIR PRIORITIZATION

Repair Prioritization		
	Timeframe to Address Following Observation	
	Priority 1 - 24 Hours	Priority 2 - 10 Days (Includes weekends)
Criteria	Service restoration, emergency, public safety, or imminent system integrity problem requiring immediate action to correct the situation or damage. Priority 1 defects are imminent failures or present an immediate threat to public safety and are not subject to reclassification.	Damage is believed to be sufficient to cause public safety or system integrity problem if left unattended beyond 10 calendar days.
Example(s)*	A wood pole which is burnt off or broken or energized conductor with less than acceptable clearance.	Cracked crossarm which could fail, a broken down ground that could contact energized conductor, or a loose down guy which could contact energized conductor.

**Examples provided are not a comprehensive list of the criteria necessary to address damages within given timeframe. Refer to Table 32 in Security Assessments below for a more comprehensive, but not all-inclusive, list of types of findings. Examples are provided for clarity of understanding only.*

We perform the following types of service restoration capital work:

- Failed Underground Cable – When a failure occurs on an underground cable, we have equipment that can pinpoint the location of the fault. If the underground cable is a direct feed, we must identify and fix the fault immediately to restore service to our customers. If the underground cable is looped (has feeds from multiple directions), the fault is isolated and service to our customers is restored.
- Failed Distribution Transformer – Distribution transformers are capable of handling a specific amount of load based on their nameplate rating. Causes for failure include exceeding maximum load levels and device capacity ratings, or degradation of the device over time. When maximum load level is exceeded, it could cause the transformer to fail. When a failure occurs, service is interrupted to the customers that the transformer feeds. This may happen when a customer unexpectedly adds load and does not inform us. It could also happen when all of the customers fed from the transformer are using a large amount of load at the same time as one another (e.g., running air conditioning). These failures are addressed immediately and could warrant

further evaluation to determine if the transformer was adequately sized for the load, which in some cases leads to replacement of the existing transformer with a larger one.

- Car Pole Accident – We have many structures located along the roadway for accessibility. There are instances where vehicles contact a pole structure. If the velocity of impact is high, this typically results in a broken pole and interruption of electric service for the customers that are fed downstream from this location (as well as upstream to our next protective device). When this happens, we immediately assign an available crew to ensure safety of the area, replace the pole, and restring or splice the conductor.
- Broken Crossarm, Pin/Insulator or Pole – Given the elements of the Michigan weather (including wind forces and ice loadings) and life expectancy of our conductor supports, our crossarms, pins/insulators, or poles can occasionally fail. When this happens, electric service may or may not be interrupted, but this can cause a public safety hazard where the wire is left hanging below our normal clearance.
- Failed Overhead Conductor – We have overhead wires that may fail due to age, deterioration, weather, trees, etc. When this occurs, we typically end up with a wire down (grounded). Overhead wires on the ground can pose a major public safety hazard and we address these conditions immediately. To restore the customers and remove the hazard, the line workers will either reconductor the wire if it is a short span or splice it back together.

Street Light Failures

This demand program is used to replace failed street light fixtures (not burnt out bulbs). Our current plan is to spend \$3 million per year to replace approximately 2,200 light fixtures annually based on historical replacements. Similar to service restoration, we respond to replacing failed street light fixtures as they fail.

TABLE 30 – STREET LIGHT FAILURES 3-YEAR CAPITAL HISTORY

3-Year Capital History (all values in \$ millions)			
Investment Category	2015	2016	2017 prelim
Street Light Failures	3	3	3

Emergent Rehabilitation

During the year, conditions evolve and issues arise that place the system out of normal configuration and accordingly require work on the system. Our plan includes spending \$8 million per year to complete approximately 500 emergent rehabilitation projects. These investments will address the following issues:

- Underground Cable Repair – After a fault is isolated and customers are restored, the underground cable is no longer looped (i.e., no longer has feeds from multiple directions) and needs to be put back into service. If this is the first time the section of line has faulted, we typically come back within the next 30 days to expose the fault and splice it. If we leave this faulted section isolated for a long period of time, we would run the risk of having another failure in this area and we would no longer have a way to restore service to our customers from that direction. If this section or area has experienced multiple faults or the vintage of the cable

warrants replacement, we will develop a project for the following year to replace the faulted section of cable and in some cases, adjacent sections of cable as well.

- Failed Equipment or Overhead Conductor (Wires) – When equipment, such as regulators or reclosers, is not functioning properly, our operators check to see if maintenance can be performed to restore it to normal condition. When maintenance is not possible, the equipment is replaced with like equipment to put the system back to normal. This may require equipment that has long lead time materials.
- Underground Padmount Equipment Inspections – Every year, padmounted equipment is visually inspected around the exterior for any signs of oil leaking or holes that expose electrical components. When found, the equipment is replaced and any environmental issues are mitigated. On average, over the last five years, we have identified 325 pieces of equipment annually that required repair or replacement.

Rehabilitation, Voltage Improvement, and System Protection

Each year, the Reliability Steering Committee (see Section IV for more details on this committee) determines a strategy to maximize the reliability benefit to customers by reducing the number of interruptions through long-term proactive investments. Our five-year plan includes \$25 million of spending in rehabilitation to fund the completion of 42 projects in a year (approximately \$600,000 per project). These projects do not reduce SAIDI from present level, but if not addressed, these targeted defects will cause outages and increase SAIDI. The investments in this category include:

- Underground Rehabilitation – This program focuses on the reduction of interruptions from end-of-life underground cable. The majority of the cable at end of life currently is the 15 kV cable. There are an estimated 2,500 miles of 15 kV cable that will need to be rehabilitated in the long term. To start replacing 93 miles per year, it would require incremental spending of \$24 million. The Reliability Steering Committee decides how many miles of underground cable will be targeted for replacement. The program manager selects specific locations by reviewing the areas where we expect the highest reliability benefit. Table 31 shows the current state of the underground system and the number of miles installed between 1968 and 1985.

TABLE 31 – UNDERGROUND REHABILITATION ESTIMATED MILES

Underground Rehabilitation		
UG Primary Conductor	Estimated Miles of Conductor (System)	Estimated Miles of Conductor (1968 – 1985)
1/0 kcmil	9,600	3,700
350 kcmil	400	200
750 kcmil	700	200
All UG Primary	10,700	4,100
<ul style="list-style-type: none"> • Approximately 1,400 miles of 15 KV HMWPE • Approximately 1,100 miles of 15 KV XLPE 		

- Failed Voltage Improvement Device – In the event of a line regulator (or other voltage improvement device) failure, we determine if the device must be replaced immediately or if we can defer replacement until a later date, with the circuit engineer evaluating how the system

would be affected without that specific device. In some cases (when system loading levels are relatively low), we can forego the replacement until the following year, considering it in the following year's projects. If the device is not replaced when the analysis deems necessary, this can cause power quality issues (low voltage) for our customers. The Reliability Steering Committee decides how many locations of voltage improvement will be targeted for replacement. The locations are determined based on where we expect the highest reliability benefit.

- Overhead Conductor Replacement – Once an overhead wire has been spliced, it becomes a weak point. When it has been spliced multiple times, it becomes weaker and the conductor span needs to be replaced. The Reliability Steering Committee decides how many miles of overhead conductor miles will be targeted for replacement. The locations are determined based on where we expect the highest reliability benefit.
- System Protection Coordination and Reach – During upgrades on our HVD or LVD system, the protective devices will no longer coordinate or reach. Reach describes the zone of protection, or area, we expect a fuse, recloser or breaker to open for faults within a minimum period of time. Coordination is the systematic application of devices to ensure the clearing of permanent faults by only the nearest upstream protecting device. The Reliability Steering Committee decides how many protective device sections will be targeted for upgrades. The locations are determined based on where we expect the highest reliability benefit.

Security Assessment Repairs

The LVD overhead line inspection program is completed on a six-year cycle. The overhead line inspection program evaluates all equipment on a structure, including the pole, through a visual inspection process. The circuits are assessed by completing driving inspections to identify public safety hazards along with failed, end-of-life, defective, and obsolete equipment. We estimate that 65 circuits will have security assessment repairs, based on \$5 million of annual spending (approximately \$77,000/circuit). To address all of the priority 3 or 4 anomalies (see definition below) inspected in previous years, it would require incremental spending of approximately \$9 million per year, or \$45 million total over five years. The Reliability Steering Committee will determine the number of circuits to target each year, in order to maximize the reliability benefit for our customers.

During the security assessment, the construction prioritization criteria are used and addressed in the timeline described in Table 29 above for Priority 1 and 2 findings. In addition, Priority 3 and 4 anomalies are typically repaired or replaced within 2 years of the inspection year.

Table 32 below presents the types of hazards found during LVD Security Assessments. The hazards are listed by the priority code for the anomaly.

TABLE 32 – LVD SECURITY ASSESSMENT HAZARD CODES

Code	Description
P1 - Public Safety	
P1A	Safety Code Violation
P1B	Unusual Public Hazard
P2 - Imminent Failure	
P2A	Floating Phase / Neutral
P2B	Broken / Severely Cracked Crossarm
P2C	Damaged / Cracked Cutout
P2D	Damaged / Cracked Insulators
P2E	Pole: Needing immediate Replacement
P3 - Failure Expected Before Next Inspection (Less Than 6 Yrs)	
P3A	Pin Pulling from Crossarm / Pole
P3B	Cracked Crossarm
P3C	Broken Guy - Leaning Pole
P3D	Pole: Damaged
P4 - Heightened Risk of Failure	
P4A	Broken/Missing Crossarm Braces
P4B	Failed Arrester
P4C	Broken Guy - Non-Leaning Pole
P4D	Damaged Equipment (Transformers, Reclosers, Etc.)
P4E	Lightning/Flashover Burn Marks
P4F	Poorly Sagged Line
P4G	Pin Through Crossarm

Planning Process

We use a number of inputs to identify capital spending needs for demand failures programs. We use the results of the Reliability Analytics Engine (RAE), a decision-support tool used to help inform the investments in LVD Lines Reliability, to analyze if poor performance is due to deteriorated equipment. Refer to capital program 4.1 LVD Lines Reliability and Appendix F for additional details.

To further understand the reason for the performance data from RAE, circuit engineers will use OMS Archive to investigate the location and cause of the interruptions. OMS tracks failure data across the distribution grid. Causes for interruptions will be coded (e.g., as equipment, trees, weather) by the field operations during restoration. Also recorded is a code for the type of equipment that is associated with the interruption – such as overhead conductors, underground cables, poles, and cutout failures.

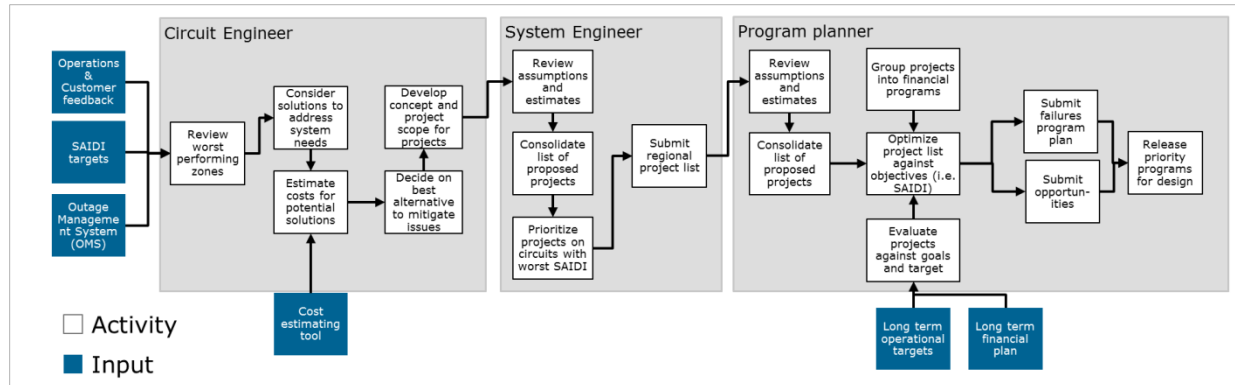
We also collect data through our Field Operations organization. For example, we may have locations that Field Operations have frequently visited to restore service for a failed underground cable in the same subdivision. This team relays this information to system planners so they can investigate and create a concept project for a full replacement of the underground cable and possibly live front transformers or padmounted switching equipment in that subdivision if necessary.

Based on the reliability (RAE and OMS) and Field Operations data, the Reliability Steering Committee determines a strategy to address issues found. Projects are developed, evaluated, and prioritized in order to have the highest impact on reliability.

Project Prioritization and Selection

For planned work, LVD projects are submitted and reviewed in a layered approval process shown in Figure 58. These layers include the circuit engineer, the system engineer, and the program planner.

FIGURE 58 – LVD DEMAND FAILURES PLANNING PROCESS



This three-stage approval process for planned LVD investments is outlined below:

- The circuit engineers will identify a potential failure or reliability issue. Once identified, they will evaluate outage history from OMS to decide which circuits or zones to target. The circuit engineer will evaluate multiple alternative proposed solutions for each area of concern (e.g., pole top rehab, upgrading equipment, or replacing deteriorated equipment) to determine the best solution for the customer, given the cost and resource availability. The solution will consider the current site conditions and if it needs to be relocated. For example, a line may be relocated to the road instead of replacing failed poles located behind a residence to make the future location more accessible while still removing the deteriorated asset. This is also done in conjunction with forestry line clearing. After the analysis is complete, the circuit engineer will develop alternatives and submit the best solution as a proposed concept.
- The system engineer will then review the submitted concepts for feasibility and validate the assumptions (including cost estimates) in the solution. After the system engineer is satisfied with the solution, the concept is approved.
- The project is then submitted to the program planner for consideration. Projects are prioritized using an evaluation of costs and benefits based on the number of customers impacted, public safety concerns and number of interruptions. The program planner takes inputs from circuit and system engineers, and based on their experience and knowledge of the system including data analysis outputs, evaluates different projects based on the availability and location of resources and total program budget. Projects that will have the greatest benefit to the grid and meet long-term investment requirements are sequenced for work and built.

Failure projects are planned for the following year during the preceding summer, starting in June and finishing in August. The key milestones measured to ensure completion are listed below:

- Strategy and circuit rankings are submitted to the system engineers and circuit engineers to start developing concepts.
- Circuit engineers finish concept submissions for system engineer review and approval.
- Regional system engineers finish reviews for LVD program planner (or planning director) approval.

- LVD program planner (planning director) sends final approval to system and circuit engineers.
- System and circuit engineers release concepts to Design, Resource Management, and Forestry.

Projects may also be submitted in the current year for construction and evaluated through the same layered approval process. However, the majority of the planning process occurs in the current year for the following year construction. In order to best benefit customers and use timely data, the planning process is completed closer to the time that the projects are to be constructed. Planning these types of investments too far in advance could result in using outdated data.

Examples

Below are four examples of projects that fall under planned rehabilitation, voltage improvement, and system protection. Refer to Appendix E for a more detailed project listing for LVD Lines Demand Failures.

- INSP17 RYNO/MORENCI – The ground inspection on Ryno/Morenci identified 55 locations on three-phase, 32 locations on open-wye, and 170 locations on single-phase. These locations include work on pole top equipment, sectionalizing, and pole replacements (as outlined above in security assessments). The 2,215 customers on this circuit will benefit from the improvement.
- REHAB16 BIRCHWOOD/KENMORE. Load Concentration Point (LCP) 481 – The 15 kV primary cable has failed three times. The line serves 55 commercial customers, including medical facilities. The project will replace 5,800 feet of three-phase 1/0 cable.
- In addition, there are projects that are selected outside of the traditional prioritization process described above. An example of this is SCDY18 SAUGATUCK/DOUGLAS. This project was added for apprentice training to replace open wire secondary with triplex.
- We have reprioritized projects in order to gain the highest SAIDI benefit across the system. An example of this is REHAB16 WEALTHY/NORTHWEST. Due to the impact on funding from hours worked for storm restoration being higher than forecast, this project was consequently moved from 2017 to 2018.

Benefits

This program and its funding are essential for both restoration of service to customers, and to address imminent failure conditions that could result in interruptions to customer(s) or create unacceptable system operating conditions. Service restoration investment provides a future reliability benefit to customers, by improving the condition of system equipment. The emergent rehabilitation investments provide a similar reliability benefit, by reducing the probability of future failures. In addition, the Underground Padmount Equipment Inspections reduce the probability of oil leaks, providing an environmental benefit.

The remaining spending (rehabilitation, voltage improvement, system protection, and security assessment repairs) is planned and targeted towards areas of the system most likely to fail. By reducing outage frequency, these investments provide a large reliability and public safety benefit. In addition, by replacing or rehabilitating equipment before failure, it allows the work to be completed in a more economical manner.

ii. 2.2 LVD Substation Demand Failures

The LVD Substation Demand Failures program addresses damaged or failed LVD substation equipment or components that we evaluate as close to failure. The capital expenditures in this program include investments in equipment or components, typically replacements, which in some cases also result in capacity and equipment upgrades. These investments reduce or avoid customer outage frequency (SAIFI) and reduce the number of emerging repetitive outage customers, as well as the customer outage durations as represented by CAIDI and SAIDI.

LVD Substation Failure projects generally consist of the following types of investments:

- Replacing failed equipment/components
- Replacing failed structural components
- Replacing equipment/components that have been deemed imminent failure
- Replacing equipment/components that have been identified to have excessive failure rates
- Repairing damaged or failed mobile substations

Due to the emergent nature of this program, it is difficult to project exact costs for any given future year. Our five-year plan is to spend \$14 million to \$15 million per year on LVD substation demand failures. This includes the replacement of 10 Allis Chalmers transformers in 2018 and 15 units per year in 2019 through 2022.

TABLE 33 – CAPITAL: LVD SUBSTATION DEMAND FAILURES

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Allis Chalmers Substation Transformer Replacements	6	9	9	9	9
Reclosers	1	1	1	1	1
Regulators	3	2	2	2	2
Other Transformers	2	2	2	2	2
End-of-Life Substation Rebuild	2	1	1	1	1
Total	14	14	14	15	15
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Allis Chalmers Substation Transformer Replacements	10	15	15	15	15
Reclosers	30	30	30	30	30
Regulators	90	60	60	60	60
Other Transformers	3	3	3	3	3
End-of-Life Substation Rebuild	2	1	1	1	1

Planning Process

The majority of work in this demand failures program is reactionary, decided on after an event has occurred or determination of an imminent failure. Based on the past five years of history, we experience approximately eight LVD transformer, 30 recloser and 90 regulator failures per year. We identify imminent failures by monitoring and tracking LVD substation equipment and components utilizing various means of analysis such as Dissolved Gas Analysis (DGA) and Infrared (IR) recordings. These inputs help to identify specific locations to target corrective action based on probability of an unplanned event, and to prioritize projects that will deliver the greatest reliability impact based on specific metrics (e.g., SAIDI, SAIFI, and CAIDI). Proactively replacing deteriorated equipment that we have deemed as an imminent failure in advance of an actual equipment failure is more economical as it typically avoids overtime and potential customer outages.

As an example, mid-20th century vintage Allis Chalmers substation transformers have experienced failure rates of roughly two times that of other transformers. Allis Chalmers, a transformer manufacturer, produced small substation power transformers in the mid-20th century at their Pittsburgh, Pennsylvania facility, and those transformers have a design deficiency associated with the top clamping structure. The

key purpose of the clamping structure is to prevent winding movement. This deficiency results in an inherent weakness of the transformer to withstand the forces accompanying certain magnitude low side faults. Winding movement typically results in electrical shorts and arcing, which lead to excessive heating, creation of combustible gasses and eventual failure of the transformer. The photo below is of an Allis Chalmers transformer failure at Gladwin Substation. Note the two bulged and deformed failed lower windings on the left and middle phases.

FIGURE 59 – AC TRANSFORMER FAILURE AT GLADWIN SUBSTATION



We purchased approximately 209 Allis Chalmers units with this design deficiency between approximately 1936 and 1970. 99 of these units remain in-service in their original design, and another 27 rewind units still in-service are considered at risk of developing the condition, for a total of 126 units. After studying this issue, in 2016 we established a replacement plan to mitigate future failures and interruptions to our customers. Allis Chalmers replacements are prioritized based on DGA and IR measurements, particularly looking at those with General Electric (GE) type U bushings and our ability to take the bank out of service based on customer and system impact. The GE type U bushings are an influencing factor as they are known throughout the industry to have a high failure rate.

IR inspections are the best way to detect when excessive heat, the leading indicator of this type of failure, begins to manifest. The condition is indicated by a warmer band typically registering in the lower one-third of the transformer tank. We perform an IR inspection annually on all Allis Chalmers transformers.

FIGURE 60 – INFRARED PHOTO OF FAILED TRANSFORMER AT GLADWIN

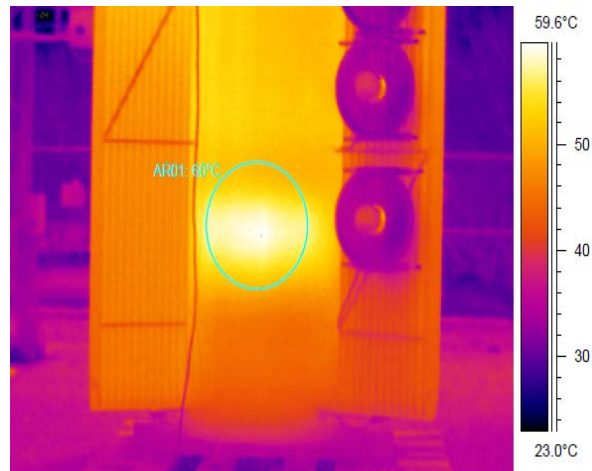


FIGURE 61 – FAILED TRANSFORMER AT SHANTY CREEK SUBSTATION



When the IR inspection detects a heating band indicating development of this condition, we put the units on a quarterly DGA monitoring schedule and they are given higher priority for replacement consideration based on the analysis of both the DGA and IR together.

Our current approach is to replace these Allis Chalmers transformers at a rate of 10–15 per year as outlined previously, at a cost of approximately \$600,000 per unit.

The deficiency and reliability risk of these Allis Chalmers transformers is well documented and understood. Substation transformer failures are long in duration (8-16 hours) and impact an average of 2,500 customers, representing approximately 0.6 to 1.3 SAIDI minutes per failure. Additionally, substation transformers are long lead time items, which take approximately 8–12 months to procure. The high customer impact and unit long lead time coupled with the propensity of continued degradation from exposure to normal low side faults creates a necessity to expedite replacement of these Allis Chalmers transformers.

Project Prioritization and Selection

We promptly address failures to minimize impact on customer minutes by maintaining adequate substation equipment, material inventories and mobile fleet. We identify imminent and end-of-life projects by monitoring and tracking substation equipment via visual inspections, DGA, and IR recordings. We prioritize projects to proactively address replacement of deteriorating equipment as identified.

Additionally, we consider replacement based on known industry equipment/component defects and trend data that indicates degrading equipment condition, but has not reached a concern of imminent failure.

Projects that have been identified as progressing toward imminent failure are monitored and re-prioritized into the schedule to address immediate needs. Equipment and components that have been identified as prone to failure may be included in other LVD capacity and reliability substation projects to maximize efficiencies and avoid additional crew deployments and mobile sets.

Priorities can change over time. For example, transformer replacement projects at Fennville, Martin, and Delton were brought forward into 2017 based on a concern of imminent failure, and the Watkins, Cooley, and Portage transformer replacement projects, which were less urgent, were delayed into 2018 to accommodate advancement of these projects.

Benefits

Maintaining adequate substation equipment, materials inventories, and mobile fleet to promptly address failures minimizes the impact on customer outage minutes. Addressing degrading equipment allows us to avoid imminent failure, reducing the potential of long-term outages and restoration delays. This helps us improve reliability, as shown in the Allis Chalmers example above. In addition, by replacing or rehabilitating equipment before failure, it reduces unit cost.

iii. 2.3A HVD Lines Demand Failures

The HVD Lines Demand Failures program includes capital expenditures incurred due to customer outage restoration and the repair or replacement of HVD line equipment due to unanticipated or imminent failure. Numerous issues can cause these failures, such as lightning strikes, trees, equipment deterioration and car pole accidents. We conduct inspections and evaluation on an ongoing basis, but not all failures can be predicted with certainty. Therefore, we constantly update and adapt the active work in progress for this program to the needs of our system and customers. We complete the vast majority of projects as quickly as can be scheduled after identifying them, following temporary repairs to quickly restore service to customers. We base our funding for this program on historical spending for failures and expected rehabilitation costs. However, we recognize that funding will fluctuate as we

respond to customer requirements. As part of our investment planning process, we aim to ensure that the safety and reliability of our customers is first priority.

We project to spend \$9 million to \$10 million per year in this program over this five-year plan, in line with our historical spending in this category of \$9.9 million, \$8.6 million, and \$11.2 million in years 2015, 2016, and 2017, respectively. This program consists of the planned activity in the table below as well as the costs associated with the unplanned needs of our system.

TABLE 34 – CAPITAL: HVD LINES DEMAND FAILURES

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Pole Replacements	4.5	5.2	5.5	5.6	5.9
Pole Top Assembly Replacements	2.3	2.6	2.6	2.7	2.8
Switch Replacements including MOAB	1.8	1.6	1.1	0.9	0.7
Miscellaneous Other Replacements	0.5	0.7	0.7	0.8	0.7
Total	9.0	10.0	10.0	10.0	10.0
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Pole Replacements	267	293	280	290	300
Pole Top Assembly Replacements	400	443	420	437	447
Switch Replacements including MOAB	27	20	17	13	10
Miscellaneous Other Replacements	27	30	27	30	27

Planning Process

We determine work needs in this program based on real-time HVD line component failures or anomalies, assessing them by severity or risk to the system.

The most urgent HVD line component failures are those resulting in customer outages, making them immediate action items. We typically identify these failures by alarms from our SCADA system in our System Control Center, and expediently dispatch system operators and/or crews to locate the electric fault and restore power to our customers. Our System Protection Engineering group is often consulted during HVD outage events and obtains data from substation digital relays to assist in identifying the location of the fault. This fault locating process allows us the ability to dispatch crews, often to a line structure within a few spans of the actual fault, reducing patrol time. Calls from customers or other third parties into the customer contact center may also assist in locating the fault if someone saw, heard or have other insight on the fault location. On rare occasions when patrol ground patrol cannot locate a fault, we may dispatch a helicopter to assist in patrolling the line. Once we determine the fault location, we quickly perform repairs as safely as possible. After the fact, we prepare and record an incident report.

Less urgent HVD line failure situations occur when a failure trips off a line but only causes either momentary or no outages to customers, due to the line configuration (usually looped). We handle such faults similarly to customer outage faults, but due to a lower level of urgency, these do not always

require an immediate response. For example, if no customers are experiencing an outage, we may postpone finding the location of this type of fault until daylight (if the fault occurs at night) when we can patrol the line more safely and make repairs more efficiently.

The third type of problem is a “trip and reclose” situation. In this case, a line relay senses an electric fault and trips (de-energizes) the line. After a set period of time (usually a few seconds), the relay senses a signal to re-energize the line. If the cause of the fault no longer exists (such as a branch that brushed against the line temporarily), the line will remain energized. In such cases, we patrol the line to determine the cause of the fault, similar to the above scenarios, and make repairs if necessary.

Some component failures do not cause a line to trip at all but decrease the integrity of the line and usually increase the risk that the line will trip or fail in the future. Examples include floating phases (when a phase wire becomes unsecured from an insulator), broken insulators, broken crossarms, broken poles, or broken static wires. We often identify these anomalies through routine annual helicopter patrols, biannual ground patrols (performed on HVD lines which cannot be overflowed due to population density or other reasons), or through calls from customers, employees, or other third parties. We assign such component failures a priority and generate orders for the repair or replacement of the component in a time frame consistent with the risk posed.

Regular inspection of equipment helps determine if assets are in need of repair or replacement, ensures components will operate as intended when called upon, and maximizes the value of those assets over their lifetimes. Equipment near the end of life can be replaced before it fails. Such inspections and replacements are more economical, safer, and can save customer outage minutes.

The table below shows the four priority levels and the guidelines for repair timelines.

TABLE 35 – HVD SYSTEM PATROL FINDINGS CRITERIA

HVD System Patrol Findings Criteria		
Priority	Description	Repair Timeline
1*	Imminent Failure	24 hours
2*	Highly Likely Failure	5 to 10 days
3*	Likely Failure	4-6 months
4	Monitor	Repair not required but condition tracked
*SAP repair orders are created for all Priority 1, 2 and 3 findings only		

Additionally, inspection and evaluation of HVD lines allows us to identify equipment near the end of life so that we can replace those items before they fail and cause an outage to customers or reduce system operability. Such inspections and proactive replacements are more economical, safer, and can save customer outage minutes.

Inspection Programs

We have four key inspection programs which help inform us on potential actions to address lines failures.

Pole Inspection Program

We inspect HVD poles on a 12-year cycle as described in O&M program 2.1 HVD Lines Reliability. A contractor performs visual inspections, sonic inspections and bore testing on all poles that are 11 years old or older along line sections that we specify. The contractor tests poles from the ground line to six feet above the ground line. If the sonic test indicates decay, visual decay, or insects present, a bore test is performed and the shell thickness is recorded. For poles indicating decay or voids near ground level, a bore test is performed at 45 degrees or below the ground line. Poles with a shell thickness less than the standard depending on the pole circumference, as shown in Table 36 below, are recommended for replacement and receive a red tag. Poles with ground line surface decay that reduces the original circumference by 2” or more or with internal decay or with insect infestation are treated with wood preserving products. Red tagged poles are not treated with wood preserving products. The bore test criteria that we provide our contractors are shown below.

TABLE 36 – BORE TEST CRITERIA TO IDENTIFY WOOD POLE REPLACEMENT CANDIDATES

Wood Pole Bore Test Criteria		
Original Ground Line Circumference (Inches)	Reduction in Ground Line Circumference due to Exterior Decay (Inches)	Minimum Shell Thickness (Inches of Solid Wood)
25 -34	0 – 3	2.00
	Over 3 – Replace	-
34 -39	0 – 3	2.50
	3 – 4	3.00
	Over 4 – Replace	-
39- 45	0 – 3	3.00
	3 – 4	3.50
	Over 4 – Replace	-
45 -55	0 -1	3.00
	2 – 4	3.50
	4 – 5	Solid Heart
	Over 5 – Replace	-
55 - 65	0 – 3	3.50
	3 – 6	Solid Heart
	Over 6 – Replace	-

Notes:

1. Column 1: Original ground line circumference when installed.
2. Column 2: Reduction in ground line circumference after scraping away decayed wood.
3. If the reduction in ground line circumference falls into a range in Column 2, there must be at least the amount of solid shell wood that is listed Column 3.

Visual inspection can be used to identify rejected poles where there is severe decay at the top of the pole or where the pole is split or has large voids above chest height or other similar conditions. We may recommend replacement in case of severe decay at the top of the pole following visual inspection.

Helicopter Inspection Program

The results of the helicopter inspection program as described in O&M program 10.0 Engineering and System Planning are a significant source of information to determine immediate action items. As an example, a flight conducted with our recently acquired corona camera identified an insulator on one of our 46 kV lines that was emitting a corona signature prompting an immediate replacement of the insulator to avoid a potential outage to the line and customers.

FIGURE 62 – SCREENSHOT FROM CORONA CAMERA SHOWING INSULATOR WITH CORONA SIGNATURE



Biannual Ground Patrol

For safety reasons, we cannot fly over approximately 400 miles of the HVD system, because it is difficult to land quickly and safely in the event of an emergency. Most of these “no-fly lines” are in urban areas. To inspect these lines, we complete biannual ground patrols, which may include infrared and/or corona inspection using handheld cameras.

MOAB Testing

MOABs allow us to sectionalize HVD lines and restore a portion of the customers who would otherwise be affected by a line outage. The controls of the MOABs require power to operate and since they are called on to operate when the line they are attached to lose power, batteries provide control circuit power. Periodic battery replacement ensures that power is always available to operate the device. MOABs are tested annually to ensure they are in proper working order and the batteries are replaced every three years, or sooner, as needed.

FIGURE 63 – TYPICAL 46 kV MOAB SWITCH



Project Prioritization and Selection

We determine necessary projects based on real-time failures or anomalies and those discovered through our inspection programs. Actions range from simply monitoring to immediate equipment replacement. Engineers and operating personnel take the safety of employees and the public, inspection results, and system operability threats into account to determine the most prudent course of action.

In general, if the HVD line equipment failure or anomaly causes an outage to customers, or its potential failure poses an immediate and intolerable electric system operating condition, we will immediately address the issue through this failures program. If the equipment failure or anomaly is not currently causing a customer outage, or its potential failure poses a nominal electric system operability condition, we will address it at a future point in time either through this failures program or through our HVD Lines Reliability program.

Benefits

This program and its funding are essential for both restoration of service to customers, and to address imminent failure conditions that could result in outages to customer(s) or create unacceptable system operating conditions. This program works in conjunction with the lines pole inspection program and helicopter patrol program that identify the HVD line anomalies that this capital program corrects. Our analysis shows that each helicopter patrol saves approximately seven million customer minutes (3.85 SAIDI minutes), based on an average of 24 Priority 1 and Priority 2 anomalies identified per patrol. In 2017, 58 Priority 1 and Priority 2 anomalies were found, indicating even more customer minutes saved due to the helicopter inspections.

Data from 2012 through 2017 indicate an average of 22 HVD pole failures occur per year, 40% of which result in outages with associated customer minutes. In 2017, we replaced 25 poles identified as Priority 1 by the pole inspection program. Based on these numbers and an average of 0.46 SAIDI minutes per outage in 2017, the pole replacement program saved approximately 4.6 SAIDI minutes.

In addition to the reliability benefits, replacing equipment with an imminent risk of failure provides a public safety benefit and allows the equipment replacement to be performed in a more economic manner.

iv. 2.3B HVD Substations Failures

The HVD Substations Failures program includes capital expenditures incurred due to customer outage restoration, and the repair or replacement of HVD substation equipment due to unanticipated or imminent failure. This program also covers replacement of known failing sulphur hexafluoride (SF₆) breakers identified by SF₆ gas tests. We use periodic Transformer Oil Analysis (TOA) to identify those HVD transformers with the highest risk of failure prior to failure occurring. The table below summarizes our expected capital spending for the five-year plan period.

TABLE 37 – CAPITAL: HVD SUBSTATIONS FAILURES

5-Year Capital Plan (all values in \$ millions)					
	2018	2019	2020	2021	2022
Total Spending	7	7	6	7	7

The mix of projects for any given year will vary greatly depending on a number of criteria including actual failures, risk posed by identified anomalies and number of replacements identified by inspection programs. Budgeting forecasts are typically based on historical averages. Below is a breakdown for 2017 which provides insight on how the values for 2018 through 2022 were established.

TABLE 38 – HVD SUBSTATION FAILURES PROJECTS (2017)

HVD Substation Failures Projects (2017)			
Equipment	Number of Projects	Avg Cost/ Project	Comments
Power Transformers	5	\$ 351,000	The HVD transformer material charges were not realized in 2017. Three of the unit charges will be realized in 2018.
Facilities	25	\$ 38,400	Fence/gate replacement, driveway replacement, upgraded animal mitigation, substation structures
Circuit Breakers	20	\$ 71,700	
Capacitors	20	\$ 9,980	Usually multiple units per order
Switches	18	\$ 55,500	Usually multiple units per order
Bushings	18	\$ 53,000	Usually multiple units per order
Station Batteries/Chargers	14	\$ 16,300	
Lightning Arresters	13	\$ 6,520	Usually multiple units per order
Fuses	8	\$ 15,900	Usually multiple units per order
Regulators	7	\$ 43,700	Strategic Customer substations
Voltage Transformers	3	\$ 19,500	

Slightly over 150 substation demand orders (with a total cost of \$6.7 million) including HVD power transformer replacements, circuit breaker replacements, bushing replacements, switch replacements, fence replacements, high side lightning arrester replacements, station battery replacements, and capacitor replacements were performed in 2017. While there is no typical mix of projects in a given year, the above table is a representative example. Slightly fewer than 100 HVD substation projects were completed in 2016 under this program.

Planning Process

Real-time substation component failures or anomalies are key program inputs. Additionally, periodic evaluation of substation equipment allows for identification of equipment near the end of life so that those items can be replaced before they fail and cause an outage to customers or reduces system operability to an intolerable level. Such inspections and proactive replacements are more economical, safer and can save customer outage minutes. Lastly, NERC compliance standards require maintenance on certain components and are another source of input in this program’s planning process.

The cadence of the HVD substation equipment evaluation and inspection is found in the table below.

TABLE 39 – HVD SUBSTATION INSPECTION CADENCE

HVD Substation Inspection Cadence		
Inspection Task	Cadence	Components Checklist
All Station Components	Monthly	Visual Inspection
Entire Substation	Annually	Infrared Inspection of entire substation
Protective Relays and Communication Systems	Depends on relay model & failure history	Maintenance & Testing Performed
Station Batteries	Monthly	Voltage Check
	Annually	Equalization
	Annually	Specific Gravity Reading
	4 Years*	Complete Inspection
Power transformers	Annually	Diagnostic Dissolved Gas Analysis of Transformer Oil**
		Periodic combustible gas test/dissolved gas analysis tests
Motor Operated Air Break Switches (MOAB) (decoupled)	Annually	Testing
	4 Years	Battery replacement
NERC Circuit Breakers & Switches	Annually	Testing
NERC Current and Voltage Sensing Devices	10 Years	Inspection
*Or periodically based on battery condition once battery reaches 15+ years in age		
**For Power transformers with Load Tap Changers Only		

Project Prioritization and Selection

We take action based on real-time failures or anomalies, or those discovered through our inspection process. These actions can range from simple monitoring to an immediate equipment replacement. Engineers and operating personnel take the safety of employees and the public, inspection results, and the system operability threat into account to determine the most prudent course of action.

Inspections and evaluation are ongoing and not all failures can be predicted with certainty; the active work in progress for this program is fluid. Promotion of projects is relatively rare as the vast majority of projects are executed as quickly as can be scheduled once they are identified following temporary repairs as necessary. Additionally, if failures or imminent failures that must be addressed exceed the annual failures program funding, we may consider shifting funding from other programs, due to the critical nature of this work. Some criteria that are utilized in these evaluations are:

- **Infrared inspections** – 100% (one-year cycle) of HVD stations and 50% (one-year cycle) of LVD stations are inspected annually. Inspections are performed by our employees in our Field Technical Services Group. Each employee is certified in infrared thermography. Tests are scheduled and results are captured in the Cascade substation asset management program. Identified anomalies are assigned a priority (1 through 4) based on a point system that takes into account the type of substation (HVD, single transformer LVD, multiple transformer LVD, or strategic customer), recorded maximum circuit amps in the past two years, temperature rise above similar equipment, wind speed, and type of equipment. Priority 1 signatures require an action plan to be in place within two working days, Priority 2 within 30 days, Priority 3 within three months and Priority 4 within one year.
- **Dissolved Gas Analysis** – HVD transformers are tested on a two-year cycle; all Load Tap Changer (LTC) transformers are tested on a one-year cycle; LVD transformers are tested on a six-year cycle. Demand tests are completed on a more frequent basis if analysis quality is trending to indicate an issue or imminent failure. DGA tests are sampled and analyzed by our Chemistry department. Samples are tested for multiple gasses including ethane, ethylene, methane, and acetylene. Results are then fed into a software program called TOA4, from Delta-X Research. The software identifies the type of issues the transformer is experiencing (based upon the mix of gasses) with a high degree of accuracy and assigns a priority code to the sample. TOA4 results are stored in Cascade. Priority 4 samples are categorized as imminent failure and are scheduled for replacement under this program.
- **SF₆ inspections** – Gas quality testing is on a three-year test cycle. Some demand tests are completed annually if the gas quality is trending to indicate failure. Gas in SF₆ breakers is tested for moisture content, SO₂ content and gas purity by the Field Technical Services group. Breakers with results outside the minimum standard for SO₂ or gas purity are tabbed for replacement under this program. Breakers with high moisture content are scheduled for a gas drying procedure.

All of the above methods have proven over time to be effective in identifying the imminent failure of equipment, resulting in a proactive action such as replacement and significant SAIDI savings.

For some HVD substation equipment (switches, voltage transformers, current transformers, and capacitor banks), this program is primarily reactionary, replacing equipment that has failed as inspection programs for this equipment have been discontinued. Some imminent failures are identified through monthly visual patrols performed by our Substation Operations group and are replaced through this program prior to failure. Some equipment (transformers, station batteries, gas circuit breakers, and transformer bushings) are monitored by various programs through our Field Technical Services and Substation Reliability Engineers organizations and are replaced prior to failure through this program.

Timing

In general, if an HVD substation equipment anomaly is causing an outage to customers or if its potential failure poses an immediate and intolerable electric system operating condition, it will be addressed immediately through this failures program. If the equipment anomaly is not currently causing a customer outage or its potential failure poses a nominal electric system operating condition, it will be addressed at a future point in time through this failures program, or alternatively through our reliability program. Some projects, such as HVD transformer replacements with longer lead times may be delayed if other replacements are identified that are determined to have a higher risk of failure or have failed in service.

Benefits

This program and the funding for it are essential, as it is utilized to either restore service to customers or address an imminent failure condition that could result in either an outage to customers or create an unacceptable system operating condition.

An analysis of 2017 data indicates that due to designed redundancies only about 26% of HVD substation equipment failures result in customer outages. The average HVD substation outage that does put customers out of service results in 0.21 SAIDI minutes. Some HVD substation equipment failures have a much higher SAIDI impact than others. For example, breakers which protect a transformer bank or HVD line have a higher customer or system integrity impact than capacitor bank failures.

For instances of imminent failure, this program has a positive impact on reliability, by the identification and replacement of failing transformers and SF₆ breakers prior to failure. As stated above, preventing one outage provides an average benefit of 0.21 SAIDI minutes. Such replacements prior to failure also have definite impact on safety, reliability, resiliency, and control of the system. Replacement of failed equipment as quickly as possible following failure has a lesser but still significant impact on all these metrics.

v. 2.4 Metering Failures

The Distribution Metering program consists of capital expenditures for meters purchased that are allocated to the demand failures program based upon the projection of meters that will be utilized in the program. See capital program 1.4 Distribution Metering New Business for additional details on the investment plan for this program.

vi. 2.5 Transformer Failures

Distribution transformers are used as part of many failures projects. The Transformers Program consists of the purchase costs of distribution transformers and the associated first set expense. See capital program 1.5 Distribution Transformers New Business for additional details on the investment plan for this program.

vii. 2.6 Street Lighting

Our MV street light program has converted approximately 70,000 original MV cobra head street lights to a standard street light chosen by the local community: either HPS lights at no cost to the customer, or LED lights at a cost calculated by taking the difference in cost between LED and HPS. We initiated this program when manufacturing of MV street light fixtures ended. To do this, we engaged all our street light communities and the MPSC to develop a 10-year plan starting in 2011 for complete conversion. Currently, this program is on track to be completed by early 2020.

TABLE 40 – CAPITAL: STREET LIGHTING

5-Year Capital Plan (all values in \$ millions)					
Projects	2018	2019	2020	2021	2022
Conversion of MV to HPS	2	2	-	-	-
Conversion of MV to LED	2	2	-	-	-
Replacement of failed cobra head lights (HPS/MV)to LED	1.5	1.5	1.5	-	-
New business LED lights	0.5	0.5	0.5	-	-
Total	6	6	2	-	-

In MPSC Case No. U-18322, we proposed a tariff change to modify the Street Lighting program beginning in 2018 to advance the deployment of LED lighting, by including expenditures to support the upgrade of Company-owned luminaires with LED fixtures, reducing customer up-front contributions in the following cases: (1) conversion and replacement of MV street lights, as part of the Company program that started in 2011; (2) replacement of failed HPS and MH street lights; and (3) installation of new street lights. Details of the proposed tariff change are listed below.

- 1) Under the new tariff, the customer can upgrade any remaining MV lights to LED at no cost to the customer. This portion of the tariff change accounts for approximately \$2 million of the additional \$4 million for the program.
 - a. Currently, approximately 14,000 MV lights remain on the system.
 - b. The cost to convert MV to HPS is approximately \$325¹⁸ per light, totaling \$2 million per year.
 - c. The cost to convert MV to LED is approximately an additional \$325¹⁸ per light, beyond the cost of upgrading MV to HPS, totaling \$2 million per year.
 - d. Combining b. and c., the total cost for this portion of the program is \$4 million.
 - e. Based on customer choices, approximately 7,000 MV lights are planned for conversion in 2018 and 2019.
- 2) Based on community preferences, failed HPS and MH street lights would be upgraded to LED, rather than replacing the existing failed street light. This portion of the tariff change accounts for approximately \$1.5 million of the additional \$4 million for the program.
 - a. Approximately 3,500 failures occur per year.
 - b. It costs approximately \$400 to convert a failed fixture to LED.^{18,19}
- 3) We will absorb the additional contribution requirements when customers elect to install LED street lighting on new business street lighting jobs. This portion of the tariff change accounts for approx. \$500,000 of the additional \$4 million for the program.

Municipalities increasingly want more efficient, economically feasible street lighting options. We offer these street lighting options to promote safety and as a value-added service. LED lights are more reliable, resulting in less street light failure issues. They last longer, and since there is no bulb, the light pattern is more consistent over the life of the light. Because LEDs use less energy, the monthly bill is

¹⁸ Cost is based on an average of multiple wattages needing to be converted. Lower wattages are more prevalent.

¹⁹ Higher cost due to one replacement at a time compared to multiple replacements in the same area.

lower which reduces the municipalities’ total street light costs. By implementing the proposed changes, we expect to increase the rate of LED deployment so that all of our customers reap the benefits sooner rather than later.

viii. 2.7 Metro Demand Failures

The Metro Demand Failures program involves the replacement of failed cables, equipment, and infrastructure within the designated boundaries of our Metro systems. We identify these failed items for replacement due to potential risks to public safety, our employee or contractor safety, and to maintain the reliability and inherent redundancy of the Metro systems.

Our Metro Demand Failures program costs are highly dependent on contractor construction costs. These costs are highly variable and will fluctuate based on the workload levels of our contractors. This makes it challenging to forecast long-term anticipated costs for this program. Our current five-year plan is to spend between \$4 million and \$5 million in annual capital outlays on Metro failures, based on our historical trends and analysis of our expected needs (refer to Table 20 for historical spending). This plan addresses failures of our cables, transformers, and crushed ducts.

TABLE 41 – CAPITAL: METRO DEMAND FAILURES

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Vault or Manhole Roof Replacement	0.3	0.3	0.3	0.3	0.3
Installation of New Manholes or Vaults	0.7	0.5	0.5	0.5	0.5
Installing New Concrete Encased Duct Bank	2.1	2.7	2.7	2.7	2.7
Replacement of Electrical Assets	0.9	1.5	1.2	1.2	1.2
Total	4	5	5	5	5
Unit Forecast (number of projects)					
Investment Categories	2018	2019	2020	2021	2022
Vault or Manhole Roof Replacement	1	1	1	1	1
Installation of New Manholes or Vaults	1	1	1	1	1
Installing New Concrete Encased Duct Bank	4	5	5	5	5
Replacement of Electrical Assets	4	5	5	5	5

Many factors contribute to deterioration of the cabling, equipment, and infrastructure in the Metro systems, including age of the system and weather. We commonly see a number of specific problems caused by the weather including:

- Rain water within vaults, manholes, and conduit/duct banks
- Snow melt water within vaults, manholes, and conduit/duct banks

- The freezing of this water due to the area's climate
- The effects of the snow melt substances used to help clear roads
- The effects of the heavy snow removal equipment over the surfaces of the vaults/manholes

These factors lead to a number of issues, including damaged cable (Figure 64), damaged/crushed duct banks (Figure 65), deteriorated manhole/vault roofs (Figure 66), sunken/deteriorated manhole access (Figure 67), and rusted/deteriorated vault hatches and vents (Figure 68).

FIGURE 64 – DAMAGED CABLE



FIGURE 65 – DAMAGED / CRUSHED DUCT BANKS



FIGURE 66 – DETERIORATED MANHOLE/VULT ROOFS

(LEFT - CONCRETE MATERIAL FALLING FROM THE ROOF; RIGHT – CRACK IN CONCRETE ROOF STRUCTURE)



FIGURE 67 – SUNKEN/DETERIORATED MANHOLE ACCESS



FIGURE 68 – RUSTED/DETERIORATED VAULT HATCHES AND VENTS



We perform the following types of capital work as a result of Metro demand failures:

- **Vault or Manhole Roof Replacement** – Vault and manhole roofs require replacement when the existing roof is damaged or deteriorated. This situation creates safety hazards to the public passing over it and anyone entering the structure. Figure 69 below illustrates a vault with the previous roof removed and in progress of having a new roof installed.

FIGURE 69 – VAULT OR MANHOLE ROOF REPLACEMENT



- **Installation of New Manholes or Vaults** – When the existing location of a vault or manhole is no longer able to be repaired, a new vault or manhole needs to be installed. The determination of whether the vault or manhole can be repaired is made by a contracted civil engineer. Figure 70 shows an example of a new vault being installed.

FIGURE 70 – INSTALLATION OF NEW MANHOLES OR VAULTS



- **Installing New Concrete Encased Duct Bank** – When the existing duct bank has been crushed or is deteriorated, it will be replaced with a new concrete encased duct bank. New cable will also be run to replace the damaged cable. The picture on the left below is of the conduit prior to concrete encasement. The picture on the right below is after the concrete has been poured.

FIGURE 71 – INSTALLING NEW CONCRETE ENCASED DUCT BANK



- **Replacement of Electrical Assets** – We have electrical assets in the Metro vaults that may fail due to age, deterioration, standing water, and runoff contaminants (e.g., salt). The most common electrical assets that fail are Metro transformers and cable (primary and secondary). If a primary cable fails, we must identify and fix the faulted asset immediately to restore service to our customers. After the fault is isolated and customers are restored, there are times that the Metro system is no longer looped (i.e., no longer has feeds from multiple directions) and needs to be put back into service. A design will be created to come back to make permanent repairs. By leaving this faulted section isolated for a long period of time, we run the risk of having another failure in this area and we will no longer have a way to restore service to our customers from that direction.

Metro System Configuration

The Metro systems consist of a series of vaults interconnected by manholes and duct banks. Each of these vaults is fed with two circuits, to maintain operation even in the event of the failure of one circuit. This redundancy allows time to plan, design, bid, obtain permits, and construct replacement systems. The replacement of this equipment may involve multiple contractors and temporary power generation to maintain service to customers during the course of the replacement, all of which contribute to the overall cost.

This inherent redundancy in the Metro system usually means that customer power can be restored fairly rapidly. However, when a failure happens and the redundancy is triggered, it leaves a weak spot in the system. If we do not respond in a timely manner, this can create an exposure that can eventually result in long outages, impacting a large number of customers and critical services in our metropolitan areas.

Planning Process

We consider many factors when determining where to make investments in the Metro Demand Failures program. These factors include customer counts, historical outages, and the anticipated outage time if a failure occurs.

The inputs to the Metro failure projects are from outages or identified failures that have not yet resulted in an outage. Depending on which input started the process, we may classify a Metro failures project as demand (orders related to an outage) or planned (orders related to a non-outage). For projects triggered by a demand event, we make it a priority to repair the items immediately to restore the customer(s)'s service. Working with operations representatives, the circuit engineers will create an order, bill of materials, and work order sketch if requested.

Projects triggered by a planned event are vetted during the Metro planning process, starting in July and ending in August. Metro projects in demand failures are submitted and reviewed in a layered approval process as described in capital program 2.1 LVD Lines Demand Failures. During Metro planning, the circuit engineers responsible for planning and design of the given area of the Metro system prepare scope documents and estimated project cost based on labor and material unit costs from the Consumers Energy standards. Projects are prioritized by the program manager using an evaluation of costs and benefits based on the number of customers impacted, public safety concerns, and number of interruptions. The program planner takes inputs from circuit engineers and the system engineer based on their experience and knowledge of the system including data analysis outputs, and compares to the availability and location of resources and total program budget. Projects that will have the greatest impact to the grid and meet long-term investment requirements are sequenced for work and built.

Once approved, circuit engineers release planned projects requiring new or modified civil infrastructure to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides a number of options for possible routes and estimated construction costs for those options. The circuit engineer reviews the feasibility study with our operations employees to determine ease of construction and impact to future electric operations. The circuit engineer notifies the civil engineering firm, who will prepare a design based on the selected option. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the ROW from the Michigan Department of Transportation (MDOT) of the municipality, including a detailed traffic control plan.

The circuit engineer takes the civil design and orders the materials for the project. Materials commonly include 4" and 6" PVC Schedule 40 conduit, conduit spacers, precast manholes, precast vaults (when applicable), manhole covers, vault hatches, handholes, and quazite boxes.

The circuit engineer also creates an electrical design, cable pulling schedule, and electrical bill of materials. Common electrical bill of materials include crosslinked polymer insulated cable, 600A T-body terminations, 200A load break elbow terminations, switching modules, 600A SF₆ switches (if applicable), dead front bushing metro style transformers, molded vacuum interrupters, padmounted transformers, and padmounted PSE deadfront 600A switchgear.

As an example of a Metro failure project, a catastrophic failure of a primary cable left many of downtown Flint businesses and county and state government offices without electricity. We made temporary repairs while developing a longer-term plan. We developed a plan to replace previously known failed subterranean civil infrastructure and failed electrical cabling and equipment. Due to the complexity of the project, we divided it into three phases. Starting at the substation, new subterranean civil infrastructure was designed to connect to other locations within the Metro system where the subterranean civil infrastructure was previously upgraded. A civil engineering firm provided a feasibility and civil design. From the feasibility study, we selected a plan to construct a duct bank in the Harrison Street ROW sidewalk. This included installing crosslinked tree retardant cables, 600A T-body terminations, and 600A switching modules in the new manholes. This successfully rerouted our electrical infrastructure in downtown Flint.

Benefits

Upgrading and replacing degraded components in the Metro system allows us to maintain a redundant system in the downtown areas of cities, providing a reliability benefit. This benefit directly impacts courthouses, jails, municipal offices, police, and fire departments, as well as many businesses and residents. A Metro system in good condition allows our employees and contractors to work in a safe environment and supports public safety. Investing in the Metro system to alleviate failure conditions allows customers not to be single-sourced as we isolate manholes and vaults for repair.

C. 3.0 Asset Relocations

This category includes capital investments necessary to relocate electric facilities due to planned road, building, or other third-party construction. The cost of relocating lines in road ROW, or in some instances on private property, is typically the responsibility of Consumers Energy. These requests are driven by the state, cities, counties, and private property owners, as well as internal departments. Some projects include reimbursements which directly offset some of the project costs.

We are currently actively involved in the Governor's Michigan Infrastructure Commission Asset Management Committee, which began its work in early 2017. The Asset Management Pilot merged all infrastructure data (water, sewer, telecom, electric, gas) onto the Environmental Systems Research Institute, Inc. GIS platform where projects for 2018 could be viewed collectively to seek opportunities for better coordination. Two summits (east and west) in early 2018 gathered stakeholders to generate ideas for improvement. The MPSC, counties, cities, agencies, and utilities participated in discussions of coordination issues such as: (1) consistent permitting processes; (2) planned meetings to discuss upcoming projects (road, water, gas, electric, etc.); and (3) single point of contact for project plans. The feedback from these discussions will lead to better coordination of infrastructure projects and will be incorporated into a report due to the Governor in April 2018.

The projected expenditures in this Asset Relocations category reflect both program history as well as requirements to meet the level of asset relocations associated with anticipated local and state government spending. Additional details for each of the individual programs can be found in the following sections. Refer to Table 20 in the beginning of Section VIII for the five-year financial plan.

i. 3.1 LVD Asset Relocations

Our LVD Asset Relocation program responds to internal and external requests to relocate our distribution lines. State and municipal agencies, private property owners, and other Consumers Energy departments make requests for relocations. The program includes any reimbursements from the requesting party, which directly offset expenses incurred to perform the work. The annual program expenditures reflect the cost to relocate less the reimbursements received. Over our five-year plan, we expect to incur capital costs between \$17 million and \$21 million per year for relocations work on our LVD system. The cost of these projects range from \$10,000 to \$1 million depending on the request. The spending required for this program will depend on economic activity and other external factors. We forecast our expected annual spending needs by reviewing both historical activity and external indicators.

Planning Process

The activity in this program is entirely driven by requests from both external and internal stakeholders. For all project requests, a party submits a request that includes timelines for completion if applicable, the project purpose, contact information, and any other pertinent information. For many municipal projects and large internal projects, we hold site meetings to gather further information.

Our LVD Engineering and Planning organizations study the descriptions, maps, surveys, designs, and/or other documentation provided by the requester, and combine that documentation with internal maps and field measurements to determine what Company facilities, if any, require relocation and where assets should be relocated.

For requests requiring significant relocation or changes to the LVD system, the LVD Planning organization evaluates the proposed changes against load flow analysis in CYME (power flow software model) and the RAE (reliability decision-support tool) to determine if the changes will have an adverse effect on the system. For more information on CYME and RAE, refer to capital program 5.1 LVD Lines Capacity and Appendix F, respectively. If a proposed project will negatively impact the reliability or capacity of the LVD system, further design changes are necessary. For example, a customer could request relocation of facilities to the edge of their property line, but that move could put the facilities in dense vegetation, making the line less accessible and requiring more line clearing. In that case, we would work with the customer to find a better route that meets the customer's needs without hurting reliability. On the other hand, if the relocation significantly changes the length of conductor, it may create a capacity issue and need to be upgraded in size.

Project Prioritization and Selection

Due to the demand-based nature of this program, we do not follow a specific planning cycle, and we cannot generally plan relocation projects far in advance. Each request contains different timelines and requirements based on the nature of the request. We prioritize this work to meet the customer's deadlines. If we do not complete this work for any reason, we could face legal consequences and reputational damage (particularly if the request comes from an external party).

Government agency-requested LVD relocations can fluctuate throughout the year for many types of projects, such as road and bridge widening or improvements, repairs to municipal facilities, and street light and traffic signal modifications. Road and bridge widening or improvements include moving poles, wires, and other LVD equipment due to changes to the road location and grade and to provide proper clearance for any large equipment that the road construction contractors have onsite.

Government agency timelines can vary widely. Municipalities may request work on an almost immediate basis, such as moving a pole for a water main break repair. They may also request work years in advance as the projects increase in size and complexity. Repairs to municipal facilities such as sewer or water lines may require us to temporarily move or remove facilities such as poles and transformers or underground equipment. Other times, the modification may be permanent. Agencies request these relocations to provide access to their facilities without having to work around LVD infrastructure or risk violating clearance requirements.

As municipalities replace traffic signals they often decide to change their configuration around an intersection. This may require the replacement or relocation of LVD poles, overhead equipment, or underground facilities. We also may need to upgrade equipment to handle the changed configuration or move it so it does not interfere with construction or operation of new traffic signals. In many places, street lights coexist with underground water or sewer lines. To access these lines, a municipality may request temporarily moving or removing the street lights in the area.

Examples of the municipality designs for these relocations are shown in the figures below. Figure 72 is a road widening project that involves moving poles and street lights. Figure 73 is a road widening project that involves relocating traffic signals.

FIGURE 72 – LVD POLE AND LIGHT RELOCATION DIAGRAM FOR MUNICIPALITY ROAD WIDENING

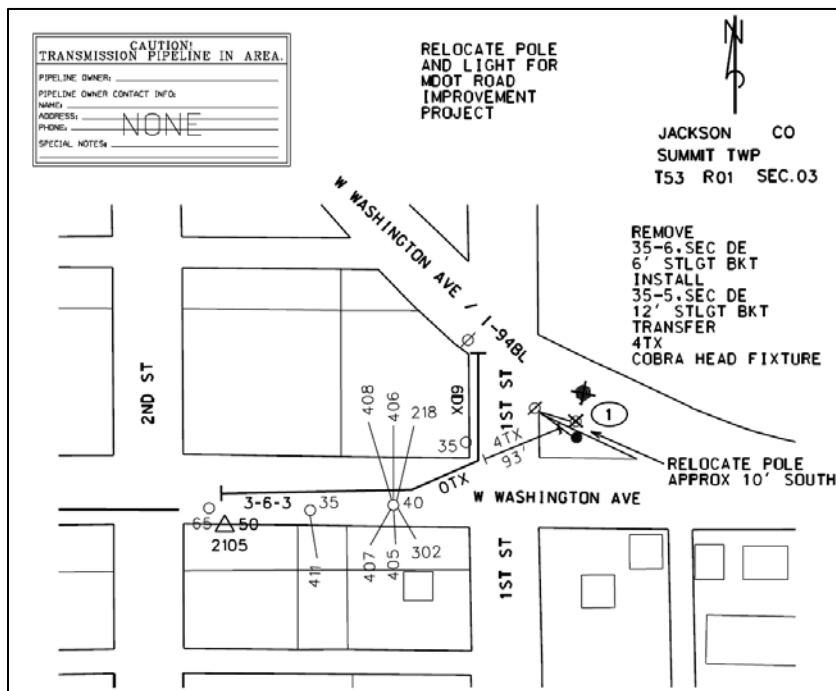
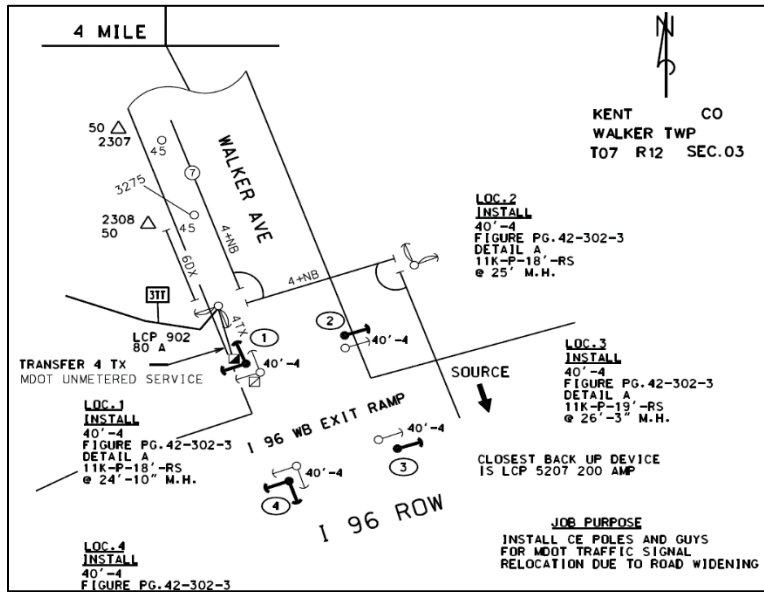
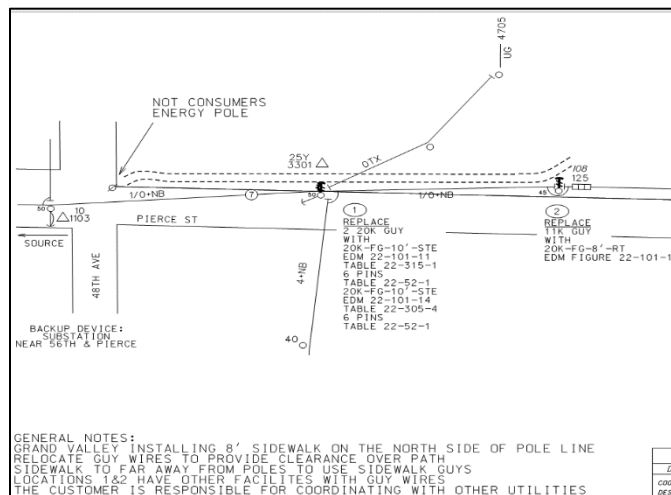


FIGURE 73 – LVD TRAFFIC SIGNAL RELOCATION DIAGRAM FOR MUNICIPALITY ROAD WIDENING



Private landowner requests vary widely based on the type of project and project timeline. Landowners request LVD relocations for building additions, logistics, landscaping, or other construction projects. Private landowners often request relocation of overhead lines out to the road or underground, particularly to facilitate moving large farm equipment. Residential customers in particular often request relocation of LVD lines to facilitate building an addition, pool, shed, barn, or landscaping feature such as a pond or berm. Commercial customers often request relocation of poles from a parking lot or other area. Figure 74 below shows an example of a private land owner request for relocation due to an addition of a sidewalk.

FIGURE 74 – LVD ASSET RELOCATION FOR PRIVATE LANDOWNER



Other organizations within the Company may make requests as well, as described below:

- The HVD Planning group may plan to move or replace facilities. For damaged or failed HVD equipment, the relocation work may be emergent. Other times, these projects are planned

months in advance of the corresponding HVD work timeframe, providing plenty of lead time. Some of the requests are to prepare for load transfers that allow safe maintenance or construction work on de-energized equipment. When there are LVD facilities attached to the same poles (known as “underbuilt”) this requires a transfer of the LVD assets to the new HVD pole (refer to figure below). Typically, these internal requests are scheduled to take place during off-peak months, particularly during the winter, to allow work to be completed outside of the summer peak load season when air conditioners and other cooling systems create high energy demand. This ensures the LVD infrastructure is robust in equipment or wire size to accommodate load transfers from one circuit to another.

FIGURE 75 – UNDERBUILT LVD ON HVD SYSTEM AWAITING TRANSFER TO NEW POLE



- Substation Planning may request LVD facility relocation to complete work on a substation. This relocation could be due to Substation Planning installing equipment or changing the LVD system to handle a load transfer or mobile substation set. Similar to HVD Planning-requested relocations, this work could be planned or emergent due to failure or damage. The type of work conducted by LVD Planning includes installing new switches outside of the substation fence, relocating poles, or adding new poles and wire for the mobile substation, which are used when no load transfer options are available at a substation site location (refer to capital program 4.3 LVD Substation Reliability for more information). At times, property ownership constraints limit the use of a mobile substation, requiring HVD and LVD infrastructure changes to either make room for a mobile substation or to allow a mobile substation at a location relatively close to, but not on the same site as, the permanent substation.
- Metro Planning may request that primary no longer be served from Metro facilities due to recent failures (or other reliability concerns in Metro). As the Metro system ages and vault conditions deteriorate, we are relocating parts of the Metro system to a direct bury LVD system (similar to those found in underground platted subdivisions). In Figure 76 below, the picture on the left represents typical padmounted equipment. The picture on the right illustrates a vault with structural damage that we would replace with a direct bury. To convert to direct bury, we must install direct buried cable and padmounted equipment (equipment in a cabinet above ground). This increases crew safety by providing access to the deadfronted equipment and

decreases the time to restore. We prefer converting to direct buried LVD when possible because:

- The cost for replacing and reconstructing a vault is very high, because it requires just as much civil engineering work (walls, foundation, roof, etc.), if not more, than electrical work. Vaults can also be dangerous to the public and our employees as they deteriorate. Many vaults have covers in parking lots and roadways, making them susceptible to heavy traffic, water, salt, and other road contaminants, causing them to break down and threaten vehicle and pedestrian traffic.
- If an outage occurs on the Metro system, the time to repair the fault is longer due to the accessibility of the Metro system components.

FIGURE 76 – DIRECT BURY SYSTEM (LEFT), VAULT WITH STRUCTURAL DAMAGE (RIGHT)



Benefits

The LVD Asset Relocation program does not deliver large reliability benefits to the LVD system since work performed is not always on facilities that are of significant age or degradation. This program primarily functions to serve customers, whether they are internal or external. However, every time we replace old or obsolete equipment, including through this program, we improve reliability because the new equipment has the latest standards at the time. Many load transfers that we perform for HVD or Substation work allow maintenance work on the facilities before a failure causes an outage. Preventatively preparing the LVD system for this work can save many customer minutes, as an outage would typically de-energize more than one circuit on these systems, with an average of 1,000 customers per circuit for two hours or more. When LVD projects are able to support a planned load transfer for HVD and Substation work, rather than emergent, the Company can perform the work in a controlled environment with little or no outage to customers.

Additionally, as mentioned above, some relocation requests provide clearance for large equipment like farm machinery and road construction equipment. Without sufficient clearance, that machinery may contact the LVD system, causing an outage, putting the operator or other members of the public in danger, and causing thousands of dollars of damage. The LVD Asset Relocation program ensures that municipal requests are completed by the deadline, so that customers are satisfied with our ability to perform these relocations at their request, as reflected in our reputation and JD Power scores for customer satisfaction.

ii. 3.2 HVD Asset Relocations

The HVD Asset Relocations program provides for the relocation of 46 kV and 138 kV lines. Relocations are typically requested by outside parties such as businesses, residential customers, County Road Commissions, or MDOT, when they require our lines to be moved due to construction projects. In these cases, the requesting party will pre-pay or reimburse us for the cost of the relocation, but the transactions will still pass through this program. When our lines are located in the public ROW and must be moved to accommodate construction projects or Michigan Electric Transmission Company (METC) project work, we are required to pay the relocation costs.

Projected funding for this program is based on historical averages. Due to the nature of the work, most projects supported by this program are unknown at the start of the year. As the year progresses, the funding is based on work requests throughout the year and is forecasted at the time of request.

Planning Process

Similar to the LVD Asset Relocation Program, the activity in this program is entirely driven by requests from outside of our Company. Depending on circumstances, we may have some input on timing or sequencing the work.

Recent examples of investments:

- We relocated three structures on the 46 kV Cascade line near the intersection of 28th Street and Kraft Avenue in Kent County to accommodate road widening by the Kent County Road Commission
- We removed four structures and installed seven structures on the Allendale 46 kV line in Ottawa County to accommodate development of the property owner's land

There are four general categories of parties that may request HVD relocations: Municipalities and other government agencies, METC, private landowners, and internal departments.

Municipalities and other government agencies request HVD relocations for many different types of projects, such as road or bridge widening or improvements, repairs to municipal facilities (emergent and non-emergent), and street light/traffic signal modifications. Road or bridge widening or improvements may require us to move poles, wires, or other HVD equipment due to changes to the road location and grade, but also for proper clearance for any large equipment that the road construction contractors may need to have onsite. Repairs to municipal facilities such as sewer or water lines can also drive requests for relocations. We are often requested to temporarily move or remove facilities such as poles and transformers, and other times the modification can be permanent. These relocations are requested to provide the municipality access to their facilities without having to work around HVD infrastructure.

METC may request HVD relocations as part of their projects. Such projects may involve Consumers Energy HVD lines that are built on the METC structures at a lower level, or simple relocations of Consumers Energy HVD line structures. Depending on the nature of the project, associated costs may or may not be reimbursed by METC. These jobs are handled on a case-by-case basis.

Private landowners request HVD relocation for additions, logistics, landscaping, or other construction projects on their property. One of the requests that are often submitted from private landowners is for relocation of overhead lines that are positioned where the customer has decided to build an addition, shed, barn, or construct a landscaping feature such as a pond or berm. Commercial customers also fall into this category when requesting poles to be removed from a parking lot or other area.

Benefits

The HVD Asset Relocation program improves reliability of the HVD system due to the installation of new equipment; however, it is not the primary function of the program to do so. This program primarily functions to serve customers. Every time we replace old or obsolete equipment, reliability improves as the new equipment has the newest design standards at the time.

iii. 3.3 Metro Asset Relocations

The Metro Asset Relocations program provides engineered responses to internal and external requests to relocate Company subterranean civil, and subterranean or padmounted electrical facilities in public right of way or on private property. External relocation requests come from state agencies, municipalities (especially Downtown Development Authorities and Tax Increment Finance Authorities) and private developers. Our asset relocation spending from external sources typically rises and falls in correlation with Michigan's overall economic health. Metro Asset Relocation is challenging to forecast, since it is contingent on (1) state agencies and municipalities contacting us in advance of the desired date of service; and (2) the city following through with required information and their portion of work to coincide with that desired date. Analysis of historical trends and data has enabled us to stay within range of our yearly spending projections and is used as a basis for future spending plans. Depending upon the scope of work, the program may include contracts with a single party specifying any reimbursements from the requesting party, which directly offset the expenses incurred to perform the work.

There are 13 projects planned for \$10 million for metro relocations in 2018 (average of \$800,000 per project). Over the remaining five-year plan period (2019-2022), we expect to incur capital costs between \$3 million and \$5 million per year for metro relocations work on our LVD system. This is based on historical trends.

Planning Process

The Metro Relocations program targets a number of specific sub-goals to ensure the long-term safe and reliable operation of the Metro electric distribution system.

State agencies and municipalities may request relocations to accommodate for upcoming civic improvement work for a specific right of way. Typical improvements include storm and sanitary sewers, water mains, street improvements, and streetscapes.

Municipalities, Downtown Development Authorities, Tax Increment Finance Authorities, and private developers may request relocations to convert overhead electric systems to subterranean civil and electrical systems. These requests typically require the customer to provide a non-refundable engineering deposit for us to perform a feasibility study to find a subterranean path for the civil infrastructure system. In addition to total project costs to install the subterranean system, the requestor

is responsible for the cost to remove the overhead system. Most requests are to increase the aesthetics of an area.

Circuit engineers conduct evaluations of the existing condition of the subterranean civil and electrical system, and if we deem it functionally obsolete, we may establish a new subterranean civil and electrical system to be built in parallel to the old system. Customer experience is improved by building a new system in parallel with the old one, minimizing construction cost and time, and limiting outages and other disruptions to downtown customers.

Metro relocation projects may be demand-based (if externally requested) or planned (if internally requested). For projects triggered by an external request, we make it a priority to meet mutually agreed upon deadlines and milestones and to perform the required work within the requested right of way.

Projects triggered by an internal request are vetted during the Metro planning process, which occurs starting in July and ending in August. During the Metro planning process, circuit engineers, who are responsible for the planning and design of their designated territorial Metro system, prepare scope documents and estimated project cost based on labor and material unit costs from the Consumers Energy standards.

Preparing the Feasibility Study

If demand and planned projects require new or modified civil infrastructure, they are submitted to a contracted civil engineering firm to create a feasibility study for a new civil infrastructure path. The feasibility study will include a number of options for possible routes and estimated construction costs for those options. The circuit engineer will review the feasibility study with our Operations group to assess the ease of construction and impacts to future electric operations. The circuit engineer will communicate the selected option to the civil engineering firm, who will then prepare a civil design. The civil engineering firm will deliver the design, along with documents needed to obtain a permit from MDOT or the municipality to perform work in the right of way, including a detailed traffic control plan.

The circuit engineer is responsible for taking the civil design and ordering the materials for the project. Materials commonly include 4" and 6" PVC Schedule 40 conduits, conduit spacers, precast manholes, precast vaults (when applicable), manhole covers, vault hatches, handholes and precast enclosure boxes.

The circuit engineer is also responsible for creating an electrical design, cable pulling schedule, and electrical bill of materials. Common electrical bill of materials include crosslinked polymer insulated cable, 600A T-body terminations, 200A load break elbow terminations, switching modules, 600A SF₆ switches (if applicable), dead front bushing metro style transformers, molded vacuum interrupters, padmounted transformers, and padmounted PSE dead front 600A switchgear.

Example

As an example, the City of Jackson approached us about a developer wishing to construct a new four-story mixed-use building. Our Metro system passed through the property in an alley way that was to be vacated. The developer requested that we relocate our Metro facilities to the road right of way, abandoning our facilities in the alley way. A civil engineering firm provided a feasibility study and civil design. From the feasibility study, we selected a project constructing a duct bank in the north sidewalk of the road right of way. We installed new crosslinked tree retardant cables, 600A T-body terminations, and 600A switching modules in the new manholes as we successfully rerouted our electrical

infrastructure to allow new growth and opportunity in downtown Jackson. The pictures below illustrate the duct bank being installed (Figure 77), installation of new duct bank and manhole (Figure 78), and installation of a manhole roof (Figure 79).

FIGURE 77 – NEW DUCT BANK BUILT IN SIDEWALK AREA



FIGURE 78 – INSTALLATION OF NEW DUCT BANK AND MANHOLE



FIGURE 79 – INSTALLATION OF MANHOLE ROOF



The above examples reflect the type of work contained in our Metro Asset Relocation program. Refer to Appendix E for a more detailed project listing.

Benefits

The Metro Asset Relocation program primarily functions to serve customers and provide a quality customer experience. Investments in this program also improve the reliability of our overall metro system. Every time we replace old or obsolete civil and/or electrical assets, reliability improves as the new equipment has the newest design standards at the time.

D. 4.0 Reliability

Our capital reliability programs are designed to ensure the long-term safe and reliable operation of the electric HVD and LVD systems. The capital expenditures in this program include investments to install, upgrade, and rehabilitate LVD lines, metropolitan underground systems, protective relay systems, HVD lines, and HVD and LVD substations.

We fund investments in the electric distribution system in order to upgrade deteriorated equipment, replace assets, and invest in new grid infrastructure capabilities to lay the foundation to enable future grid modernization investments. The goal of our reliability programs is to reduce system outages and to harden the electric distribution system assets. The capital investments in this program are directed specifically at preventing or reducing the duration of outages.

Starting in 2016, we improved collaboration across our operations, LVD, HVD, and forestry groups to improve circuits holistically, aiming to make all improvements, such as all line upgrades and forestry line clearing, in the same timeframe to prevent having to address the same circuit multiple times. The investments described in the subsequent reliability sections are underpinned by this enhanced cross-functional approach.

This program also includes funding to continue upgrading existing LVD substations with DSCADA, adding additional Distribution Line Automation switching schemes on LVD circuits, and grid communications. This category also includes funding to support system conditioning to reduce losses and support automation, grid analytics, and the deployment of ADMS.

Additional details for each of the individual programs can be found below.

i. 4.1 LVD Lines Reliability

The LVD Lines Reliability program aims to ensure the long-term safe and reliable operation of our electric LVD system. The capital expenditures in this program include investments to install, upgrade, and rehabilitate LVD lines. The performance goals of this program are to reduce customer outage frequency (SAIFI), reduce the number of emerging repetitive outage customers (CEMI), and reduce customer outage durations (CAIDI and SAIDI). These objectives are achieved through investments in three categories: replacement of LVD poles as a result of our pole inspection program, targeted circuit improvements, and circuit exit enhancements.

TABLE 42 – CAPITAL: LVD LINES RELIABILITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Poles replaced due to inspection	22	25	27	30	30
Targeted circuit improvements	23	23	23	23	23
Circuit exit enhancements	1	1	1	1	1
Total	46	49	51	54	54
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Poles replaced due to inspection	3,300	3,750	4,050	4,500	4,500
Targeted circuit improvements	95	95	95	95	95
Circuit exit enhancements	37	37	37	37	37

Our current five-year plan calls for increasing spending to accelerate the replacement of our LVD poles, moving towards the ideal annual replacement rate of 8,000 poles. This target rate is based on historical annual rejections (on a 12-year inspection cycle). Refer to Appendix G for pole inspection and replacement history.

While we plan to increase the rate of pole replacements, we will continue to invest in targeted circuit and circuit exit switch investments based on our historical levels of investments in these programs to continue to address reliability and safety concerns.

The below sections include descriptions of the major LVD Lines Reliability investment sub-programs.

Poles Replaced Due to Inspection

The LVD pole inspection program inspects all pole configurations using trained contractors. As part of the inspection program, we evaluate the results of these pole inspections to determine if a simple pole replacement is required. We further evaluate inspection results to determine if an entire pole line should be replaced or relocated to improve reliability. The Reliability Steering Committee determines

how many poles will be targeted for replacement in order to maximize the reliability benefit for our customers. For 2018, we plan to spend \$22 million to construct 3,000 poles (approximately \$7,000 per pole). Ideally, we would construct 8,000 poles, based on the historical annual rejection rate. This would require an incremental investment of \$149 million over five years. We have historically treated a minimum of 3,000 poles each year. To ensure that our system reliability does not suffer, we need to maintain at least this replacement rate to address LV poles that exhibit the greatest risk of failure.

Targeted Circuit Improvements

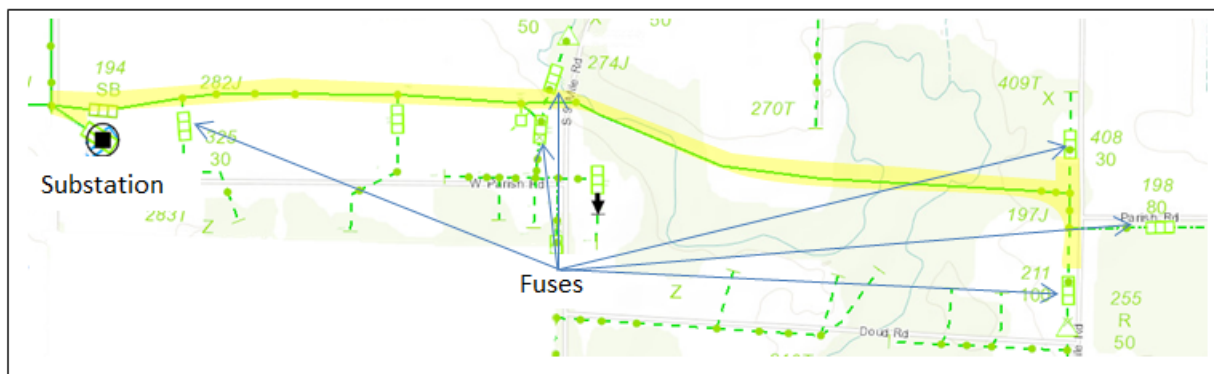
Our investments in targeted improvements include a number of investment strategies with customized solutions to address specific reliability concerns. The Reliability Steering Committee determines the type of work that will be conducted based on financial targets and maximizing the reliability benefit for our customers. With our current annual funding plan of \$23 million, we plan to target an estimated 95 circuits each year with these types of improvements at approximately \$245,000/circuit. The most common strategies employed are (1) non-standard voltage reduction; (2) first zone interruption reduction; and (3) zonal targeted investments.

1. Non-Standard Voltage Reduction – This program converts distribution circuits and substations energized at non-standard voltages to the three standard operating voltages that Consumers Energy operates on. We currently operate 13 general distribution voltage systems; the three standard operating voltages are 4.8/8.32 kV, 7.2/12.47 kV and 14.4/24.9 kV grounded-wye. Customer-dedicated systems are not within the scope of this program. The benefits of converting the non-standard systems to the three standard operating voltages are:
 - Safer operating systems – Grounded-wye operating systems are safer to operate than non-standard Delta systems. Delta systems require two phase-ground faults to be present before the phase protective device operates/trips, which means a downed Delta wire will not trip a primary protective device until a second phase fault develops.
 - Reduced system losses and increased system line capacity – Converting Delta systems to grounded-wye reduces load current on primary lines, thereby increasing available line capacity. For the same electric load, the grounded-wye system will carry 58% of the load current that the Delta system carries [e.g., a 400 amp rated conductor carrying 360 Delta amps (90% loaded) will carry 208 wye amps (52% loaded) after the conversion]. Since the amount of loss in an electric system is proportionate to the square of the load current, reducing the load current by voltage conversion lowers the electric loss associated with that portion of the electric system. Further loss reduction is typically realized through voltage conversion as older transformers and isolators are replaced as part of the voltage conversion project.
 - Improved system reliability – Voltage conversions on the distribution lines are similar to pole top rehabilitation work, in that older equipment is replaced with new, so we realize corresponding SAIDI and SAIFI improvements.
 - Reduced number of interrupted customers for single-phase faults – When a single-phase fault occurs on the Delta system, two primary phases trip, interrupting two-thirds of the customers; when a single-phase fault occurs on the grounded-wye system, only one phase trips, interrupting one-third of the customers.
 - Increased system transfer capability – Circuit conversions create the opportunity to improve transfer capability between like systems and build a platform for increased distribution automation and smart grid systems.
 - Reduced equipment inventory – Eliminating the non-standard line transformer inventory would not significantly increase the cost to maintain the standard voltage

transformer inventory. The non-standard line transformer population is very small compared to the standard transformer population, so the re-order points for standard voltage equipment would remain the same. It would, however, reduce and eventually eliminate the need to maintain non-standard line transformer inventory.

2. First Zone Interruption Reduction – This program reduces interruptions in the first protective zone on distribution circuits. The first zone is between the substation and the first protective devices that isolate this first section of distribution circuit from other segments of circuit. In Figure 80 below, the first zone is represented by the highlighted section. Since the majority of interruptions in the first zone are caused by vegetation, the Forestry department determines the best areas to target for improvement. The LVD circuit engineer then identifies electric assets that require replacement or the addition of protective schemes. Items identified for replacement include, but are not limited to, poles, crossarms, pins and insulators, lightning arresters, non-standard equipment, and cutouts. Protective schemes, such as fuses or reclosers, are added or upgraded to reduce the number of customers that are impacted by an interruption. The Reliability Steering Committee will determine how many miles of first zone work to complete by using historical zone performance to maximize the reliability benefit for our customers.

FIGURE 80 – ILLUSTRATION OF FIRST ZONE INTERRUPTION REDUCTION



3. Zonal targeted investments – Targeted investments improve the reliability of our LVD system by reducing the likelihood of an additional interruption over the next five years or more. A zone for targeted improvement can include multiple protective device zones or a single protective device zone. Circuit engineers perform a driving inspection of overhead lines on a circuit to identify and note imminent failures and system deficiencies that threaten to cause customer outages. In addition, the Forestry team will complete line clearing, including on trees outside of the right of way, on circuits that have evidence of tree related interruptions. The Reliability Steering Committee decides how many circuits and zonal areas starting from the substation to target in order to maximize the reliability benefit for our customers. For example, the Reliability Steering Committee may decide to target the three-phase lines on the worst-performing 15 circuits to increase performance for the largest amount of customer benefit.

Circuit Exit Enhancements

Circuit exit switches are installed on each phase outside the substation fence, providing additional safety by creating an isolation point for line workers in case the substation (and substation equipment) becomes energized. If the substation becomes energized without having the circuit exit switches opened, the line workers could be at serious risk while they are working on that line. Our current plan is to spend \$1 million annually to install circuit exit switches on approximately 35 circuits at a cost of approximately \$28,000 per circuit. We currently have a backlog of approximately 1,100 circuits eligible for exit switch installation. Besides the safety benefit, we will experience the benefit of the installation when DSCADA is installed.

Planning Process

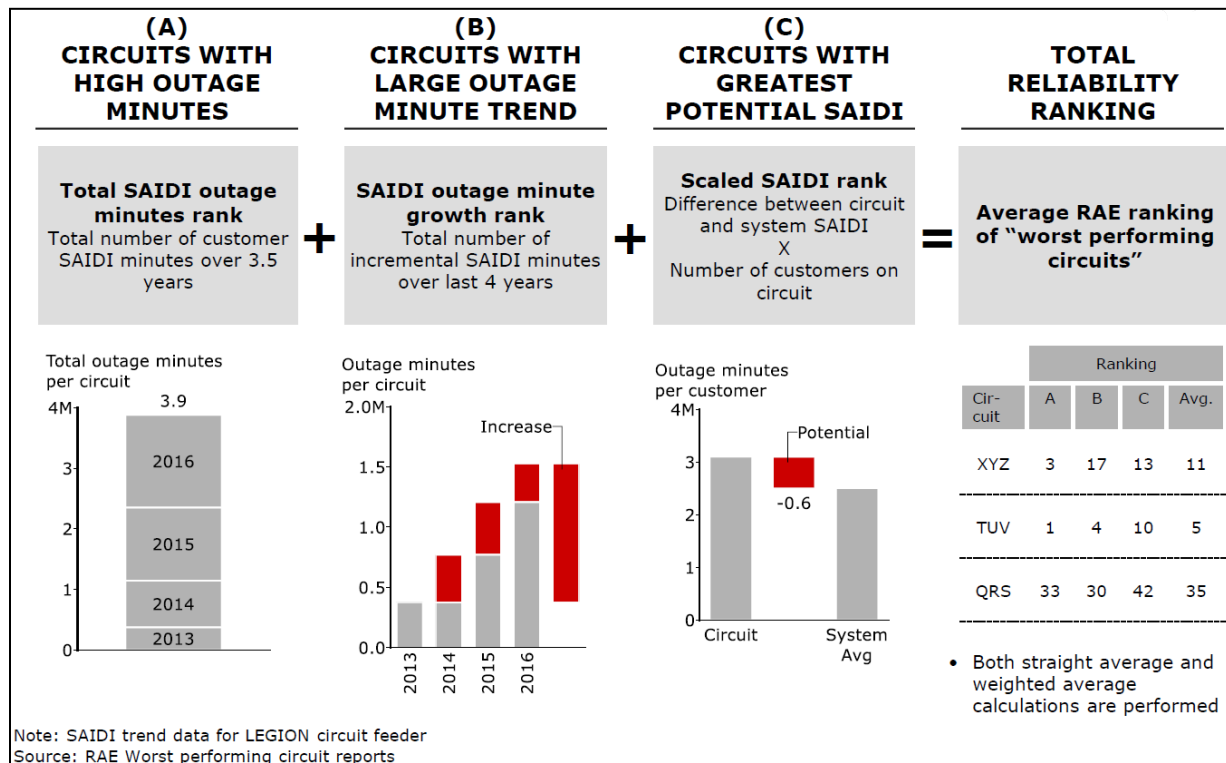
We use several critical inputs and analyses to aggregate multiple data sources in order to best target and prioritize reliability issues facing our customers. The analyses used help us identify specific areas to target investments based on probability of future issues, and helps to prioritize projects that will deliver the greatest reliability improvements based on the objectives of improving reliability (e.g., SAIDI, SAIFI, and CEMI-5). SAIDI reduction can be achieved by reducing outage frequency (SAIFI) as well as by improving duration (CAIDI) through faster customer restoration.

The primary input for deciding where to invest is data provided in the RAE. Refer to Appendix F for full detail on how the data from RAE is acquired. The RAE data is used to help the Reliability Steering Committee evaluate how to maximize the reliability benefit to customers through reduced outages, using the strategies outlined above.

This data is analyzed in three ways to determine the final ranking of a circuit compared to all others in the statewide LVD system. The results of the three analyses are averaged to determine the total reliability ranking, as shown in Figure 81 below.

- A. Circuits with High Outage Minutes – Circuits are first ranked by the total minutes that they each contributed to LVD SAIDI over the past three and a half years.
- B. Circuits with Large Outage Minute Trend – Circuits are then reviewed to determine if they are performing better or worse than the previous year. Each year is compared against four total years, including prior three years and a projection of the current year-end performance.
- C. Circuits with Greatest Potential SAIDI – Finally, each circuit is compared against the performance of the total system average, determining the potential of the circuit to provide the best SAIDI reduction after investment.

FIGURE 81 – RAE RANKING FORMULA



By analyzing historical outage minutes across the grid, identifying trends, and assessing circuits with the greatest potential reliability improvement, RAE provides a ranking of circuits and zones to target to maximize SAIDI avoidance. Once reliability inputs are used to identify circuits to target on the LVD system, reliability projects are developed, evaluated, and prioritized in order to develop an investment plan that maximizes the reliability benefit for our customers.

The LVD Planning department also receives input from operations, forestry, economic development and customer care departments. The operations and forestry departments collaborate with regular input to provide the planners with the ability to serve customer needs while considering accessibility, resource and system constraints. For example, a line may be experiencing multiple tree related interruptions. The LVD Planning circuit engineer will review the recommendation to relocate the line to the road with the forestry department and operations field leadership to determine if this would provide the best solution for accessing the line and preventing tree related interruptions. In some cases, we may choose to reconductor with tree wire or aerial spacer cable (premium cable for reducing tree related interruptions) instead of relocating.

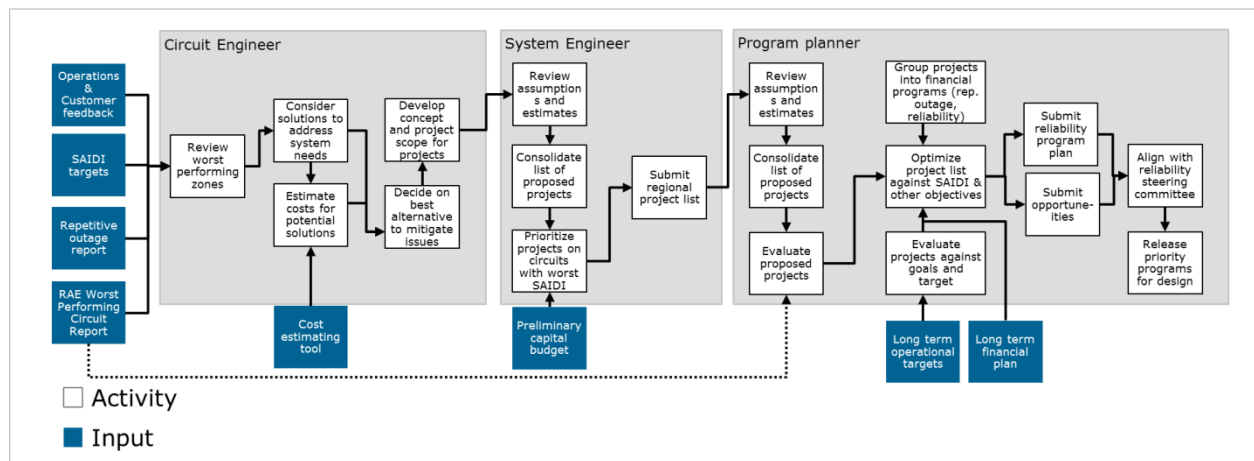
The customer-facing Economic Development and Customer Care departments provide information on customer expectations to incorporate into the planning process. For example, we may have a segment of line where our C&I customers experience brief interruptions to their power but not extended interruptions. This could still impact their level of production as brief power interruptions causes the motors on their equipment and machinery to restart. This insight would be brought to the attention of our system planners through our customer-facing teams. Another example is if we know that there is planned development of an area that will increase electric load. When we plan for work to improve

reliability, we will also incorporate any needed capacity upgrades, such as larger conductor, to ensure all aspects of service are covered in the enhancement plan for that particular part of the electric system.

Finally, line investments may need to be made as part of a circuit automation project. For example, a distribution automation scheme may be needed in a low performing area. However, to be able to consider this project for distribution automation, the system may need line upgrades such as adding a phase of conductor to create a line section consisting of all three phases. This will stage the system for building a future loop scheme with another nearby circuit in the electric system.

LVD projects in reliability are submitted and reviewed in a layered approval process as described in capital program 2.1 LVD Lines Demand Failures and shown in Figure 82. As with LVD Lines Demand Failures projects, LVD Lines Reliability projects are prioritized by the program planner using an evaluation of costs and benefits with inputs from circuit engineers and system engineers based on their experience and knowledge of the system, and the availability and location of resources and funding. The projects that meet long-term investment requirements and are most effective at improving reliability are sequenced for work and built as part of the Company’s LVD Reliability Program for the following year.

FIGURE 82 – LVD RELIABILITY PLANNING PROCESS



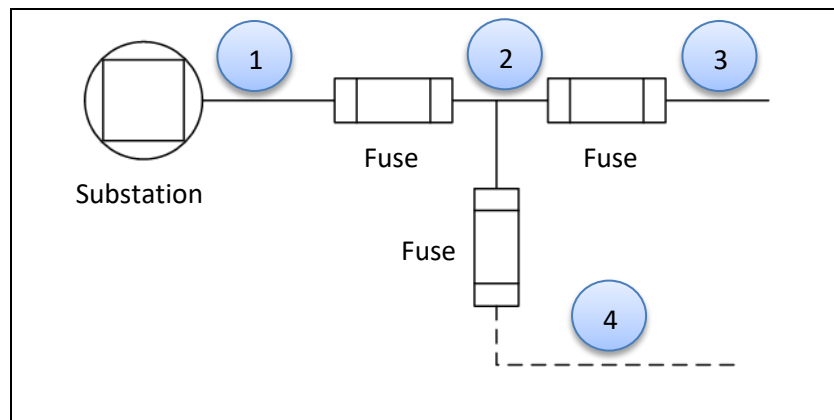
Once a reliability issue has been identified, the circuit engineers will consider a number of potential actions to upgrade or improve the system including pole top maintenance, sectionalizing, system upgrades like aerial spacer cables, replacing conductors, and localized tree clearing. Detailed descriptions of the types of investments can be found below:

- Upgrading lightning protection to meet standards – Our standards dictate that we install lightning arresters (also known as surge arresters) every 1,300 feet on LVD lines, to protect the system from damage due to overvoltage transient conditions caused by external (lighting) or internal (e.g., switching) events. An arrester is not a surge diverter, but rather a voltage limiting device that limits the voltage across its terminals. To protect equipment from transient voltages occurring on an attached conductor, an arrester is connected to the conductor and also connected to ground. This routes energy from an over-voltage transient to ground, if one occurs, while isolating the conductor from ground at normal operating voltages. Arresters will

not protect against a direct strike to the conductor, only against induced transients from lightning discharge's rapid rise-time.

- Replacing equipment that has reached the end of its expected life, including poles, crossarms, switches (cutouts), and overhead and underground conductors.
- Installing System Protection devices (e.g., fuses, switches, reclosers, etc.) – This prevents or minimizes line and equipment damage caused by system faults to maintain continuity of service. This is done by segmenting the electric distribution system into smaller sections to minimize the number of customers affected by any individual outage. Smaller sections create zones of protection on the circuit. Figure 83 below illustrates an example of four zones of protection:

FIGURE 83 – DIAGRAM OF SYSTEM PROTECTION ZONES



- Relocating lines to more accessible areas, such as moving poles and conductors from behind homes, or out of forested or swampy areas, to the road side for timely access and maintenance.
- Upgrading conductors to tree wire or aerial spacer cable for additional tree protection (See Section VI.B Design Standards).
- Converting lines from non-standard voltages to one of the three standard ones, as discussed above. This includes reconductoring, replacing customer transformers, and moving isolation between voltages (isolators). An isolator is a large transformer and has the same internal components as a transformer. Isolators are used on the primary distribution system whenever there is a difference in voltage and the output voltage needs to be raised or lowered. For example, if a 14.4/24.9 kV line is connected to the substation, but some of the lines further out on the circuit are 4.8/8.32 kV, then the 14.4/24.9 kV isolator uses taps to lower the output voltage to 4.8/8.32 kV.

Below are three examples of projects that fall in the targeted improvements. Refer to Appendix E for a more detailed project listing for LVD Lines Reliability.

Some examples of projects that were selected for 2018 construction include:

- RLBY17 SPRUCE ROAD_EAST BAY 518 – This project is to reconductor three-phase bare wire to tree wire for approximately 3.5 miles due to the amount of exposure to tree related interruptions. This project will improve reliability for 323 customers by reducing interruption frequency from an average of one per year to none.

- RLBY17 GERRISH-LEGION LOAD TRANSFER – Transfer customers from Gerrish Substation/Legion Circuit to an adjacent circuit to reduce the circuit length. This project will improve reliability for 412 customers by reducing interruption frequency from an average of two per year to none.
- In addition, there are projects that are selected due to extraordinary circumstances. An example of this is RLBY16 HARRIETTA-CABERFAE. This project is for a priority customer to move the line to the road right of way out of the National Forest since the customer experienced six outages in 12 months.

Benefits

Investments in our LVD Lines Reliability program have a major impact on customer experience by reducing the number of outages, improving the overall power quality, and ultimately lowering the long-term costs to the customer.

The investments in reliability are made to proactively replace underperforming assets and make lines more accessible to employees, thus improving employee and public safety. Furthermore, by making proactive investments in upgrading our infrastructure in the LVD Lines Reliability program, we are able to reduce costly work associated with emergent response to interruptions in the LVD Line Demand Failures and Service Restoration program.

For further details on the SAIDI benefit of the LVD Lines Reliability program, refer to Section VII.C which summarizes the overall reliability impact of our investment plan.

ii. **4.2 HVD Lines Reliability**

The purpose of our HVD Lines Reliability program is to ensure the long-term safe and reliable operation of our electric HVD line system. The HVD system is the foundation and source for the LVD system. Simply put, the LVD system cannot function without the HVD system as its source.

The reliability improvement strategies of this program generally include overhead line rebuilds, pole top rehabilitation, underground line replacements, and pole and tower replacements. The majority of the program funding goes towards overhead line rebuilds, pole top rehabilitation and pole replacements. An overhead line rebuild consists of replacement of poles, pole top appendages (crossarms, crossarm braces, insulators, etc.), conductors, and associated switches. Pole top rehabilitation projects replace crossarms and insulators only.

We are currently forecasting to spend between \$37 million and \$41 million annually over the next five years on this program. This is an increase from historical averages as we continue working to improve the reliability of the HVD system by increasing the number of rebuilds and rehabs completed while steadily replacing poles rejected by inspections.

TABLE 43 – CAPITAL: HVD LINES RELIABILITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Line Rebuilds	21	22	21	22	23

Pole Top Rehabilitations	6	7	7	7	7
Pole Replacements	10	11	10	10	11
Total	37	39	38	39	41
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Line Rebuild Miles	64	63	61	60	60
Pole Top Rehabilitation Miles	80	79	78	77	77
Pole Replacements	560	560	560	560	560

Planning Process

Due to deterioration, our HVD lines infrastructure can struggle against the elements of wind and precipitation. Taking action to address the reliability of our HVD lines is a priority due to the aging condition of the system, the time it takes to procure right of way and construct lines, and the large number of customers served by our HVD lines. Over 1,000 miles (23%) of our HVD lines were constructed prior to and immediately following World War II; these lines have a higher outage rate due to their deteriorated condition and the outdated construction standards (unshielded, small single layer conductor, and/or copper conductor) to which they were built. Poor performing HVD lines are emerging at an increasing rate in recent years resulting in customer dissatisfaction, bad publicity, and a reputational risk to the Company (e.g., McBain, Hughes Road, Gun Lake, Fine Lake, and Waldron 46 kV Lines).

HVD line incidents tend to affect large blocks of customers, up to 10,000 per incident, and average nearly 0.5 SAIDI minutes per incident. Investments have neither kept pace to prevent an increasing number of incidents, including those to high profile customers, nor to avoid creation of repetitive outage situations.

While we continuously monitor the reliability of the HVD lines system, we also perform an annual review to determine which lines and line components need to be addressed in the next year or years, as some projects may be large enough to span multiple years. Additionally, we determine which remediation strategy to use. The three key inputs utilized in our HVD line reliability assessment are: (1) Line performance; (2) Line condition; and (3) Other; with line performance being the primary driver.

Line performance is an aggregate of both the number of incidents on the line segment as well as the number of customer minutes generated by an incident to the line segment. The primary driver for investment decisions is line performance. Therefore, lines with the highest average of incident rates and customer minute totals in a rolling three-year period are given higher priority for remediation. Additionally, the configuration of the HVD line influences and informs us on relative line performance. Typically, events on poor-performing radial lines result in higher customer impact compared to those HVD lines that are looped as part of the networked system that can be sourced from different directions.

A sample of the data utilized in the line performance analysis is shown below.

TABLE 44 – HVD OUTAGES SORTED BY NUMBER OF INCIDENTS OVER THE PERIOD OF 1/1/2015 – 12/31/2017

Line Name	Voltage	Line Length	2015-2017 Total		
			Incidents	Customers Affected	Customer Minutes
GUN LAKE (HAZELWOOD - GUN LAKE)	46	24.0	11	52,365	17,640,181
MCBAIN (CADILLAC - VIKING MCBAIN)	46	21.0	6	25,296	8,466,386
NASHVILLE (HASTINGS - NASHVILLE)	46	36.6	6	11,936	4,258,916
WALDRON (DOWLING - FRONTIER)	46	37.6	6	32,218	8,820,318
AUGUSTA (LAFAYETTE - MORROW)	46	32.7	5	14,746	3,870,862
LAKESHORE (CLEVELAND - LAKE SHORE)	46	12.4	5	14,944	2,736,348
DIETZ - GAYLORD	46	18.4	4	1,074	78,880
EATON RAPIDS (RICE CREEK - ISLAND RD)	46	34.6	4	13,175	1,141,051
FENNVILLE (SCOTT LAKE - MANLIUS)	46	23.3	4	8,747	3,305,117
GALESBURG (MORROW - SONOMA)	46	17.6	4	13,779	1,396,675

TABLE 45 – HVD OUTAGES SORTED BY CUMULATIVE CUSTOMER MINUTES

Line Name	Voltage	Line Length	2015-2017 Total		
			Incidents	Customers Affected	Customer Minutes
GUN LAKE (HAZELWOOD - GUN LAKE)	46	24.0	11	52,365	17,640,181
MAPLE CITY (ELMWOOD - MAPLE CITY)	46	16.5	1	5,112	10,535,452
WALDRON (DOWLING - FRONTIER)	46	37.6	6	32,218	8,820,318
MCBAIN (CADILLAC - VIKING MCBAIN)	46	21.0	6	25,296	8,466,386
MANCHESTER (CEMENT CITY - PARR RD)	46	28.1	2	19,697	7,320,226
BRETON (BEALS RD - BRETON)	46	6.4	1	7,947	6,937,731
HOMESTEAD (HODENPYL - FARR RD)	46	62.3	2	16,045	6,729,980
GOODALE (LAFAYETTE - VERONA)	46	19.3	1	10,027	5,284,406
METRO (RANSOM - BUCK CREEK)	46	15.2	1	6,620	4,957,556
FROST (BARD RD - WARREN)	46	52.2	2	6,885	4,926,726

Line condition is informed by three key inputs:

- Pole Inspection Program** – We inspect HVD poles on a 12-year cycle as described in capital program 2.3A HVD Lines Demand Failures and O&M program 2.1 HVD Lines Reliability. This ground level pole inspection rejects an average of 15% of poles tested. Approximately 1,300 poles are replaced each year via HVD lines reliability and other HVD line programs, which represents a 60-year replacement rate. Of these 1,300 poles, approximately 800 of them are

replaced via this reliability program. Replacement of some rejected poles is delayed on older lines with the intention of rebuilding the line rather than further investing in outdated construction.

- **Helicopter Inspection Program** – We inspect HVD lines as mentioned in capital program 2.3A HVD Lines Demand Failures and as described in O&M program 10.0 Engineering and System Planning. The photo below is from a special helicopter hover inspection performed in 2017. This type of inspection, beyond our normal helicopter inspection program, provides a much more detailed view of the pole top, and will be used on a select basis going forward. This photo shows deterioration at the top of a pole that had passed the standard ground level pole inspection.

FIGURE 84 – DETERIORATION OF HVD POLE TOP FROM HELICOPTER INSPECTION

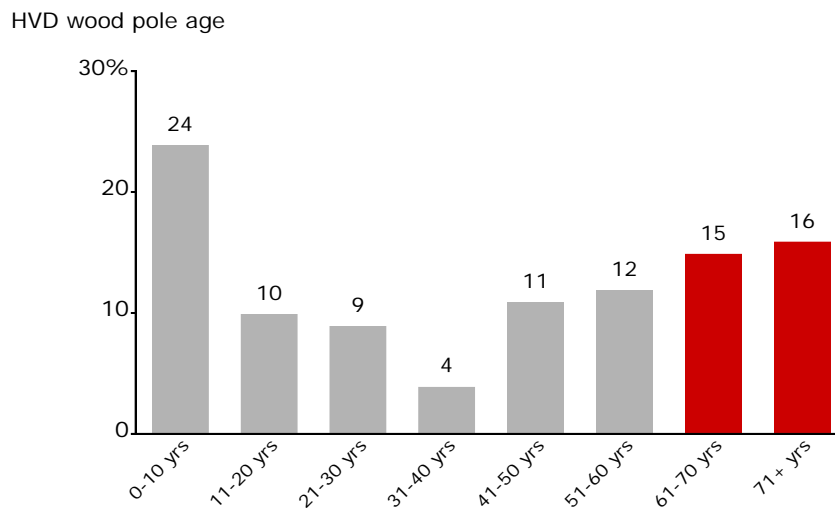


The ground level pole inspections reject an average 15% of poles tested, while preliminary results from hover inspections have found an additional 11% of poles on inspected lines that should be replaced rendering approximately 26% of the system very susceptible to a failure of some type.

- **Biannual Ground Patrol** – For safety reasons, we cannot fly over approximately 400 miles of the HVD system, because it is difficult to land quickly and safely in the event of an emergency. Most of these “no-fly lines” are in urban areas. To inspect these lines, we complete biannual ground patrols, which may include infrared and/or corona inspection using handheld cameras.

In addition to the above inputs, line condition can be impacted heavily by the age of the line segment. However, we do not replace HVD lines and equipment simply due to age. Unless an operational problem or an inherent failure mode is identified for a particular manufacturer or vintage of HVD conductor or equipment, we do not have a systematic program to replace aging lines, crossarms, insulators, or other pole top equipment, other than as associated with the pole replacement program. For example, over 23,000 (31%) HVD poles are beyond their 60-year life expectancy, with the majority (12,300 poles) being over 70 years old as illustrated in the chart below.

FIGURE 85 – AGE OF HVD WOOD POLES



If a pole replacement program based solely on age existed, the HVD wood pole age distribution would look much different. Older lines were typically built to what would be considered outdated construction standards (unshielded, small single layer conductor, and/or copper conductor) today. So the age of assets does increase the probability of reliability issues. Other factors that can influence the reliability assessment are existing projects with and/or near the line. These could include pole replacements occurring on lines nearing capacity, construction projects in the vicinity of the line or multi-year projects in which the majority of reliability issues have now been addressed.

Project Prioritization and Selection

When prioritizing, we focus on lines that are consistently poor performers, and we look for the best remediation strategy to prevent future outages in the most economical way. Occasionally, projects outside of the worst performers are chosen based on completing multi-year plans, rapidly degrading reliability, customer commitments, or other unique circumstances.

We customize our responses to poorly performing lines individually, based on the configuration, construction style, inspection results, and other key factors. Lines that meet modern construction and design standards and have standard conductors will primarily receive pole top rehabilitation, while lines that utilize non-standard construction or equipment will typically be rebuilt. Occasionally, lines that meet modern standards will need to be rebuilt; this could be due to access issues or upgrades that could improve operational flexibility.

In years 2012 through 2016, our HVD lines contributed approximately 24 SAIDI minutes per year (excluding MEDs), which represents approximately 12% of the overall annual SAIDI performance in these same years. In 2017, the HVD lines contribution was 24.9 minutes, which represents approximately 15.4% of our overall SAIDI (excluding MEDs) performance of 160.9 minutes. This indicates a degraded HVD lines performance relative to the overall electric system performance.

Over the last five years, we have rebuilt an average of 25 miles per year. Additionally, in years 2015 through 2017 we averaged 58 miles per year of HVD line rehabilitation.

Given this decline in HVD lines system performance, coupled with our need to improve the reliability of the HVD system from its 2017 performance, the miles of rebuild and rehabilitation will be increased further in future years.

There are occasions when an HVD line suddenly performs poorly, which can prompt a need to react immediately and reprioritize. A recent example was the emergent poor performance of the Waldron Line in 2017. When we performed our reliability analysis in 2016 for 2017 projects, the Waldron Line's performance and condition did not warrant any action in 2017. However, in April 2017, our customers (approximately 5,200) served from the Waldron, Pittsford, Frontier, and Tripp Road substations experienced three interruptions in one week, caused by failure of the Waldron 46 kV line. This prompted an immediate action item to perform pole top rehabilitation on approximately nine miles of line, which was completed in October of 2017, solving the problem for those customers.

Benefits

The pole top rehabilitation and pole rebuild projects we deploy have proven benefits, as described below.

- **Pole Top Rehabilitation** – In 2015, we began our HVD pole top rehabilitation in earnest. In that year, we performed pole top rehabilitation on two HVD line segments on the Big Rapids and McBain HVD lines. During 2014 and 2015, these line segments had seven and eight outages, respectively. Since completing that work in 2015, neither line has incurred an outage.
- **Line Rebuilds** – We have been completing line rebuilds for many years. The table below clearly shows how, after completing a rebuild, a line typically experiences zero or minimal line equipment related outages.

TABLE 46 – IMPACT OF LINE REBUILDS ON OUTAGES

Impact of Line Rebuilds on Outages				
Work Order	Description	Completion Date	Prior Outages	Post Outages
10002056	2281- WARREN-GROUT-RBLD LINE 33A & 33C	3/4/2009	3	0
10002059	2288- MORENCI TO DOW-BEECHER-RBLD 27C	4/11/2011	4	0
10002060	2289- DOWLING-BEECHER-REBUILD LINE 27B	2/24/2009		
10002057	2292 MONITOR-ALMEDA-RBLD LN 107A	4/8/2010	3	0
10007977	LN107C KAWKAWLIN RBLD 5MI 46 kV	2/11/2010		
10083107	LN107K STANDISH 46 KV RBLD 10.62 MI	7/6/2011		
10083117	LN021E PARMA 46 KV RBLD 11.92 MI	11/1/2011	5	0
10083110	LN021F PARMA 46 KV RBLD 10.89 MI	4/11/2011		
14788117	LN025I NORTH ADAMS C RBLD	1/13/2014	3	1
14788114	LN025I NORTH ADAMS N RBLD	10/10/2011		
11732242	LN029F WHITESTONE POINT 46 KV 4 MI RBLD	6/30/2010	11	0
15729189	LN033K SANFORD(CROS JCT-JASP JCT) RBLD	11/3/2014	3	0
15191352	LN042A CHESTER TAP-NASHVILLE RBLD	10/31/2011	3	1
14850499	LN042A NASHVILLE E REBUILD	2/24/2012		
15019261	LN088B BRIDGEPORT RBLD	6/15/2012	1	0
10002049	2823- BARRY-BROADMOOR-RBLD 46kV LINE	2/26/2009	11	0
20101384	LN019U FREMONT E RBLD 4.6 MI	9/10/2014	7	0
20100798	LN019U FREMONT W RBLD 4.4 MI	5/19/2014		
10007734	LN032I SUTTONS BAY_N RBLD 6.4 MI	7/31/2012	4	0
17183385	LN032L SUTTONS BAY_S RBLD 3.8 MI	10/11/2012		
10083000	LN119V MANCELONA 46 KV LINE REBUILD	11/4/2011	3	0
		Totals	61	2

Table 47 below provides a list of the 2018 approved HVD Reliability lines rebuild and pole top rehabilitation projects. A more detailed listing of current work orders for HVD Lines Reliability can be found in Appendix E.

TABLE 47 – HVD LINES RELIABILITY APPROVED PROJECT LIST

2018 Approved Projects		
Line Rebuilds	SAP WO #	Miles
Gun Lake - Hazelwood to STR 634	28346071	1.8
Wentworth	28337907	1.2
Fennville - Casco Spur	21993161	7.3
Fine Lake North (023B)	21992292	9.7
Augusta (Eastwood Dbl Ckt)	28345868	1.3
Union City - South Rebuild (025A)	26796506	2.5
Union St	27220557	3
West Branch East (066I)	27629949	5.5
Stockbridge - Battice Spur (026G)	19713496	2.7
Markey	15596837	1.6
West Branch (066A)	27951911	5.7
Nashville Towers	15604017	1.6
West Branch Center	27633369	3.6
New Richmond	21992599	3.5
Union City - North rebuild	28357769	8
Manitou Beach North (027A)	15136881	4.6
Lamoreaux - Gravel Pit relocate	31735448	0.98
Mendon	31335413	1.7
Pole Top Rehabilitation	SAP WO #	Miles
Augusta - Gull Lake spur (carryover)	27952675	10.8
Waldron - 27H	31166608	9.7
Waldron - 27N	31023844	9.4
Homestead, Fkft spur & Honor spur	31168480	15.8
Grand Blanc - Spur to Atlas	31465293	3.9
Breedsville (72KK)	31333371	8.5
Cheboygan - entire line	31333361	11.5
Stanton - entire line	31333373	13.4
Grand Blanc - Spur to Newark	31578254	3.3
Mecosta - Appleton spur (19AI)	31546561	1
Rankin - Spur to Rankin	31578646	3.5

iii. 4.3 LVD Substation Reliability

Our LVD Substations Reliability program ensures the long-term safe and reliable operation of the electric distribution LVD substations. The capital expenditures in this program include investments to install new substations or substation equipment and replace existing substations or substation equipment. These investments are intended to reduce customer outage frequency (SAIFI) and reduce the number of emerging repetitive outage customers, as well as the customer outage durations as represented by CAIDI and SAIDI. The projects that fall under the LVD Substation Reliability program fall into one of the following categories of investments: new or rebuilt substations, mobile substations, animal mitigation, transformer replacements, regulator replacements, or other (e.g., recloser replacements, transrupter installation to eliminate Spring Operated Grounds (SOGs), or transformer bushing replacements).

TABLE 48 – CAPITAL: LVD SUBSTATION RELIABILITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
New or rebuilt substations	5	6	6	6	6
Mobile substations	4	5	2	2	2
Animal mitigation	4	4	4	4	4
Transformer replacements	1	1	1	1	1
Regulator replacements	3	3	3	3	3
Other	2	1	4	5	4
Total	19	20	20	21	20
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
New or rebuilt substations	5	4	4	4	4
Mobile substations	2	3	1	1	1
Animal mitigation	40	40	40	40	40
Transformer replacements	2	2	2	2	2
Regulator replacements	90	90	90	90	90

The scope of our five-year plan includes the following:

- Installing one or two new substations per year to improve reliability, operating flexibility, and until there are no customers directly served from a hydro generation plant.
- Purchasing one to three new mobile substations per year in order to maintain a strong operating fleet.
- Installing animal mitigation measures at 40 substations per year until all the distribution substations are brought up to current substation animal mitigation standards which will take approximately six to eight years.

- Replacing two substation transformers and approximately 90 substation regulators based on degrading trend data.
- Replacing five to ten obsolete substation reclosers, installation of transrupters to advance our protection system and replacing substation transformer bushings based on a degrading trend.

Planning Process

There are several inputs and analyses we conduct and use to aggregate multiple data sources to best target reliability issues. These inputs help to identify specific areas to target investments based on probability of future issues, and help to prioritize projects that will deliver the greatest reliability improvements based on specific metrics (e.g., SAIDI, SAIFI, and CAIDI). These inputs are listed below and include: (1) the RAE; (2) reliability improvement initiatives; (3) animal intrusion data; (4) equipment trend data; and (5) mobile substation planning.

1. RAE and input from the LVD Lines Engineers:
 - As described in Appendix F, the RAE analyzes and aggregates a large amount of customer and operational data across our maintenance systems to provide us with reliability performance reporting across the grid. The RAE produces a bi-weekly Repetitive Outage report, which our system engineers review to identify key zones of frequent customer outages.
 - Historical outage trends are analyzed by the system to identify parts of the grid where reliability concerns are greatest based on the total number of outages, trends in reliability performance, and the potential reliability impact.
 - The system engineers may then request our Substation Planning group to initiate a substation project to supplement an LVD Lines project (e.g., new substation, new circuit, substation equipment upgrades, and animal mitigation). When new substations are proposed, we develop long range studies to compare the SAIDI/SAIFI/CAIDI benefits and economic costs of the substation alternative with traditional line solutions, and to consider long-term system capacity needs to optimize new substation locations. A new substation may be installed if the system reliability improvements and economic benefits are comparable to traditional line solutions.
2. Reliability improvement initiatives:
 - Collaboration and regular input from field organizations and other departments provide our substation planning engineers with operational concerns and system constraints that may trigger a need for sub-programs and individual projects (e.g., identification of substations with working clearance constraints, replace 138 kV SOGs with transrupters, and replace 138 kV fuses with transrupters).
 - Installation of new distribution substations to serve customers that are currently served from a Hydro Generation Plant.
 - Animal mitigation initiatives to bring all distribution substations up to the current substation animal mitigation standards.
 - Planned replacement of obsolete reclosers when unexplained tripping events occur and obsolete reclosers with depleting inventory levels (e.g., type ME, NOVA1, and VXE reclosers).
3. Animal intrusion information:
 - A substation animal mitigation project is implemented to mitigate recurrence following one animal-caused outage inside the substation. If an animal is capable of getting inside a substation, the animal could climb the structures and equipment, contacting energized

electrical components and causing an outage by damaging equipment and/or tripping protection devices that detect the electrical short circuit caused by the animal.

- Animal mitigation projects are also initiated when animals are observed within the substation, even though an outage may not have occurred. The presence of an animal indicates that a future outage is possible.
4. Equipment Trend Data:
- Planned replacement of substation equipment may be triggered with trend data that indicates degrading equipment condition, but has not reached a concern of imminent failure.
 - Dissolved Gas Analysis trend data are used to identify when replacement of substation transformers and regulators are needed.
5. Mobile Substation Planning:
- We maintain our mobile substation fleet based on historical project usage.
 - We purchase new mobile substations to replace those nearing end of life.
 - Mobile substations are used when no load transfer options are available at a substation site location. It is typically parked next to a substation and temporarily attached to the feeder circuit. The Company uses the mobile substation to pick up the circuits and de-energize portions of or all of a substation to perform maintenance work safely, and with no outage to customers. This sort of planning takes time and is much easier for preventative maintenance rather than emergent work, due to the setup, transportation, and availability constraints of the mobile substation. Below is an example of a mobile substation and an underbuilt line.

FIGURE 86 – MOBILE SUBSTATION



Once we have identified substation projects based on the above mentioned inputs, we execute on project implementation. We balance the need to improve current poor performance and experienced operating issues, while also addressing degrading trend data and supporting our reliability initiatives to minimize customer outages on a go forward basis.

System planning is an ongoing process. Project engineering and scheduling typically occur in the current year for the following year’s construction. New projects can be inserted into the plan based on experienced system outages and operational concerns, which may result in the deferment of previously planned projects depending on need and available construction resources and/or mobile substations.

Benefits

Reliability investments minimize potential adverse impacts on customer experience through the improvement of the overall energy reliability, operation, and maintenance of the distribution substations over the long term. Addressing operational concerns, planned replacement of degrading equipment and maintaining an adequate mobile substation fleet reduces the potential of long-term outages and restoration delays, which can result in SAIDI and CAIDI minute avoidance in the year that operational issues are experienced.

iv. **4.4 HVD Substation Reliability**

Our HVD Substations Reliability program ensures the long-term safe and reliable operation of the electric distribution HVD substations. The capital expenditures in this program include investments to replace existing substation equipment. These investments are intended to reduce customer outage frequency (SAIFI) and reduce the number of emerging repetitive outage customers, as well as the customer outage durations as represented by CAIDI and SAIDI.

TABLE 49 – CAPITAL: HVD SUBSTATION RELIABILITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Circuit Breaker and Circuit Switcher Replacements	1.5	2.5	2.5	2.5	2.5
Transformer Bushing Replacements	1	1	1	1	1
Switch Replacements	1	1	1	1	1
Animal Mitigation, Potential Transformer Replacements, and Other	0.5	0.5	0.5	0.5	0.5
Total	4	5	5	5	5
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Circuit Breaker and Circuit Switcher Replacements	10	18	18	18	18
Transformer Bushing Replacements	8	8	8	8	8
Switch Replacements	8	8	8	8	8

Circuit breakers and circuit switchers are key and integral components of the HVD protection system. The purpose of this protection system is to minimize customer outage impact and mitigate equipment damage when the system experiences and clears an electrical fault. Increasing replacement by eight units (10 to 18) in years 2019 through 2022 will ensure our protection system remains fully functional. The breakers targeted for replacement are generally 1950s and 1960s vintage units. Breaker performance and increasingly scarce parts availability are two key inputs also driving these replacements.

Planning Process

We use multiple inputs and analytic processes to aggregate multiple data sources to best target reliability issues. These help to identify specific areas to target investments based on probability of future issues, and to prioritize projects that will deliver the greatest reliability improvements based on specific metrics (e.g., SAIDI, SAIFI, and CAIDI). The key inputs used in our planning process are listed below.

1. Input from Raw Test Data and Analytic Algorithms:
 - Transformer, LTC, Circuit Breaker, and Voltage Regulator Oil Dissolved Gas test data are reviewed and also set to subscription Industry Standard Analysis Algorithms (DeltaX TOA4, TJH2B, Doble, etc.).
 - Transformer and battery electrical test data are reviewed.
 - Circuit Breaker operational testing and operation history are reviewed.
 - The Criticality, Health, and Risk (CHR) algorithm has been developed for specific equipment groups in the Cascade work/asset management software. We developed CHR in collaboration with Digital Inspections (Cascade) experts, and it has been customized to our equipment based on equipment analysis experience coupled with industry parameters. Where applied, the algorithm will produce a Risk analysis based on an applied Criticality (to the system) input, and a Health value developed using test results. This can be a useful component in the prioritization process for equipment replacement projects. The Reliability Engineers may then request Substation Planning to initiate a substation equipment replacement project.
2. Reliability Improvement Initiatives:
 - Collaboration and input from field organizations and other departments, to provide substation Reliability Engineers with information regarding operational concerns that can initiate individual substation equipment replacement projects.
 - Planned replacement of obsolete switches, or those with known operational issues.
 - Planned replacement of obsolete transformer bushings, or those with known failure modes and histories.
 - Planned replacement of obsolete circuit breakers, or those with known operational issues.
 - Planned replacement of obsolete potential transformers, or those with known failure modes and histories.
 - Planned replacement of obsolete circuit switchers.
 - Animal mitigation upgrade projects where an animal outage has occurred and measures can be implemented that will likely reduce the probability of future similar outage events.
3. Equipment Trend Data:

- Planned replacement of substation equipment may be triggered with trend data that indicates degrading equipment condition, but has not reached a concern of imminent failure.
- Dissolved Gas Analysis trend data are used to identify when replacement of substation transformers and regulators are needed.

Project Prioritization and Selection

Once we have analyzed the reliability inputs and identified potential substation projects, we execute project implementation based on program budgets. Projects are also prioritized based on test result data trends, industry experience, and experienced operating issues, and then balanced to complete the reliability improvement initiatives:

- Install animal mitigation where an animal outage has occurred inside the substation and present mitigation measures can be improved.
- Implement reliability improvement projects to address and mitigate substation repetitive outages.
- Replace one to two HVD substation transformers per year based on degrading trend data.

Timing

Project planning is an ongoing process. Project engineering and scheduling typically occur in the current year for the following year's construction. New projects can be inserted into the plan based on operational concerns, which may result in the deferment of previously planned projects depending on program funding, available construction resources, and/or mobile substation availability.

Benefits

Reliability investments minimize potential adverse impacts on customer experience through the improvement of the overall energy reliability, operation and maintenance of substations over the long term. Addressing operational concerns and the planned replacement of degrading equipment reduces the potential of long-term outages and restoration delays, which can result in SAIDI and CAIDI minute avoidance in the year that operational issues are experienced.

v. 4.5 Substation Communication Upgrades

The Substation Communications Upgrade program is intended to upgrade end-of-life telecommunications networks currently providing Supervisory Control and Data Acquisition (SCADA) functionality at our substations. SCADA functionality provides remote control and monitoring capabilities to ensure the long-term safe and reliable operation of the electric grid system. Upgrading these communications circuits will reduce the need for multiple dedicated circuits and improve situational awareness that will be necessary to manage the growing number of system automation deployments and DER assets. Furthermore, telecommunications service providers have communicated their intention to sunset the analog technology in the near future, so we will replace the existing analog multi-drop circuits with dedicated high-speed, open standards-based communications and modern cybersecurity.

TABLE 50 – CAPITAL: SUBSTATION COMMUNICATION UPGRADES

5-Year Capital Plan (all values in \$ millions)								
Investment Categories	Historical			Plan				
	2015	2016	2017 prelim	2018	2019	2020	2021	2022
Analog Multi-Drop and security	-	1	12	23	41	-	-	-
Frame Relay	1	0	-	-	-	-	-	-
Total	1	1	12	23	41	-	-	-
Unit Forecast								
Investment Categories	Historical			Plan				
	2015	2016	2017	2018	2019	2020	2021	2022
Analog Multi-Drop replacements	-	-	4	75	151	-	-	-
Frame Relays	18	6	-	-	-	-	-	-

Planning Process

We currently have approximately 230 HVD substations with telecommunications in need of upgrading. Similar to our aging grid infrastructure, our telecommunications to these substations are aging and becoming obsolete. The investment prioritization process used to determine where to deploy our upgrades takes into consideration a number of factors such as NERC Critical Infrastructure Protection (CIP) requirements, generation asset support, and site scope elements. This prioritization helps to direct not only our rollout plan but also which communication technology should be implemented.

The project scope includes a number of site-specific critical decisions. One overarching principle for all the sites is to have a future-proof modular design that can handle potential changes. Consistent engineering standards are used wherever possible, but on some occasions, our substations have constraints that require deviations. Project scope examples include:

- **Shared fenced area (CE, ITC & Telecommunications)** — By constructing a shared fenced area, we can increase safety at the substation by enabling communications work without entering substation control houses. This design principle will also facilitate quicker communication circuit restoration by eliminating the need for our personnel to coordinate access and escort telecommunication technicians.
- **New control house** — At sites where working space issues exist and cannot be easily mitigated, we will build new control houses. The new houses will support communications equipment plus enough space to consolidate grid equipment in the future.

Grid communications investments are usually large and long-term; therefore, it is essential that they include as much future-proofing as possible. As the rate of technological change increases, especially when it comes to telecommunication investments, our designs are standards-based, standardized, and modular. This will help minimize the risk of technology manufactured with proprietary standards, “one-off” communication installations, and will allow providers to install equipment without needing to be escorted in the field.

Benefits

The project will implement the Grid Communications design, allowing multiple applications to use the same network instead of having a single communications circuit per application. This includes substation telemetry, automation applications, internet protocol cameras, phones, and physical security equipment. In order to ensure success beyond the initial project, a communications catalog is being developed to ensure communications in the field and substation adheres to a Company standard. The catalog will deliver a single reference source for all substation and line device related communication options.

vi. **4.6 HVD System Protection**

The HVD System Protection program targets replacement of relays that are reaching end of life, which are more likely to fail. Investments in this program are directed at replacing obsolete, high maintenance electromechanical (EM) relays with digital devices. Many of the EM relays are either no longer manufactured or no longer have parts available, while those parts that are available are no longer cost-effective to replace. Replacing end-of-life relays reduces O&M expenses, as older electromechanical relays require more periodic maintenance than newer digital relays.

Our five-year plan consists of replacing between 21 and 32 electrical line exit relays per year at a cost of approximately \$2 million per year.

TABLE 51 – CAPITAL: HVD SYSTEM PROTECTION

5-Year Capital Plan (all values in \$ millions)					
	2018	2019	2020	2021	2022
Total Spending	1.9	2.3	2.3	2.3	2.4
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Line Exit Relay Replacements	21	30	30	30	32

Planning Process

In 2017, we had 6,634 protective relays on the HVD electrical system, 57% of which are EM devices, 7% solid state, and 36% digital. In 2018, we are slated to replace approximately 21 relay schemes. Currently, about 16% of the total relay population is older than the designated design life (27% for EM relays).

We base our investment selection in this program on numerous factors, including:

- Overall Protection System performance
- Component technology – EM, Solid-State, Digital
- NERC compliance requirements
- Manufacturer information on known defects, problems, or alerts
- Component availability for replacement/repair, spare parts, cost
- Component age

While we do not have definitive relay replacement thresholds for all relay types, a number of factors are considered when selecting projects for the HVD System Protection program. A key criterion is the performance history of specific relay types. If a specific relay type or model is known to have failure or maintenance issues, it will be prioritized in the program. One particular EM relay model requires maintenance twice as often as other EM relays in order to keep them within their setting tolerance. These relays are targeted for replacement to reduce O&M expenses as well as the risk of failure. Similarly, relay age is often a factor as older relays typically have an increased failure risk.

We also target replacing relay schemes that rely on analog phone lines for communication. These phone circuits are becoming increasingly more expensive as the phone companies reduce their support of analog circuits. Replacing relays with newer communication technologies reduces the O&M expense associated with these circuits.

We also select HVD System Protection projects to coordinate with other reliability or capacity projects in order to realize synergies in construction and to take advantage of the planned system element outages needed to support the construction. Completing relay projects at the same time as other projects reduces labor costs and reduces the number of planned system element outages.

Certain HVD System Protection projects are also necessary due to regulatory compliance requirements. Some HVD protection schemes fall under NERC standards and may need to be replaced or upgraded as necessary for compliance. The HVD System Protection program also supports the NESC working space requirements noted earlier in capital program 4.5 Substation Communications Upgrades.

Generally, relay replacements are planned one year in advance of the desired construction year. Relay replacements for the next two years are tentatively identified to assist with project coordination and to accommodate time to engineer larger projects. Some future projects may be addressed by system improvements completed using other capital programs. Timing of relay replacements may be advanced or delayed to coordinate with other known project work and to take advantage of the planned system element outages.

Benefits

The failure of a relay to trip properly under fault conditions can lead to severe system consequences. These consequences could include extended breadth and length of outages experienced by customers, increased likelihood of major equipment or conductor damage, and possible unsafe employee or public safety conditions.

Digital relays contain oscillographic recording functions that allow for evaluation of system conditions in real time and enable remote interrogation by the protection engineer to help determine the location of HVD system faults much more quickly. Identifying the fault location quicker and with more precision allows repair crews to get to the problem location sooner, leading to faster repairs and restoration, thus reducing CAIDI.

Newer digital relays are also cheaper to purchase and require less panel space than older relays. One HVD relay scheme project typically replaces six EM relays with two new digital relays. Digital relays are designed with more flexibility in settings and applications, so they can be reconfigured easily to accommodate proposed projects or reconfigurations of the HVD system without incurring additional relaying expense.

As our relay population continues to age, more money will need to be spent on O&M. Experience has shown that as relays age they are found to be out of tolerance more often; therefore, more frequent field testing and calibration is required in order to ensure proper performance. Digital relays are tested less often than EM relays reducing O&M test expenses. Experience has shown that digital relays can be tested once every five years instead of once every four for EM. Further, the time spent to test and calibrate digital relays is 50% less than a comparable EM relay. As we invest in replacing old EM relays with digital, functionality and performance will improve and O&M expenses will be reduced.

vii. 4.7 LVD Repetitive Outages

The LVD Repetitive Outage program addresses areas of consistently recurring customer outages, inclusive of all interruptions including MEDs. The primary metric used to address repetitive outage performance is the CEMI. The CEMI metric measures the percent of overall customers that have experienced more than a specific number of interruptions in a given period year. We measure CEMI performance based on the CEMI-5 measure, or the percent of our customers that experience more than five interruptions annually, as discussed previously in Section IV.

TABLE 52 – CAPITAL: LVD REPETITIVE OUTAGES

5-Year Capital Plan (all values in \$ millions)					
	2018	2019	2020	2021	2022
Total Spending	10	9	10	10	10
Unit Forecast					
	2018	2019	2020	2021	2022
Repetitive Outage Zones	200	180	200	200	200

The LVD Repetitive Outages spending plan will remain relatively flat over the next five years at \$9 million to \$10 million annually. This will allow for us to target approximately 200 zones annually at an average cost of \$50,000 per project.

The investments in this program also address customer complaints related to frequent outages by targeting a zone for improvement. This active and targeted work to improve the CEMI-5 index tends to decrease the number of customer complaints. Our customer outage analysis has shown us that the number of complaints by customers increases most dramatically when customers experience more than three service interruptions within six months.

As discussed in Section II, we have included the ‘% of customers with ≥ 3 interruptions per year’ as one of the reliability metrics for our five-year plan. Customer survey results indicate that this is a tipping point for customer satisfaction – so we track both this metric, and the MPSC CEMI-5 index to have a more fulsome view of customer sentiment. The prioritization logic for this program will continue to use the CEMI-5 index and customer complaints, while also working to decrease the number of customers experiencing three or more outages per year.

Planning Process

We use RAE data as the primary input in deciding where to target our investments in the LVD repetitive outage program. Additional details on RAE can be found in capital program 4.1 LVD Lines Reliability and Appendix F. The RAE produces a bi-weekly Repetitive Outage report which is reviewed by circuit engineers. The report is broken down to identify specific zones, showing the number of customers that experience repetitive outages in each zone of the circuit.

Circuit engineers analyze the data from this report, and they develop solutions that reduce the potential of a customer having five or more interruptions annually. This lets us create solutions that have the greatest reliability benefit for the highest number of customers first.

Figure 87 below shows a segment from the bi-monthly RAE Repetitive Outage report. In this example, we found that several customers had experienced five interruptions on the entire circuit (noted as “SUB”). In addition, there were customers that experienced an additional interruption in other zones (noted as “Primary”). When you add the five interruptions to those in other zones, these customers were seeing six interruptions each. A cross-functional team was assembled consisting of HVD, LVD, Substation Planning, and Forestry personnel to develop an action plan. We immediately prioritized work to respond to these customer needs.

FIGURE 87 – SCREENSHOT EXAMPLE OF THE REPETITIVE OUTAGE REPORT

Feeder	Adqu	Substation na	Feeder nar	System Engr	System Ov	Incidents per customer	Customers rolling 12 months	Customers per incident	Incide	Facility	Area of fau	Cause	Time of Outag
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6	551	612					
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		609	3312529	SUB	HVD Line	Planned Scheduled	2017-02-19 00:07
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		177	3350815	0928	Primary	Weather	2017-03-08 10:30
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		398	3326481	0720	Primary	Weather	2017-03-08 10:30
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		2	3329181	0786	Primary	Weather	2017-03-08 11:43
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		9	3367245	0786	Primary	Trees	2017-03-11 12:25
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		612	3398203	SUB	HVD Line	Equipment Failure	2017-04-26 21:47
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		612	3398775	SUB	HVD Line	Weather	2017-04-27 11:11
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		612	3400915	SUB	HVD Line	Equipment Failure	2017-04-30 01:06
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		612	3451941	SUB	HVD Line	Equipment Failure	2017-06-30 02:38
042602	Adrian	PITTSFORD	BIRD LAKE	jhrehneh	pjokonie	6		2	3462921	0816	Primary	Weather	2017-07-07 05:11

Additionally, LVD Planning continuously collects feedback from customer-facing groups in our Economic Development and Customer Care groups to better understand the priorities and needs of our customers to incorporate into our investment planning process. For example, we may have a segment of line that is not experiencing multiple outages longer than five minutes. However, customers on that line might be experiencing brief interruptions causing their motors to restart and reduce production. For another example, if we know that there is planned development in an area that will increase electric load, then when we plan work to improve reliability, we will also incorporate any needed capacity upgrades, such as a larger conductor, to ensure all aspects of service are covered in the enhancement plan for that particular part of the electric system.

Project Prioritization and Selection

Once we have identified circuits to target on the LVD system, we develop, evaluate, and prioritize to target outage minutes and provide the highest reliability impact for our customers. This allows the circuit engineers to direct investment to areas that are most affected by repetitive outage issues. The circuit engineers start by looking at outage history from OMS to decide which circuits or zones to target, evaluating multiple alternative proposed solutions for each reliability concern (e.g., pole top maintenance, forestry clearing, or fusing) to determine the best customer reliability benefit, given the availability of money and resources. After the analysis is complete, the circuit engineer submits the best

solution as a proposed concept. Ideally, this program addresses issues quickly by designing short lead time projects that address issues on a short turnaround time. Projects are coordinated with Forestry line clearing work to maximize improvement and ensure the correct zones are targeted.

The type of work depends on specific circuit conditions and attributes, but typically includes investments such as:

- **System protection upgrades (e.g., to fuses, switches, reclosers)** – This prevents or minimizes damage to lines and equipment caused by system faults, using devices that maintain continuity of service by segmenting the electric distribution system into smaller sections, minimizing the number of customers affected by any individual outage. Refer to capital program 4.1 LVD Lines Reliability for more information.
- **Upgrading lightning protection to meet standards** – For example, we install lightning arresters (otherwise known as surge arresters) every 1,300 feet as a Company standard. Refer to capital program 4.1 LVD Lines Reliability for more information.
- **Replacing deteriorated or non-standard equipment** – Items identified for replacement include poles, crossarms, pins and insulators, lightning arresters, non-standard equipment, and cutouts.

A wide range of repetitive outage solutions are applied depending on each situation. At times, a long-term solution may be considered under the LVD Lines Reliability or LVD Lines Failures programs (refer to capital programs 2.1 LVD Line Demand Failures and 4.1 LVD Lines Reliability). This can include relocating a line, installing an aerial spacer cable, or reconductoring or reconfiguring the circuit. Projects are prioritized by the program planner using a cost-benefit analysis, based on the number of customers impacted, number of complaints, and number of interruptions.

Timing

The majority of project planning for this program is completed, along with other Reliability planning, for the next year in the summer starting in June and finishing in August. Projects may also be submitted in the current year for construction during the same year and evaluated through the same layered approval process described in previous LVD capital programs. The planning process is completed closer to the time that the projects are to be constructed so that timely data is utilized to provide the most benefit to customers. Planning these types of investments too far in advance could result in using outdated data. Further, project areas identified for proactive reliability improvements too far in advance could have system improvements done under other capital or O&M programs (e.g., LVD Lines Demand Failures) in the interim.

Below are two examples of projects that were selected as part of repetitive outage. Refer to Appendix E for a more detailed project listing for LVD Repetitive Outage.

- RPOUT16 KALKASKA/RUGG LCP 229 – This is a single phase line that runs along some trees and has several unfused laterals. The recommended solution is to fuse all laterals and ensure adequate lightning protection, including moving lightning arrester down on transformers, and clear trees on entire zone. This project will improve reliability for 95 customers by reducing interruption frequency from an average of one per year to none.
- RPOUT17 SIMMONS DAM RD LCP 871 – The sectionalizing device in this zone had three interruptions affecting 20 customers on the circuit in two years. Work consists of replacing a line recloser with larger fuse, increasing the substation recloser settings, replacing a solid blade with

a fuse and the installation of lateral fuses. This project will improve reliability for 20 customers by reducing interruption frequency from an average of three per year to none.

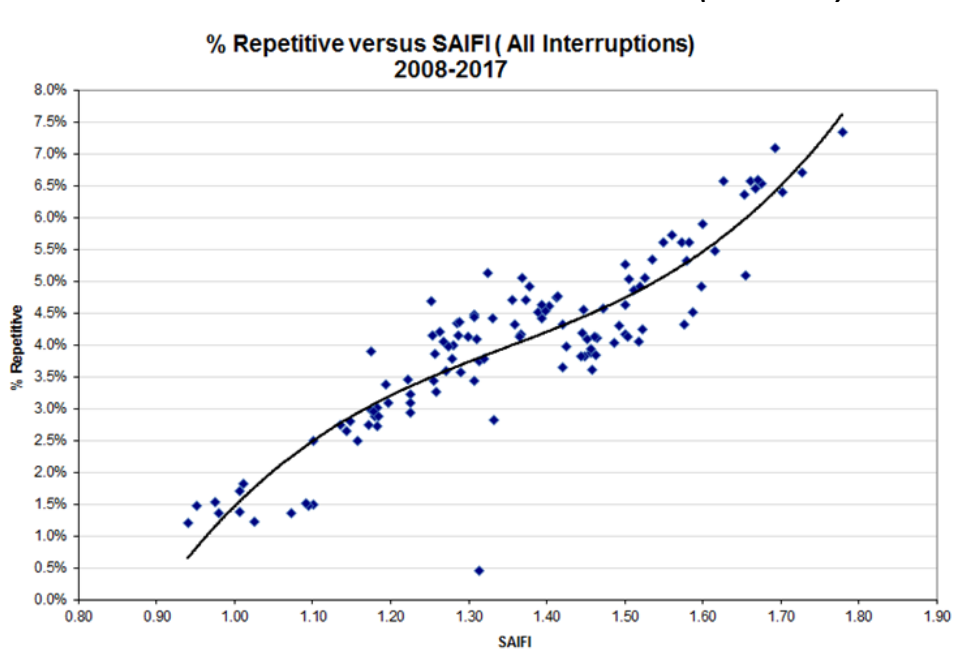
The list may be adjusted throughout the year as additional projects are identified for new repetitive zones.

Benefits

There is a correlation between SAIFI (including MEDs) and the MPSC’s Repetitive Outage performance standard (which, by definition, includes storms). Based on a statistical comparison of the two metrics, we can see that once SAIFI (including MEDs) exceeds approximately 1.60, it becomes likely that the Repetitive Outage performance index standard will not be met. As can be seen in Figure 88 below, our 2008 through 2017 year-end SAIFI performance including MEDs has ranged from approximately 1.0 to 1.8 and the Repetitive Outage year-end performance has ranged from approximately 1.5% to 7.0%.

The data in this chart shows the SAIFI (including MEDs) and Repetitive Outage calculated on a rolling 12-month basis for each month from December 2008 through December 2017, measured for all conditions. To improve customer satisfaction, we continue to focus on sustained SAIFI performance to meet the Repetitive Outage performance standard. A deteriorating SAIFI increases the probability that more than 5% of customers experience five or more outages per year.

FIGURE 88 – REPETITIVE OUTAGE CUSTOMERS VS. SAIFI (2008-2017)



By targeting investment to the worst performing areas of our system, we expect to improve both SAIDI and SAIFI, improving the customer experience. For further details on the SAIDI benefit of the LVD Repetitive Outages program, refer to Section VII.C, which summarizes the reliability impact of our investment plan.

The proactive investments made to replace depreciated assets and reduce zones of influence improve employee and public safety. Furthermore, investments in the LVD Repetitive Outages program reduce overall cost associated with emergent response for additional interruptions in the capital program 2.1 LVD Lines Demand Failures.

viii. 4.8 Metro Reliability

Our Metro Reliability program ensures the long-term safe and reliable operation of our electric Metro system. The capital expenditures in this program include investments to install, upgrade, and rehabilitate the Metro system. The performance goals of this program are to reduce customer outage frequency (SAIFI) and reduce customer outage durations (CAIDI and SAIDI). These objectives are achieved through investments in three categories: obsolete equipment replacements, dead fronting equipment for safety, and new technologies.

Over the next five years, we expect to spend between \$3 million and \$4 million annually, based on the above objectives, starting with 21 projects currently planned for 2018. This level of funding is the estimated need to improve reliability as part of our long-term metro plan in specific regions.

TABLE 53 – CAPITAL: METRO RELIABILITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Obsolete Equipment Replacements	3.6	2	3	2	2
Dead Fronting Equipment for Safety	0.4	0.5	0.5	0.5	0.5
New Technologies	0	0.5	0.5	0.5	0.5
Total	4	3	4	3	3
Unit Forecast (number of projects)					
Investment Categories	2018	2019	2020	2021	2022
Obsolete Equipment Replacements	15	8	13	8	8
Dead Fronting Equipment for Safety	6	4	6	4	4
New Technologies	0	2	2	2	2

Our Metro Reliability program develops engineered responses to maintain and improve the reliability of our Metro system, by performing the following:

- **Obsolete Equipment Replacements** – Replacing functionally obsolete equipment, including:
 - Oil-insulated switches with SF₆ insulated switches
 - Polychlorinated biphenyls (PCB) oil-insulated voltage transformers with Non-PCB transformers and dead front busing well inserts
 - Impregnated Paper Lead Covered (IPLC) and Varnished Cambric Lead Covered (VCLC) cable with crosslinked tree retardant polymer insulated (TRXLPE) cables

- **Dead Fronting Equipment for Safety** – Increasing the safety of our equipment by replacing:
 - Live-front, dry type transformers, in buildings that fall under our ‘high rise policy’ with dead front bushing well inserts
 - Live-front, vault-style, transformers and fusing with molded vacuum interrupters (MVIs)
 - Encapsulated transformer bushings (fuses and elbow type) and live secondary buss with guarded load centers
 - High rise live-front transformer replacement
- **New Technologies** – We are enabling new technologies in subterranean civil and electrical infrastructure systems including expanding manhole lid covers, manhole chimneys, and capitalized civil repair systems. Electrical components include the replacement of:
 - 600A rated SF6 switches with 600A rated molded vacuum interrupters
 - SCADA applications providing real time monitoring and metering of assets, such as sump level alarms, secondary load monitoring, and remoting switching capabilities

Planning Process

Similar to the planned portion of the Metro Demand Failures program (refer to capital program 2.7 Metro Demand Failures), we vet reliability projects during the Metro investment planning cycle starting in July and ending in August of each calendar year. During this period, circuit engineers identify the most critical needs of the system to increase the integrity of the grid. The system components are upgraded to increase operability in order to improve safety for operating and decrease complexity of operating and maintaining equipment as described previously. They then prepare scope documents and estimated project costs based on labor and material unit costs from the Consumers Energy Standards.

While we continuously monitor the reliability of the Metro system, we also perform an annual review to determine which line segments and components need to be addressed in the next year or years, as some projects may be large enough to span multiple years. Additionally, we determine which remediation strategy to use. Due to the lengthy outages that a metro interruption can incur, these projects are proactive to prevent an outage from occurring and not due to a previous interruption. The three key inputs utilized in our Metro line reliability assessment are: (1) Current System Condition, (2) Customer base, and (3) efficiency gains with other projects:

- **Current System Condition** – The metro condition is assessed by certified sub metro operations personnel based on the safety and ability to operate existing equipment (during emergency and maintenance). The sub metro operations personnel provide feedback to the circuit engineer upon findings for consideration in future plan years.
- **Customer base** – The projects are prioritized by the reliability benefits by customer category. The customer categories in order of priority are:
 1. Critical customers are highest priority due to the negative impact an interruption could have to the community. Examples of these critical customers include, but are not limited to, water supply, sewage facilities, hospitals, and public safety.
 2. Large residential are the second priority to reduce the number of customers interrupted by a single outage. Large residential in Metro is considered to be approximately 50 customers or more.
 3. Other commercial or residential are the final category of customer priority. This includes, but is not limited to, offices buildings, limited residential (e.g., less than 10 customers), and store fronts.
- **Efficiency Gains with Other Projects** – When we receive an external request (refer to capital programs 1.3 Metro New Business and 3.3 Metro Asset Relocation) we will determine if

upgrades are needed, such as dead fronting equipment. This is done to gain overall efficiencies by performing upgrades at the time we are constructing the requested work. This reduces the cost of the project by constructing at the same time as the request compared to returning at a later time to conduct the work. The cost of the upgrade is not passed on to the requester and is funded through this program.

For projects that require new or modified civil infrastructure, we release the scopes to a contracted civil engineering firm, who creates a feasibility study for a civil infrastructure path. The feasibility study provides a number of options for possible routes and estimated construction costs for those options. The circuit engineer reviews the feasibility study with operations representatives to determine ease of construction and impact to future electric operations. The circuit engineer notifies the civil engineering firm, who will prepare a design based on the selected option. The circuit engineer will prepare an electrical design, cable pulling schedule and electrical bill of materials. The civil engineering firm delivers the design and any documents needed to obtain a permit to perform work in the right of way from MDOT of the municipality, including a detailed traffic control plan.

There are a number of risks that we may encounter during construction of Metro Reliability projects including:

- Encountering crushed conduit while attempting to replace cable. Conduit can be crushed as a result of heavy loaded objects above the ground or the fiberglass becoming brittle as a result of exposure to soil conditions.
- Increased costs associated with temporary transformation and other items required for a mobile vault. This is similar to the use of a mobile substation to allow for safe maintenance or construction work on de-energized equipment. It has a set of padmounted equipment built at grade level and fenced off to guard from the public.
- Potential fluctuation in contractor costs. Contractor costs can fluctuate between projects based on the bids received. This is based on the amount of work that the contractor already has secured and the cost for them to add this to their work plan (additional or mobilizing resources).

Examples

The following is an example to reflect the type of work contained in capital program 4.8 Metro Reliability. Refer to Appendix E for a more detailed project listing.

The Robinson Vault services customers in downtown Battle Creek, including Western Michigan University, the City of Battle Creek (street lights and signals), Kellogg Community Credit Union, and the Riverwalk Centre. The Robinson Vault had lead secondary cables, live front transformers and non-load break fuses, and live secondary buss work. This vault violated many Minimal Approach Distances rules and working clearances for sub metro mechanics to perform their work safely. We arranged for a mobile vault to be onsite to provide continuous service to local businesses while we performed work in the vault. Electric cables were intercepted in an adjacent manhole or passed through the vault hatch to redistribute energy to the Metro system. The scope of work involved the replacement of the live-front, metro style transformers with dead-front bushing metro style transformers; non-load break fuses with molded vacuum interrupters; and live secondary buss with guarded load centers, 200A dead front elbow switching modules. Figure 89 illustrates the equipment in the Robinson Vault before the project and Figure 90 illustrates the equipment after the project was complete.

FIGURE 89 – OLD ROBINSON VAULT EQUIPMENT BEFORE RELIABILITY PROJECT



FIGURE 90 – NEW ROBINSON VAULT EQUIPMENT

(DEAD FRONT BUSHINGS ON HIGH SIDE OF TRANSFORMER AND MVIS ABOVE, LOAD CENTERS AT WALL)



Benefits

Reliability investments minimize potential adverse impacts on customer experience through the improvement of the overall reliability and operation. These proactive investments also improve employee and public safety, through reduced outage incidents. Furthermore, investments in the Metro Reliability program reduce overall cost associated with emergent response in the capital program 2.7 Metro Demand Failures.

ix. **4.9 Advanced Capabilities Infrastructure: Automation**

The Advanced Capabilities Infrastructure: Automation program includes investments in grid devices and coordinated infrastructure upgrades to improve our grid management for better grid resiliency and reliability, enabling implementation of substation and line automation on our system. This includes both upgrades to aging infrastructure and installation of new distribution system devices and controls. For details on these grid devices, see Section V.B.

TABLE 54 – CAPITAL: ADVANCED CAPABILITIES INFRASTRUCTURE: AUTOMATION

5-Year Capital Plan (all values in \$ millions)								
Investment Categories	2015	2016	2017 prelim	2018	2019	2020	2021	2022
DSCADA	6	4	8	10	8	10	12	13
SCADA	-	-	1	2	2	2	2	2
ATR	0	1	3	9	16	19	22	22
Line Sensors (early deployment)	0	1	1	1	1	1	1	1
Regulator Controllers (early deployment)	-	1	0	3	4	6	6	6
Total	6	7	13	24	31	39	43	44
Unit Forecast								
Investment Categories	2015	2016	2017	2018	2019	2020	2021	2022
DSCADA	31	21	64	60	50	65	70	80
SCADA	-	-	42	50	50	50	50	50
ATR (loops)	5	5	11	60 (14)	50 (17)	65 (20)	70 (22)	80 (22)
Line Sensor Sets (individual units)	6 (18)	39 (117)	15 (47)	90 (300)	150 (50)	150 (50)	150 (50)	150 (50)
Regulator Controllers	-	-	8	50	75	100	100	100

DSCADA

Our DSCADA automation project is a multi-year capital investment effort to upgrade our existing LVD substations and enable situational awareness and control capabilities. The deployment began in 2012 and will cover up to 70% of our distribution system by the end of 2022. See Section V.B for additional details on these devices.

Project Prioritization and Selection

We developed a multi-year deployment plan for DSCADA to allow for potential project issues to be addressed. This allows us to incorporate any changes to process or design standards in a scheduled revision process to maximize the impact of lessons learned. While many considerations went into establishing the deployment schedule, there were three primary factors: (1) the need for DSCADA as a platform to achieve additional grid modernization benefits (e.g., ATRs and VVO), (2) to maximize AMI deployment benefits, and (3) to reflect the preference to deploy DSCADA by region instead of at dispersed substations across the state.

Our DSCADA implementation plan historically focused on reliability metrics to prioritize installation, but that is evolving to a greater focus on supporting other grid modernization initiatives. For example, in 2018, 27 of the new DSCADA sites coincide with new or existing substation installations of ATRs. Going forward, all ATR installations will align with DSCADA installations, due to the additional capabilities that an ATR can deliver when served from a DSCADA substation. Although all of these sites were part of the initial deployment plan, we may have adjusted their planned deployment year to match ATR installations.

From 2019 onwards, we may further adjust DSCADA prioritization to coincide with VVO and CVR efforts. Currently, VVO and CVR are not affected by DSCADA priority.

Each of our almost 2,000 circuits has multiple characteristics, and we consider these characteristics when prioritizing circuits for DSCADA. These include:

- Three-year average SAIDI statistics by circuit;
- Scheduled substation work (full rebuilds, new builds, and other projects); and
- ATR deployment schedule.

Benefits

The primary benefit of DSCADA is to enable other grid modernization efforts. DSCADA is a prerequisite for advanced ATR functionality, VVO, CVR, and a number of other advanced grid modernization capabilities. Furthermore, there are also direct benefits immediately upon installation of DSCADA at a substation. DSCADA provides operators with an early outage indicator for interruptions to an entire circuit, which allows for improved response and customer restoration time. DSCADA also allows substation devices to be operated remotely, which often accelerates restoration, and always provides cost savings by avoiding the need to physically send field operators to the substation. As the deployment of these processes was being ramped up in 2017, DSCADA was used to avoid nearly 200 truck rolls (deployment of substation operators).

DSCADA also allows us to monitor substation health and preemptively remove equipment from service before it causes a permanent outage. This process is currently being developed and will be expanded as our condition-based maintenance and distribution asset management programs are developed.

For further details on the SAIDI benefit of DSCADA, refer to Section VII.C, which summarizes the reliability impact of grid modernization investments.

SCADA

The SCADA program includes two sub-programs designed to use SCADA systems to ensure the long-term safe and reliable monitoring and control of the electric system. The capital expenditures in this program include investments to install, upgrade, and replace SCADA devices.

The two primary components of the SCADA program include:

1. The SCADA device capital replacement program which replaces end-of-life SCADA devices on an annual basis.
2. The MOAB SCADA program which upgrades our existing MOABs to the current SCADA design standard. The current MOABs SCADA plan began in 2014 and will cover 100% of our MOABs by the end of 2022, bringing a similar level of monitoring and data to our HVD lines as at our HVD substations.

Planning Process

We conduct and use a number of analyses, based on several critical inputs, to aggregate multiple data sources to best determine optimal SCADA deployments. The analyses identify specific areas to target investments, based on probability of future issues, and help prioritize projects that will deliver the greatest reliability improvements based on specific metrics. These inputs include:

- RAE
- Input from operations, planning, and Operations Technology groups:
 - Collaboration with and regular input from operations and field organizations gives our SCADA Applications team the ability to serve customer needs while considering resource and system constraints.
 - Collaboration with our planning groups improves monitoring in areas of both reliability and capacity concerns.
 - Collaboration with our Operations Technology group ensures that we maintain the SCADA system in an efficient and secure manner.

Once we identify a SCADA investment opportunity, we develop and prioritize individual SCADA projects to improve monitoring and control of the distribution system based on the following criteria:

1. End-of-life device replacement projects – We ensure that the SCADA system meets present SCADA installation standards, and that obsolete units are replaced as needed, for both security and interoperability purposes.
2. Operational visibility – We increase operational visibility in locations where needed, reducing reliance on assumptions and state estimation. System devices and substations are prioritized based on historical operational needs, allowing us to target investment to areas most affected by operational issues. Whenever possible, this is coordinated with planned projects in other programs. By analyzing historical monitoring and control needs across the grid, identifying trends, and assessing locations with the greatest potential operational improvement, we can target areas that maximize operational efficiencies and SAIDI avoidance.
3. Improving system operating resource optimization – Some areas of the grid require enhanced operational flexibility to ensure that the grid operates as efficiently as possible. In these locations, we can increase monitoring and control capabilities to reduce system losses and improve power quality. This allows more work to be done remotely, instead of sending a truck

to a substation to make a setting change; this remote work can be done faster, more safely, and more securely than having a resource physically onsite at the substation.

We prioritize projects as stated above using an evaluation of costs and benefits. The benefits, outlined below, are calculated based on inputs from engineers and program managers, based on their experience and knowledge of the system. Projects that will have the greatest impact to the grid are sequenced for work and built based on availability and location of resources and funding.

Benefits

With approximately 330 MOABs active in 2017, we documented saving over 43 million customer minutes (including MEDs), through the automated sectionalizing of faulted HVD lines. Adding SCADA to 42 of these switches in 2017 saved an additional 414,000 customer minutes (including MEDs), and full MOAB SCADA deployment will add the capability to remotely monitor and operate all of these switches, with a projected operational improvement of an additional two to four million customer minutes (including MEDs) by 2022.

Reliability benefits associated with SCADA include:

- CAIDI and SAIDI Improvement – Being able to remotely operate MOABs and being aware of their locations will reduce the frequency and duration of outages.
- Reduced Failure Rates – Reducing asset failures will be realized, especially of electric system components.

Safety benefits associated with SCADA include the ability to monitor and operate MOABs remotely, reducing the amount of time employees spend in the field and reducing the potential for injury.

Sustainability benefits associated with SCADA include:

- Extended asset life – Status awareness and remote operation capability of MOABs allows faster operation, reducing stress on those assets and improving maintenance.
- Improved asset performance – This benefit occurs if system assets can be made to perform more efficiently.
- Deferred investment – This benefit occurs when asset life can be extended.
- Increased renewable hosting capacity – With increased monitoring in control of the distribution system, the ability to host non-dispatchable renewable energy sources will be increased.

Control benefits associated with SCADA include:

- Improved situational awareness – This improves our real time visibility into the electric system's status, allowing for quicker identification and resolution of system performance issues. There have been incidents in the past where HVD substation breakers have been opened for scheduled work and employees were unaware that a downstream MOABs was also open. When the substation breakers were opened, customers were dropped inadvertently. The increased system visibility that comes with SCADA would reduce the likelihood of such occurrences.
- Improved benchmarking against other utilities – All major utilities have a functioning SCADA system.

Cost benefits associated with SCADA include:

- Increased employee productivity – Field employees will spend less time in the field and Operations employees spend less time doing analysis, allowing for more work to be accomplished.
- Reduced back office support costs – Automation, communications, and efficiency improvements will reduce back office costs.

Automatic Transfer Recloser (ATR)

By the end of 2017, we had 31 automation loops installed on the distribution system, utilizing over 100 ATRs and impacting approximately 1.5% of the distribution system. By 2022, we expect that deployment to impact approximately 10% of the system. This multi-year deployment plan was developed in coordination with the DSCADA deployment plan to maximize the benefit provided by ATRs while enabling the advanced capability of ADMS functions such as FLISR and switching order management.

Project Prioritization and Selection

When selecting ATR locations, we first identify all locations with existing infrastructure that can partially or fully support an automated transfer. The list of potential locations begins with a list of all three-phase ties between circuits, extracted from the Electric GIS. LVD planners then expand this potential site list with the locations of known historic load transfers, pulled from the Load Transfer Database. We then rank the circuits by SAIDI and LVD planners evaluate the list of potential ATR sites from the top down.

We generally target the top 20% of potential ATR sites, sorted by composite SAIDI contribution of the two affected circuits. After evaluation by the LVD planners, a loop proposal is developed for each potential location, including a calculated cost/benefit ratio based on estimated unit costs for the required upgrades and projected performance, using three years of OMS archive data for the proposed ATR locations. All proposals are then ranked by their cost/benefit ratio to ensure the maximum reliability benefit for our customers.

Benefits

ATR benefits are easily measured using industry standard methods for distribution automation. When an ATR operates during an outage incident, the distribution system fault is automatically isolated and the rest of the customers are automatically restored within 90 seconds. In 2017, we had 26 successful ATR operations resulting in 3.81 million customer interruption minutes avoided.

For further details on the SAIDI benefit of distribution automation loops, refer to Section VII.C, which summarizes the reliability impact of all grid modernization investments.

Line Sensors

We ramped up deployment of LVD line sensors in 2016 and 2017, with nearly 200 line sensors in service near the end of 2017. By 2022, we expect to install approximately 10,000 line sensors on the distribution system, covering approximately 400 circuits or 20% of the system.

Project Prioritization and Selection

During the initial phases of the line sensor deployment, we chose a grouping of circuits in two service regions to normalize the deployment statistics gathered, and to encourage support from field organizations. Going forward, we will install LVD line sensors on a circuit-wide basis, so the selection process is performed using a circuit-by-circuit analysis, using three-year average SAIFI and CAIDI

statistics from the OMS Archive via the RAE. The historic SAIFI score is given approximately 70% weight for prioritizing circuits for line sensor deployment and the top “poorest-performing reliability circuits” are excluded from this analysis to minimize overlap with other reliability improvement programs addressing those circuits.

After circuits for line sensors are chosen, additional analysis is performed to choose the specific sensor installation locations. The CYME load flow model is used to ensure we meet the minimum current requirement for the line sensor. The Aclara line sensor presently in use requires three amps for basic functionality, and 12-15 amps for full capability. Locations meeting the minimum loading criteria are also checked against the cellular tower geolocation data from Verizon to ensure all locations are within approximately four miles of the nearest cell tower. The cell signal strength is also validated as part of the installation process.

Benefits

Sensors can improve the entire LVD planning process by allowing more accurate load flow modeling. Not only can sensors improve the model for the circuits they are installed on, but the analysis performed using the data from line sensors can improve our system-wide load model. This more accurate and near real-time load information can improve the load transfer process for both planned and unscheduled outages. This will reduce the duration of the manual load transfer writing process, and improve the accuracy of the modeled transfers.

For further details on the SAIDI benefit of line sensors, refer to Section VII.C, which summarizes the reliability impact of all grid modernization investments.

Regulator Controllers

Distribution line regulator control upgrades began in late 2017, and we expect to reach 100% deployment by 2022. Full deployment will include replacing over 1,700 controls for over 3,800 line regulators. The new regulator control is multi-phase, so most multi-phase regulator sites have a single control, versus the current standard of one control per regulator.

Project Prioritization and Selection

Distribution line regulators play a vital role on the electric grid, as a fundamental method to combat voltage drop and line loss on distribution feeders. These devices increase and decrease line voltage automatically based on set conditions, ensuring that our customers receive reliable power. Currently, the regulator controllers operate these devices automatically without employee intervention. The regulator operations are based on measured data readings and pre-determined settings that are programmed locally on each device.

Line regulators controlled using SCADA or ADMS as part of a system-wide VVO program must operate in coordination with distribution capacitors. Since capacitors in the VVO program require DSCADA information as a data source, only line regulators on circuits with DSCADA are included in the regulator control upgrade program at this stage. As the VVO and CVR programs evolve, this scope will likely be expanded to include circuits with line sensors installed near the substation.

We currently choose regulator controller locations based upon regulator health, determined through field inspections performed by our electric field lab. In the future, we expect to prioritize regulator

control upgrades based on customer service voltage, substation average power factor, substation average power flow, and other criteria that are being evaluated as part of the initial installation.

Benefits

Line regulators with two-way communicating controls have many benefits, primarily CVR. We estimate that an average voltage reduction of 2.5% on our distribution system may be feasible and cost-effective, and this reduction in average voltage could yield an estimated load reduction of 2% system wide. Load reductions are especially important during peak conditions, where they can be used to help defer capacity upgrades.

x. **4.10 Advanced Capabilities Infrastructure: Advanced Technology**

Our Advanced Capabilities Infrastructure: Advanced Technology program will implement several software components, data readiness, and emerging operational demonstrations or pilots. This includes ADMS applications, allowing for more system visibility, system control and integration of DERs. This program also includes Electric GIS system model improvements to increase the accuracy of our electric connectivity model. Finally, the program involves ongoing deployment of operational analytics for reliability improvements and potential pilot projects. In 2018, we plan on investing \$16 million in Advanced Technology, and this spending will increase over the following two years as we make additional investments.

TABLE 55 – CAPITAL: ADVANCED CAPABILITIES INFRASTRUCTURE: ADVANCED TECHNOLOGY

5-Year Capital Plan (all values in \$ millions)					
All values in \$ millions	2018	2019	2020	2021	2022
ADMS	-	16	15	10	-
ESME	10	11	3	-	-
Grid Operational Analytics	1	1	1	1	1
Operational Demos, Pilots, etc.	5	5	5	5	5
Total	16	32	24	16	6

Advance Distribution Management System (ADMS)

ADMS is an advanced applications platform designed to manage the distribution system with higher levels of automation, more real-time outage management, and support for DER. Through ADMS, we will maximize the benefits of automation, improving system efficiency and reliability. Our OMS will soon no longer be supported by the vendor, and will need replacement in any case. Integrating DMS applications with OMS on one system platform will enhance our operations and customer service processes. ADMS is estimated to take 35 to 40 months to fully deploy, at a cost of approximately \$41 million. Cost components include planning and procurement, internal and external resources to implement the system, hardware and software costs, and maintenance of the system.

Benefits

Benefits of ADMS include improvements in reliability, energy efficiency/system optimization, and O&M reduction. Details of these benefits include:

- Improve operational visibility — Provide faster recovery from outage events, including natural disasters. System operators will use it to assess, monitor, and analyze the system more effectively.
- Integrate DG — Provide the ability to model and integrate two-way power flow resulting from customer generation into the system.
- Improve capacity utilization — Optimize system-wide energy efficiency by reducing line losses and controlling voltage levels. At peak load conditions, ADMS will automatically operate distribution devices to increase system capacity, without the need for customer opt-in programs.
- Restore more customers, faster — Identify possible switching locations to isolate the damage and restore as many customers as possible, sometimes completely automatically, at other times with manual field switching. Damage assessors will provide real-time feedback on physical damage, leading to faster material handling time, better determination of staffing levels, and more accurate restoration times.
- Optimize operational efficiency — Quickly formulate switching strategies, allowing operators to verify actions before the order is dispatched.
- Reduce operating cost — Reduce both crew time and miles driven as outage times decrease. Supporting one system instead of three will result in reduced need to integrate separate data, a single model to maintain, and less required training.

Electric System Model Enhancement (ESME)

ESME will support the advanced applications described in Section V of this report. These applications rely on the accuracy of the Electric GIS data model for operation. We have contracted with the Davey Resource Group to field test the existing Electric GIS data model, and correct and collect data up to one meter spatial accuracy. The project started in the fourth quarter of 2016 with expected completion by the end of 2019. To date, the project has identified and corrected 10.34% of the customer connectivity issues on the 161 circuits returned from the field.

Project Prioritization and Selection

This project is sequenced to follow our AMI meter deployment, in order to capture the spatial information collected during the meter deployment process. Now that the AMI deployment is finished, the field assessment resources for ESME are split across three separate areas within our service territory. The field work started in the Muskegon service region due to the mixture of urban and rural service areas. Data quality degradation issues can come in various forms, so a diverse area was beneficial for training field assessors. Resources have since shifted into a northern group, a Grand Rapids group, and a southeastern group to gain increases in field production. We also had areas where we were deploying our Outage Two-Way Communication program for customers. Improving the quality in the Electric GIS model will help our accuracy with outage information proactively sent to enrolling customers.

Benefits

This effort will improve our customer-connected and distribution asset information, maximizing the benefits of ADMS applications and improving existing business processes for outage analysis, load flow planning, electric design, and asset management. Improving the GIS information will also provide benefits for managing the lifecycle of assets and how customers are connected to system. Also, retiring

old mapping systems and processes will help improve the accuracy and availability of one accurate, shared model.

Grid Operational Analytics

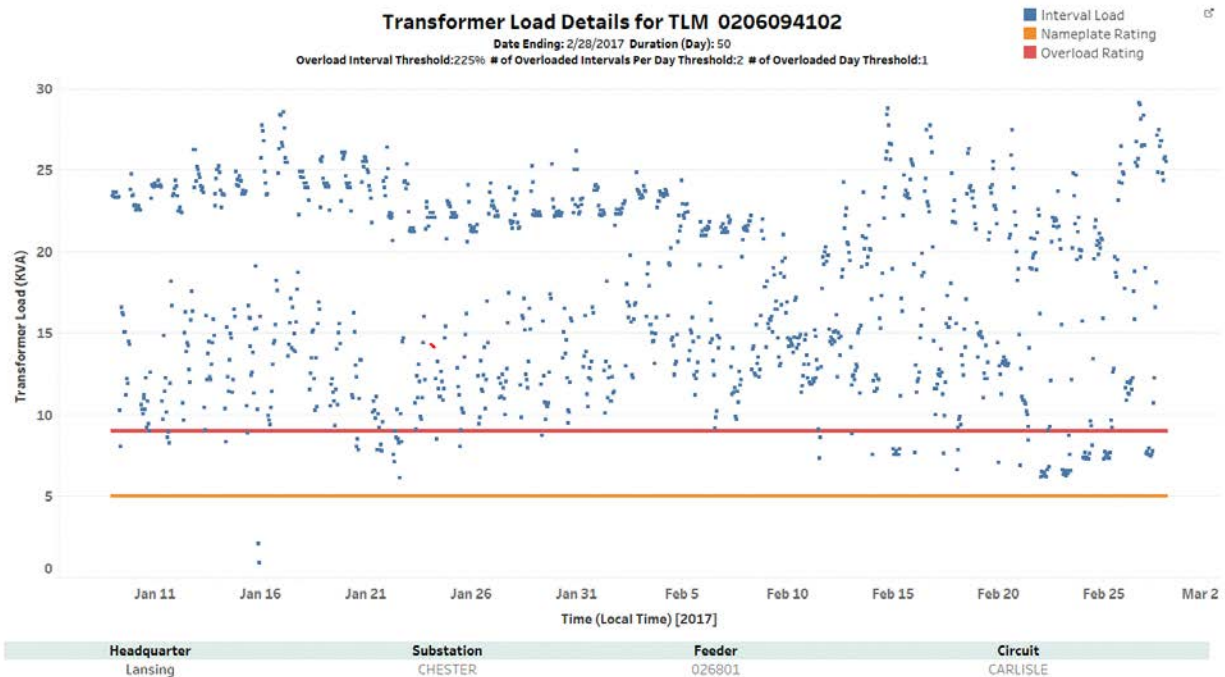
The Grid Operational Analytics effort provides a phased approach to enable new analytics with ongoing incremental improvements. The initial phase will establish the design and implementation of a scalable data management architecture platform. See Section V for more information on the “Data Lake” enterprise data platform. The second phase will create a consistent process for designing, implementing, testing, and deploying integration services and analytics with visualization for the first set of analytics, which identify overload transformers. Completion of the first set of analytics will lead into three other sets with similar processes, focused on mis-phasing studies, customer power quality, and outage analysis. See Section V of this report for details on these four specific analytic sets. Table 56 presents the respective key data entities of the systems that will be integrated into the Data Lake.

TABLE 56 – GRID OPERATIONAL ANALYTICS KEY DATA

Acronym	Description	Key Data Entities
CIS	Customer Information System	Customer, Customer Account, Premise, Address, Service Agreement, Rate, Service Delivery Point, Meter, Equipment/Device, Trouble Ticket, Trouble Order, Service Request, Load Profile, and Service Order
OMS	Outage Management System	Outage Event and Prediction, Outage Statistics, Trouble Crew, Distribution Equipment, Distribution Network Model, Customer Information, Customer Connectivity, Trouble Order
Smart Energy PI Historian	Smart Energy PI Historian	Meter, Meter Reading and Event (time series)
Electrical PI Historian	Electrical PI Historian (DSCADA)	IED/Device, Point and Measurement (time series)
W/AMS	Work and Asset Management System	Work Request, Work Order, Service Order, Compatible Unit, Functional Location, Crew, Equipment, Material, Purchase Order, Asset Model, Asset Lifecycle, Supplier
GIS	Geographical Information System	Distribution Network Connectivity Model (primary and secondary), Distribution Asset, Spatial Information, Landbase

Figure 91 below shows a sample of the visualization developed for transfer overloading, which is enabled by the Data Lake.

FIGURE 91 – TRANSFORMER ANALYTICS EXAMPLE



Project Prioritization and Selection

There are new activities associated with the delivery, deployment, and maintenance of the integration and data management for these analytics. These new activities will be developed over time by building the three other sets of analytics within this program scope. The prioritization of analytics sets are based on the complexity of the analytics and the data sources required.

Benefits

This approach for analytical data information services will establish data ownership and improve data quality and accuracy. Without this approach, we will continue to handle the same business data and data services in different formats, making data difficult to exchange and costly to maintain. This approach to analytics reduces the amount of time and money spent on maintenance and ongoing system integration, so we can develop new and innovative analytic capabilities. The initial set of analytics will help avoid interruptions caused by failing transformers, and improve LVD planning and preventative maintenances processes. Subsequent analytics sets will automatically identify mis-phasing on our system; improve the integrity of our data in GIS system model; and lead to improvements in real-time distribution applications, outage management, and asset management applications. The outage analytics will help restore customers sooner, reducing customer interruption minutes and improving customer satisfaction.

Operational Demonstrations and Pilots

Our five-year plan includes a placeholder to spend \$5 million dedicated to operational demonstration and pilot projects. The goal of these investments is to evaluate the integration and associated benefits and costs of advanced technologies in support of our longer-term development of a modernized grid (See Sections V.A and V.B). As part of our pilot project selection and prioritization process, we look at the fit with our long-term strategy, potential improvement to our customer experience, cost reduction

opportunities, and the scalability and repeatability of the business model. Through our pilot deployments, we will continue to test if we are meeting our predefined success criteria based on real time data and customer feedback, and determine if we need to iterate on the solution (i.e., adjust as we learn what is and is not working). Near-term, these operational demonstration investments include our Circuit West and Parkview projects (see Section V.B), focused primarily on battery storage but also exploring solar integration and microgrids. We will use the learnings from these projects to advance and adapt our long-term strategy. Going forward, through successful deployments of these projects, we will uncover additional opportunities and will continue to invest in further pilot projects to advance our vision for the modern distribution system using new technology and an integrated approach. A specific example of our approach to operational demonstrations at Circuit West is provided below.

Circuit West Automation

The automation efforts with the Circuit West project are part of a technology demonstration to integrate advanced technology for advanced use cases and create standards for future deployments. The components of this automation system include a hybrid metro/underground system, battery storage, solar generation, distribution automation, substation communication, and substation security. This project is a permanent installation with targeted benefits, but it is also a research project to study the capabilities of the distribution system when advanced technologies are integrated into a single system.

Project Prioritization and Selection

With the implementation of multiple new technologies in the same location, Circuit West is being deployed in a phased approach to allow for the development of processes and standards to support future deployments. Phase I will place equipment in service and serve the new customer load. Phase II will include connecting and configuring the communications system while placing the automation system in service. Phase III will be the final phase and will include additional data monitoring, redundant communication, two-way load monitoring and analysis, and remote configuration and settings control including advanced event retrieval from control relays.

Benefits

Circuit West will develop a standard for automation of the Metro and underground distribution systems. Typical Metro infrastructure is networked in a way that is conducive to automation, but the complicated switching that must take place requires more advanced equipment, communication, and logic than is presently employed for overhead Distribution Automation. Configuring Circuit West to meet these needs will result in safer underground vault and padmount equipment that provides breakthrough visibility and control.

In addition to these immediately realized benefits, Circuit West will allow more advanced capabilities in the future. The automation, solar generation, and battery storage are configured to enable future installation of a micro-grid controller. This will allow Circuit West to operate as a configurable and expandable micro-grid. The future micro-grid effort, combined with the existing use cases for advanced automation, solar smoothing, peak shaving, VVO, and frequency regulation, make Circuit West the perfect platform for showcasing the capabilities of a modern distribution grid.

E. 5.0 Capacity

Our capital capacity investments are made to: (1) ensure that the HVD electric system is capable of serving forecasted electric peak demand with all HVD with all HVD facilities in-service; (2) ensure that

single facilities of the HVD system can be taken out of service during non-peak demand periods for maintenance and construction without loading remaining HVD facilities above or beyond equipment ratings or serving customers with unacceptable low voltage; and (3) fix LVD system overloads after they occur.

Over the next five years, we plan to spend between \$50 and \$65 million dollars on capacity targeted projects. Capacity investments are directed at preventing line and equipment overload due to excessive demand beyond its threshold. These investments are grouped into LVD, HVD, and substation programs. These necessary investments will ensure that we meet load and voltage service requirements, which change over time due to expanding and shifting of system load.

i. 5.1 LVD Lines Capacity

Our LVD Lines Capacity program invests in preventing line and equipment overloads due to increased demand on the LVD system, resulting from customer load growth or load shifting from one area to another. We invest in a number of critical projects to address capacity loading issues in accordance with our planning criteria, and to address new load additions, to ensure that the LVD system can meet known and experienced distribution customer loads.

LVD Lines Capacity projects fall into one of the following categories of investments: (1) upgrades for overloaded equipment; (2) new business capacity; and (3) line work associated with substation capacity projects. Over the next five years, we plan on investing between \$17 and \$19 million in LVD Lines Capacity projects, as shown in Table 57 below.

TABLE 57 – CAPITAL: LVD LINES CAPACITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Upgrade of Overloaded Equipment	3	3	3	4	4
New Business Capacity	7	7	7	7	7
Line Work Associated with Substation Capacity Projects	8	6	8	8	8
Total	18	17	18	19	19
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Upgrade of Overloaded Equipment (# of Upgrades)	14	14	14	14	14
New Business Capacity (# of Projects)	23	23	23	23	23
Line Work Associated with Substation Capacity projects (# of Subs)	14	14	14	14	14

Investments in new business capacity and substation line work have a higher priority than upgrades to overloaded LVD equipment, because we must complete these projects for our customers and due to the need to provide minimum load and voltage service to the most customers. We expect these investments

to remain at a high level over the next five years due to new business growth (refer to capital program 1.1 LVD Lines New Business) and the priority of addressing substation projects. This results in a lower level of spending on upgrading our LVD overloaded equipment through 2018 and 2019 (compared to the ideal rate described further below), after which we will be able to increase spending in 2021 and 2022.

The following sections describe these categories of investments in detail.

Upgrade of Overloaded Equipment

We upgrade or replace overloaded lines and equipment to reduce equipment failure risk. If overloaded equipment is not replaced, it creates many risks including: a reduction of the equipment's ongoing load limits; nuisance disruptions of sectionalizing devices (e.g., fuse links melting); potential oil spills; equipment heating with a potential risk of fire; and conductor melting or sagging, creating a public safety hazard of potential contact. Our current plan includes spending \$3 million for an estimated 14 upgrades (approximately \$220,000/equipment upgrade). This program does not drive incremental SAIDI improvement, but it prevents future failures that increase SAIDI. Our current funding levels let us address equipment with a 185% overload or higher. To reduce that to 125% overload levels, we would need to invest an additional \$33 million (\$7 million each year for five years). If the capacity growth rate due to new business is higher than the current funding levels anticipate, the amount of overloaded equipment we can address would be further reduced to offset increased spending for new business.

New Business Capacity

When businesses upgrade their equipment or increase their load beyond the current capacity of the lines, equipment and lines need to be upgraded to maintain adequate service to customers. By spending \$7 million, we will invest in an estimated 23 projects (approximately \$300,000/new business upgrade project).

Line Work Associated with Substation Capacity Projects

Since substations are part of the backbone infrastructure of our electric distribution network, LVD Lines Capacity projects must be completed to reduce the risk of failure due to substation overcapacity. By spending \$8 million in a given year, we can complete projects for an estimated 14 substations (approximately \$575,000/substation project).

Planning Process

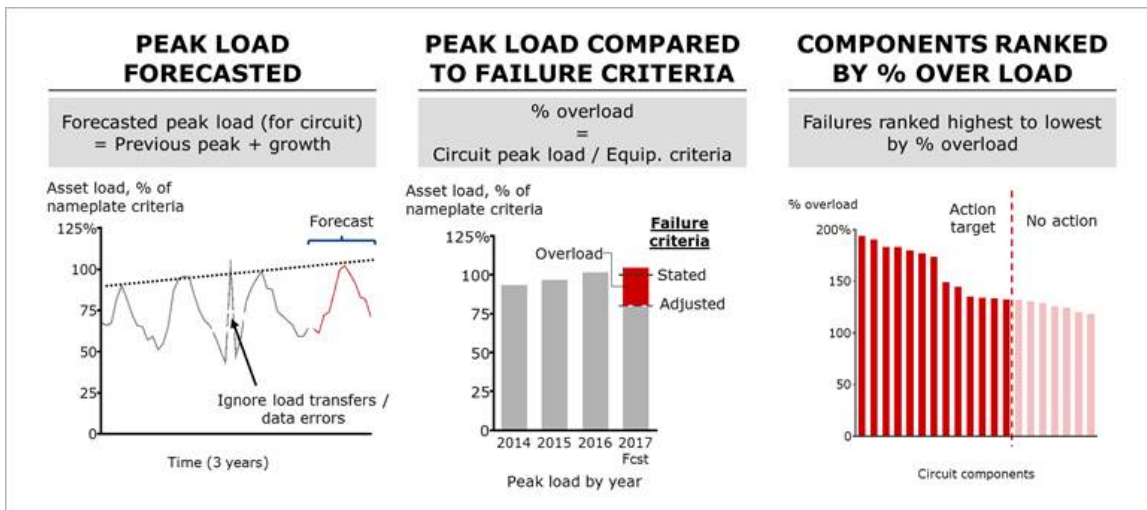
The LVD system is evaluated using CYME, an industry standard load flow software, to perform a load flow analysis. CYME uses load information from two databases to perform load flow studies, on Feeder Demand and Customer Loads. Feeder Demand provides the maximum amperage seen on the circuit with data from the metering equipment in our substations. Customer Loads are calculated using customer meter data and the customer's meter entry point. The load study in CYME compares the Feeder Demand load at the substation, to the Customer Load distributed across the circuit to determine power flow, voltages, and system protection needs based on current and future states of the system. Through our capacity planning process, we identify distribution equipment that is overloaded and instances where we are providing unacceptably low or high voltage during system peak load conditions. We develop and test project plans to eliminate loading above normal ratings on equipment, and to address voltage issues identified during capacity planning.

We typically evaluate loading on our LVD distribution equipment, utilizing CYME, on an annual basis. Capacity planning criteria requires that a component of the distribution system have a projected load over its peak capability (typically 125%), based on our standards for equipment overload capability,

before we develop a potential capacity project. At present, our planning criteria requires that a component of the distribution system experience a load over its calculated peak capability a minimum of one year prior to a capacity project being initiated.

Previous year loadings and future customer growth are taken into account when projecting future loadings. While most equipment has emergency ratings that enable higher capacity for short durations, these are not considered during capacity planning. The planning process is shown below in Figure 92. We prioritize projects for construction to address the highest overloads prior to lower overloads.

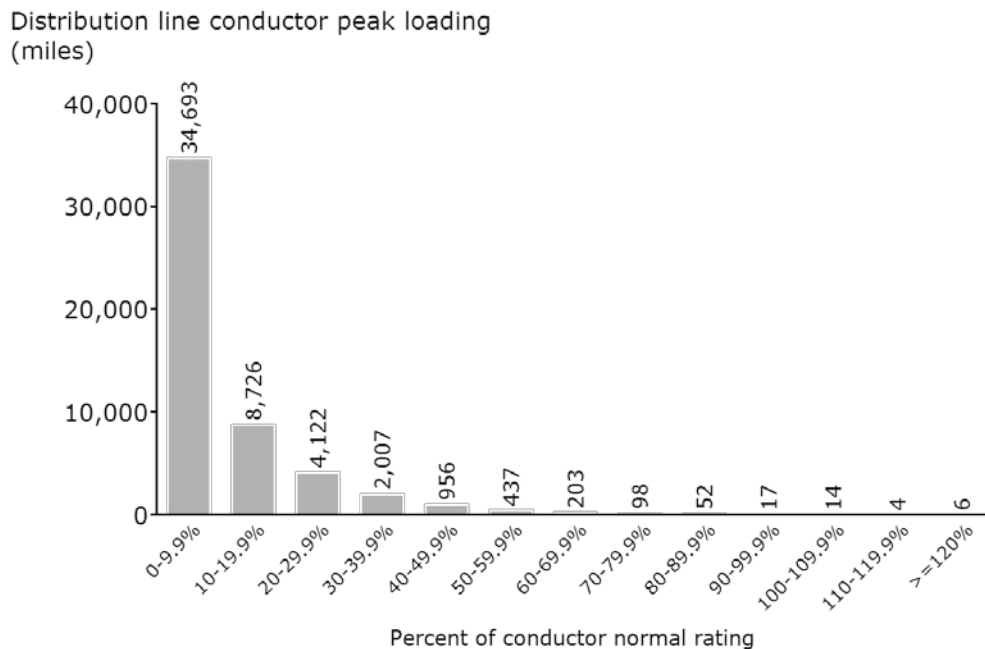
FIGURE 92 – LVD LINES CAPACITY LOAD REVIEW PROCESS



All planning activities are based on peak load conditions. As described above, we do not rely on emergency ratings for planning, due to the heightened risk of equipment failure or degradation when operating above the capability rating. The loadings on equipment are established by the manufacturer, or by a recognized industry source such as IEEE, and specify the optimal operation of the equipment based on the capability characteristics of the components. The specific evaluation of each piece of equipment depends on its use. For example, equipment using oil is rated based on a temperature limit not to be exceeded. If that operating temperature is exceeded, then the equipment can start to break down and possibly lead to a shorter lifespan. Other equipment has a defined set of characteristics that, when taken beyond the manufacturer specifications, can lead to a change in characteristics of the material, altering its strength and durability.

Figure 93 shows our current conductor overloads in the system based on peak loading. In this illustration, over 90% of the conductors are loaded to 50% or less of the normal conductor rating. Also, less than 1% of the conductor miles are overloaded at 120% or above.

FIGURE 93 – DISTRIBUTION LINE CONDUCTOR PEAK LOADING



When a capacity issue is identified by the circuit engineer, we evaluate a number of alternatives for addressing the overload. These alternatives include:

- **Upgrading equipment** – The current equipment is replaced with items of a larger nameplate rating, matched to the increased loads, to handle increased ampacity. For example, we may increase the size of a fuse, isolator, regulator, capacitor bank, or substation recloser to accommodate ampacity. Ampacity measures the maximum amount of electric current a conductor or device can carry before sustaining damage or deterioration.
- **Conductor upgrades** – Conductor upgrades can be used in place of increasing the size of equipment, or to handle the increased ampacity on the conductor. For example, the circuit engineer may choose to replace the conductor instead of the regulator to increase voltage stability and reduce line losses.
- **Voltage conversion** – The circuit engineer may decide to convert the voltage to a standard voltage (refer to capital program 4.1 LVD Lines Reliability) rather than replacing the isolator.
- **Load balancing or transfer** – When equipment or conductors are overloaded, we may be able to decrease load on that equipment by balancing the load with other phases on the same circuit or transferring load to a neighboring circuit. This may require a phase change for the customer or adding an additional phase to offset the overloaded zone. Distribution line systems carry between one and three phases on each circuit.

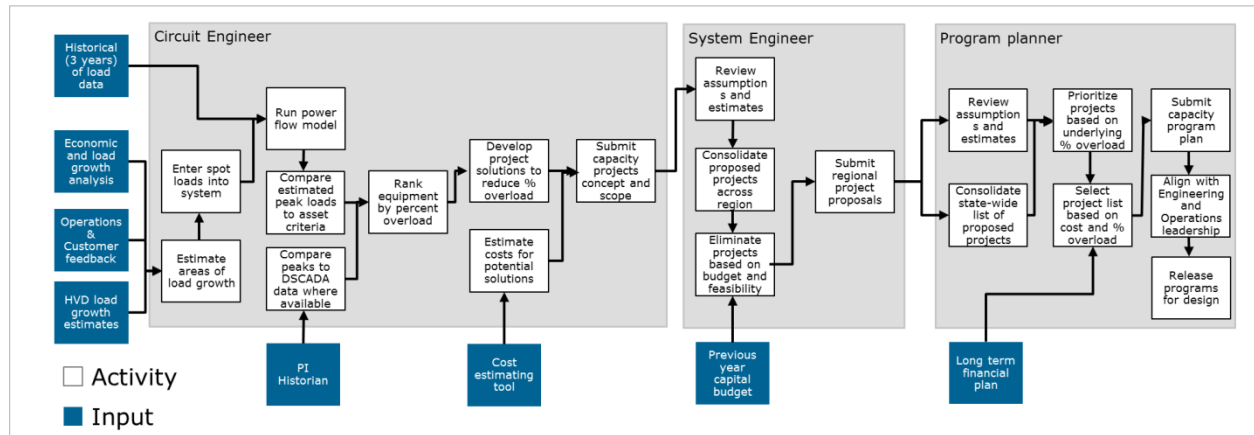
Project Prioritization and Selection

LVD projects are submitted and reviewed in a layered approval process as described in capital program 2.1 LVD Lines Demand Failures (refer to Figure 94 below).

Circuit engineers identify overloaded equipment and develop project proposals based on the overload percentage, overloaded equipment type, number of customers affected, estimated project cost, and any related customer complaints. The annual goal in capacity planning is to address all projects for

equipment with greater than 125% overload. However, the availability of capital funding may constrain the number of approved projects.

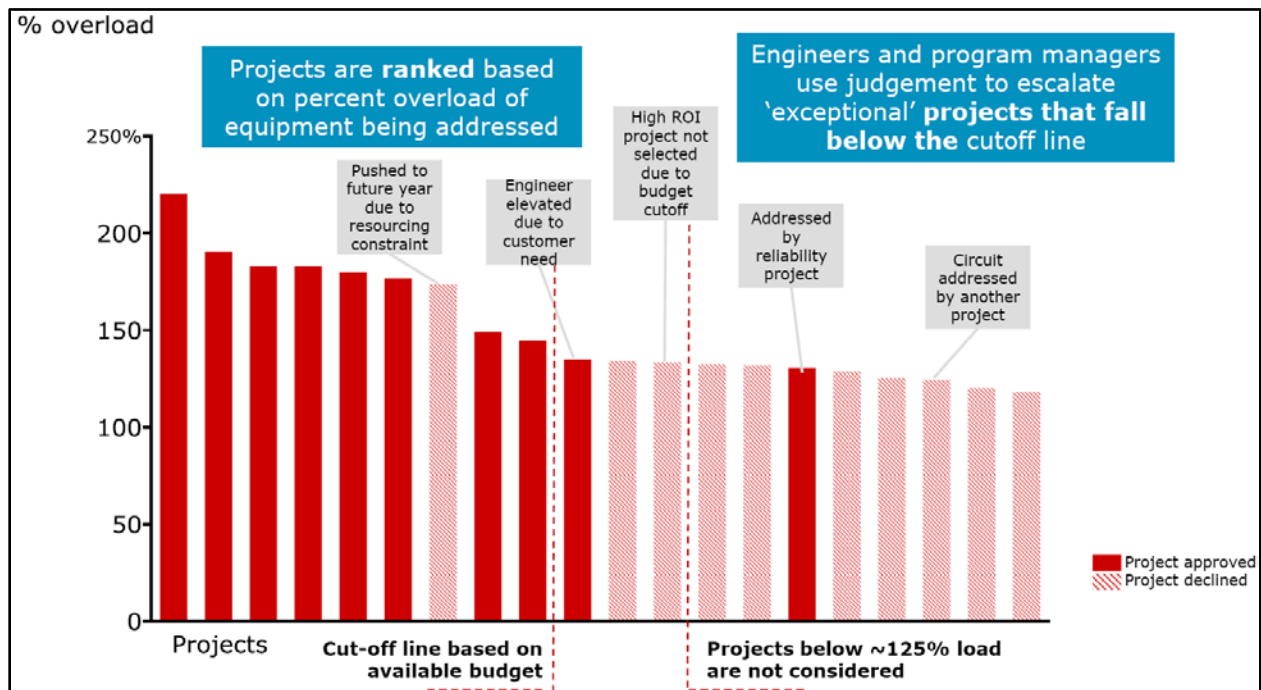
FIGURE 94 – LVD CAPACITY PLANNING PROCESS



As with LVD Lines Demand Failures and LVD Lines Reliability, LVD Lines Capacity projects are prioritized by the program planner by evaluating costs and benefits, with inputs from the circuit engineers and system engineers, based on their experience and knowledge of the system, the availability and location of resources, and funding. Projects that will have the greatest benefit to the grid and meet long-term investment requirements are sequenced for the work plan and added to the construction plan.

Figure 95 below illustrates how projects are prioritized in a typical year. While the 125% overload is used as the primary criteria for approval, our planners consider the reliability and safety benefits for customers and the resource and feasibility constraints to ensure that we prioritize projects that will have the greatest benefit on the grid.

FIGURE 95 – RANKING OF PROPOSED CAPACITY PROJECTS



The planning process occurs in the current year for the following year’s construction, closer to construction time, so that timely data is available. Proactive capacity projects identified too far in advance might be addressed by system improvements completed using other capital or O&M programs (e.g., Demand Failures) in the interim. In order to maximize customer benefit, it is a prudent business practice to utilize the best, most timely data available.

Below are two examples of projects that fall in the overloaded equipment investment category. Refer to Appendix E for a more detailed project listing for LVD Lines Capacity.

- DARE18 BRECKENRIDGE/VILLAGE LCP 607 – This was approved to address several line devices being overloaded, with one overload contributing to an outage. Most severely, a 40 amp fuse had a 283% overload. The chosen solution is to replace the identified fuses and reclosers with larger ones, and upgrade one mile of open-wye line to three-phase.
- DARE17 MILTON/FEDERAL SCRW LCP 077 – This was approved to address an isolator (system voltage transformer) that was 257% overloaded. The proposed solution is to perform a voltage conversion to the circuit downstream, which allows for the removal of the isolator entirely.

In addition, we select some projects that are not solely based on the overload ranking. For example, DARE16 FIELD ROAD SUB is a large capacity project that was selected for construction even though no LVD equipment exceeded the 125% overload limit. This project will construct and reconfigure LVD lines for a newly constructed substation that was built to address overloaded substation equipment on another substation. This line will break up the load and alleviate the overload on the existing substation.

Benefits

In addition to the expected SAIDI benefit, the Forestry benefit associated with this capital work increases the overall benefit, as capacity projects generally include some line clearing work that benefits the larger system. The investments made to upgrade overloaded assets and alleviate voltage issues

increase the longevity of the equipment on our system and prevents service issues/interruptions to our customers while improving employee and public safety.

ii. 5.2 HVD Lines and Substations Capacity

Our HVD Lines and Substations Capacity program consists of HVD enhancements in accordance with our HVD planning criteria; work to accommodate new interconnections; and work to improve functionality through standards, upgrades to protection, operability of the system, and coordination with transmission infrastructure additions. It also supports right of way acquisition projects to support HVD Lines, HVD Substations, and LVD Substations capacity and reliability projects.

Since the HVD system is the backbone infrastructure of our electric distribution network, capacity projects must be completed on an as-needed basis to serve customers and maintain the overall reliability of our grid. These projects tend to require long lead times, typically one and a half to two years, due to the need to acquire large equipment such as transformers, and right of way procurements. For this reason, projects are planned using projected future loading (using the 65% confidence level of the corporate forecast of future system peak loads) to ensure the project can be constructed in time to meet the system need. The table below provides a summary of our five-year HVD Lines and Substations Capacity plan.

TABLE 58 – CAPITAL: HVD LINES AND SUBSTATIONS CAPACITY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
Load Carrying Capabilities and Voltage Support	4	6	6	6	6
New Interconnections	1	3	3	3	3
Improved Functionality	9	5	5	5	5
Coordination with Transmission	1	2	2	3	3
Right of Way Procurement	3	3	3	3	3
Potential Large Projects	0	3	3	2	5
Total	18	22	22	22	25
Unit Forecast					
Investment Categories	2018	2019	2020	2021	2022
Load Carrying Capabilities and Voltage Support (# of Projects)	6	10	10	10	10
New Interconnections	9	7	7	7	7
Improved Functionality (# of Projects)	19	24	24	24	24
Coordination with Transmission (# of Projects)	5	6	6	6	6
Right of Way Procurement (# of Projects)	28	27	27	27	27
Potential Large Projects (# of Projects)	-	1	1	1	1

Our 2018 plan includes a number of projects that are either in-progress or scheduled for work during the year. Projects are listed in Appendix E. After 2018, our future year financial plan is based on historic spending in this program with variations based on projected potential large projects and changes in loadings year by year.

Our HVD Lines and Substation criteria specify that the HVD system must be capable of: (1) serving forecasted electric peak demand with all HVD facilities in service; and (2) withstanding single elements (equipment or lines) of the HVD system being out of service during non-peak demand periods due to failure or for maintenance and construction, without loading remaining HVD facilities beyond equipment ratings or reducing voltage to unacceptably low levels. The criteria also specify that interrupting devices must be capable of interrupting the available short circuit current. Interrupting devices are scheduled for replacement with higher capability units when the available short circuit is projected to exceed the equipment interrupting capability.

Types of investments include:

- New or rebuilt HVD lines (\$400,000-\$500,000/mile)
- New 138/46 kV substations (\$6 million)

- Upgrading existing substation equipment and relays (breaker \$150,000, transformer \$1.5 million)
- Additional HVD and LVD capacitor banks (HVD \$700,000)
- HVD interconnection facilities (to new 138/46 kV substations, LVD substations, and generation substations) (\$500,000/mile)

The following sections describe these types of investments in more detail.

Load Carrying Capabilities and Voltage Support

Study Procedure and Base Case Development

We study the HVD system using power flow analysis to calculate the base power flow and voltages, and changes in power flow and voltages resulting from single outages for present and future versions of the HVD system. Through this process, we identify HVD facilities that would violate criteria due to line or equipment overload, or due to unacceptably low voltage during base (normal) conditions at system peak load or during single (N-1 equipment out of service) outage conditions at 80% of system peak load. Contingencies include single line, single transformer, single bus, and single generator outages. Projects are developed to eliminate unacceptably low voltage, and loadings above line and equipment ratings.

We update our computer models annually to model peaks one, three, and six years forward, with 80% HVD loading. These planning models are developed by our Models and Dynamics group, working in conjunction with our HVD Planning group. Modeling data are stored in a Microsoft Access database and then imported into PSS/E, a commercially available AC power flow modeling program from Siemens Power Technologies, Inc.

The models include a detailed representation of our HVD network. Distribution and dedicated customer substations are individually modeled with the loads aggregated on the low-side bus of the substation transformers. Modeled loads are reviewed and updated on an annual basis using various sources such as SCADA, MaxLoad, and MV90.

Distribution buses are grouped into 20 geographic planning areas as per Figure 96 with one additional area comprised of 138 kV-connected, dedicated industrial-customer substations. Load projections are developed for each planning area based on the area's individual historic growth rate. Individual bus loads within each planning area are also reviewed to capture load shifts that occurred since the last series of planning models. The individual projected area loads are then normalized so that the total system load, plus losses on our system and METC's system, matches our corporate peak MW demand forecast at the 65% confidence interval for the peak case. For each peak load model developed, a corresponding model at 80% of peak load is derived from the peak case.

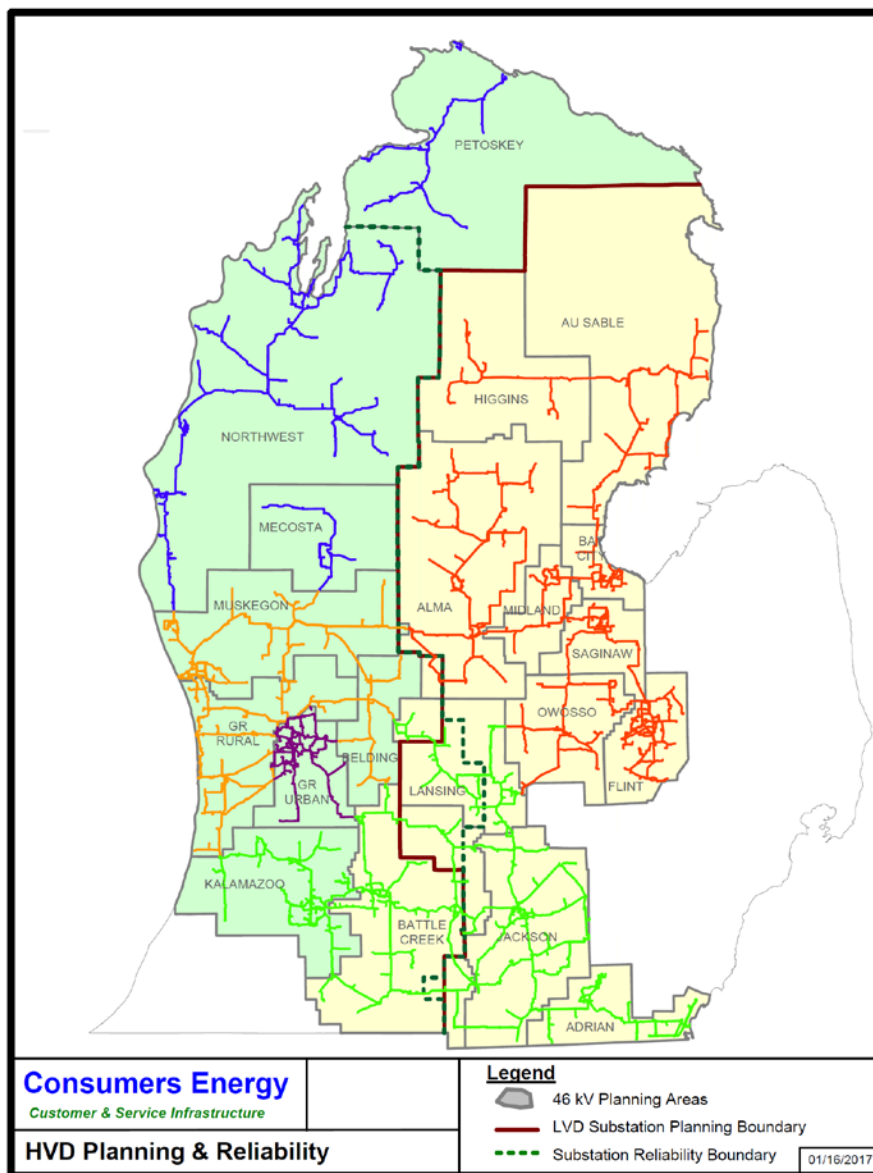
System changes and bulk reactive additions planned to be in service by the summer of 2017 were modeled in the Series 2016 cases. Bypass switch ratings were included in the peak and 80% models, but for this assessment we assumed that scheduled breaker maintenance would not be scheduled during system peak, so normal overloads of bypass switches were ignored in the peak load models.

Our HVD system interconnects to the transmission system and, accordingly, HVD planning models are integrated into a model of the transmission network. The transmission network used for this assessment was the peer-reviewed, Series 2016, transmission model from the NERC Multiregional Model Working Group (MMWG). This MMWG model represented the entire Eastern Interconnection, including remote transmission systems such as Florida Power and Light. Since they have no material impact on our

system, these remote systems were block loaded in the model using standard activities within the PSS/E program. The MMWG model representations of nearby transmission systems such as METC/ITC, AEP, First Energy, IESO (Ontario), ATC, and NIPSCO were retained with full detail.

Generation dispatch for the models was based on the integrated Consumers Energy HVD/NERC MMWG model. For the peak models, our base load and peaking units were dispatched so that the net MW interchange matched the scheduled transactions. The 2017, 2019, and 2022 models have different system loads, so our generation was adjusted to hold the net interchange constant. For the 80%-of-peak-load models, the peaking units were turned off and the base load units owned by us and by DTE Energy, as well as independent power producer units in Michigan, were adjusted based on an economic dispatch in proportion to the reduced system load.

FIGURE 96 – GEOGRAPHIC HVD PLANNING AREAS



Selection of Plans

Proposed plans are tested in the models to ensure they fulfill their designed purpose. SCADA information is used to project future load on radial lines. The short circuit model of the HVD network compares the available short circuit current to the interrupting capability of the HVD interrupting equipment. These capacity projects must be completed on an as-needed basis, based on projected loading in power flow models. As an example, the Kelloggsville 46 kV line was studied in 2016 and was projected to be overloaded at normal system conditions at system peak load in 2018. Therefore, we scheduled a project in 2016 with a May 2018 in-service date to ensure we could obtain the needed right of way and finish engineering in time to rebuild this section of line, with higher capacity, on time.

The HVD system model is updated annually, following summer peak loading and into the first quarter of the following year. We perform system studies in the second quarter each year, and develop projects to address identified projected issues. Projects are scheduled in the third quarter of each year for the following year and future years to ensure completion before the projected issue actually occurs.

New Interconnections

New interconnections to LVD substations, other utilities, and generation facilities must be completed as requested by the interconnecting party. Costs to interconnect to other utilities and generation facilities to our HVD system are reimbursed by the other utility or generator being interconnected.

Improved Functionality

We typically complete projects to meet changes in standards and upgrades to protective schemes on a planned basis over a period of time. This can be done on a programmatic basis, such as by alleviating substation control cabinet working space issues systematically over a 10-year period. It can also be addressed through coordination with other major projects as they occur at the same location. Configuration changes to improve operability are added at the request of our System Control group, or through coordination with other major projects as they occur at the same location. Air break switches (ABS) and MOABs are planned so they will have a direct impact on SAIFI and SAIDI and are evaluated based on the reliability impact for our customers.

Coordination with Transmission

HVD relay upgrades associated with transmission upgrades must be coordinated with those transmission upgrade projects that require the HVD upgrades to be completed. These are completed as needed over time in conjunction with the transmission owner.

Right of Way Procurement

Projects to procure HVD line rights or substation sites are critical, and must be prioritized to adequately support the project (e.g., new HVD line, HVD line relocation or rebuild off-center, new HVD or LVD substation, or improved easements where rights are determined to be inadequate).

Improved functionality, coordination with transmission, and right of way procurement projects are scheduled as they develop in conjunction with the associated project being supported.

Benefits

ABS and MOAB additions improve system reliability by preventing future overloads. Furthermore, these investments help avoid dangerous wire downs due to overloads, improving the safety of our system. Finally, the HVD and LVD capacitor bank upgrades completed help support system voltage and reactive requirements.

iii. 5.3 LVD Substation Capacity

Our LVD Substations Capacity program ensures the long-term safe and reliable operation of our electric distribution LVD substations. The capital expenditures in this program include investments to install new substations or substation equipment and to upgrade existing substations or substation equipment. These investments serve customer electric loads within the operating capability of the installed substation equipment (i.e., transformers, fuses, reclosers, regulators, switches).

LVD Substation Capacity planning activities are based on peak load conditions. We monitor and analyze for situations where a component of the LVD substation has an experienced overload or a projected overload of its capacity, based on our standards for the equipment. LVD substation capacity projects are prioritized to address the highest overloads in advance of lower overloads. When assessing loads, we consider actual and projected overloads including known new business loads.

When we identify a capacity issue, we conduct a distribution study, comparing the benefits and costs of several options, including:

- Load transfer to a less loaded substation or line
- Capacity increase through upgrading our lines or equipment
- Building a new LVD substation to split the load
- Create an alternative connection to a different HVD or transmission line

When we build or modify substations, we “right-size” them based on load forecast, future distribution automation plans, HVD system restrictions, site configuration, property size, and individual operational considerations of the local system. For example, substations located in relatively close proximity to each other (such as urban areas) or substations with stout distribution tie-lines are built with more capacity to facilitate load transfers, both manual and automated, and improve overall system reliability. Conversely, substations in rural areas with a long history of low growth are built with equipment to meet the needs of the local system only while minimizing upfront equipment cost.

LVD Substation Capacity projects include the following types of investments:

- Installing a new substation
- Rebuilding an existing substation
- Installing a new transformer position
- Installing a new circuit position
- Transformer upgrades
- Fuse upgrades
- Recloser upgrades
- Breaker upgrades
- Regulator upgrades
- Switch upgrades
- Bus upgrades

Over the next five years, we expect to spend between \$12 million and \$14 million per year on new substations and capacity increases on our substation LVD system. This projected spend amount is based on historical spending rates and can be adjusted each year based on the number of identified projects required for each year. Projects in this program are prioritized and implemented according to the type of criteria issues, risk of recurrence, and the impact to customers of a recurrence.

TABLE 59 – CAPITAL: LVD SUBSTATION CAPACITY

5-Year Capital Plan (all values in \$ millions)					
	2018	2019	2020	2021	2022
New substations	6	5	6	6	6
Existing substations capacity increase projects	6	8	8	8	8
Total	12	13	14	14	14
Unit Forecast					
	2018	2019	2020	2021	2022
New substations	4	3	3	3	3
Existing substations capacity increase projects	7	14	12	12	12

Planning Process

We use several inputs and conduct analyses to aggregate multiple data sources to best evaluate electric loads on substation equipment. These analyses help to identify electric loads that exceed substation equipment ratings and capability limits. Substation equipment ratings and capability limits are established based on equipment manufacturer publications and incorporated into our planning process.

The inputs that we use include:

- MaxLoad System:
 - Our Substations Operations personnel record electric load data from substation equipment and substation metering points during onsite substation inspections. We input this load data into the Cascade system; Cascade archives this data nightly into MaxLoad.
 - MaxLoad data is inputted into substation planning engineer spreadsheets and compared to the substation equipment electric capabilities for annual loading analyses.
 - We also analyze MaxLoad data directly from MaxLoad reports for individual project evaluation.
- SCADA
 - Electric load data is recorded remotely at frequent intervals from substation equipment in LVD substations where SCADA systems are installed. We have been working to install SCADA in all LVD substations over time.
 - Processes are being developed to input SCADA data directly into the substation planning engineer spreadsheets. Once the processes are in place, SCADA data can be compared to the substation equipment electric capabilities for annual loading analyses.
 - We also currently analyze SCADA data directly from the PI SDK Utility system for individual project evaluation.
- New Customer Load Data
 - New electric customer load data and existing customer load addition data are received from various departments that interface directly with customers.

- Substation planning engineers analyze the new customer load data with the actual substation loads to determine if the new loads will exceed substation equipment ratings and capability limits.
- Distribution Automation Plans – Grid Modernization
 - Distribution Automation plans are received from the Grid Modernization and the LVD Lines Planning departments.
 - Substation planning engineers analyze the electric load transfers that will occur between each substation source to determine if the transferred load will exceed substation equipment ratings and capability limits.
- Electric Load Trends
 - We analyze electric load data and trends to identify areas of electrical growth that are projected to exceed substation equipment ratings and capability limits.
 - We develop long range studies and project alternatives to determine strategic solutions that address the projected planning criteria issues and to optimize system reliability improvements and overall economic investment.
 - The chosen substation solution will be implemented when the planning criteria issue is experienced; however, long lead time activities and purchases may be completed in advance of the actual substation project to avoid delays when the project is needed (e.g., new substation property acquisition, line easement acquisition, non-standard equipment purchases).

Project Prioritization and Selection

Once all of the planning criteria issues are identified, substation projects are initiated and scheduled. We prioritize and implement projects based on an assessment of the projected system risk, projected customer impact, projected economic impact, regulatory requirements, and customer/contractual commitments.

Project planning is an ongoing continual process, but plans for the upcoming year are finalized after summer peak loads are received and analyzed. Most substation peak loads occur between June and September, and few substations experience peak loads during winter months.

LVD Substation Capacity Project Examples

- 4 new substations in 2018
- 7 existing substation capacity increase projects in 2018
- 3 new substations in 2019

New Substations in 2018:

- Buchanan Substation (Ottawa County) – New substation to resolve Ottawa Beach Substation regulator overload.
- Benston Substation (Muskegon County) – New substation to resolve Tanium Substation regulator overload.
- Ash Road Substation (Hillsdale County) – New substation to resolve projected Litchfield Substation regulator overload that will be caused by new industrial loads coming online in 2018.

- Forest Grove (Ottawa County) – New substation to resolve Jamestown Substation regulator overload. Forest Grove Substation will also serve new commercial and industrial loads currently under construction by several customers.

Existing Substation Capacity Increase Projects in 2018:

- Deerfield Substation (Lenawee County) – Increasing the transformer size and converting to circuit regulation due to new business load.
- Ellsworth Substation (Kent County) – Completing the last phase of a six-year project to replace 1920's vintage equipment and to increase the overall substation capacity to serve the new and future area growth in downtown Grand Rapids.
- Fort Custer Substation (Calhoun County) – Increasing the Transformer #2 size due to new industrial loads and area growth.
- Grayling Substation (Crawford County) – Converting to circuit regulation to resolve regulator overload.
- Harvey Street Substation (Kent County) – Increasing the Circuit #6 regulator size to resolve regulator overload.
- Lagrave Substation (Kent County) – Replacing Transformer #1 and Regulator #1 with an LTC Transformer to resolve regulator overload.
- Long Lake Substation (Genesee County) – Increasing the transformer size and converting to circuit regulation to resolve regulator overload.

New Substations in 2019:

- Case Lake Substation (Genesee County) – New substation will be constructed if the area growth causes equipment overload at Rankin Substation in 2018.
- Hawthorne Substation (Kent County) – New substation will be constructed if the area growth causes equipment overload at Four Mile Substation in 2018.
- Kromdyke Substation (Kalamazoo County) – New substation to serve new industrial load. Construction on Kromdyke will start in 2018 and will be finished in 2019.

Solutions to resolve planning criteria issues can be straightforward, such as equipment upgrades, substation capacity increases or new substations in pre-planned locations. Examples of these solutions include the new Buchanan substation, new Benston substation and the capacity increase of the Long Lake substation. Solutions to solve other system capacity issues require more detailed and involved long range studies, voltage studies, or system protection studies.

Projects such as Buchanan, Benston, and Long Lake are being implemented in 2018 because the substation equipment loading criteria was exceeded by actual customer loads. Continued loadings at those levels would result in equipment failure and long-term customer outages. The Ash Road substation project is being implemented in 2018 because new industrial loads are being installed that will cause an overload of the Litchfield substation equipment once the industrial loads become operational. Three new substations have been identified in 2019 due to projected area growth and new industrial load.

Benefits

LVD Substation Capacity investments are necessary for the overall operation and reliability of the electric distribution system serving our customers. It is the obligation of the electric utility to ensure the electric distribution system has adequate electrical capacity to serve the connected customer load.

iv. 5.4 LVD Transformers Capacity

Our LVD Transformers Capacity program consists of the purchase costs of distribution transformers and the associated first set expense. The purchase costs are allocated to the Distribution Transformer programs in New Business, Demand Failures, and Capacity. See capital program 1.5 Transformers New Business for additional details on the investment plan for this program.

F. 6.0 Tools and Technology

This category includes expenditures for Computer and Equipment, Tools, System Control Projects, NERC cyber security compliance requirements, NESC working space compliance requirements, and Substation Fall Protection.

TABLE 60 – CAPITAL: TOOLS AND TECHNOLOGY

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
System Control Projects	1.7	2.1	2.0	2.3	2.6
Tools	5.1	5.2	5.3	5.4	5.5
NESC/NERC Compliance	2.9	3.2	3.3	3.0	3.0
Computer & Equipment	0.3	0.3	0.3	0.3	0.3
Substation Fall Protection	0.2	0.2	0.2	0.2	0.1
Total	10	11	11	11	11

i. 6.1 System Control Projects

Our current five-year plan for System Control Projects is to spend between \$1.7 million and \$2.6 million per year on a variety of programs to manage the operations of the LVD and HVD systems. These include a number of major projects that will improve operations of our control centers, help us streamline our operations, and result in direct impacts to safety, reliability, and system operations for our employees and customers.

TABLE 61 – CAPITAL: SYSTEM CONTROL PROJECTS

5-Year Capital Plan (all values in \$ millions)					
Investment Categories	2018	2019	2020	2021	2022
46 & 138kv Operations Projects	0.5	0.6	0.6	0.6	0.6
HVD Remote Monitoring & Control Operational Demonstrations	0.75	1.0	1.25	1.5	1.8
Operating Technology Enhancements	0.1	0.1	0.1	0.1	0.1
SCC / DCC Office Expansions	0.4	0.4	-	-	-
Total	1.7	2.1	2.0	2.3	2.6

46 & 138kv Operations Projects

Our 46 kV and 138 kV HVD projects are identified by our System Operations Engineering personnel to facilitate better real-time system operation. This program includes switches to isolate faults and minimize the number of customers interrupted.

We select projects based on the following criteria:

- Number of high load op-guides on which the switch appears (i.e., operational switching restrictions)
- The potential to increase line capability with a switch replacement
- Load level at which the switch presents power flow or N-1 criteria violations
- Switches that are on priority lists that have not been scheduled

Installation of replacement of switches has a positive impact on the duration of outages (SAIDI, CAIDI).

HVD Remote Monitoring & Control Operational Demonstrations

These projects increase the operational visibility of the SCC and DCC and provide a proof of concept to demonstrate the operational benefits of combining technology such as line sensors with SCADA-enabled MOABs.

We select projects based on the number of interruptions experienced within the past few months that resulted in increased customer outage times. Recent projects that fall within this program include:

- 18-5009 Replace Obsolete Capacitor Bank Controllers
- 18-5010 Waldron 46 kV Line - Install SCADA-Enabled MOABs

Operational Technology Enhancements

We currently expect to perform at least two operational technology enhancements per year over the next five years. These enhancements will improve the functionality of our Operating Technology programs, and facilitate the operations of our SCC and DCC from a safety, effectiveness, and efficiency perspective. Furthermore, these projects support and improve the performance of our staff.

We currently plan to invest in projects including:

- Enhancements to RMS for service restoration (Catastrophic Crewing)
- Enhancements to Transmission Outage Application

These investments will improve operational safety and process efficiency, and reduce human performance errors, benefiting our customers and our employees.

SCC/DCC Office Expansion

To house the controllers in the SCC and DCC, we expect to make capital investments of approximately \$800,000 over the next two years. These investments are critical to SCC/DCC operations. This project is currently in planning stages and will most likely involve building modifications to control centers and/or technology upgrades for increased areas of responsibilities.

Similar to our operational technology enhancements, this investment will help us improve our operational safety, effectiveness, and process efficiency, and reduce human performance errors.

ii. 6.2 Tools

Our Tools program provides funding for tools that are priced over \$1,000 per item. More specifically, this program covers the purchase of new tools and replacement of tools that are worn, broken, outdated and/or unreparable. Some examples of tools covered in this program include:

- Cordless cutting tools
- Cordless crimping tools
- Cordless hammering/breaking tools
- Concrete cutting/boring tools
- Silica mitigation systems
- Calibrated tools
- Test meters/instruments
- Diagnostic equipment
- Locating equipment
- Line segmenting (load drop/load pickup) devices
- Wire pulling machines/accessories
- Specialty rigging equipment
- Specialty work lighting
- Specialty pumping equipment
- Specialty “bridging” and “matting” equipment (for access to deep right away assets)

Our five-year plan includes approximately \$5 million spending per year and is comprised of two main categories:

1. We plan for approximately \$1.5 million per year for new and replacement tools needed to complete routine compliance and maintenance work – e.g., inspections, testing, repairs and replacements of live line tools and equipment (for work on energized systems) as well as rigging equipment (used for hoisting or lifting materials and equipment). This level of funding is comparable to historical amounts.
2. In 2016, we started outfitting new Company trucks (service buckets, two-person buckets, and digger derricks) with new tools as they are deployed. These “Truck Tool Kits” are purchased in

alignment with our Fleet Acquisition/Deployment Plan and under a Fleet Work Order. The appropriate dollar amounts are then transferred from the Tools budget to the Fleet Work Order to cover the cost of the assets as they are deployed. Our five-year plan includes approximately \$3.6 million per year for these kits (80-90 based on truck replacements per year at an average cost of \$40,000-45,000/truck tool kit). This level of investment reflects an increase from 2016-2017 levels for two reasons. First, we plan for a slight ramp-up in volume since 2016. Second, 2017 reflected a year of lower volume due to a manufacturer/truck defect issue. The purpose of these Truck Tool Kits is to ensure our crews are sent out with an appropriately equipped truck to effectively complete their work.

The purchase of the tools covered in this program is necessary to improve electric reliability, reduce employee safety incidents and injuries (strains and sprains) and improve employee productivity (e.g., avoiding a stop-the-job due to not having the proper tool available).

iii. 6.3 NESC/NERC Compliance

The NESC as adopted by the MPSC serves as a basis for the engineering standards which Consumers Energy utilizes. The purpose of this program is to address working space issues that exist in some of our substation control houses. Modifications to address this standard are made in conjunction with projects associated with other capital programs such as 4.6 HVD System Protection and 5.2 HVD Substations Capacity. This strategy allows for an efficient and effective use of design and construction resources by accomplishing two objectives within one project.

G. 7.0 Costs of Removals

The five-year plan for our LVD and HVD Cost of Removals programs are described in the following sections for each system. There is no direct SAIDI benefit tied to the Cost of Removal programs. Rather, the benefit is within the program which the installation of assets is incurred.

i. 7.1 LVD Cost of Removals

The LVD Cost of Removal Program primarily accounts for the cost of dismantling and removing assets from the LVD system as required to adhere to accounting principles.

The cost of removal percentage is calculated as part of the work order close-out process, using the design documents of individual orders across the LVD capital programs. This is then applied to the labor cost elements for each order. This financial process allows for removal costs to be allocated to the LVD Cost of Removal program instead of against individual programs. Sales of scrap material and salvage are accounted for in this program as credits.

Our five-year capital spend projections are developed using historical cost of removal percentage rates, retirement only projects, and sales and salvage credits.

TABLE 62 – HISTORICAL CAPITAL: COST OF REMOVALS – LVD

Historic Spend (all values in \$ millions)			
Investment Categories	2015	2016	2017 prelim
Allocated from Lines New Business – LVD	0.6	0.7	1.0
Allocated from Lines Reliability – LVD	1.5	4.4	4.5
Allocated from Repetitive Outages – LVD	0.8	0.7	0.5
Allocated from Lines Capacity – LVD	0.9	0.9	1.3
Allocated from Lines Failures – LVD	7.8	12.2	20.9
Allocated from Street light Mercury Vapor	0.3	0.1	0.2
Allocated from Lines Relocations - LVD	1.4	1.2	1.9
Retirement Only – direct charge	3.3	3.4	4.6
Meter and Transformer Final Removal	9.1	11.3	15.2
Sales/Salvage	(2.2)	(1.5)	(1.8)
Total	23.5	33.4	48.3

Meter and transformer final removal costs in the table above represent the labor costs associated with retiring meters and transformers, assets that are capitalized upon purchase rather than installation. The labor cost per retirement is allocated based on the established cost of removal rates and is posted as part of the month-end close process. Upward trends in spending can be attributed to increases in labor costs and increases in LVD infrastructure replacement. In addition, the Smart Energy Program has increased the volume of legacy meters being retired.

In addition to allocated costs from other programs, we charge retirement-only jobs directly to this program. Costs for this type of work are accounted for in the five-year plan based on history. Below are a few examples of retirement-only work orders directly charged to the program in 2017.

TABLE 63 – 2017 SAMPLE RETIREMENT-ONLY WORK ORDERS: COST OF REMOVALS – LVD

2017 Sample Retirement-Only Work Orders		
Order #	Order Description	2017 Charges - \$
30024742	RPOUT13 YORKVILLE/YORKVILLE-CEMI PULL PL	192,342
31023036	BKBNP13NORTH ADAMS/NORTH ADAMS 130-150	191,060
29756812	DEMO13 BELL RD/ALBEE RAILROAD	166,376
29977838	DEMO16 CEDAR LAKE PMN	100,529
21736105	BKBNP13Kinderhook/Lake DR #4	61,399
30628814	DEMO Batteese / Munith Part 1	55,488
28121612	THDPY16 MDOT M-43 @ M-89 Richland (DEMO)	30,830
28367392	Peninsula to Boardman Union LVD ERET	29,982
23327830	DEMO14 STANWOOD/TYLER RD #1D	27,672
29918148	FARMERS ALLEY - RM DEC STLTS & VAULTS	25,564

ii. 7.2 HVD Cost of Removals

The HVD Cost of Removal program primarily accounts for the cost of dismantling and removing assets from the HVD system as required for accounting principles. As part of the work order close-out process, a cost of removal percentage is determined using information provided by construction crews or field leaders, which is then applied to the labor cost elements of the order. This financial process allows for removal costs to be allocated to the HVD Cost of Removal program. Spend projections are developed using historical cost of removal percentage rates.

TABLE 64 – HISTORICAL CAPITAL: COST OF REMOVALS – HVD

Historic Spend (all values in \$ millions)			
Investment Categories	2015	2016	2017 prelim
Allocated from HVD Strategic Customers New Business	3.1	0.0	1.1
Allocated from Metro New Business	0.2	(0.3)	0.1
Allocated from LVD Substation Demand Failures	1.0	0.4	1.5
Allocated from HVD Lines and Substations Demand Failures	3.4	1.2	3.2
Allocated from Metro Demand Failures	0.3	(0.6)	0.9
Allocated from HVD Asset Relocations	0.1	0.2	0.0
Allocated from Metro Asset Relocations	0.1	0.1	1.0
Allocated from HVD Lines Reliability	2.7	4.4	5.2
Allocated from LVD Substation Reliability	1.6	0.3	1.4
Allocated from HVD Substation Reliability	0.9	0.3	0.6
Allocated from HVD System Protection	0.3	0.1	0.3
Allocated from Metro Reliability	0.3	(0.2)	0.2
Allocated from Advanced Capabilities Infrastructure or Substation Communication Upgrades	0.2	1.0	1.8
Allocated from HVD Lines and Substations Capacity	1.1	0.8	3.0
Allocated from LVD Substations Capacity	0.6	0.6	1.7
Total	16.0	8.2	21.9

IX. O&M Programs

Operations and maintenance spending on the electric distribution grid is expected to range between \$179 million and \$207 million per year over the next five years. This spending represents an average increase of 2% per year between 2017 and 2022, as we dedicate more funds to O&M programs that specifically target improvements in reliability, safety, control, and sustainability. In particular, our five-year O&M plan reflects a commitment to improved reliability by increasing our spending on line clearing and other forestry activity across our system. At the same time, we are dedicated to improving our O&M cost effectiveness and ensuring that we maximize the productivity of every O&M dollar through continuous improvements.

In the next five years, the largest components of our O&M expense will be forestry line clearing and outage service restoration. These two programs make up roughly half of the overall O&M costs directly attributed to the electric distribution grid. In addition to these two major categories, we have a number of O&M programs and services that provide critical support to the operation of a safe, reliable, and responsive electric distribution grid. The major O&M categories in the five-year plan can be found in Table 65 below, with additional details for each program in subsequent sections.

Our financial forecast has been developed based on a robust investment planning process that starts with reviewing our historical performance, forecasting our future expected activity, estimating improved cost efficiencies, and developing financial spending plans that will tie to our expected objectives. Similar to our capital programs, many of our O&M costs depend highly on external factors such as weather, storm activity, market costs and labor rates, and unexpected customer or system needs. For this reason, each financial forecast value in this report represents our best estimate as of March 2018 for how much we will spend each year.

TABLE 65 – FIVE-YEAR O&M PLAN

5-Year Plan – O&M Programs									
<i>All values in \$ millions</i>		Actual			Plan				
		2015	2016	2017 prelim	2018	2019	2020	2021	2022
1.0	Net O&M Assoc. with Construction	-2	1	-3	0.3	0.3	0.3	0.3	0.3
2.1	Reliability	3	3	3	3	3	3	3	3
2.2	Forestry	37	51	50	51	53	56	60	64
2.0	Reliability	40	54	53	55	56	59	63	67
3.1	Service Restoration	38	36	50	33	39	39	39	39
3.2	Demand Maintenance	7	6	6	6	6	6	6	7
3.3	Corrective Maintenance	9	3	5	4	4	4	4	4
3.4	Staking / Street light / Service Calls	17	15	8	7	7	8	8	8
3.5	Meter Services and Credits	6	3	0	6	7	7	7	8
3.6	Meter Reading	11	12	5	2	2	2	2	2
3.7	Smart Energy MTC - Elec	0	0	7	8	8	9	9	9
3.8	Other Ops and Metering	2	2	2	2	2	2	2	3
3.0	Ops, mtc, mtr, service restoration	89	76	83	69	77	77	78	79
4.1	Training	6	4	6	6	5	6	6	6
4.2	Facilities Building Ops & Maint	4	4	4	3	4	4	4	4
4.3	Supervision / Admin-Staff	7	6	7	7	7	8	8	8
4.4	Other Field Operations	6	5	5	4	4	4	4	4
4.0	Field Operations	23	19	22	20	20	20	21	22
5.1	Smart Energy Operations Center	0	0	1	1	1	1	1	2
5.2	Grid Management	3	3	4	5	5	5	5	6
5.0	Grid Management & SEOC	3	3	5	6	6	6	7	7
6.0	Planning & Scheduling	3	4	6	6	6	6	6	6
7.0	Operations Performance	0	1	2	2	2	2	2	2
8.0	Operations Management	7	8	6	7	7	7	7	7
9.0	Engineering & Ops Support	2	2	3	4	4	5	4	4
10.0	Engineering & System planning	12	10	9	9	10	11	11	11
11.0	Joint Pole Rental	2	2	2	2	2	2	2	2
O&M Plan		180	180	189	179	190	196	201	207
12.0	Energy Efficiency & Demand Resp.	78	79	121	128	127	130	134	135

A. 1.0 O&M Associated with Capital Investments

In order to supply our customers with electricity at proper voltage levels, we must purchase transformers, regulators, auto boosters, and isolators for use across our electric distribution system. The costs in this program account for the O&M spending associated with these necessary equipment purchases and capital investments.

Our current five-year forecast is estimated based on the capital programs that install the transformers, regulators, auto boosters and isolators. These programs include distribution Lines New Business, Reliability, Repetitive Outage, Relocations, Capacity, and Demand Failure programs. The higher the labor hours or costs for installation, the higher the costs will be for associated O&M. The five-year plan is based on an average of 6% of the capital funding of these programs.

For these capital investments, the initial equipment purchase is allocated to our capital programs for the material, labor, and loadings cost to install the equipment. At purchase, credits are created on the books, which are allocated back to this O&M program. When the equipment is installed or retired, the costs associated with the installation are allocated as an expense to this program. On a monthly basis, credits and costs are reconciled and the intent is for these credits to balance. However, for transformers the time lag and rate changes between the purchase and installation cause a small non-zero balance, as shown in Table 66.

TABLE 66 – O&M: O&M ASSOCIATED WITH CAPITAL INVESTMENTS

5-Year O&M Plan (all values in \$ millions)					
	2018	2019	2020	2021	2022
Transformer Costs	7.4	7.4	7.5	7.7	7.8
Transformer Credits	-7.1	-7.1	-7.2	-7.4	-7.5
Total	0.3	0.3	0.3	0.3	0.3

Our Supply Chain team orders material when re-order points are triggered. Re-order points are based on history and usage to determine optimal inventory levels. Buyers in Supply Chain review re-order points to determine whether or not to buy materials.

B. 2.0 Reliability O&M

Similar to our Reliability capital programs described in Section VIII, we have a number of O&M programs that improve reliability for our customers. Our O&M reliability program objectives are to minimize the occurrences of outages, respond effectively to shorten outage durations, and improve how we manage voltage on our system. We do this through inspecting, replacing, and upgrading our system equipment, and through our proactively managed forestry program.

Details for our two O&M reliability programs are described in further detail in the sections below.

i. 2.1 Reliability

The HVD and LVD Lines and Substations O&M Reliability programs work in coordination with our Reliability capital programs to maintain and improve our system assets. Some of these costs represent the O&M portion of work that is allocated to both O&M and capital, while other costs are purely O&M. Table 67 presents the five-year plan for our O&M Reliability programs, which include spending on LVD and HVD Lines, LVD Substations, and HVD Substations.

TABLE 67 – O&M: RELIABILITY

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
LVD and HVD Lines	0.2	0.2	0.2	0.2	0.2
LVD Substations	1.6	1.6	1.6	1.5	1.5
HVD Substations	1.3	1.3	1.3	1.3	1.3
Total	3.1	3.1	3.1	3.0	3.0

LVD Lines Reliability

Our LVD Lines Reliability O&M program supplements the LVD Lines Reliability capital program and funds activities that ensure the long-term safe and reliable operation of the LVD system. Spending in this program is primarily driven by demand, and our five-year forecasted spending levels are based on historical spending in the category. These expenses involve incremental repairs to the LVD lines infrastructure that are not captured by our capital projects.

This program improves public and employee safety, addresses imminent concerns, reduces customer outage frequency (SAIFI), and reduces the number of emerging repetitive outage customers (CEMI), as well as customer outage durations (CAIDI and SAIDI).

Planning Process

Our planning process depends on the severity of the issue being addressed. When we identify an imminent safety issue, we must take immediate action to address the concern. When we identify other O&M-related issues that do not pose a safety concern, we conduct analyses to help identify specific areas for investment to help prioritize projects that will deliver the greatest reliability improvements against specific metrics (e.g., SAIDI, SAIFI, and CEMI-5).

The critical inputs and analyses that we employ to best target reliability issues are:

- RAE and OMS – These tools help us identify and analyze reliability and repetitive outage zones as described in capital programs 4.1 LVD Lines Reliability and 4.7 LVD Repetitive Outage, respectfully.
- Collaboration and regular input from operations and field organizations – This provides our Engineering planners with the ability to serve customer needs while considering resource and system constraints.

- General public observations of issues and calls into our customer contact centers – These provide additional line of sight of system needs.
- Underground Padmount Equipment Inspections – Every year, padmounted equipment is visually inspected around the exterior for any signs of oil leaking, holes that expose electrical components, or missing labels. When found, the holes are patched and labels are replaced. The replacement of equipment is completed in the capital program 2.1 LVD Lines Demand Failures.
- LVD Security Assessments – As described in capital program 2.1 LVD Lines Demand Failure, all LVD feeders are inspected on a six-year cycle for public and employee safety, and for reliability concerns. Issues identified that are not capital components are addressed in this O&M Program. Some examples include:
 - Replacing a fuse link to put a fuse back into service or correct system protection issues, including device reach and coordination between devices.
 - Replacing a fuse link to correct system protection issues including device reach and coordination between devices.
 - Moving a jumper on a line or device to balance load among phases.
 - Bringing assets up to current standards, such as by moving lightning arresters to the load side of the transformer cutout.
 - Replacing damaged/stolen components, such as sections of copper down grounds that have been stolen.
 - Adding or correcting existing labels for devices in the field to match our records.
 - Adding animal mitigation due to past animal-related outages.

Once we are notified of an issue and have assessed the level of severity, our planners will evaluate and sequence work based on the priority ratings, as described in capital program 2.1 LVD Lines Demand Failures.

Examples

Below are three examples of LVD line issues identified during security inspections that create a number of customer benefits:

1. Replacing a Fuse Link

Figure 97 shows an example of where we needed to re-fuse a blown capacitor fuse. The O&M cost associated is to replace the fuse link. Depending on the location of this fuse, we could choose to defer this until we have a crew working in the area. For example, a blown capacitor fuse affects our system, but it may or may not be urgent based on several factors including time of year and system loading.

FIGURE 97 – BLOWN CAPACITOR FUSES



2. Re-sagging Wires

A number of outages on a circuit in the Flint area resulted in an investigation where we identified a section of line that was poorly sagged. This created the potential for the primary wires to intermittently contact one another when experiencing cross winds and create a service interruption for approximately 860 customers in each instance. As a result, we decided to re-tension the wires to prevent future outages.

FIGURE 98 – SAGGED WIRES ON PIERSON FEEDER



3. Voltage Regulator Adjustment

Electric customers file complaints when they are having power quality issues, such as power-related equipment malfunctions or experiencing too bright or too dim lights. We use our CYME power flow modeling program to determine if we are within 5% of the nominal system voltage (for a 120 volt base, this is a range from 114 volts to 126 volts). If not, one of the corrections that can be made is to increase voltage by changing the settings on our substation or line regulators. LVD Planning determines the correct settings and a lab technician adjusts the settings on the device to correct the voltage problem. The O&M cost associated with adjusting the regulator settings falls within this program.

Benefits

In addition to the reliability benefits of reducing outages, we also address safety concerns in order to protect the public and our employees.

Poorly sagged conductors can inadvertently contact one another in windy conditions, causing outages that take time to identify. Installing bird diverters on our lines in an area known for bird issues can both prevent outages and prevent animal death.

HVD Lines Reliability

Our HVD Lines Reliability O&M program includes the O&M spending portion of our HVD pole inspection program at a 12-year cycle (performed by a contractor), and one MOAB test operation cycle per year (performed by internal Consumers Energy resources). A 12-year pole inspection cycle in the state of Michigan is supported by established wood pole decay severity zones. Pole inspections and MOAB testing are fundamental tactics used to manage the health and functionality of key HVD line assets. The five-year plan for this program is presented below.

TABLE 68 – O&M: HVD LINES RELIABILITY

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
MOABs Test Operations	0.09	0.09	0.09	0.09	0.09
Pole Inspections	0.04	0.04	0.04	0.04	0.04
Total	0.13	0.13	0.13	0.13	0.13
Unit Forecast					
Spending Categories	2018	2019	2020	2021	2022
MOABs Test Operations	345	350	355	360	365
Pole Inspections	6,125	6,125	6,125	6,125	6,125

Note: it is anticipated that additional MOABs will be added to the electric HVD system each year as an additional method of improving reliability

Planning Process

HVD poles are identified in the HVD Lines Construction database. The HVD pole inspection plan is predicated on a 12-year cycle (estimated 6,125 poles per year), but the exact number of HVD poles inspected in a year may vary from the targeted amount, predominantly influenced by the amount of pole replacements outstanding from prior inspections. If a backlog of pole replacements exists, we may reduce inspections for a given year to avoid increasing the backlog and to manage overall costs. Conversely, if a need exists, we can increase the inspection amount for a given year, staying aligned with the overall goal of a 12-year inspection cycle. For example, in 2017, there were 6,792 HVD poles inspected. Line segments that were inspected included: Waldron, Linden, Parma, Flushing, Bridgeport, Alabaster, Harper Road, Kawkawlin and Whitestone Point.

The MOABs tested under this program are identified in the Cascade substation asset management database. We prioritize test operating every MOAB on the system every year, as proper MOAB operation is a known method to reduce or maintain SAIDI. However, system operating conditions sometimes restrict the ability to test operate some MOABs. In 2017 approximately 340 MOABs were test operated.

Benefits

Like other reliability investments, the spending in this program provides a number of benefits to the customer experience by improving overall long-term energy reliability. Through a holistic approach to coordinating projects across a number of programs, including repetitive outages, line clearing, and pole inspection and replacement, we aim to maximize the reliability benefit for our customers.

- Reliability – The MOABs test operating and pole inspection programs are key inputs to our capital reliability and demand failures programs. One round of MOABS test operating is calculated to save approximately 1.3 SAIDI minutes per year. This is based on a historical failure rate of six units per year when the switches were not test operated and an impact of 0.46 SAIDI minutes per HVD line outage and about 50% of customers on a given outage not being restored due to the switch’s failure to operate.
- Control – Maintaining MOABs ensures maximum flexibility for operating the HVD system under both normal and outage conditions.

LVD Substation Reliability

Our LVD Substation Reliability O&M program maintains the safety and reliability of LVD distribution substations. This program includes several activities, such as every-other-month substation inspections, substation equipment inspections, recloser and breaker test operating, and substation battery maintenance. This program has traditionally included required environmental inspections due to the Spill Prevention, Control and Countermeasure (SPCC) program. Funding for 80% of the mowing and weed spraying programs (contracted, split with HVD) falls in this program, and consists of one weed spray per year and a five-month (May-September) mowing program with a two-times-a-month mow interval. Issues identified by inspections or patrols under this program are corrected through work orders in the LVD Substation Demand O&M program, the LVD Substation Reliability capital program or the LVD Substation Failures capital program.

The 2018 plan, which is typical for most years, includes:

- 29 station battery inspections
- 4,842 substation bi-monthly inspections
- 2,554 distribution transformer combustible gas tests
- 2,496 recloser test operations
- 82 breaker test operations
- Various other substation operation procedures
- Semi-monthly mowing at approximately 800 LVD substations
- Annual weed spray at approximately 800 LVD substations
- Miscellaneous overheads and charges (fleet charges, test equipment, Electric Field Lab testing, etc.)

HVD Substation Reliability

Our HVD Substation Reliability O&M program maintains the safety and reliability of HVD and Strategic Customer substations. This program includes several activities such as monthly substation inspections, substation equipment inspections, breaker test operating and substation battery maintenance. This program has traditionally included required environmental inspections due to the SPCC program. Funding for 20% of the mowing and weed spraying (split with LVD) programs falls in this program. Issues identified by inspections or patrols under this program are corrected using orders created under the HVD Substation Demand program, HVD Substation Reliability program, or HVD Lines & Subs Failures program.

The 2018 plan, typical of most years, includes:

- 174 station battery inspections
- 2304 substation monthly inspections
- 417 transformer combustible gas tests
- 878 breaker test operations
- Various other substation operation procedures
- Semi-monthly mowing at about 190 HVD substations
- Annual weed spray at about 190 HVD substations
- Miscellaneous overheads and charges (fleet charges, test equipment, Electric Field Lab testing, etc.)

Planning Process for LVD and HVD Substation Reliability

Of the activities in this program, most are mandated (e.g., NERC inspections, substation patrol inspections, substation mowing, and weed spraying) or operationally required (e.g., breaker test operating, station battery inspection and maintenance). Orders for these activities are created and tracked within the Cascade substation asset management database. Some substation inspection activities such as power transformer oil testing, SF₆ breaker gas testing and substation infrared inspections are performed outside of this budget (for more information on these other programs, including SF₆ breaker gas testing, see the HVD Substation Demand Failures capital section).

Prioritization Logic for LVD and HVD Substation Reliability

We prioritize work in this program to focus on the most essential work required. As we aim to minimize costs in order to benefit our customers, we have deprioritized lower urgency activities such as maintenance equipment inspections on equipment such as load tap changers, voltage regulators, reclosers, current transformers and voltage transformers over the past few years. Over time, as additional funding is made available, these lower-urgency inspections can be reinstated, based on the priority assigned within the Cascade substation asset management database.

Timing

Planning for a given year is performed as soon as the budget for the upcoming year is available. The plan is typically finalized in December for the following year. The plan may be adjusted during the year based on budget changes or newly identified issues. Additionally, planning activities are also aligned to follow the substation inspection cadence shown below.

TABLE 69 – SUBSTATION INSPECTION CADENCE

Substation Inspection Cadence			
Inspection Task	Cadence		Components Checklist
	LVD	HVD	
All Station Components	Bi-Monthly	Monthly	Visual inspection Routine patrol inspections
Entire Substation	Bi-Annually	Annually	Infrared inspection of entire substation
Protective Relays and Communication Systems	Depends on relay model & failure history		Maintenance & testing performed
Station Batteries	Monthly		Voltage check
	Annually		Equalization
	Annually		Specific gravity reading
	4 Years**		Complete inspection
Power Transformers	Bi-Monthly	Monthly	Visual inspection (including fans and pumps)
	Periodic		Combustible gas test (follow-up dissolved gas analysis tests, if warranted)
	As determined by combustible gas tests	Annually*	Diagnostic dissolved gas analysis of transformer oil
Motor Operated Air Break Switches (MOAB)	Annually		Test Operated (decoupled)
	4 Years		Battery replacement**
Single Phase Regulators	Set cadence not yet established	n/a	Limited program of dissolved gas analysis
NERC Circuit Breakers & Switches	n/a	Annually	Test Operated
NERC Current and Voltage Sensing Devices	n/a	10 Years	Inspection
*For Power Transformers with Load Tap Changers Only **Or periodically as needed			

Benefits of LVD and HVD Substation Reliability Spending

Since 2008, over 15,000 alerts have been generated in Cascade. Alerts are used to communicate issues, anomalies and observations from members of one group (such as Substation Operations) to other groups (such as Substation Maintenance, the Electric Field Lab, or the Reliability Engineers) that are responsible for the evaluation of the issue and whether corrective measures need to be taken either under the O&M demand maintenance programs or capital demand failures programs. The vast majority of these alerts are generated by Substation Operators or by Cascade based on inputs from the operators during their regular patrol inspections. The average LVD substation outage in 2017 resulted in 0.123 SAIDI minutes whereas the average HVD substation outage in 2017 resulted in 0.068 SAIDI minutes. As

such, each outage avoided has a significant benefit to system reliability. Additionally, there are public and Company safety benefits from having periodic inspections of substations. Lastly, maintaining equipment allows the system to be operated as intended and at its most efficient.

ii. 2.2 Forestry

Our Forestry program includes a number of separate sub-programs that together form part of an integrated vegetation management program to improve customer reliability through line clearing and other forestry work. The goal for our Forestry program is to move towards a seven-year effective clearing cycle for our LVD system, and to maintain a four-year clearing cycle for our HVD system (as described in more detail below). In order to achieve this objective, we will need to increase our spending over a multi-year period to annually clear more miles of the LVD system.

In 2018, we plan to spend \$51.5 million on our line clearing program, increasing this spending incrementally each year until our LVD Forestry program achieves an effective seven-year cycle. When we attain a seven-year clearing cycle on the LVD system, the cost per line-mile will decrease as the time between clearings is reduced. Overall, the impact of these investments over time will allow us to considerably improve the electric reliability to our customers by reducing the number of tree-related outages that occur on our system.

TABLE 70 – O&M: FORESTRY

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
LVD Line Clearing	41	43	46	50	53
LVD Contractor Full Circuit Clearing	36.3	38.3	41.0	44.8	48.4
Demand Work	1.1	1.1	1.1	1.1	1.1
Repetitive Outage	1.2	1.2	1.2	1.2	1.2
First Zone	1.2	1.2	1.2	1.2	1.2
Brush Control	1.5	1.5	1.5	1.5	1.5
HVD Line Clearing	10	10	10	10	10
Full Circuit Clearing	7.1	7.0	7.0	7.2	7.2
Brush Control	2.8	2.8	2.8	2.8	2.8
Hot-spotting	0.2	0.2	0.2	0.2	0.2
Noxious Weeds	0.1	0.1	0.1	0.1	0.1
Total Forestry Spending	51	53	56	60	64

As discussed in Section II.C, one of our metrics is ‘forestry cost per line-mile cleared.’ This metric is calculated by taking the total cost of the Forestry program, and dividing by the number of miles cleared (sum of LVD and HVD). In 2017, approximately 4,500 miles were cleared with a preliminary program spending of \$50 million, giving a cost per line-mile cleared of \$11,000. Since this metric uses a blended

cost between LVD and HVD, and includes all Forestry spending, it differs from the cost per line-mile cleared values discussed below.

LVD Line Clearing

Clearing trees benefits customers by reducing outages and decreasing impact of storms. Clearing the rights of way allows easier access to lines, resulting in faster restoration when an outage occurs. For the three major distribution voltages used on our LVD system, the benefit of clearing is demonstrated in Figure 99 and Figure 100 below. On a circuit that is cleared, SAIFI and SAIDI both improve substantially in the year that clearing is completed. In general, this trend continues in subsequent years before eventually reversing further into the future.

FIGURE 99 – SYSTEM SAIFI IMPROVEMENT POST CLEARING

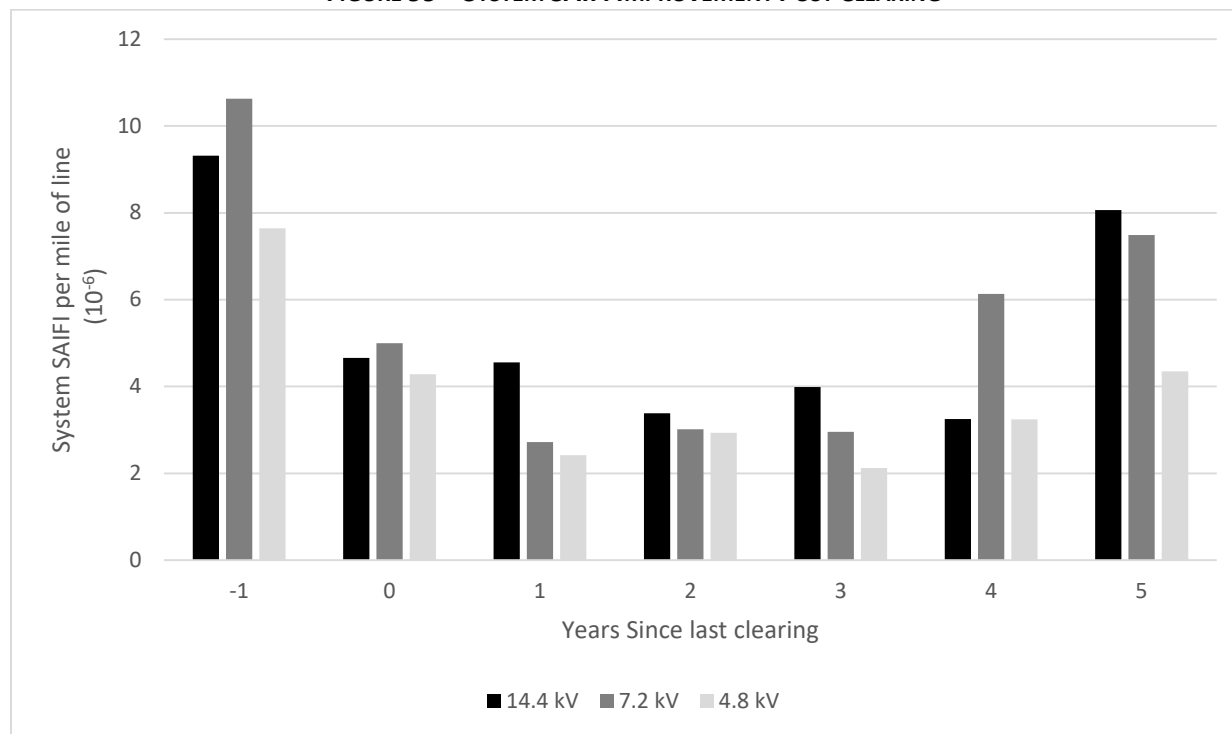
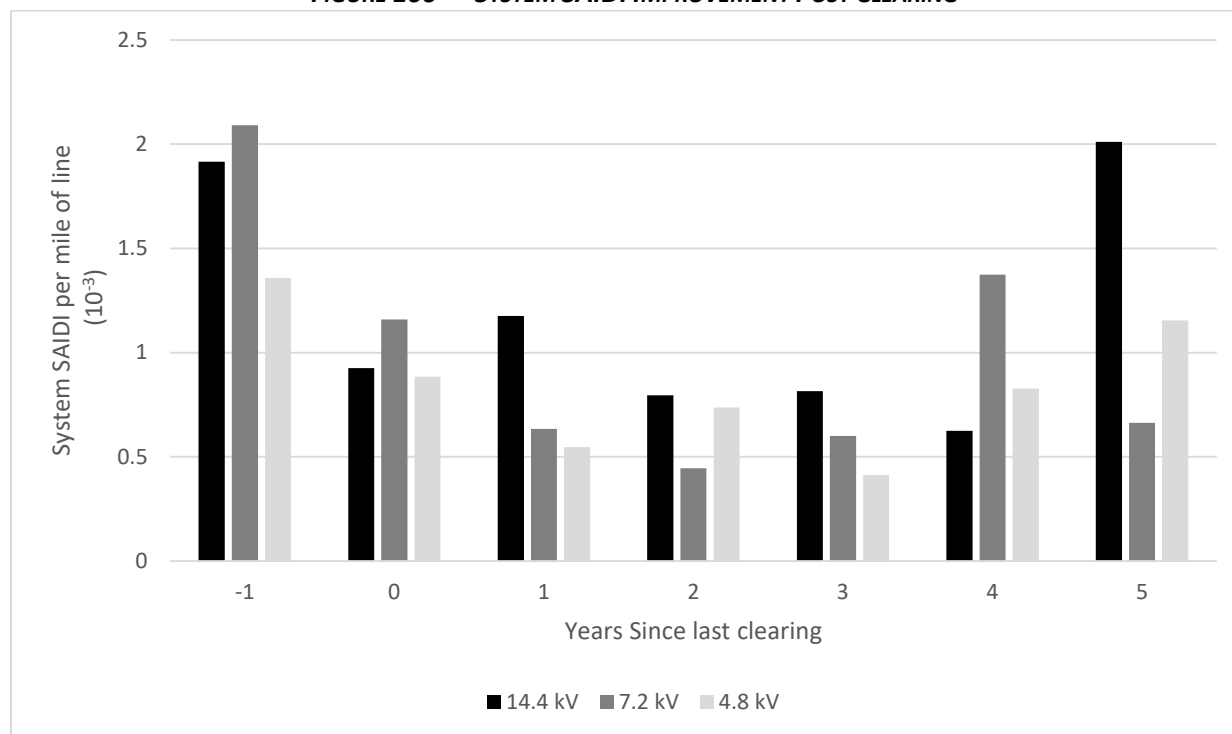


FIGURE 100 — SYSTEM SAIDI IMPROVEMENT POST CLEARING



Full Circuit Clearing

Full circuit maintenance clearing is the primary scheduled maintenance clearing sub-program for the LVD system. Full circuit clearing work is performed using production-oriented contracts and includes line trimming, tree removal, and brush cutting.

Each year, circuits are selected using the forestry reliability model. This model provides a ranking of LVD circuits based on projected improvement in reliability, while also providing adequate geographic coverage for emergent work, capital clearing work, and service restoration coverage.

The goal of the forestry model is to rank circuits to maximize the reliability benefit at the lowest cost. Our forestry model ranks circuits based on the potential reduction of tree-caused outages or number of customer minutes per mile. The model uses a number of inputs including historical tree outage performance, tree density and the average number of customers affected by a tree-caused outage against the actual historic tree outage performance of that individual circuit over a three-year period.

Circuits are then sometimes promoted in our queue based on total circuit contribution to SAIDI or when circuits are located in high SAIDI impact service territories. Circuits with more outages per mile have been deprioritized the past two years to complete circuits with a higher total number of outages or to accommodate circuits in high SAIDI impact service territories.

It currently costs approximately \$9,900 per mile, including hazard tree removal program costs, for full circuit clearing on the LVD system. This is higher than our historical line clearing costs for several reasons:

1. First, there is a nationwide shortage of qualified tree trimmers, and increasing the available workforce is a lengthy process. It takes a year of training for a new employee to qualify to perform work clearing distribution lines, and another year to qualify as a crew leader. As a result, we have supplemented the existing workforce with out-of-state based crews, which have higher travel expenses and are therefore more expensive. In general, the pool of qualified tree trimmers is undergoing a generational shift, and many utilities are facing the prospect of having to increase wages to attract new talent.
2. Second, environmental requirements such as the use of wetland mats, time of year restrictions on work, and other issues have added costs.
3. Finally, in 2016 we began removing hazardous trees outside of LVD rights of way due to the mortality of ash trees from the Emerald Ash Borer (EAB), accounting for an approximate 10% increase in the per mile cost.

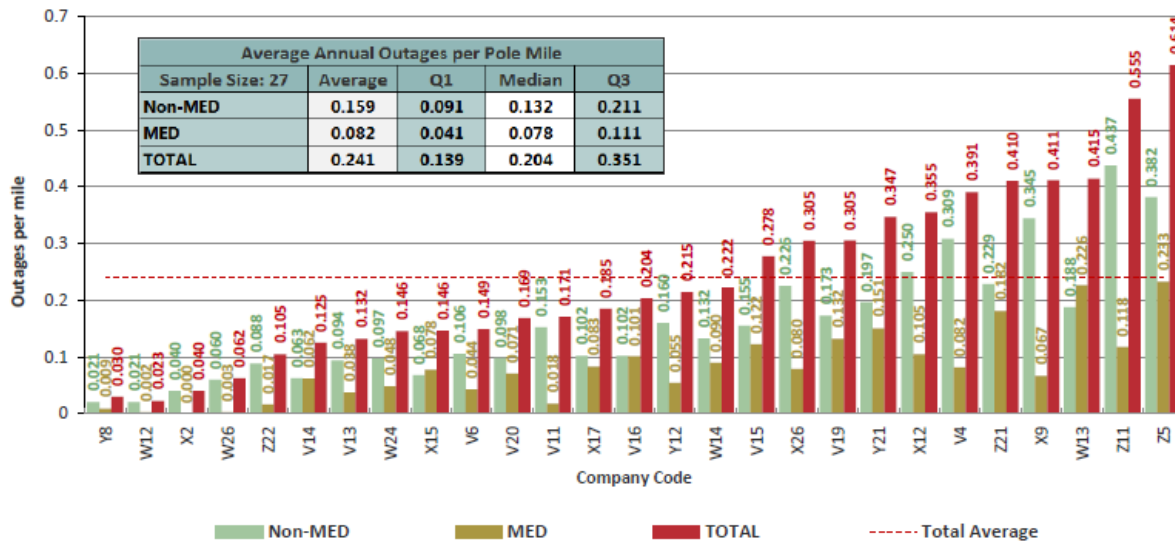
In 2017, our target was to clear 3,322 miles of LVD lines. We met that target, ultimately clearing 3,503 miles at a cost of \$38.4 million. During the year, we accelerated our clearing schedule in April through June in order to clear as many miles as possible before summer storms hit. This resulted in markedly improved third and fourth quarter SAIDI performance, one of the best periods in our history.

Rationale for a Seven-Year Effective Cycle

In 2017, our LVD line clearing program was commensurate with a 14-year clearing cycle. For comparison, a recent study from CN Utility Consulting, Inc. (CNUC) established a benchmark clearing cycle of 4.9 years.

Over the period from 2011 through 2015, we averaged 0.415 tree-related outages per LVD mile per year, compared to CNUC’s benchmark average of 0.241 tree-related outages per LVD mile per year as shown in the Figure below (Consumers Energy is Company Code W13).

FIGURE 101 – CNUC BENCHMARK STUDY – 5 YEAR ANNUAL AVERAGE TREE RELATED OUTAGES PER SYSTEM POLE MILE (2011-2015)



We can expect to be much closer to achieving the benchmark for average outages per mile if we clear our LVD circuits on a seven-year effective cycle, accounting for the three main LVD voltage groups. Reaching this target would significantly decrease our number of forestry incidents per year, and could eventually permit the related outage restoration costs to be used elsewhere for further system improvement.

These improvements and costs savings would occur over time as the system average clearing cycle decreases to the seven-year average. We estimate that the full decrease in outages and savings would occur after completing five years of clearing at a consistent seven-year average cycle.

Additionally, in recent years we have had to remove approximately 20 feet of a tree’s canopy to achieve ten feet of clearance to conductors. When the effective cycle is ten years, the amount of canopy removal drops to approximately 16 feet. On a seven-year clearing cycle, the amount of tree canopy removal would be approximately 12 feet to achieve 10 feet of clearance to conductors. This greatly lessens the aesthetic impact of line clearing to customer properties, which reduces customer complaints.

Explanation of Seven-Year Effective Cycle

Under a seven-year effective cycle, it is not necessary to clear every circuit every seven years. Instead, we would take advantage of the fact that tree contact affects different voltage lines differently; tree contact with a higher voltage wire is more likely to result in a fault. Therefore, to achieve comparable levels of performance across all circuits, we would clear higher voltage circuits more frequently than lower voltage circuits. While individual circuits may be scheduled for clearing earlier or later than shown in Table 71 below, it provides average miles of each voltage class that would be cleared each year under a seven-year program.

TABLE 71 — LVD CLEARING SCHEDULE FOR SEVEN-YEAR EFFECTIVE CYCLE

LVD Clearing Schedule					
Voltage Group	System Miles	14% Clearing Program – mi/yr. Cleared	Effective Cycle (Years)	10% Clearing Program – mi/yr. Cleared	Effective Cycle (Years)
11.0-14.4 kV	16,100	3,200	5	2,680	6
7.2 kV	9,300	1,325	7	1,030	9
2.4-4.8 kV	30,600	3,455	9	1,890	16

The 14% clearing program results in a seven-year effective cycle across all voltage classes, and about 0.27 tree-caused faults per mile per year.

Business Plan to Achieve Seven-Year Effective Cycle

Achieving a seven-year effective clearing cycle will be challenging. There is currently a backlog of lines that are overdue for clearing, and additional qualified forestry crews will be required. Due to these challenges, we plan to phase in a seven-year effective cycle over the next several years, through a

combination of increased total spending on line clearing and improvements in efficiency that will reduce the cost per line-mile of clearing.

In 2018, we will spend \$36 million on line clearing on LVD circuits, at a cost of approximately \$9,400 per line-mile. Over the next five years, we will increase our annual spending to roughly \$48 million for LVD lines. During this period, we expect inflationary and wage pressure to drive up our cost per line-mile due to the fact that there is currently a nationwide shortage of qualified tree trimmers. At the same time, we expect to offset this upward cost pressure as we see improvements in cycle efficiency. Our cost per line-mile will improve as we move our LVD line clearing program towards a seven-year effective cycle, clearing significant parts of the backlog noted above.

TABLE 72 – O&M: LVD LINE CLEARING FIVE-YEAR PLAN

Current forestry plan to achieve 7-year cycle					
	2018	2019	2020	2021	2022
LVD O&M (\$ millions)	36	38	41	45	48
LVD O&M Miles Cleared	3,860	3,890	4,160	4,530	4,915
O&M \$/Mile	9,400	9,800	9,900	9,900	9,850
Crews Needed	285	324	339	361	381

Partial Circuit Clearing

The spending detailed in Table 70 above includes several clearing programs that are not focused on clearing full circuits. These include: clearing trees at customer requests (demand work), clearing sections of circuits to reduce repetitive outages, and clearing first zone three-phase sections when outage data indicates excessive outages are occurring in this zone.

Demand Work

The customer requests sub-program is used to address emergent vegetation threats to the LVD system. EAB mortality ash trees have driven spending for this area higher in recent years and this trend will continue until we perform hazard tree removals across the entire LVD system (approximately seven years). Emergent vegetation threats are identified predominately by customers calling in personal observations around their homes and from forestry operations personnel while performing duties in the field. We are forecasting to complete approximately 45 miles per year based on average trees per mile on the LVD system. This program receives higher priority over scheduled maintenance since failure to address identified locations will likely result in an LVD line outage. The program has a high impact on our customer in preventing outages to the LVD system, maintaining the repetitive outage metric in an acceptable range, and reducing the number of formal complaints.

Repetitive Outage

The repetitive outage forestry sub-program is used to clear specific sections of circuits that are experiencing high levels of outages due to trees. The goals of this program are that we address sections so that they do not continue to be repetitive outage areas.

Circuit metrics on tree-caused outages are reviewed periodically throughout the year. Investments are made on sections with a high customer density per mile of clearing when greater than five tree-caused

outages have occurred in the load concentration point zone for that section of the circuit. We also receive requests from the LVD engineering planning organization based on high number of customer outages due to trees and formal complaints made by at least one customer in the affected LCP zone. Over the next five years, we are forecasting to spend approximately \$1.2 million per year to complete approximately 105 miles per year. The zones that are targeted by this program have had a high occurrence of outages with as many as 21 tree-caused interruptions in the previous 12 months.

First Zone

First zone forestry spending is used to clear sections of circuits from the substation outward along the three-phase portion of a circuit to logical load concentration points. Spending on the first zone will reduce the likelihood of full circuit lockouts due to trees. Potential circuits are reviewed annually and are selected based on historic tree-caused outages affecting the entire circuit.

This sub-program is also used for clearing areas directly related to customer complaints without a direct benefit to system reliability. First zones areas are generally “mid-cycle,” meaning that they are considered for selection only if the circuit has not been cleared in at least three years. Investments are selected based on the regular review of outage data and projects are created for first zone areas when historic data indicates habitual tree outages affecting the entire circuit over several years.

Our current forecast calls for spending \$1.2 million per year to target 200 miles. Although these zones have lower outage frequency than some areas, outages that occur impact a much higher number of customers, and have a much higher SAIDI impact. As such, line clearing in first zones helps provide the maximum reliability benefit for our customers.

Brush Control

We aim to treat brush with herbicide two to three years following full circuit clearing. The costs of this program are tied to the LVD brush control sub-program. Circuits are selected based on their geography (rural and suburban) with high levels of brush growing within the rights of way. The treatments reduce future stem volume and keep the rights of way accessible to line crews for a longer period of time. Circuits are selected amongst the list of circuits cleared in the prior two to three years when brush height is amenable to foliar herbicide treatments.

We are planning to spend approximately \$1.5 million per year for brush control activities on approximately 150 miles per year based on 10% mileage count in the off cycle (1,500 geographic miles equates to an MPSC reportable mileage of 150 miles).

LVD Clearing Benefits

As discussed throughout this section, LVD forestry provides a significant reliability benefit to our customers. In addition, forestry work helps reduce wire downs and improve safety for our customers and employees. For further details on the SAIDI benefit of the LVD Forestry program, refer to Section VII.C which summarizes the reliability impact of our investment plan.

HVD Line Clearing

Full Circuit Clearing

Our HVD full circuit clearing program is comprised of the scheduled cycle maintenance activity for line clearing and removal work on the HVD system. EAB mortality ash trees have driven spending for this

program higher in recent years. This trend will continue until we have completed a cycle on the HVD system that includes hazard tree removals (complete in approximately two and a half years). Maintaining the HVD system right of way is critically important for the overall reliability of our grid and customers, as this system feeds all of our LVD circuits. When outages occur on the HVD system, they typically impact a higher number of customers for longer durations. Currently, the HVD system is on an approximate four-year scheduled clearing cycle. We plan to maintain this level of clearing for the HVD system into the foreseeable future.

TABLE 73 – HVD CLEARING SCHEDULE

HVD Clearing Schedule		
Voltage	System Miles	25% Clearing Program – mi/yr. Cleared
23 kV	35	9
46 kV	4,780	1,195
138 kV	168	42
Total	4,983	1,246

In 2017, our HVD full circuit clearing cost was approximately \$11,200 per mile. Our HVD lines are more expensive to clear when compared to LVD lines, because we exercise more aggressive hazard tree removal rates, and because HVD rights of way are more difficult to access. EAB impacted trees along the HVD system have increased full circuit clearing costs. We believe HVD per mile clearing costs will decline over time as hazardous EAB trees are removed. Through 2018 and thereafter, our projected spend (2018-2022) is approximately \$7.1 million per year. The forecasted quantity is 500 miles cleared (50% of geographical miles “1,000 miles” counted with the remaining 50% counted when brushing work is completed).

Partial Circuit Clearing

Besides clearing on a scheduled four-year cycle, we inspect lines for vegetation conditions one year prior to being cleared. This permits us to address fast growing trees that are encroaching on conductors before full clearing takes place. Aerial inspection of HVD lines also records and reports questionable tree conditions. These inspections occur approximately once per year and capture changing tree conditions such as leaning or uprooting trees.

Brush Control

We conduct regularly scheduled cycle maintenance brush cutting or herbicide treatment work on the HVD system. As aforementioned, maintaining the HVD system right of way is critical for overall system reliability due to the high number of customers impacted by HVD outages. Clearing brush permits access to facilities for line crews, inspections, and security. This program is already scheduled on a four-year cycle, with minor adjustments made annually to level out spending on transmission spending (HVD-T came into existence halfway through first four-year cycle) and to accommodate HVD capital line rebuilds.

We expect to spend approximately \$2.8 million per year to brush cut 500 miles (50% of geographical miles “1,000 miles” counted with the remaining 50% counted when tree work is completed).

This spending will have a high impact to preventing outages on the HVD system, maintaining repetitive outage metric in acceptable range, and reducing formal complaints.

Hot-Spotting

Our hot-spotting sub-program is used to address emergent vegetation threats to the HVD system. As discussed above, EAB mortality ash trees have driven spending for this program higher in recent years, and this trend will continue until we complete a full clearing cycle of the HVD system. Emergent vegetation threats are identified predominately by forestry HVD vegetation inspections and helicopter patrols of the HVD system. These situations require immediate remediation of between one and a few trees to protect the system from an imminent outage.

This area receives higher priority over scheduled maintenance since failure to address identified locations will likely result in an HVD line outage. We are forecasting to spend \$240,000 per year over the next five years to complete the equivalent of 35 miles. The benefits of this program are a high impact to preventing outages on the HVD system and reducing formal complaints.

Noxious Weeds

Our noxious weed sub-program is used for compliance to local ordinances for maintaining certain HVD rights of way in predominately urban areas. These ordinances do not permit vegetation growth above a specified height (Flint – five inches, elsewhere generally 12 inches). Not performing this activity will result in local governments needing to perform the work with added penalties against Consumers Energy. These costs get added to property taxes for these affected fee-owned lands. We expect to spend approximately \$40,000 annually to complete between three and six mowings of affected rights of way per year; however, this will vary greatly year to year based on rainfall and temperature.

HVD Clearing Benefits

It is more difficult to quantify line clearing benefits on the HVD system due to the infrequency of tree-related outages that occur (historically, we saw an average of only 15 annual tree-caused outages on the HVD system). Most HVD tree-related outages are caused by trees growing outside of ROW. Also, during high load periods, or when maintenance has temporarily removed a section of the HVD system from service, an outage on an HVD line can have localized cascading potential. When an outage does occur, it often impacts several substations, each with multiple LVD circuits. Because an outage to an HVD line impacts many more customers than a typical LVD outage, clearing widths are wider, trimming clearances are greater, and clearing cycles are shorter.

Across the HVD system, our 2017 target was to clear 1,016 miles of HVD lines. We achieved that target, clearing 1,019 miles at a cost of \$11.4 million.

Transmission Clearing

In addition to our LVD and HVD systems, we are also responsible for clearing the rights of way for the transmission lines that we own. This costs about \$9,200 per mile, and we spend about \$600,000 per year on this program. Although we have a single Forestry department responsible for all line clearing on both the distribution and transmission systems, we do not recover funding that we spend on transmission line clearing through MPSC-established rates. Instead, we recover that money through a FERC-approved formula rate process administered by MISO.

Clearing Specifications

Clearing specifications fall into two categories:

- Specimen trees in maintained landscapes
- Trees or brush growing in unmaintained landscape areas, or non-specimen trees in maintained landscapes

Specimen trees are planted trees or naturally seeded trees that have been actively maintained in a landscape area, such as lawns, city streets, or developed areas of parks such as picnic areas and sports fields. Specimen trees are generally trimmed to remove branches and attain sufficient clearance to conductors to permit the line to operate without interference for several years. They may be removed if they present a hazardous condition; removal is preferable to repeated trimming over the expected lifespan of the tree. When trimmed, the following table reflects applicable clearances. Clearances are measured from the conductor to the closest point of the tree. For aerial spacer cables, an exception can be allowed to permit trees to grow no closer than three feet from conductors. For a system neutral conductor functioning as both primary and secondary neutral that is located on the pole in the secondary zone, clearance falls into the service/secondary category.

TABLE 74 – O&M: SPECIMEN TREES IN MAINTAINED LANDSCAPES

Specimen Trees in Maintained Landscapes				
Description	Voltage	Minimum Clearance for Trees Trimmed		
		Top	Side	Overhang
Service/Secondary	<750 volts	2 feet	2 feet	2 feet
Primary Open Wire	2.4-14.4 kV	10 feet	10 feet	10-20 feet*
Primary Aerial Spacer Cable	2.4-14.4 kV	6 feet	6 feet	6 feet
HVD	46 kV	15 feet	15 feet	No overhang allowed
HVD	138 kV	Not Applicable	20 feet	No overhang allowed

Unmaintained areas are all other areas such as forested areas, agricultural fields and fencerows, and old fields. They rarely include specimen trees. Trees and brush growing in these areas are cleared to the width of the right of way. Similarly, non-specimen trees growing in or near maintained landscapes are removed to the width of the right of way.

For HVD lines, the clearing width is wider and fewer specimen trees are permitted. For 46 kV lines, public street specimen trees may be permitted, but specimen trees on private property growing directly below conductors are generally removed. For 138 kV lines, all specimen trees growing directly below conductors are removed. Specimen trees that require only side trimming to attain minimum clearance are permitted within the right of way clearing width.

TABLE 75 – ROW WIDTH AND CLEARING FOR NON-SPECIMEN TREES

ROW Width and Clearing for Non-Specimen Trees					
Description	Voltage	ROW Width from Centerline	Clearing	Hazard Zone Width (each side of ROW)	Clearing
Service/ Secondary	<750 volts	15'	Removal when needed	none	Removal when needed on case by case basis
Primary Open Wire	2.4-14.4 kV	15'	Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal	20'	Hazard trees removed when work can be safely accomplished by crews with standard equipment
Primary Aerial Spacer Cable	2.4-14.4 kV	15/5 '*	Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal	20'	Hazard trees removed when work can be safely accomplished by crews with standard equipment
HVD	46 kV	40'	Non-specimen trees removed, specimen trees removed if hazardous or cost/benefit justifies removal	40'	Hazard trees removed when work can be safely accomplished by crews with standard equipment
HVD	138 kV	45-66'	Non-specimen trees removed. Specimen trees removed if hazardous or within the wire zone or cost/benefit justifies removal	40'	Hazard trees removed when work can be safely accomplished by crews with standard equipment
*ROW width for aerial spacer cable is 15 feet from centerline on the bracket side of the pole and 5 feet from centerline on the non-bracket side of the pole.					

We do not grind or remove stumps of trees removed for line clearing, nor do we remove tree debris from customers' properties during or after emergency restoration work.

We follow guidelines for line clearing work to prevent the spread of oak wilt disease as published by the Michigan Oak Wilt Coalition. These guidelines limit certain work or require additional precautions throughout most of the year.

Several threatened or endangered species exist within or along our rights of way including the Karner blue butterfly, Mitchell satyr butterfly, Indiana bat, Northern long-eared bat, Massasauga rattlesnake, and many other species of concern. Each of these species requires adjustments to line clearing practices or timing to protect individuals of the species or their habitats.

Gaps in Current Program

The largest gap in the current program is funding to achieve a reasonable level of tree-caused interruptions for our customers. We believe that the optimal cost to benefit cycle is the effective seven-year cycle described above.

We are also reviewing the clearing specifications for our 14.4 kV primary system. Typically, lower voltage circuits are converted to 14.4 kV to alleviate power quality issues, reduce line loss and increase capacity, instead of extending the 46 kV HVD system and adding of new substations to achieve similar results. The 14.4 kV system is much more sensitive to tree and branch contact than lower voltages, and reliability data suggests that clearing to current specifications does not provide the same immediate improvement in reliability nor length of time of benefit. A wider right of way or changes to line design for 14.4 kV lines may be necessary to ensure that the 14.4 kV system performs at the same level as the lower voltages that we use.

As seen with the emerald ash borer, the process of adjusting clearing specifications and costs to new pests in Michigan's trees and forests is a slow one. Our customers experience outages due in part to a slow process before changes are approved. More flexibility would improve our ability to maintain reliability.

Alternatives to Mitigate Tree Outages

As discussed earlier in Section VI on design standards, we are installing aerial spacer cables when rebuilding primary lines in areas of heavy tree density, such as along county road rights of way running through Department of Natural Resources land. This type of conductor and bracketed spacing reduces the area requiring clearing, and the coated conductor is much more resistant to tree-caused faults than an open wire conductor. It is similar in installation expense to an underground primary, but it can be used in more areas with less disruption to existing infrastructure, and is easier and faster to repair when a fault occurs.

A second alternative on the secondary system is to replace the existing open wire secondary with triplex conductors. Similar to aerial spacer cables, triplex conductors offer a compact footprint and are more resistant to tree contact than open wire. Fewer customers are impacted by a secondary outage than a typical primary outage, but in urban settings where secondary is used this is also an alternative.

Finally, the Grid Modernization program will help reduce the impact of tree-caused outages to our customers as previously described in Sections V and VIII.

C. 3.0 Operations, Meter Services, Meter Readings, and Service Restoration

Our Operations, Meter Services, Meter Readings, and Service Restoration O&M spending consists of a number of demand programs related to the front-line operations of our distribution grid.

Storm restoration is the most wide-reaching component of this program and consists of several key activities including: monitoring weather to proactively identify threats, mobilizing office and field resources, securing down wires, assessing damage, repairing assets, communicating with public and government agencies, and performing a post-storm assessment to improve preparedness for future events.

We use two platforms to coordinate these activities: (1) an OMS, which allows us to identify where outages occur; and (2) an RMS, which enables us to ensure crews respond quickly to outages. See Appendix F for more information on these platforms.

We use a continuous feedback loop to find ways improve our restoration program, using the experience from each outage response to better prepare for future events. This category also includes spending on meter services, corrective maintenance, and demand programs. More detail on these programs can be found below.

i. 3.1 Service restoration

Our Service Restoration program prepares for and executes work related to public emergencies and restoration activities for all outage categories, including MED and Catastrophic Events. This work includes addressing hazards such as broken poles, wire downs, and emergency orders. In addition to the work plan projections, this program includes the non-capital portion of standby costs and on-call costs for field resources. The program also includes operating and maintenance of the two-way customer communications systems related to outage communications and alerts, and media costs such as radio advertisements related to wire downs and generator safety, to remind our customers and the public of precautions to take during an emergency. This program also supports customer claims associated with operating and maintenance restoration or emergency response activity.

Over the next five years, we plan to spend between \$33 million and \$39 million on service restoration activity each year. This range represents the wide variance possible from year to year, depending on the amount of storm activity.

TABLE 76 – O&M: SERVICE RESTORATION

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Outage Related Incidents	29	36	36	36	36
Emergency Incidents	0.6	0.6	0.6	0.6	0.6
Two-Way Customer Communication (2WCC)	0.2	0.2	0.2	0.2	0.2
Media	1.0	1.0	1.0	1.0	1.0
Contractor on-call/Stand-by	1.5	1.5	1.5	1.5	1.5
Total	33	39	39	39	39

Our 2018 plan was built based on the expected cost of storm recovery using a historical trend for storm recovery and outages. After experiencing higher outage-related incident costs during 2017 due to increased storm activity, we re-adjusted our long-term forecast for 2019 through 2022 to reflect a new long-term average. Due to the expected annual variability in our cost of outage related incidents, we expect our forecast for storm recovery to fluctuate around this average of \$36 million over the next five years.

After 2018, we are targeting to spend an average of \$39 million each year, a decrease from our current three-year average, which will come from improved efficiency across our operations and a focus on reducing the cost per service restoration.

This plan provides funding for service restoration and emergency response activities to address the types of issues outlined in Table 77, including outages, emergency orders, and hazards.

TABLE 77 – HISTORICAL INCIDENTS

Historical Incidents			
Type of Incident	2015	2016	2017
Outage Related Incidents	39,662	39,743	43,787
Emergency Orders	6,447	5,640	5,187
Wire Down Hazards	21,005	21,399	27,157
Broken Pole Hazards	1,751	1,655	1,974
Car/Pole Hazards	942	1,077	818
Pole Fire Hazards	285	259	202
Transformer Fire Hazards	2,047	1,952	1,369
Tree on Line Hazards	13,312	9,543	11,085
Electrical Dig In Hazards	383	417	249

Planning Process

We integrate data from multiple sources, including from OMS and emergency response data, to help inform our multi-year forecast. Data collection begins with three to five years of historical activity for each planning year, since this work is primarily in response to emergent needs.

We compare this data to the work plan, comparing actual performance to the plan defined at the beginning of each year, and we analyze calculated unit costs to determine trends. After this review process, we incorporate any known changes in activity and costs within this program. Examples of potential changes include modifications to working agreements related to employee response performance, or expenses and maintenance costs to support outage-related alerts to customers.

After combining all of the inputs, we use a utility-wide prioritization method to review activities across financial programs. Priorities in this program include safety and customer satisfaction.

We define the forecasted activities for this program during our budgeting and financial planning effort for the subsequent five years. A monthly review of activity and spending occurs throughout the year, to facilitate decision making regarding any necessary adjustments to the original plan.

Benefits

A well-managed and funded service restoration program ensures we can expediently respond to safety concerns and that we have effective restoration activities focusing on customer impact. This includes preparatory actions for forecasted impacts to our electric distribution system. It also includes measures to ensure we can safely execute restorations. A final key benefit of this program is the communications process that relays overall progress during an event to groups of customers and communities, and provides status updates to individual customers.

ii. 3.2 Demand Maintenance

Our Demand Maintenance O&M programs support the emergent work needed to perform repairs, restoration, and corrective maintenance on our HVD Lines, LVD Substations, and HVD Substations. The five-year plan averages approximately \$800,000 less per year than the average over the past five years of actual spending, predominantly due to HVD crossarms and insulator line components becoming capitalized units. The five-year plan for these programs is presented below:

TABLE 78 – O&M: DEMAND MAINTENANCE

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
HVD Lines	0.8	0.8	0.9	0.9	0.9
LVD Substations	3.1	3.2	3.2	3.3	3.3
HVD Substations	2.1	2.2	2.2	2.3	2.3
Total	6.0	6.1	6.3	6.4	6.6

Note: we anticipate that additional MOABs will be added each year as an additional method of improving reliability

Our 2018 plan for HVD Lines Demand Maintenance, which is typical for most years, includes the following types of work:

- Performing HVD line patrols to investigate line performance anomalies or reported abnormalities.
- Performing asset maintenance and emergent repairs that are not capitalized (replacing down guys, repairing broken conductors, repairing switches, removing tree obstacles, repairing down grounds, etc.).
- Covering costs for the observer required for the Helicopter Inspection Program.

Our 2018 plan for LVD Substation Demand Maintenance, which is typical for most years, includes the following types of work:

- Emergent substation response (outages, alarms, key calls, etc.)
- Emergent LVD Metro response (outages, alarms, key calls, etc.)
- Electric Field Lab demand response (technology issues)
- LVD substation transformer failure and/or demand maintenance
- LVD substation recloser/breaker failure and/or demand maintenance
- LVD substation voltage regulator failure and/or demand maintenance
- Various other substation equipment failures and/or demand maintenance
- Miscellaneous overheads and charges (fleet charges, test equipment contract, Lab testing, etc.)

Our 2018 plan for HVD Substation Demand Maintenance, which is typical for most years, includes the following types of work:

- Emergent substation response (outages, alarms, key calls, etc.)
- Emergent LVD metro response (outages, alarms, key calls, etc.)
- Electric Field Lab demand response (technology issues)
- HVD substation transformer failure and/or demand maintenance
- HVD substation circuit switcher failure and/or demand maintenance
- HVD substation breaker failure and/or demand maintenance
- HVD substation airbrake/switches failure and/or demand maintenance
- HVD capacitor bank failure and/or demand maintenance
- HVD battery failure and/or demand maintenance
- Various other substation equipment failures and/or demand maintenance
- Miscellaneous overheads and charges (fleet charges, test equipment contract, Lab testing, etc.)

For each category of asset, we identify all failures resulting in customer outages and failures resulting in equipment outages. We also may rely on helicopter and foot patrols, various kinds of testing, and algorithms in our Cascade substation asset management database, depending on the type of asset. The following subsections describe each of these programs in more detail.

HVD Lines Demand Maintenance

The purpose of our HVD Lines Demand Maintenance program is to repair our 46 kV and 138 kV HVD lines equipment that have failed or need emergent repair. This includes associated on-call costs and helicopter inspection observer costs.

Planning Process

Activities in this program are typically emergent and identified by failures resulting in customer outages, failures resulting in equipment outages, key calls, helicopter patrol, and foot patrols. Orders for these activities are created and tracked within our internal SAP database. We prioritize our work based on employee and customer safety concerns, customer outage minutes, system stability, and system reliability.

Contractor crews from Hydaker Wheatlake perform our HVD Lines Demand Maintenance work, led by Consumers Energy Field Leaders. The number of demand jobs has steadily increased from 2015 to 2017 (22-33% annually), as has the cost for each specific job. We project that our plan to rebuild or rehabilitate more HVD line miles, as described in the section of this report on the HVD Lines Reliability capital program, will curb this trend and allow for a fairly consistent five-year demand O&M spending plan.

Benefits

The costs and activities for this program directly support our Safety and Reliability objectives by ensuring customer and electric system safety, outage restoration, and replacement of failing or deemed failure equipment, which are all essential activities.

LVD Substation Demand Maintenance

The purpose of our LVD Substation Demand Maintenance program is to perform emergent restoration and corrective maintenance on LVD substations and the LVD metro system. This program includes work on the equipment, facilities, infrastructure and property associated with LVD Substations and the LVD metro system. Issues identified by the program may also be associated with the LVD Substation Reliability capital program or the LVD Substation Failures capital program.

Planning Process

Activities in this program respond to failures resulting in customer outages, failures resulting in equipment outages, testing (IR, oil sampling, etc.), and Cascade substation asset management database algorithms. Orders for these activities are created and tracked within the Cascade substation asset management database. We prioritize our work based on employee and customer safety concerns, customer outage minutes, system stability, and system reliability.

Benefits

The costs and activities for this program directly support our Safety and Reliability objectives by ensuring customer and electric system safety, outage restoration, and replacement of failing or deemed failure equipment, which are all essential activities.

HVD Substation Demand Maintenance

The purpose of the HVD Substation Demand Maintenance program is to perform demand/emergent restoration and corrective maintenance of HVD and Strategic Customer substations. This program includes work on the equipment, facilities, infrastructure and property associated with HVD and Strategic Customer substations. Issues identified by the program may also be associated with the HVD Substation Reliability capital program or HVD Lines and Substations Failures capital programs.

Planning Process

Activities in this program respond to failures resulting in customer outages, failures resulting in equipment outages, testing (infrared, oil sampling, etc.), and Cascade substation asset management database algorithms. Orders for these activities are created and tracked within the Cascade substation asset management database. We prioritize our work based on employee and customer safety concerns, customer outage minutes, system stability, and system reliability.

Benefits

The costs and activities for this program directly support our Safety and Reliability objectives by ensuring customer and electric system safety, outage restoration, and replacement of failing or deemed failure equipment.

iii. 3.3 Corrective Maintenance

Our Corrective Maintenance program supports customer and field generated orders associated with imminent safety issues or system deficiencies, including emergent and short-term planned maintenance requirements. These work orders are categorized for reporting purposes among two main activity types: Investigations and Maintenance. More specifically, the spending in this program includes:

- Work plan projections and the non-capital portion of electric environmental clean-up
- Electric lines damage credits
- Operating and maintenance allocation for electric property restoration

Planning Process

We conduct a number of analyses based on multiple inputs to review, validate, and complement our operating and maintenance plan. Multiple data sources are leveraged to forecast anticipated safety concerns and system deficiencies for the subsequent year(s). Data collection begins with three to five years of historical activity by year, since the work is generated primarily based on demand. This data is compared to the work plan for each year and calculated unit costs are analyzed for trends. This review process is followed by incorporating any known changes to activity within this program.

After combining all of the inputs, we leverage a prioritization method to review activities across various financial programs. This program must address priorities including regulatory requirements, capacity/deliverability, and customer satisfaction for each of the identified activities within the program.

Example

In the images below, we needed to replace a broken or inadequate down guy. The O&M cost associated with the project was to replace or reattach the down guy to the existing anchor. If we had not completed this work, the poles could have broken or leaned further and caused a public safety hazard and potentially an outage to all downstream customers. Figure 102 shows a secondary pole with very few customers affected while Figure 103 shows a primary pole that would interrupt service to over 1,000 customers.

FIGURE 102 – SECONDARY POLE WITH BROKEN GUY



FIGURE 103 – PRIMARY POLE WITH BROKEN GUY



Timing

The forecasted activities are defined during our long-term financial planning effort each year for the subsequent five years with an opportunity to update and validate the first three years. Monthly reviews of activity and spending occur throughout the year, to inform decision-making for any necessary adjustments to the original plan(s).

Benefits

The costs and activities for this program directly support our Safety and Reliability objectives by ensuring compliance with regulatory requirements and performing maintenance to address safety issues and system deficiencies.

iv. 3.4 Staking, Street Light and Service Call Program

The Staking, Street Light and Service Call program supplies external resources to locate and mark our underground electric distribution facilities in accordance with the Miss Dig law (Public Act 53, replaced by Public Act 174 in 2014).

TABLE 79 – O&M: STAKING, STREET LIGHT AND SERVICE CALL

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Staking	3.5	3.6	3.7	3.8	3.9
Street Lighting	1.5	1.5	1.5	1.5	1.5
Service Calls	2.5	2.5	2.5	2.5	2.5
Total	7.5	7.6	7.8	7.9	7.8

Our current five-year plan is based on the expected hours and activities required to complete the work in each of the above program areas. Our assumptions for each of the three primary programs within this category are based on historical spending, with a focus on improving efficiency going forward while continuing to meet the needs of our customers. For our staking program, we expect to complete approximately 400,000 units per year through our contractors. We expect to replace approximately 18,700 burnt out street lights per year in our communities at a cost of approximately \$80 per unit. Finally, for our service calls, we expect to make between 19,500 and 20,000 calls per year.

We use both internal and external resources and materials to perform street light maintenance and repairs, customer-requested service calls (e.g., wires down, part power, blinking lights, investigations, etc.) and associated customer-reimbursed services (e.g., temporary services, disconnect/reconnects, third party attachment requests). The staking is currently completed by a contractor. All of the service work and street light work is completed by Consumers Energy crews.

The associated reimbursements return to this program, including Make Ready reimbursements with no asset replacement. All of the services provided by this program are related to public safety and customer service.

v. 3.5 Meter Services

Electric Meter Operations (EMO) is a 100% O&M program that is offset by first set and retirement credits of both meters and metering transformers. EMO responds to customer-initiated and Company-generated orders for replacement or repair of existing metering. EMO also conducts handheld read routes, which are meter reads outside of our regular Meter Reading program and require special equipment. The department works with Meter Reading to resolve consecutive estimate issues that arise when Meter Reading cannot find or read a meter for various reasons.

TABLE 80 – O&M: METER SERVICES

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Routine Exchanges	0.7	0.7	0.7	0.7	0.8
Maintenance	1.4	1.4	1.4	1.5	1.5
Installs	1.4	1.5	1.5	1.5	1.6
Investigations	3.8	3.9	4.0	4.2	4.3
Other Costs (Salary, Admin)	2.9	3.2	3.2	3.3	3.3
Meter / Transformer Credits	(3.7)	(3.7)	(3.7)	(3.7)	(3.7)
Total	6.4	6.9	7.2	7.5	7.8

The funding levels for this program for 2016 and 2017 were historically low due to participation in the Smart Energy project. During this period, EMO assisted in the conversion of legacy meters to Smart Meters. This allowed the program to charge much of its O&M costs to the project, capitalizing the costs. 2017 was the last year of the program, so EMO funding levels will need to increase accordingly.

As a result of the Smart Energy program, we received a waiver for the Routine Exchange Program, which allowed EMO to exchange meters in the field based on vintage, time in field and other factors in order to test them and determine accuracy. That waiver expired at the end of 2017 and will result in an increase in O&M costs. The plan for 2018 is to exchange approximately 13,000 meters resulting in an estimated \$330,000 in additional costs.

The five-year funding level was determined by several factors. First, the team analyzed the five-year average of all work types performed prior to the start of the Smart Energy project. They then applied the benefits of Smart Energy, which included a 90% reduction in turn on and turn off activity as it relates to non-paying customers. Also included was the added work load due to the Routine Exchange program, increased investigation orders and an increase in new business applications. This formula was then applied to the Standard Labor Rate to determine the funding required for operating the program and serving our customers. The five-year plan also includes an annual 3% increase to account for inflation.

vi. 3.6 Meter Reading

Our Meter Reading program consists of the costs for our field workforce to read meters, perform annual inspection of padmount transformers, client water meter reads, and gas leak surveys. In addition, the program houses an office support staff to manage the scheduling and re-routing efforts to optimize efficiency in the field operation. Due to the implementation of advanced meter technology, we expect the costs of this program to be significantly reduced from historical levels. Our five-year plan does include a plan to spend \$2 million per year in this program to continue to conduct meter reading in places where the technology is not implemented due to customers opting out or where devices are not communicating. The average historical cost for this program has been closer to \$12 million since 2013.

vii. 3.7 Smart Energy Metering Technology Center – Electric

The Smart Energy Metering Technology Center (MTC) – Electric budget consists of two components – communications backhaul and meter software maintenance charges. The charges are fixed by the contract that establishes the charging rates through 2022. These rates are based on the number of active electric smart meters we have installed at customer locations, and meter inventory levels required to meet new business and meter failure requirements throughout the year. As these charges are fixed, the spending forecast is based on the projected number of meters, and is adjusted annually based on projections for new business, regulatory requirements, or other large projects. For this five-year plan, an assumption of a 4% annual increase in the number of meters has been applied.

TABLE 81 – O&M: SMART ENERGY MTC – ELECTRIC

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Communication Backhaul	4.6	4.7	4.7	4.8	4.9
Software Maintenance	3.5	3.6	3.8	4.0	4.2
Total	8.1	8.3	8.5	8.8	9.1

Communications Backhaul

Our communications backhaul charges represent the annual charges for data transmitted from the meter, via cellular communication, to our data collection engine. This data includes all customer usage information and any events logged by the meter. Each year, we receive an invoice for the cumulative total of all smart meters purchased in previous years that will be subject to backhaul charges in the coming year, less any meters that have been retired from service in the current year.

For meter installation location in which both a smart electric and smart gas meter are present (“combination locations”), the backhaul charges are distributed between the Smart Energy MTC – Electric (88%) and Smart Energy MTC – Gas (12%) programs, as the electric meters are transmitting both electric and gas usage and event data. Through the end of 2017, we had an estimated 709,090 such locations.

In addition to the backhaul charges for previous years’ purchases, any meters purchased in 2018 will be subject to backhaul charges beginning the month that Consumers Energy receives the meter. Table 82 below shows a summary of the cost calculation for 2018. The operating assumption for 2018 is that one-third of new units purchased in 2018 will go to combination locations and two-thirds will go to electric-only locations, and be charged backhaul charges accordingly.

TABLE 82 – COMMUNICATIONS BACKHAUL CHARGE CALCULATION

2018 Communications Backhaul Charges			
Meter type	Number of meters (thousands)		Total cost (\$ millions)
Electric only meters	1,172		2.9
Combination locations	709		1.6
New meters received in 2018	38		0.1
Total	1,881 existing + 38 new		4.6

Software Maintenance

In addition to the communications backhaul charges, electric smart meters are also subject to a monthly software maintenance charge, to keep the meter software up to date with the most current version. This ensures that the meters are compatible with both the communication and data collection systems.

Each year we receive an invoice for the cumulative total of all smart meters purchased in previous years that will be subject to software maintenance charges in the coming year, less any meters that have been retired from service in the current year.

The total 2018 cost is \$3.5 million. In addition to the software maintenance charges for previous years’ purchases, any meters purchased in 2018 will be subject to software maintenance charges beginning the month after the meter is received.

viii. 3.8 Other Operations and Metering

The Other Operations and Metering budget consists of two programs – Alma Equipment Repair, and Electric Metering Technology and Management System Support. These programs support necessary maintenance of our metering and substation equipment. The five-year O&M plan for these programs is presented below and is based on historical spending levels.

TABLE 83 – O&M: OTHER OPERATIONS AND METERING

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Alma Equipment Repair	1.2	1.2	1.2	1.2	1.2
Elec Meter Tech & Mgmt Sys Support	1.2	1.2	1.3	1.3	1.3
Total	2.4	2.4	2.4	2.5	2.5

The Alma Equipment Repair program maintains substation and distribution lines reliability by providing equipment and services as needed. This program includes maintenance activities (testing, repairing, reconditioning) for assets such as mobile substation equipment, substation oil processing equipment, and substation power transformer cooling equipment. The program also includes activities such as substation equipment acceptance testing and ensuring compliance with all environmental regulations

regarding the handling, storage, and disposal of PCB equipment. These activities are considered base level maintenance for system reliability and emergency response to demand outages.

The purpose of the Electric Metering Technology and Management System Support program is similar to the above and supports the MTC activities described in capital program 1.4 Distribution Metering New Business, including testing, refurbishing, and technology evaluation of electric metering equipment. Our MTC is accountable on an annual basis for the accuracy, maintenance, and stability of our electric metering (including metering transformers) population. The MTC is required to test a sample of each shipment of new electric meters and metering transformers prior to releasing the equipment for use in the field. Legacy meters are tested for accuracy; smart meters are tested for accuracy and communications functionality as part of shipment acceptance testing.

D. 4.0 Field Operations

The Field Operations program consists of the cost of training, supervision, facilities, and facilities maintenance for our in-field operations teams. These costs are planned annually based on the expected costs to maintain an in-field operations team to carry out the various activities required for supporting the safe, reliable, and efficient operations of our electric distribution system.

TABLE 84 – O&M: FIELD OPERATIONS

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Training	6	5	6	6	6
Facilities Building Opers & Maint	3	4	4	4	4
Supervision / Admin-Staff	7	7	8	8	8
Other Field Operations	4	4	4	4	4
Total	20	20	20	21	22

Our Electric Training program includes skills-based training for Electric Operations employees including Electric Lines, Substation O&M, and Electric Meter. The expenses to operate our Apprenticeship Program includes the labor of those attending training, instructors, and committee members. Aside from the Apprenticeship program, union labor associated with additional training like continuing education (refresher) are included in this training category.

Our facilities and operations maintenance budget includes labor and expense associated with upkeep of Company facilities within distribution and other O&M repairs and maintenance expenses.

This category also includes the salaries and expenses of the supervision and leadership for electric operations. The activity associated with this program ensures the safe operation of the facilities as well as adherence to the policies of the Company. In forecasting these funds, we assume that annual O&M merit and inflation increases will be offset by future efficiency savings.

Other field operations expenses include the O&M tools utilized by the electric operations crews to safely complete their daily tasks (including new and replacement tools, personal protective equipment, fire resistant clothing) as well as their daily business expenses and the charges to provide modems and connectivity devices in the trucks.

E. 5.0 Grid Management and SEOC

i. 5.1 Smart Energy Operations Center

The Smart Energy Operations Center (SEOC) program budget captures salaries and expenses relating to all of the SEOC daily responsibilities as well as the funding required for potential IT demand fixes. The SEOC is responsible for the asset reliability and data delivery of the AMI electric meter and AMI Gas Communication modules (gas-related costs not included below). These responsibilities also include the regular maintenance of the assets, e.g., firmware upgrades and hotfixes, and teaming with IT to fix any demand issues that prevent meter data from getting to our internal and external customers.

TABLE 85 – O&M: SMART ENERGY OPERATIONS CENTER

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Salaries & Expenses	1.2	1.2	1.2	1.2	1.2
IT Demand Resolution / Business Expenses	0.1	0.1	0.2	0.2	0.3
Total	1.3	1.4	1.4	1.5	1.5

The SEOC is still in its infancy and the final staffing needs have not been determined, but the current forecast is based on the current expectation for our long-term needs. There are many potential changes with MPSC billing and meter reading requirements that could impact the IT demand and resource requirements funded by this program. There are also unknowns regarding the total cost of meter maintenance (e.g., service requests, firmware, and hotfixes to ensure our customers are getting a good experience). There may be a potential that the budget will change in future years based on 2018 and 2019 trends.

The SEOC benefits both our internal and external customers by providing reliable data and eliminating waste through:

- Improved electric meter read rate
- Saved truck rolls for storm restoration, meter reading, remote reconnect/disconnect
- Theft program analytics, keeping our employees safe by only investigating large potential theft cases
- Data analytics for detailed grid analysis, meter to transformer
- Customer programs
- Demand response

ii. 5.2 Grid Management

Our Grid Management program is responsible for providing statewide 24/7 monitoring and control of the electric distribution system. This includes providing statewide coordination of major service restoration efforts and is responsible for operating the modernization and automation of the electric grid. Operation of grid modernization and automation includes the use of devices on distribution substations and lines as well as implementation of advanced applications to improve system reliability, power quality, and reduce energy waste.

Most of the expenses in this program go toward the salaries and expenses for employees operating and supporting the monitoring and control of the electric distribution system, but there are also costs associated with specific investments that have been made into this program to improve and streamline operations. The current plan is to spend between \$5 and \$6 million per year on this program.

TABLE 86 – O&M: GRID MANAGEMENT

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Salaries & Expenses	4.8	4.9	5.1	5.3	5.4
Incident Command System (ICS) Dev & Training	0.2	0.1	-	-	-
New Control Center Facility	-	-	-	0.2	0.2
Total	5.0	5.0	5.1	5.4	5.6

Changes from previous years are due to organizational changes as well as staffing 24/7 operations. Project work included is based on upkeep to best practices and tools for monitoring and controlling the electric grid. A number of recent investments in this program include:

- ICS development and training for restoration events
- Transmission Outage Application Upgrade
- Wire Down and SAP script changes
- New tools for modernization and automation
- Research and develop scope for new control room facility

F. 6.0 Planning and Scheduling

Planning and scheduling services include the O&M costs associated with electric resource planning, closeout, scheduling and dispatch, and contract administration. These costs primarily comprise salaries and business expenses.

TABLE 87 – O&M: PLANNING AND SCHEDULING

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Scheduling & Dispatch	4.8	4.9	5.1	5.2	5.4
Resource Planning & Closeout	0.4	0.4	0.5	0.5	0.5
Contract Administration	0.4	0.4	0.4	0.4	0.4
Total	5.6	5.7	5.9	6.1	6.3

This program also includes the office support functions that include closeout, work planning, contract administration, and business operations support. These work activities for Electric include all work (both capital and O&M) for Electric Service and Distribution employees, electric underground and overhead contractors, and electric meter operations. Especially noteworthy is the critical role that employees in scheduling and dispatch perform during storm restoration. The program is primarily responsible for long range planning, weekly planning, scheduling, and dispatching for the following activities:

- Service calls
- Street lighting
- Line extension
- New business requests (added customers)
- Relocates (house moves, build overs, etc.)
- Alterations (upgrades, downgrades, generators)
- Demolitions (lost customers)
- Make ready
- Failures services
- Corrective maintenance
- Capacity
- Repetitive outage
- Cutout, pole replacement
- Sectionalizing
- Investigations
- Storm restoration
- Electric Meter Operations

G. 7.0 Operations Performance

This program consists of salaries, business services, and associated expense for the Operations Performance group allocated to support electric grid operations. Operations Performance includes team members across the state who deploy and execute continuous improvement activities applying lean business tools to make problems visible, bring together grid operations personnel to review and respond to performance trends, conduct formal problem-solving projects and implement improvements to or totally new standard processes within grid operations. Operations Performance also delivers accurate real-time reporting of performance analytics and works with the team to develop and deliver predictive and prescriptive analytics to improve future performance. Operations Performance maintains, improves,

and deploys operating standards and document lifecycle management insuring that procedures and standards are current, easy to find, and easy use for team members in grid operations.

H. 8.0 Operations Management

Our Operations Management program includes the salaries and expenses for our senior management staff, as well as chargebacks from internal departments specifically related to the operations of our electric distribution grid. This program also includes the electric portion of the reserves for our incentive programs accruals, injuries and damages, and electric claims. On average, we plan to allocate roughly \$7 million to the operations management programs, which are in line with our historical costs. The chargeback and reserves included in this program are established outside of the electric distribution organization.

I. 9.0 Engineering and Operations Support

Multiple support functions allow our Engineering and Operations teams and organizations to work effectively. These programs, funded by the Engineering and Operations Support program, are expected to cost between \$4 million and \$5 million per year over the next five years to cover the salaries and expenses of these critical support teams.

A number of these programs are listed below, including IT projects support, rate case administration, regulatory and compliance, geospatial management and data quality, customer energy specialists, financial management, and project management. Only the portions of the total costs that are directly attributable to the electric distribution organization are included in the table below.

TABLE 88 – O&M: ENGINEERING AND OPERATIONS SUPPORT

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Unallocated Emergent Fund (Ops)	-	-0.5	-0.5	-0.5	-0.5
IT Projects including ADMS	0.4	1.0	1.3	0.7	0.4
Rate Case Support	0.1	0.1	0.1	0.1	0.1
Regulatory & Compliance	0.2	0.2	0.2	0.2	0.2
Customer Energy Specialist	0.4	0.4	0.4	0.4	0.4
Geospatial Management & Data Quality	0.9	0.9	1.0	1.0	1.0
Agreements - LVD & HVD	0.7	0.7	0.8	0.8	0.9
Financial Management & Controls	0.5	0.5	0.5	0.6	0.6
Project Management	0.8	0.8	0.9	0.9	0.9
Total	4.0	4.1	4.6	4.1	4.0

Additional details for some of the above listed sub-programs can be found below:

Geospatial Management and Data Quality

This group provides the staffing and technical capabilities related to: planned and emergent electric distribution work orders, customer master data creation and maintenance, regulatory reports and business geographical analysis on demand. This group also updates GIS facility records and supports GIS applications and data requests related to GIS and CAD LVD records and underground services. Expenses include software licenses, plotter maintenance, and associated costs to support design and GIS functionality.

Agreements

Our agreements costs are broken into three groups: distribution agreements, NERC security, and interconnections.

- **Distribution Agreements** – Ensures compliance to legal obligations of electric distribution as part of contractual agreements with METC and other interconnecting parties (both Consumers Energy and METC customers). This includes the salaries and expenses of this team.
- **NERC Security Electric** – Covers the O&M cost of the NERC CIP-identified telecom lines. These lines require special security. They are also transitioning from hard-wired telecom circuits that are being discontinued by the provider, who is also escalating the charges for the same lines during this sunset period that ends 2018. Consumers Energy is transitioning to new technology which will require different security measures. The transitions costs are being handled as a capital project (in part with the NERC Compliance capital program).
- **Interconnection Costs** – These costs fall into two categories that are reimbursed – Third-Party Interconnection Telecom and METC Telecom.

Project Management

This program funds the labor and expenses for Enterprise Project Management Office Project Managers and Project Controls. These resources are essential in executing large and moderate sized projects that are part of the Capital Spend Plan and reporting/controlling costs per Sarbanes/Oxley requirements. This program covers the O&M portion of salaries and non-labor expense. Non-labor includes business expenses, tool expense such as cell phones, Sprint cards, and training.

Customer Energy Specialist

The Customer Energy Specialist (CES) is primarily responsible for customer-requested work order design and coordination for the following customer-driven activities:

- New business requests (added customers)
- Relocates (house moves, build overs, etc.)
- Alterations (upgrades, downgrades, generators)
- Demolitions (lost customers)
- Additional design work support for LVD Planning, third-party work, etc.
- Storm restoration support (dispatch, analyzing, wireguard, etc.)
- The majority of the CES Program is related to capital work activities with only 5% allocated to O&M. Training is charged 100% O&M. Storm restoration activity is charged to specific storm activity.

J. 10.0 Engineering and System Planning

Engineering and System Planning programs include the O&M portion of the costs associated with our engineering teams, system planners, HVD helicopter inspections, and grid technology.

TABLE 89 – O&M: ENGINEERING AND SYSTEM PLANNING

5-Year O&M Plan (all values in \$ millions)					
Spending Categories	2018	2019	2020	2021	2022
Engineering – LVD	3.3	3.4	3.4	3.5	3.6
Engineering – HVD	3.5	5.1	5.2	5.3	5.3
Grid Technologies	1.3	1.3	1.4	1.4	1.5
Infrastructure Attachments & Standards	0.3	0.3	0.3	0.3	0.3
Standards & Materials	0.2	0.2	0.2	0.2	0.2
Total	8.6	10.3	10.5	10.7	10.9

Engineering – LVD

The LVD Planning department is responsible for the planning responsibilities for the electric distribution facilities in LVD. This includes LVD systems that are overhead (on poles), underground (direct buried), and metropolitan underground. LVD Planning’s mission is to deliver a safe and dependable electric distribution system in order to become the leading electric utility in customer value and public safety. We realize this mission by managing the electric distribution assets with knowledge and expertise through timely and effective results. Circuit engineers perform both office and field reviews to evaluate the performance of the electric distribution circuits.

This encompasses key responsibilities that are comprised of four main areas:

1. **Reliability Planning** - Develop and execute actions in both long and short range planning to improve reliability of assigned circuits:
 - Complete all assigned security assessments by year end and designs by design want date.
 - Perform annual review of load transfer database and propose tie points as needed.
 - Review and recommend distribution automation projects.
 - Support distribution automation planning and proposals.
 - Coordinate reliability efforts Forestry, HVD, Substations, and Metro Planning.
 - Obtain Metro feasibility studies for civil infrastructure improvements and direction to civil design consultants.
 - Perform final complex design reviews with Metro Field Leader prior to work order release.
 - Attend pre-bid and pre-construction meeting with contactor to ensure understanding of scope.
2. **Capacity Planning** - Develop and execute actions to reduce potential capacity overload and system protection mis-operations of LVD circuits:
 - Perform load flow studies in CYME software.

- Submit overload project proposals for overloaded equipment low voltage, reach and coordination findings.
- 3. **Customer Advocacy** - Reduce number of repetitive outages and formal complaints by ensuring the system is reviewed every two weeks so that the right decisions are made to meet the needs of the customer:
 - Monitor repetitive outage and create proposals to resolve multiple interruptions.
 - Investigate and resolve complicated customer issues, including:
 - Radio/TV Interference
 - LVD power quality issues /harmonics
 - Motor start / flicker analysis
 - Other concerns
 - Coordinate with Infrastructure Communications Consultant to communicate specific plans.
 - Create resolution to municipality and/or large customer requests.
 - Submit forestry repetitive outage proposals for multiple tree related interruptions.
- 4. **Storm Restoration Support** - Provide support for emergency response in office and/or field:
 - Accept and respond to on-call when available.
 - Assist with damage assessment or other storm roles as requested.

Engineering – HVD

The Engineering – HVD program includes the O&M portion of the joint expense funding for the following activities:

- **Substation Layout Design and Standards:**
 - Preparation and maintenance of SPCC plans
 - Monitor and update standards based on NESC and MPSC adoption
 - Environmental interface / civil structural design
 - Support of working space inspections
- **Instrumentation and Control, Design and Standards:**
 - Substation communication installation / protection
 - Field inspection to support design
- **HVD Lines Design and Standards:**
 - Work Order Process Team and asset identification
 - Monitor and update standards based on NESC and MPSC adoption
 - Development of HVD Lines GIS interface and design posting
- **System Protection:**
 - NERC PRC-005 program for relays and HVD System Protection
 - Distribution system protection and Mobile settings
 - Protective relay settings for Consumer Energy generators
 - Managing the System Protection capital program
 - Lab Services O&M relay maintenance program (NERC, FERC, and RFC compliance requirements)
 - Provide fault analysis and monitoring for system outage events
 - NERC PRC-027 protective system coordination
- **System Models and Dynamics:**
 - Development of System Models and tracking system updates
 - MISO models updates (MOD NERC requirements)

- Stability studies
- NERC FAC-008 facility ratings

Grid Technologies

The Grid Technologies O&M program includes the O&M portion of the joint expense funding for the following activities:

- **SCADA Applications:**
 - Energy Management System;
 - Distribution Management System
 - Generation Management System
 - Distribution Power Flow – CYME Application
 - System Operational Model Maintenance and Interface with MISO and METC;
 - Inter-Control Center Protocol (ICCP) link administration (MISO, METC, and DTE);
 - NERC Compliance
 - SCADA Device Check-outs
- **Grid Modernization:**
 - CVR Operational Demonstration
 - Grid Communications
 - Analog Multi-Drop Replacement
 - SCADA Generation 2
 - Substation Security Card Readers
 - Device Management (Configurations, Firmware, etc.)
 - Electric Geographic Information Systems (EGIS)
 - Production EGIS Support
 - ESME Project
 - eMAP Project
 - LVD Applications – ATR, VVO, FLISR, Line Sensors, DSCADA
 - HVD Line Sensor Deployments and MOAB SCADA
 - Advanced Technology Projects – Utility Analytics, Data Lake, and ADMS

Distribution Agreements and Infrastructure Attachments

The Distribution Agreements component of this program includes O&M spending to administer the following agreements and processes:

- Wholesale Distribution Service - Agreement creation, enforcement and revenue recovery for the non-retail use of the electric distribution system.
- Extraordinary Facilities Agreement - Agreement creation, enforcement, and cost recovery for capital projects associated with interconnection of retail customers 1 MW and greater.
- Facilities Agreements - Agreement creation, enforcement and cost recovery for capital projects associated with interconnection of Wholesale Distribution Customers and other non-Consumers Energy utility interconnections.
- Generator Interconnection and Operating Agreements - Agreement creation, enforcement, and cost recovery for application process fees and capital project costs associated with generator interconnections.
- Generator Interconnection Process - Process ownership of MPSC Rule 460.60 Rule 20 generator interconnection process.
- Federal Energy Regulatory Commission Electric Quarterly Reporting.

- Quarterly and yearly reporting of renewable generator applications as required by the EIA.

The Infrastructure Attachments component of this program includes O&M spending on the following activities:

- Creation, enforcement, and cost recovery of the capital project costs and yearly system space rental on electric system structures.
- Process ownership of the pole attachment permit process including fee cost recovery and capital project cost “Make-Ready” recovery.
- Electric system communication space survey for communication attachment violation, correction, and cost recovery.

Standards and Materials

The Standards and Materials sub-program includes O&M funding to perform the following activities:

- Monitor and update electric distribution standards and policies based on changes to MPSC adopted NESC code, MIOSHA, and other applicable rates/tariffs
- Test and approve new material for use on the electric distribution system
- Technical design assistance
- MV street light conversions
- Development of new technology (e.g., battery storage and UAV applications for the electric grid)

HVD Line Helicopter Inspections

We currently fly one or two helicopter patrols per year on our approximately 4,400 miles of 46 kV lines and 192 miles of 138 kV HVD lines. The cost of each helicopter patrol, covering the helicopter itself, a pilot, and an observer, is approximately \$350,000. Of this amount, \$300,000 is accounted for in this program and the remaining \$50,000 is accounted for in the HVD Lines Demand O&M program as described in section 3.2. A complete patrol requires about 45 flying days.

We contract with a third-party for these patrols. We conduct two types of helicopter patrols: (1) visual inspections, and (2) visual inspections with the infrared or corona camera.

FIGURE 104 – HELICOPTER INSPECTION



TABLE 90 – HELICOPTER PATROL INSPECTION TYPES

Helicopter Patrol Inspection Types		
Type of Patrol	Crew	Work Performed
Visual Inspection	Two or three person crew <ul style="list-style-type: none"> • Pilot • Observer (must be Union member)* • Trainer if observer is not fully trained 	Look for anomalies <ul style="list-style-type: none"> • Deterioration of/damage to wood pole, cross arms and braces • Damage to insulators • Damaged or floating conductors • Forestry concerns (primarily danger trees) • Damage on LVD underbuild • Damaged/missing/slack guy wires • Third party concerns (deer stands, construction in right of way, etc.) • Blown arresters • Evidence of tracking
Visual Inspections w/Infrared or Corona	Three person crew <ul style="list-style-type: none"> • Pilot • Fully trained observer • Technician to run corona and/or infrared camera** 	All of the above plus monitoring equipment detects hot spots or corona signatures on lines

*Current Observer contracted through Michels Power
 **Trained internal Consumers Energy employee

A corona/infrared camera is mounted to the underside of the helicopter. A technician onboard the helicopter monitors the output of the camera. Infrared inspection detects hot spots on the lines, such as splices and switches, which usually indicate a degraded material or corroded condition that will likely result in failure.

Corona inspections detect ultraviolet emissions on HVD lines, due to ionized air, which is most commonly associated with cracked insulators. These cracks are typically very fine and not easily observed from the helicopter by the naked eye at patrol speed. These fine cracks allow moisture to penetrate the insulator, degrading its effectiveness and eventually leading to an insulator failure and a line outage. We piloted use of the corona camera in 2017 and will be rolling out this new technology to proactively identify cracking insulators during our 2018 patrols. Victor-type grey pin insulators of 1970s-1990s vintage are prone to this type of failure. Results of the corona inspections so far have been mixed. We are working to evaluate when corona inspections are most effective as there appears to be some dependency on weather conditions.

K. 11.0 Joint Pole Rental

The Joint Pole Rental program includes the costs associated with using poles that are jointly used by Consumers Energy and other utilities (e.g., telecommunications). This includes the O&M associated with the expenses of attaching electric facilities to phone company poles. These expenses are determined by contractual formulas defined by Joint Use Agreements with AT&T and Frontier North (formerly Verizon).

The expenses and costs are based on the Federal Communications Commission (FCC) maximum rate calculations for Incumbent Local Exchange Carrier (ILEC) and contractual multiplier.

X. Conclusion

This EDIIP outlines our vision for the future of our electric distribution system and our five-year plan to move towards this end-state. The future of the electric distribution system is customer-driven and requires a dynamic electric distribution system that integrates cleaner, more distributed sources of electric supply with grid enhancements that are engineered for customer value. Our investment plan lays out a roadmap to deliver that vision and will be adapted for technology and customer expectation evolutions to ensure we achieve our five primary objectives:

- Optimizing system cost over the long term;
- Improving reliability and resiliency;
- Enhancing cybersecurity and physical security and safety;
- Reducing waste across the system and improving sustainability; and
- Enabling greater customer control.

With much of our system ready for replacement, we have numerous opportunities to make progress on these objectives. Our five-year investment plan will both reinvigorate our distribution system through traditional investments and set the foundation for future technologies. We look forward to working with the MPSC and the broader set of stakeholders to refine the details of our EDIIP and ensure our plan effectively delivers on our stated objectives.

Appendix A – List of Acronyms and Abbreviations

Table 91 contains the list of acronyms and abbreviations used throughout the report.

TABLE 91 – LIST OF ACRONYMS AND ABBREVIATIONS

Acronyms and Abbreviations	
Acronym	Full Text
ABS	Air Break Switch
AC	Air Conditioning
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ARCOS	Automated Resource Call Out System
ASC	Aerial Spacer Cable
ATR	Automatic Transfer Recloser
BESS	Battery Energy Storage Systems
C&I	Commercial & Industrial
CAIDI	Customer Average Interruption Duration Index
CAM	Customer Account Manager
CELID	Customers Experience Long Interruption Duration
CEMI	Customer Experiencing Multiple Interruptions
CHR	Criticality, Health, and Risk
CIAC	Contribution in Aid of Construction
CIP	Critical Infrastructure Protection
CNUC	CN Utility Consulting, Inc.
COTD	Customer on Time Delivery
CU	Compatible Units
CVR	Conservation Voltage Reduction
DA	Distribution Automation
DCC	Distribution Control Center
DER	Distributed Energy Resources
DERMS	Distributed Energy Resource Management System
DG	Distributed Generation
DGA	Dissolved Gas Analysis
DMS	Distribution Management System
DOE	Department of Energy
DOR	Daily Operating Review
DR	Demand Response
DSCADA	Distribution Supervisory Control and Data Acquisition
EAB	Emerald Ash Borer
EDIIP	Electric Distribution Infrastructure Investment Plan
EE	Energy Efficiency
EI	Edison Electrical Institute
EMO	Electric Meter Operations

Acronyms and Abbreviations	
Acronym	Full Text
EPRI	Electric Power Research Institute
ESME	Electric System Model Enhancement
ETR	Estimated Time of Restoration
EV	Electric Vehicle
EWR	Energy Waste Reduction
FAA	Federal Aviation Administration
FAN	Field Area Network
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
FR	Frequency Regulation
GE	General Electric
GI	Grid Infrastructure
GIS	Geographic Information System
HPS	High Pressure Sodium
HVAC	Heating, Ventilation and Air Conditioning
HVD	High-Voltage Distribution
IEEE	Institute of Electrical and Electronics Engineers
ICE	Interruption Cost Estimate
IP	Internet Protocol
IPLC	Impregnated Paper Lead Covered
IR	Infrared
IRM	Investment Recovery Mechanism
IT	Information Technology
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWh	Kilowatt-Hour
LCP	Load Concentration Point
LED	Light Emitting Diode
LIDAR	Light Detection and Ranging
LMRs	Load Modifying Resources
LTC	Load Tap Changer
LVD	Low-Voltage Distribution
MDOT	Michigan Department of Transportation
METC	Michigan Electric Transmission Company
MED	Major Event Day
MH	Metal Hallide
MISO	Midcontinent Independent System Operator
MMSA	Michigan Metropolitan Statistical Area
MMWG	Multiregional Model Working Group
MOAB	Motor Operated Air Break Switch
MOR	Monthly Operating Review
MPSC	Michigan Public Service Commission

Acronyms and Abbreviations	
Acronym	Full Text
MSU	Michigan State University
MTC	Metering Technology Center
MTTD	Mean Time to Detect
MV	Mercury Vapor
MVI	Molded Vacuum Interrupters
MW	Megawatt
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NESC	National Electrical Safety Code
NWA	Non-Wires Alternatives
OMS	Outage Management System
O&M	Operations and Maintenance
PCB	Polychlorinated Biphenyls
PDCA	Plan, Do, Check, Act
PEV	Plug-in Electric Vehicle
RAE	Reliability Analytics Engine
RFP	Request for Proposals
RMS	Resource Management System
ROW	Right of Way
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SCC	System Control Center
SEOC	Smart Energy Operations Center
SF ₆	Sulphur Hexafluoride
SOG	Spring Operated Grounds
SPCC	Spill Prevention, Control and Countermeasure
SQL	Structured Query Language
SS	Service Suite
TOA	Transformer Oil Analysis
TOU	Time of Use
TRXLPE	Tree Retardant Polymer Insulated
UAV	Unmanned Aerial Vehicles
VCLC	Varnished Cambric Lead Covered
VVO	Volt-Var Optimization
WAN	Wide Area Network
WMU	Western Michigan University
WOR	Weekly Operating Review

Appendix B – Public Safety During Storms and Outages

Ensuring the safety of the public and our employees is our primary concern during storm and outage response. We have a number of programs that focus on ensuring the safety of the public and our employees.

Public Safety Outreach

We have a Public Safety Outreach Team, composed of outreach coordinators at our service centers throughout the state, which acts as a conduit to help prioritize safety concerns from fire chiefs, police chiefs, and emergency managers during service restoration. During major events, our State Incident Command (SIC) directs these outreach coordinators to reach out to the affected local agencies to collaborate with them; the outreach coordinators relay relevant information back to the SIC.

We keep customers safe and informed through various communication avenues. Customers highly value receiving a timely and accurate Estimated Time of Restoration (ETR), and the steps taken during restoration processes allow us to proactively determine an ETR and communicate it through the customer's preferred channel (voice, email, or text). Along with providing ETR information, we use other communication avenues such as:

- An online outage map for customers to access information on any outages in the territory;
- Online and phone outage reporting;
- Press releases, wire down ads, and social media to communicate pertinent information, specifically the danger of downed wires; and
- Public Service Announcements with severe wind, thunderstorm, and winter storm information.

Wire Down Management

The first step in our restoration philosophy is to ensure public and employee safety by securing wire down hazards. Reported downed wires are evaluated to determine if a hazard exists to the public and are secured by:

- A qualified Consumers Energy employee confirming that all phases of an upstream device are open;
- Removing the hazard; and
- Placing qualified personnel at the site to keep the public away and safe.

In addition to crewing field resources, we employ specifically trained wire evaluators and wire guards to secure wire down hazards during a storm event. Wire evaluators are trained to identify electrical utility hazards versus non-electrical utility hazards such as phone and cable TV wires. Wire guards are trained to barricade a downed wire and stay onsite to keep the public away and safe. A wire guard stays at the location until a qualified employee can secure the wire down hazard. We offer annual certification training and conduct annual recertification for wire guards and wire evaluators. We currently have over 2,100 trained wire down resources, including wire guards, wire evaluators, damage assessors, and electric service workers who are trained to perform this function. During severe storms, we have the ability to bring in additional Contractor and Mutual Assistance crews as we did during severe windstorms in March 2017.

Incident Command System

We have adopted the ICS as our common response structure and process for significant utility emergencies.

A key role in this structure is the Liaison Officer, typically part of our Public Safety Outreach team, who interfaces with key public sector stakeholders (County Emergency Managers, fire/police commanders, and 911 dispatch centers) to ensure timely communication and response to public safety related concerns identified.

In addition to coordination during utility emergencies, we regularly communicate any public safety risks during “blue sky” days.

Current office staffing capacity can safely support 225 wire down field resources, limiting the number of field resources we can deploy closer to the number of wire downs. We plan to create a Wire Down Task Force within the ICS structure to increase the number of field employees that can be managed by office resources.

We recognize how critical this component is to public safety and will continue to enhance the effectiveness of its incident response and wire down programs.

Ongoing Public Safety Efforts

We instituted a “Public Safety Good Catch” program, which allows our employees to report public safety concerns that they identify involving third parties. The program encourages employees to safely intervene and communicate if public safety is at risk and then report the “good catch.” In 2017, we had 51 public safety good catch submittals.

In addition, we are currently working to incorporate statewide traffic crash data into our electric design processes to avoid placement of poles in locations with frequent traffic crashes.

Appendix C – Consumers Energy Service Center List

Table 92 below contains the list of service center abbreviations used in Section IV.

TABLE 92 – CONSUMERS ENERGY SERVICE CENTER LIST

Service Center Abbreviation List		
No.	Abbreviation	Full Name
1	ADR	Adrian
2	ALM	Alma
3	BCK	Battle Creek
4	BCY	Bay City
5	BEN	Benzonia
6	BIG	Big Rapids
7	BNC	Boyne City
8	BRO	Bronson
9	CAD	Cadillac
10	CLR	Clare
11	GRE	East Kent / Grand Rapids East
12	FLT	Flint
13	FRE	Fremont
14	GRA	Grand Rapids
15	GVL	Greenville
16	HML	Hamilton
17	HST	Hastings
18	JAC	Jackson
19	KAL	Kalamazoo
20	LAN	Lansing
21	LUD	Ludington
22	MDL	Midland
23	MUS	Muskegon
24	GRN	North Kent / Grand Rapids North
25	OWS	Owosso
26	SAG	Saginaw
27	SMN	South Monroe
28	TRA	Traverse City
29	WBR	West Branch

Appendix D – Energy Efficiency and Demand Response

Customer Enrollments

The following table shows the forecasted cumulative enrollment at year end from 2018-2022 for our residential and commercial & industrial demand response programs. The MW enrollment numbers represent delivery at the customer level.

TABLE 93 — 2018-2022 DEMAND RESPONSE ENROLLMENT FORECAST

2018-2022 DEMAND RESPONSE ENROLLMENT FORECAST					
Cumulative Enrollment at Year End (Customers)					
Residential					
Tariff & Sheet No.	2018	2019	2020	2021	2022
DLM; Sheet No. D - 11.00 - 11.10	63,462	96,493	126,413	153,285	177,659
RDP & RDPR; Sheet No. D - 11.10 - 11.30	28,334	33,304	38,125	42,801	47,337
Commercial & Industrial					
Rate GDP, GI Provision	19	19	19	19	19
Rate EIP	18	18	18	18	18
C&I Demand Response Program	175	300	450	600	675
Cumulative Enrollment at Year End (Customer-Level MW)					
Residential					
Tariff & Sheet No.	2018	2019	2020	2021	2022
DLM; Sheet No. D - 11.00 - 11.10	37	56	73	89	103
RDP & RDPR; Sheet No. D - 11.10 - 11.30	18	21	24	27	30
Commercial & Industrial					
Rate GDP, GI Provision	105	105	105	105	105
Rate EIP	153	153	153	153	153
C&I Demand Response Program	70	120	180	240	270

Financial Forecast

The following table shows forecasted financial investments at year end from 2018-2022 for our residential and commercial & industrial demand response programs.

TABLE 94 — 2018-2022 DEMAND RESPONSE FINANCIAL FORECAST

2018-2022 DEMAND RESPONSE FINANCIAL FORECAST (all values in \$ millions)					
Annual O&M Plan					
Residential					
Tariff & Sheet No.	2018	2019	2020	2021	2022
DLM; Sheet No. D - 11.00 - 11.10	4.0	3.8	3.7	3.5	3.4
RDP & RDPR; Sheet No. D - 11.10 - 11.30	0.7	0.7	0.7	0.7	0.7
Commercial & Industrial					
GI Rate	0.4	0.3	0.2	0.2	0.2
Rate EIP	0.4	0.3	0.2	0.2	0.2
C&I DR Program	2.3	2.9	4.0	5.1	5.7
Incentive Payments (PSCR) *	1.8	3.2	4.8	6.6	7.4
Total	9.5	11.1	13.7	16.5	17.7
Annual Capital Plan					
Residential					
Tariff & Sheet No.	2018	2019	2020	2021	2022
DLM; Sheet No. D - 11.00 - 11.10	8.3	8.4	8.6	7.7	7.4
RDP & RDPR; Sheet No. D - 11.10 - 11.30	-	-	-	-	-
Commercial & Industrial					
GI Rate	0.2	-	-	-	-
Rate EIP	0.2	0.4	0.7	0.5	0.3
C&I DR Program	0.2	0.4	0.6	0.5	0.3
Total	8.9	8.9	9.2	8.2	7.6
*This row assumes PSCR incentive payments will be recovered in Power Supply Costs Recovery (PSCR). The incentive payments assume \$25/MWh for a 50MW program and \$30/MWh for a 100 or 150MW program.					

We will continue offering economic demand response programs to our customers. We will continue to use these resources to balance short-term deployment and scalability with long-term supply resource planning and reliability, all to the benefit of customers.

Energy & Demand Savings

The following table shows forecasted energy and demand savings at year end from 2018-2022 for our energy efficiency programs.

TABLE 95 – 2018-2022 ENERGY EFFICIENCY FORECAST

2018-2022 ENERGY EFFICIENCY FORECAST					
Energy Savings (MWh) & Demand Savings (MW)					
	2018	2019	2020	2021	2022
Annual Energy Savings	558,266	528,556	531,572	532,376	536,231
Annual Demand Savings	80	74	74	74	75
Cumulative Energy Savings	558,266	1,086,822	1,618,394	2,150,770	2,687,001
Cumulative Demand Savings	80	154	228	302	377
Average Measure Life (Years)	12	12	12	12	12

Financial Forecast

The following table shows forecasted financial investments at year end from 2018-2022 for our energy efficiency programs.

TABLE 96 – 2018-2022 ENERGY EFFICIENCY FINANCIAL FORECAST

2018-2022 ENERGY EFFICIENCY FINANCIAL FORECAST (all values in \$ millions)					
Annual O&M Plan					
	2018	2019	2020	2021	2022
Annual Program Spending	119	115	117	118	117

Appendix E – Selected Distribution Work Order Lists

This appendix details distribution engineering and planning work orders in support of our major capital projects during the 2018-2022 time period, as described in Section VIII of this report. Table 97 below contains the summary of work orders as of February 2018, over the period from 2018 to 2020.

Work orders exist for most of the 2018 planned spend budget. As the planning process is not yet complete for 2019 and 2020, less of the budget from those years currently has a work order.

As discussed throughout Section VI.A, a large portion of the unplanned work is customer requested or emergent replacements. Although we have estimates for total spend based on historical trends, a much lower percent of the unplanned spend budget currently has a work order.

TABLE 97 – SUMMARY OF WORK ORDERS, AS OF FEBRUARY 2018

Summary of Work Orders, as of February 2018						
	Unplanned		Planned		Total	
Year	Total Work Order Spend (\$ millions)	Percent of Unplanned Budget	Total Work Order Spend (\$ millions)	Percent of Planned Budget	Total Work Order Spend (\$ millions)	Percent of Total Budget
2018	116	43%	219	89%	335	65%
2019	17	6%	112	37%	129	22%
2020	7	2%	23	9%	30	6%

Unplanned Spending

Table 98 to Table 107 show the twenty largest cost work orders by program for unplanned programs, over each year from 2018 to 2020. Since these lists are from an extract in February 2018, the cost listed for each work order is an estimate, and subject to change. In addition, for many of these programs (e.g., 1.1 Lines New Business – LVD), new requests are received throughout the year, meaning that the projects currently listed for 2018 will not be the same as the end of year largest projects.

In some years, certain programs do not currently have at least 20 work orders; in these cases, only the available projects are included. Finally, for some programs, the order number is created later in the project planning cycle and is shown as ‘TBD’ within these tables.

TABLE 98 – 1.1 LINES NEW BUSINESS – LVD – 20 LARGEST WORK ORDERS BY YEAR

Lines New Business – LVD, 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
30941274	2362 JOLLY OAK - ELEVATIONS ECNC NLU	2018	219
30794335	5650 W MAIN ST - DEVELOPMENT	2018	139
31494586	5600 N WALDO RD PRIMROSE	2018	101
31404400	8763 E K AVE, GALESBURG	2018	79
31718624	2901 76TH ST SE-----ECNC NLO	2018	58

31196928	7738 N LONG LAKE RD, TC - NLU	2018	56
31088726	SHERWOOD FOREST ESTATES, HUBBARD LAKE	2018	50
31260089	GREENSPIRE PHASE 5 ECNC NJL	2018	43
31680105	5300 HARVEY ST, MGN NLU	2018	39
31233918	FOX MEADOW CT - PHASE 1	2018	39
31589728	1231 M-75 -	2018	35
31073336	MEADOW WOODS EAST PHASE 2	2018	35
31557129	3719 E GRAND RIVER RD BANCROFT INFO	2018	30
31050304	SPRINGS AT KNAPP'S CORNER PHASE 2 NLU	2018	29
31507379	4300 68TH ST SW-ECNC NLO	2018	27
31625123	667 SOUTH PARK AVE, NEWAYGO CELL TOWER N	2018	24
31430514	13811 SHAFTSBURG RD PERRY	2018	23
31346749	4363 WALNUT DALE DR DORR ECNC NLU	2018	21
31347885	10655 HOLLISTER RD HSE, LNGB ECNC NLU	2018	17
31508172	11168 W VANBUREN RD RIVERDALE NLU	2018	16

TABLE 99 – 1.2 HVD LINES STRATEGIC CUSTOMERS – 20 LARGEST WORK ORDERS BY YEAR

HVD Lines Strategic Customers 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
27559095	WD1655 FLAKEBOARD NEW SUB \$	2018	3,432
26564765	WD0978 MEDUSA INST NEW CKT \$	2018	3,009
30844268	WD1665 PENWAY NEW 46 KV SUBSTATION \$	2018	2,850
30459203	LN097F VAN SLYKE 1 ADD 2 STEEL POLES \$	2018	875
31079912	LN020_ SCHOOLFIELD NEW SPUR 46 kV RUSH \$	2018	365
31080368	WD2173 SCHOOLFIELD PROVIDE EQUIP RUSH \$	2018	150
30846459	LN071K PHILLIPS#1 NEW 0.1 MI 46 KV TAP \$%	2018	75
31080379	WD0095 CROTON INST DTT RUSH \$	2018	60
30887457	LN016LL HUGHES RD 46 KV REM TAU RD TAP	2018	30
31113216	LN109X BROADMOOR REM TAP TO KEELER BRASS	2018	9
30887442	WD1181 TAU ROAD RET & REM SUBSTATION	2018	-
29763516	LN006FM NORTH STAR LINE 138 KV 10 Mi \$	2019	4,398
28331904	WD1662 MADISON NEW 138 KV SUB \$	2019	1,650
31187707	LN017S MADISON NEW 138 KV SPUR 0.2MI	2019	210
30346088	LN071TT - TEMPORARY 46 KV SUB TAP (MDOT)	2019	150

TABLE 100 – 1.3 METRO NEW BUSINESS – 20 LARGEST WORK ORDERS BY YEAR

Metro New Business 20 Largest Work Orders by Year			
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Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
28196179	METRONB17 GR ARENA SOUTH CIVIL	2018	1,200
16168048	METRONB12 KZO EXCHANGE BUILDING	2018	990
28915289	METRONB17 GR 150 OTTAWA	2018	800
27646028	METRONB17 GR 601 BOND	2018	600
16093247	METRONB12 GR OLD FEDERAL BUILDING	2018	250
19030912	METRONB13 GR STEKETEE VAULT CAPACITY	2018	250
16167918	METRONB12 GR KEELER VAULT REPLACEMENT	2018	248
28915290	METRONB17 GR 50 MONROE	2018	200
30720797	METRONB17 KZOO 220 W MICHIGAN	2018	150
25644739	METRONB15 KZO 200 W MICHIGAN	2018	120
31750145	MERTOREL18 JAXMASONIC ALLEY DUCT / ELEC	2018	75
28517957	METRONB17 FLI MOTT CC CULINARY	2018	70
31463208	METRONB18 SAG DELTA COLLEGE	2018	70
29251378	METRONB17JXN-LouisGlick Grocery/Apts	2018	53
30933010	METRONB18 KZOO 155 W Michigan Perm SRV	2018	50
29251581	METRONB17JXN-163 W PEARL ST-COMMERCIAL S	2018	50
31188104	METRONB18 KZOO 162 W Michigan Perm SRV	2018	25
31317832	METRONB17 FLI 600 SAGINAW ST	2018	23
24186326	METRONBUS15jxn-159wMichigan-coffee shop/	2018	23
30293673	METRONB17 406 /407 BURDICK CITY OF KZOO	2018	15
26283376	METRONB16 GR 12 WESTON	2019	375

TABLE 101 – 2.1 LVD LINES FAILURES – 20 LARGEST WORK ORDERS BY YEAR

LVD Lines Failures 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
TBD	REHAB16 OWOSSO-GOULD (Ball St) UG	2018	1,095
TBD	CC REHAB17 MICOR/LOSEY enterprise drive	2018	1,045
TBD	INSP17 ROSE CITY_ ISLAND LAKE PT 1.1	2018	742
TBD	INSP17 ROSE CITY_ ISLAND LAKE PT 1.4	2018	742
TBD	INSP18 LAKE CITY-STITTSVILLE PART 1	2018	572
27195188	BKBNH14 MARNE/MARNE LCP SUB	2018	524
TBD	INSP17 HUBBARD LAKE_ MILLER ROAD	2018	393
TBD	REHAB16 KALKASKA/BUSINESS LCP 327 OHL	2018	392
TBD	REHAB16 KALKASKA/BUSINESS LCP 327	2018	390
TBD	REHAB16 KALKASKA/BUSINESS LCP 327 UG	2018	390
29914220	REHAB16 BIRCHWOOD/KENMORE. LCP 481 PH2	2018	389
TBD	REHAB17 LELAND/NARROWS LCP 469	2018	366

29638056	REHAB16 WEALTHY NORTHWEST LCP538 A	2018	349
29461736	REHAB15 FULTON/ALTA DALE. AdaWay Ave PH1	2018	340
29313603	REHAB16 BIRCHWOOD/KENMORE. LCP 481 PH1UG	2018	336
29776129	REHAB16 WEALTHY/NORTHWEST 1ST ZONE 1/2 B	2018	316
TBD	BKBN18 ONEKAMA-CHIEF LCP 738	2018	311
TBD	INSP18 Homestead/Beulah	2018	309
27696885	THDPY16 Trufant/Trufant	2018	278
23119097	RLBY14 STANWOOD/TYLER RD PHASE 1C	2018	277

TABLE 102 – 2.2 LVD SUBSTATIONS FAILURES – 20 LARGEST WORK ORDERS BY YEAR

LVD Substations Failures 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
26256734	WD6011 MOBILE #11 REFURBISHMENT	2018	2,250
28360486	WD1192 CHAUVEZ - REBUILD SUB	2018	1,500
29673713	WD1631 BUTTERFIELD - NEW 46 kV SUB	2018	1,500
28461855	WD0300 ASHLEY - REBUILD SUB	2018	1,500
27957649	WD0751 YORKVILLE - REPL TRF & INC CAP	2018	750
28321662	WD0289 Miller Rd - Repl 10(AC)/12 MVA	2018	675
26708968	WD0903 LEE ST - REPL TB2	2018	600
27951847	WD0571 CASCO - REPL TRF (AC)	2018	600
30934788	WD1251 LOOMIS - REPL TRF (AC)	2018	600
30934419	WD0414 BATH - REPL TRF (AC)	2018	600
30934417	WD0351 BELSAY - REPL TRF (AC)	2018	600
27963087	WD0965 METRO - REPL TRF (AC) & EQUIPMENT	2018	600
29877898	WD0109 ELLSWORTH - REPL TRF #2	2018	600
30934787	WD0134 TECUMSEH - REPL TRF NO. 1 (AC)	2018	600
28113565	WD1120 HOGSBACK - REPL RCL <(>&<)>TRF NO	2018	525
31729981	WD0050 MICHIGAN CASTING #1 TRANS FAILURE	2018	525
31728439	WD0604 OKEMOS #1 TRANSFORMER FAILURE	2018	525
27957792	WD0369 COOLEY - REPL TRF #2 (AC)	2018	525
29829700	WD0149 BURR OAK - REPL TRF (AC)	2018	525
28109662	WD0292 MANCHESTER - REPL TRF (AC)	2018	525
30788030	WD1612 HIGH BRIDGE - NEW 46 kV SUB	2019	1,500
30934418	WD0104 GLADWIN - REPL TRF & MAKE CKT REG	2019	1,125
30934784	WD0067 OWOSSO - REPL TRF No2 & No3 (AC)	2019	1,050
30934781	WD0766 JUDD ROAD REPL TRF No1 & No2 (AC)	2019	1,050
28365171	WD0705 KALKASKA REPL TRF (AC)	2019	600
27952243	WD0220 PITCHER - REPL TRF (AC)	2019	600
27951856	WD0269 OTSEGO - REPL TRF (AC)	2019	600

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30934783	WD0609 NAPOLEON - REPL TRF #1 (AC)	2019	600
27960342	WD0244 PORTAGE - REPL TRF #2 (AC)	2019	600
27952256	WD1339 WATKINS - REPL TRF #2 (AC)	2019	600
31074129	WD0322 MARNE - REPL TRF (AC)	2019	570
28141081	WD0602 TRUFANT - REPL TRF #2 (AC)	2019	450
29252969	WD0475 BECKER - REPL 138 kV SWITCH	2019	150
21906043	WD0220 PITCHER - INST DSCADA	2019	83
30967803	WD1022 FILLMORE REPL LS BUSHINGS & LAS	2019	45
30884609	WD0455 KALEVA - RETIRE SUBSTATION	2019	30
29008303	WD1022 FILLMORE - REPL CKTSWS	2019	12
27960532	WD0370 OTTAWA BEACH - REPL TRF (AC)	2020	1,350
27952252	WD0557 EAST LAKE - REPL TRF (AC)	2020	600
30934785	WD0393 NIAGARA - REPL TRF (AC)	2020	600
30231685	WD0360 LIBERTY - REPL TRF #1 (AC)	2020	600
30231693	WD1210 NORTH KENT - REPL TRF #2 (AC)	2020	600
27952254	WD0783 FOX FARM - REPL TRF (AC)	2020	600
27958053	WD0327 COMSTOCK - REPL TRF (AC)	2020	600
31038870	WD0025 SUTTONS BAY - REPL TRF (AC)	2020	600
31074482	WD0110 HASTINGS - REPL TRF #6 (AC)	2020	570
29845162	WD0325 BOSTON SQUARE - REPL TRF #1	2020	480

TABLE 103 – 2.3 HVD LINES AND SUBS FAILURES – 20 LARGEST WORK ORDERS BY YEAR

HVD Lines and Subs Failures 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
29298551	WD0208 PASADENA, REPL FAILING #2 TRF	2018	2,775
29298460	WD0136 EDENVILLE, REPL FAILING HVD #1TRF	2018	2,100
24479535	WD0136 EDENVILLE DAM TB#2 FAILURE %	2018	1,125
31168120	LN027H WALDRON REPL 34 STRS %	2018	612
26293891	WD0139 Secord Dam Repl #1 bank (failure)	2018	600
31637099	LN057L WEALTHY - ELLS #2 RPL COND & TERM	2018	585
31464065	LN116C GALESBURG REBUILD 1.32 MI % EXP	2018	426
31035698	LN027N WALDRON REPL 18 STRS	2018	324
31174055	WD1068 WILLARD REPL PERIMETER FENCE	2018	270
31375107	WD0908 OAK ST, REPL 277 & 377 SWs	2018	150
30787409	WD0095 CROTON, REPL FAILING 395 & 396 SW	2018	150
31719302	LN078N NEW HAVEN REPL 8 STRS "RUSH" %	2018	144
30669936	LN072A HAMILTON RP 12 STRS "RUSH"	2018	135
31372328	WD0095 CROTON, REPL 6 FAILING SWs	2018	135
31679048	LN029G ALABASTER REPL 7 STRS "RUSH" %	2018	126

30781056	WD0151 DELHI, REPL FAILING 1188 BKR	2018	120
30622639	WD0036 HIGGINS, REPL FAILING 146 BKR	2018	120
29105636	WD0100 WEALTHY ST, REPL 666 OCB	2018	120
31167033	WD0924 AC, REPL FAILING 1088 SF6 BREAKER	2018	120
31733597	WD0979 HALSEY, REPL FAILED 1077 GCB	2018	120
27526719	LN025B UNION CITY REPL 14 STRS "RUSH" %	2019	210
31451577	WD0212 PHILLIPS, REPL FAILING SWs, FUSES	2019	180
31454071	LN0122AK FILLMORE - REPL TAP SPAN	2019	38

TABLE 104 – 2.7 METRO FAILURES – 20 LARGEST WORK ORDERS BY YEAR

Metro Failures 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
29369822	METROFAIL18 GR WESTON COMM VAULT ROOF	2018	1,000
20021827	METROFAIL15 BUCKHAM PH3 (Civil & Elec)	2018	855
28516547	MFAIL17 FLI BUCKHAM PH 3 ELEC	2018	795
31664842	MERTROFAIL18 BC JACKSON ST DUCT / CIVIL	2018	525
31664846	MERTOREL18 BC LOVELL DUCT / ELECTRIC	2018	263
29319683	METROFAIL16 GR OAKES CKT	2018	225
24600152	METROFAIL16 FLI BRUSH-VWD 525 REBUILD	2018	170
27316386	METROFAIL16 BCK SECURITY VAULT ROOF	2018	100
20971562	METROFAIL14 GR UNIVERSAL MED XFMR	2018	100
22930377	METROFAIL14 GR KEELER VAULT ROOF	2018	100
24297290	METROFAIL15 GR MURRAY VAULT ROOF	2018	100
24650844	METROFAIL15 GR PRANGE VAULT ROOF	2018	100
24416262	METROFAIL15 FLI YWCA VAULT GAS SW 2-6	2018	60
31242620	MERTOFAIL18 KZOO CPCO Vault	2018	50
31483010	METROFAIL18 GR CATHOLIC CENTRAL	2018	50
16004832	METROFAIL11 FLI BIG LOTS VAULT	2018	50
28472168	METROFAIL17 KZO CPCO TRANSFORMERS	2018	38
31680073	METROFAIL18 GR 25 DIVISION PMH	2018	30
27111454	METROFAIL16JXN-CITYHALL ALT 480VSEC MH44	2018	30
29359256	METROFAIL17JXN-Mechanic vault to Vermeul	2019	38

TABLE 105 – 3.1 LVD LINES RELOCATIONS – 20 LARGEST WORK ORDERS BY YEAR

LVD Lines Relocations 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
TBD	THDPY18 Homestead/Beulah SUB	2018	794

TBD	THDPY18 Cottonwood Dr Widening	2018	582
TBD	LN066I WEST BRANCH EAST RBLD 5.5 MILE 2	2018	361
31640667	LN032F UNION ST RBLD 3.0 MILES % LVD 1	2018	318
TBD	THDPY18 Leonard St widening	2018	287
TBD	LN066A WEST BRANCH RBLD 5.7MILES %-LVD1	2018	281
TBD	LN066A WEST BRANCH RBLD 5.7MILES %-LVD1	2018	281
TBD	LN066A W BRANCH RBLD 920 W ROSE CITY OH	2018	281
TBD	LN071H COOLEY RBLD% - LVD1of3	2018	233
TBD	THDPY17 St Helen/Artesia LCP101 pt.1	2018	229
31626654	THDPY17 BRICKER SUB 453 EXITS MOBILE SUB	2018	223
31700515	THDPY18 Jackman sub 46 kv line rebuild	2018	205
31677555	LN032F UNION ST RBLD 3.0 MILES % LVD 2B	2018	197
25054985	THDPY12 ALMA-DEJA 33J/N 46 KV REBLD SHT3	2018	185
31237983	DISTA17 HARPER/ONONDAGA COLUMBIA HWY	2018	185
25054983	THDPY12 ALMA-DEJA 33J/N 46 KV REBLD SHT3	2018	181
TBD	LN071H COOLEY RBLD% - LVD2of3	2018	174
TBD	THDPY17 St Helen/Artesia LCP101 pt.2	2018	164
TBD	THDPY18 ST MARYS VLT METRO CONVERSION	2018	163
25053811	THDPY12 ALMA-DEJA 33J/N 46 KV REBLD	2018	160

TABLE 106 – 3.2 HVD LINES RELOCATIONS – 20 LARGEST WORK ORDERS BY YEAR

HVD Lines Relocations 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
21833715	LN0021C BLACKSTONE-CHURCHILL RELOCATE	2018	512
21833840	LN 26D BLACKSTONE - STOCKBRIDGE RELOC	2018	450
27197868	LN049C LARKIN RELO 378-380 M-20 BRIDGE \$	2018	90
31032994	LN080C GOODALE, REPL DDE #87 W/2 SDEs \$	2018	60
28708389	LN064A Riga Line RELO #115 for Nexus \$	2018	45
29391787	LN0100J_BECKER SPUR - RELO STR #2	2019	150

TABLE 107 – 3.3 METRO RELOCATIONS – 20 LARGEST WORK ORDERS BY YEAR

Metro Relocations 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
23242817	METRORELOC15 GR FULTON JEFF LAFAYETTE	2018	1,000
21123240	METRORELOC14 GR OTTAWA AVE ALLEY	2018	1,000
31146456	MERTORELOC 18 JAX BLACKSTONE	2018	1,000

28915296	METRORELOC17 GR SHELDON FUL WES ELEC	2018	675
29251592	METRORELOC18JXN-PEARL VAULT CIVIL-	2018	500
29251593	METRORELOC18JXN-PEARL VAULT ELECTRIC	2018	500
28915291	METRORELOC17 GR ENER DIST BRIDGEWATER	2018	250
28915292	METRORELOC17 GR ENER DIST CONVENTION	2018	250
28915293	METRORELOC17 GR ENER DIST SECONDARY	2018	250
31589329	MRELOC18 FLI HUNTINGTON BANK WEST	2018	150
28915294	METRORELOC17 GR SHELDON FUL WES CIVIL	2018	75
31418749	METRORELOC18 GR MUSK FIRST VAULT B DEMO	2018	-
30529330	METRORELOC18 GR NEWBERRY MONROE CIVIL	2018	-

Planned Spending

Table 108 to Table 119 show the twenty largest cost work orders by program for planned programs, over each year from 2018 to 2020. Since these lists are from an extract in February 2018, the cost listed for each work order is an estimate, and subject to change. In some years, certain programs do not currently have at least 20 work orders; in these cases, only the available projects are included. Finally, for some programs the order number is created later in the project planning cycle and is shown as ‘TBD’ within these tables.

TABLE 108 – 4.1 LVD LINES RELIABILITY – 20 LARGEST WORK ORDERS BY YEAR

LVD Lines Reliability 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
TBD	RLBY18 RYNO_MAPES SUB	2018	845
TBD	RLBY17 COOKE DAM_NEW SUB MONUMENT_AUSABL	2018	763
TBD	RLBY18 BATTEESE/COON HILL FIRST ZONE	2018	628
30436580	RLBY17 REYNOLDS/SEARS-s jacksonrd lcp718	2018	568
TBD	RLBY18 RANGER LAKE_LUPTON LCP 090 PHASE1	2018	542
30368961	RLBY15 MARION GASCOM LCP 198	2018	437
31680292	RLBY17 SPRUCE ROAD_EAST BAY 518 - PT 1B	2018	424
TBD	RLBY17 LEVELY/STURGEON LCP 860	2018	409
31680298	RLBY17 SPRUCE ROAD_EAST BAY 518 - PT 4A	2018	400
TBD	RLBY18 OBERLIN MEREDITH LCP 292	2018	396
TBD	RLBY18 Ranger Lake_Goodar LCP 158	2018	382
TBD	RLBY18 ROSE CITY_ISLAND LAKE LCP 096 P1	2018	366
TBD	RLBY17 CONWAY ODEN 2nd ZONE PII	2018	359
TBD	RLBY17 SPRUCE ROAD_EAST BAY 518 - PT 3	2018	357
TBD	RLBY18 ABBE_CALDWELL LCP 876	2018	357
TBD	RLBY17 CONWAY ODEN 2nd ZONE PI	2018	348
TBD	BKBN18 DOEHLER JARVIS/JEFFERSON	2018	345
30516761	RLBY17 REYNOLDSSEARS Browns lk so Kimmel	2018	342

30474747	RLBY17REYNOLDS/SEARS-715-kimmel e/o s j	2018	341
TBD	RLBY16 LAKE CITY-STITTSVILLE LCP 5297	2018	334

TABLE 109 – 4.2 HVD LINES RELIABILITY – 20 LARGEST WORK ORDERS BY YEAR

HVD Lines Reliability 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
15596837	LN066E MARKEY-HOUGHTON HTS N RBLD 1.5MI%	2018	2100
27220557	LN032F UNION ST RBLD 3.0 MILES %	2018	1991
21993161	LN072N FENNVILLE RBLD LN 7.3 MILES RR%	2018	1650
27951911	LN066A WEST BRANCH RBLD 5.7 MILES %	2018	1539
27629949	LN066I WEST BRANCH EAST RBLD 5.5 MILES %	2018	1485
26796506	LN025A UNION CITY (ELM-U) SOUTH REBUILD%	2018	1350
31168480	LN018A HOMESTEAD POLE TOP REHAB	2018	1218
31333361	LN099A CHEBOYGAN POLE TOP REHAB	2018	1099
31333373	LN020G STANTON POLE TOP REHAB	2018	1086
27633369	LN066I WEST BRANCH CENTER RBLD 3.6 MILE%	2018	975
31335413	LN070A MENDON REBUILD 1.64 MI %	2018	735
31333371	LN072KK BREEDSVILLE POLE TOP REHAB	2018	718
21992599	LN072F NEW RICHMOND RBLD LINE 3.5 MILES	2018	716
27952675	LN116I AUGUSTA POLE TOP REHAB	2018	713
31023844	LN027N WALDRON POLE TOP REHAB 9.38 MILES	2018	615
28346071	LN076A GUN LAKE REBUILD 1.9 MI RR%	2018	600
19713496	LN026G STOCKBRIDGE (SPUR) REBUILD 2.69MI	2018	570
31721377	LN099A CHEBOYGAN RP 43 STRS %	2018	516
28345868	LN116G AUGUSTA REBUILD 1.3 MI RR%	2018	450
31735448	LN081K LAMOREAUX RBLD/RELOC 0.98M %	2018	450
29076351	LN033BZ ROSEBUSH NEW 46KV 5.7MI	2019	2264
14795029	LN015B IONIA #2 REBUILD-B 4.83 MI *RR* %	2019	2124
15596986	LN066E MARKEY-HOUGHTON HTS S RBLD 7.46MI	2019	2100
15585628	LN110A ORLEANS N REBUILD 4.24 MILES	2019	2070
21992292	LN023B FINE LAKE REBUILD NORTH SECTION	2019	1950
28055683	LN025I NORTH ADAMS WEST RBLD 6.2 MILES %	2019	1725
21993173	LN119A HAMMOND RD N RBLD 6.1 MILES	2019	1575
28357769	LN025B UNION CITY(U-B) N_REBUILD % 8 MI	2019	1539
15136881	LN027A MANITOU BEACH N_RBLD 4.6 MILES	2019	1350
15137755	LN020A TRUFANT - GREENVILLE_W RBLD	2019	1260
15137758	LN020A TRUFANT - GREENVILLE_E RBLD	2019	1260
30787231	LN116D JOPPA RBLD 2.31 MILES %	2019	840
25730214	LN025I NORTH ADAMS REPL 34 STRS %	2019	383

31725506	LN104A OVID REPL 20 STRS %	2019	270
21187150	LN072F NEW RICHMOND REPL 19 STRS	2019	200
19203694	LN033F ROSEBUSH REPL 12 STRS	2019	189
27583062	LN025B UNION CITY REPL 16 STRS %	2019	180
22106353	LN023B FINE LAKE REBUILD TOWER SECTION	2019	173
25660099	LN015B IONIA #2 REPL 11 STRS	2019	158
14478807	LN033W WEIDMAN SPUR R/W ONLY	2019	150
29334854	LN033CA ROSEBUSH 46 KV NEW 8 MI	2020	2943
27632106	LN066I WEST BRANCH WEST RBLD 10 MILES	2020	2700
22091165	LN023B FINE LAKE REBUILD SOUTH SECTION	2020	1905
31747044	LN066T WEST BRANCH (S/W) REBUILD %	2020	405
20819726	LN072F NEW RICHMOND REPL 288 ABSW	2020	53

TABLE 110 – 4.3 LVD SUBSTATIONS RELIABILITY – 20 LARGEST WORK ORDERS BY YEAR

LVD Substation Reliability 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
22169819	WD6019 Mobile #19-New 46 kV Mobile	2018	3,000
24048670	WD6622 MOBILE #22 - NEW 138 KV MOBILE	2018	3,000
25565281	WD1572 MAINES ROAD NEW SUB	2018	1,800
30614442	WD0358 FRONTIER REBUILD SUB	2018	1,500
16619387	WD0148 MORENCI REBUILD SUB	2018	825
26512415	WD1653 REA ROAD-New 46 kV Dist Sub	2018	750
26512417	WD1654 MONUMENT-New 46 kV Dist Sub	2018	750
21910510	WD0448 PENTWATER - RPL TRF & REGS	2018	600
26667518	WD1348 PAVILION - REPL CKTSWS & INST CKT	2018	525
27734135	WD0433 FOUR MILE INST ANIMAL MITIGATION	2018	315
31175298	WD0364 IRON STREET REPLACE REGS	2018	315
31186745	WD0901 WAGER REPLACE REGS	2018	315
25498959	WD0708 MICHIGAN - REPL CKTSWS	2018	300
29307687	WD1035 KNAPP - REPL CKTSWS	2018	300
30972003	WD1157 NORTH CORUNNA - REPL CKT SWITCHER	2018	300
29896523	WD0842 STACEY - REPL SOGS W/TRANSRUPTER	2018	300
30972013	WD1418 HACKETT - REPL CKT SWITCHER	2018	300
31043838	WD0324 HOWARD CITY -INST CKTS & RPL REGS	2018	300
28917650	WD1496 CLEAR LAKE - INST 2-6 CIRCUIT	2018	225
31175296	WD0106 ATLAS REPLACE 2-6 AND 3-6 REG	2018	210
29232921	WD6623 Mobile #23 - New 138 kV Mobile	2019	3,000
25341606	WD6020 Mobile #20 - New 46 kV Mobile	2019	2,400
25340114	WD6621 Mobile #21 - New 46 kV Mobile	2019	2,400

17945971	WD0573 OHMAN ROAD - REPL 138 kV FUSES	2019	870
17535808	WD0223 CARSON CITY - RPL TRF (AC) & 3RD	2019	675
31035990	WD0231 MENDON - REPL TRF (FP)	2019	675
20681116	WD0721 PORT CALCITE - RPL BANK NO. 1-2	2019	615
26703681	WD0632 HARLEM - REPL TRF & 199 SW (FP)	2019	600
31035875	WD1511 LELAND - REPL TRF (FP)	2019	570
25499181	WD0453 BRICKER - REPL CKTSWS	2019	525
31035697	WD0602 TRUFANT - REPL TRF #1 (FP)	2019	525
29246965	WD0476 JAMESTOWN - REPL CKTSWS	2019	300
28419349	WD0574 PENINSULA - REPL VXE RCLRS & REGS	2019	150
30535399	WD0700 DEAN ROAD ANIMAL MITIGATION	2019	113
30535390	WD1179 SKYLARK ANIMAL MITIGATION	2019	113
30535386	WD0045 LARKIN ANIMAL MITIGATION	2019	113
29880857	WD1353 VILLAGE GREEN - INST ANIMAL MIT	2019	113
29880582	WD1298 VANDERBILT - INST ANIMAL MIT	2019	113
30534950	WD1359 KIPP ROAD ANIMAL MITIGATION	2019	113
30535393	WD1159 BALLENGER ANIMAL MITIGATION	2019	90
29307064	WD0196 CONVIS - REPL SOGS W/TRANSRUPTER	2020	1,500
21889056	WD0825 NORTHERN FIBRE - REPL CKTSWS	2020	375

TABLE 111 – 4.4 HVD SUBSTATIONS RELIABILITY – 20 LARGEST WORK ORDERS BY YEAR

HVD Substations Reliability 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
29062896	WD0725 BEGOLE, REPL 4 BKRS	2018	480
29105190	WD0713 EMMET, 3 BRKRS & 2 SPTs	2018	420
30623009	WD0559 MONITOR, REPL 100, 166, 1388 BKRS	2018	360
30622781	WD0036 HIGGINS, REPL 266 & 1188 OCB BKRS	2018	240
21888181	WD1359 KIPP RD REPL TB1 BUSHING	2018	199
21888362	WD1396 STEERING GEAR REPL BUSH	2018	166
29058221	WD0730 WARREN, REPL 156 CSW	2018	158
15751951	WD0924 AC REPL 100 OCB	2018	158
30781244	WD0151 DELHI, REPL 600 BKR	2018	120
21981123	WD1108 WILLIAMS REPL 277,188,E BUS,W BUS	2018	112
21889003	WD0646 ORBITAL REPL TB1 BUSHING	2018	107
27698005	WD0785 DELANEY REPL OPTO SNAP	2018	105
21888874	WD1145 CADMUS REPL TB1 BUSHING	2018	103
21888190	WD0370 OTTAWA BEACH REPL TB1 X,Z BUSH	2018	97
21982734	WD0978 MEDUSA REPL 399 CSW	2018	95
21841418	WD0520 WHITEHALL REPL TB1 TYPE U BUSH an	2018	90

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21842564	WD1121 ABBE REPL TB1 HS BUSH	2018	87
21847106	WD0978 MEDUSA REPL 299 CIRCUIT SW	2018	84
15868428	WD0369 COOLEY REPL 177 & 277 BKRS	2018	68
15868436	WD0437 EDGEWOOD REPL 199 SW, INST LA's	2018	68
31016816	WD0680 WHITE LAKE, REPL OCBs & SWs	2019	713
30091071	WD0100 WEALTHY ST, REPL 3 BKRS	2019	420
21951593	WD0270 N BELDING REPL 200,1488&1588 BRKR	2019	38
29081869	WD0281 WHITESTONE PT, REPL 177&277 BKRS	2019	240
21954808	WD0152 CEMENT CITY REPL 266&388 BRKR	2019	168
15751312	WD0230 BRONSON REPL 288OCB W/ MOAB	2019	141
30378190	WD1489 VERNON, REPL 166 OCB	2019	120
21951436	WD0966 VENTURA REPL 400 BREAKER	2019	96
15875918	WD0535 PRESCOTT REPL 199 SW	2019	68
15876228	WD0910 WAWATAM REPL 199 SW	2019	68
31329772	WD0281 WHITESTONE PT, REPL 175 VVL SW	2019	45
31329777	WD0281 WHITESTONE PT, REPL 275 VVL SW	2019	45
31329774	WD0281 WHITESTONE PT, REPL 199 RBS SW	2019	45
31298976	WD0281 WHITESTONE PT, REPL BUSHINGS & LAs	2019	45
21973392	WD0966 VENTURA REPL (3) 277 PT	2019	42
21981121	WD0680 WHITE LAKE REPL GRN BUS,X,Z PT&SP	2019	42
21980942	WD1215 HUGHES RD REPL PT	2019	15

TABLE 112 – 4.5 SUBSTATIONS COMMUNICATIONS UPGRADES – 20 LARGEST WORK ORDERS BY YEAR

Substations Communications Upgrades 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
28942373	WD1220 BASS CREEK ANALOG MULTI-DROP REPL	2018	330
30022062	WD1272 MIDLAND TREATMENT ANALOG MULTI-DR	2018	330
30042738	WD0387 DORT ANALOG MULTI-DROP REPL \$	2018	330
29972933	WD0720 BANGOR ANALOG MULTI-DROP REPL \$	2018	330
29973060	WD0959 BEVERIDGE ANALOG MULTI-DROP REPL\$	2018	330
30032219	WD0232 DIESEL ANALOG MULTI-DROP REPL	2018	330
29973658	WD0682 CLEVELAND ANALOG MULTI-DROP REPL\$	2018	330
30023231	WD0966 VENTURA ANALOG MULTI-DROP REPL	2018	330
30022888	WD0140 UNION CITY ANALOG MULTI-DROP REPL	2018	330
29974165	WD1213 EUREKA ANALOG MULTI-DROP REPL \$	2018	330
30022394	WD0930 SALT STREET ANALOG MULTI-DROP REP	2018	330
30064914	WD0100 WEALTHY STREET ANALOG MULTI-DROP	2018	330
30022066	WD0067 OWOSSO ANALOG MULTI-DROP REPL	2018	330
30023120	WD2033 UNION CITY MUNICIPAL ANALOG MULTI	2018	330

CONSUMERS ENERGY ELECTRIC DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN

30021830	WD0660 MCGULPIN ANALOG MULTI-DROP REPL\$	2018	330
30021825	WD0039 MAUMEE ANALOG MULTI-DROP REPL	2018	330
29974417	WD0389 HAZELWOOD ANALOG MULTI-DROP REPL	2018	330
29975417	WD0208 PASADENA ANALOG MULTI-DROP REPL \$	2018	330
29978462	WD0721 PORT CALCITE ANALOG MULTI-DROP RE	2018	330
29978467	WD1099 RAISIN ANALOG MULTI-DROP REPL \$	2018	330
29978869	WD0670 STOVER ANALOG MULTI-DROP REPL \$	2019	330
29978871	WD1083 SUMMERTON ANALOG MULTI-DROP REPL\$	2019	330
30002609	WD2064 GRAYLING COGEN ANLOG MULTI-DROP R	2019	330
29978875	WD1000 THETFORD ANALOG MULTI-DROP REPL \$	2019	330
29979068	WD0076 TIPPY HYDRO ANALOG MULTI-DROP REP	2019	330
29979720	WD1109 WACKERLY ANALOG MULTI-DROP REPL \$	2019	330
29979570	WD1135 UPJOHN ANALOG MULTI-DROP REPL \$	2019	330
29979214	WD0958 LAYTON ANALOG MULTI-DROP REPL \$	2019	330
29979569	WD0276 TWINING ANALOG MULTI-DROP REPL \$	2019	330
29979727	WD1149 WASHTENAW ANALOG MULTI-DROP REPL	2019	330
29978475	WD0775 ROCKPORT ANALOG MULTI-DROP REPL	2019	330
29979574	WD1489 VERNON ANALOG MULTI-DROP REPL \$	2019	330
29975131	WD1161 OAKLAND ANALOG MULTI-DROP REPL \$	2019	330
29974647	WD0565 HOLLAND ROAD ANALOG MULTI-DROP RE	2019	330
29974649	WD0167 HSC ANALOG MULTI-DROP REPL \$	2019	330
29974654	WD0684 IOSCO ANALOG MULTI-DROP REPL \$	2019	330
29974763	WD1255 LAFAYETTE ANALOG MULTI-DROP REPL	2019	330
29974779	WD1100 LINDBERGH ANALOG MULTI-DROP REPL	2019	330
29974921	WD1140 LUDINGTON PUMPED ST ANALOG MULTI-	2019	330
29974926	WD1169 MECOSTA ANALOG MULTI-DROP REPL \$	2019	330

TABLE 113 – 4.6 SYSTEM PROTECTION – 20 LARGEST WORK ORDERS BY YEAR

System Protection Upgrades 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
22340209	WD0389 Hazelwood Repl Relays	2018	338
24997593	WD0083 Blackstone Repl Old Relays	2018	338
29775533	WD0979 Halsey Resolve Working Space	2018	338
29759690	WD1083 Summerton Resolve Working Space	2018	240
24799068	WD0978 MEDUSA REPL TB 2&3 Relays	2018	225
22341033	WD0100 Wealthy Repl Relays	2018	203
29749071	WD0959 Beveridge Repl 1277 Relays	2018	135
26675669	WD0100 Wealthy Repl 1688 Relays	2018	90
29716063	WD0100 Wealthy Resolve Working Space	2019	900

31256526	WD1085 Amber 266 Relay Rpl	2019	150
31073175	WD0720 BANGOR, REPL TB#2 RELAYS	2019	113

TABLE 114 – 4.7 LVD REPETITIVE OUTAGES – 20 LARGEST WORK ORDERS BY YEAR

LVD Repetitive Outages 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
TBD	RBL15 ROGUE RIVER/CANNON FARMS LCP-066	2018	329
30211738	RPOUT16 BROUHWELL MINARD PT2 1of2	2018	313
TBD	RPOUT16 BIG PRAIRIE/OXBOW LCP 908-PART 1	2018	251
TBD	RPOUT16 BIG PRAIRIE/OXBOW PART 1 15-34	2018	251
29816575	RPOUT16 MONTROSE/VOLKMER LCP 832	2018	232
TBD	RPOUT11 Vandercook/Ackerson Lk LCP 708J	2018	221
TBD	RPOUT18 ALGER_SKIDWAY LCP 950	2018	218
TBD	RPOUT18 HILL RD/PINE WAY	2018	193
TBD	RPOUT18 MCBAIN-VOGEL CNTR LCP 129	2018	177
30211893	RPOUT16 BROUHWELL MINARD PT2 2of2	2018	169
TBD	RPOUT18 PRESCOTT_LOGAN 615_158_159	2018	124
TBD	RPOUT18 PRESCOTT_LOGAN LCP 579_582	2018	124
TBD	RPOUT18 DUCK LAKE DUCK LK 142	2018	111
TBD	RPOUT18 RANGER LAKE_LUPTON LCP 150	2018	106
TBD	RPOUT18 ALGER_FOREST LAKE LCP 909_920	2018	100
TBD	RPOUT18 Withey Lake/Pettit Fusing	2018	100
30139431	RPOUT17 BRECKENRIDGE/WHEELER LCP 691	2018	99
TBD	RPOUT18 CONVIS WALNUT POINT 086	2018	98
30254511	RPOUT16 CEDAR SPRINGS/NELSON LCP 329	2018	97
TBD	RPOUT17 BEADLE SPAULDING LCP 257	2018	95

TABLE 115 – 4.8 METRO RELIABILITY – 20 LARGEST WORK ORDERS BY YEAR

Metro Reliability 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
31074771	MRLBY17 SAG BACKBONE 4 WEST CIVIL	2018	550
28471228	METRORELI16 KZO LOVELL CRUSHED DUCT	2018	500
31073579	MRLBY18 SAG WATER ST CIVIL	2018	440
31074763	MRLBY17 SAG BACKBONE 4 EAST ELEC	2018	430
28516685	MRLBY17 SAG BACKBONE 4 EAST CIVIL	2018	400
16462644	METRORELI12 FLI DOYLE COMMONS	2018	309

31639616	METROREL18 KZOO LOVELL DUCT / ELECTRIC	2018	250
31074053	MRLBY18 SAG WATER ST ELEC	2018	160
28517686	MRELI17 FLI NORTH BRUSH ALLEY	2018	150
31188345	METRORELI18 GR LAGRAVE OAKES EXIT	2018	100
31188346	METRORELI18 GR LAGRAVE FOUNTAIN EXIT	2018	100
31188344	METRORELI18 GR LAGRAVE PRESS EXIT	2018	100
22473511	METRORELI15 GR MONROE I196 FOUNDRY CKT	2018	100
22473513	METRORELI15 GR MONROE I196 ROWE CKT	2018	100
22473508	METRORELI14 GR MONROE I196 IONIA CKT	2018	75
22473505	METRORELI14 GR MONROE I196 ARMORY CKT	2018	75
22473503	METRORELI14 GR MONROE I196 HOSPITAL CKT	2018	75
22473138	METRORELI14 GR MONROE I196 WATERS CKT	2018	75
31458719	MERTOFAIL18 BC 215 MICHIGAN POLE / SRV	2018	15
30534407	METRORELI17 BC SUMP PUMP ALARMS	2018	15

TABLE 116 – 4.9 GRID CAPABILITIES: AUTOMATION – 20 LARGEST WORK ORDERS BY YEAR

Grid Capabilities Automation 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
31225571	METRORELOC18 GR CKT WEST GRID MOD	2018	2,865
31589458	WD0241 DOELHER-JARVIS REPL TRF #1	2018	600
TBD	DISTA18 OHMAN ROAD/SEARS	2018	572
TBD	DISTA18LOAD-NAPOLEON-STONEY LAKE-RECONDU	2018	491
TBD	DISTA18SOURCE-BROOKLYN-FORD-RECONDUCTOR	2018	491
30438556	REHAB17 DOEHLER JARVIS/GRIGGS 1	2018	458
30444038	REHAB17 DOEHLER JARVIS/GRIGGS 2	2018	406
21903316	WD0608 PALMER - DSCADA & REPL REGS	2018	395
31292585	WD0706 BOWEN REPL 177 & 277 MOAB & CTRLS	2018	375
31492696	WD0608 PALMER MOAB SCADA & REPL	2018	375
30444221	REHAB17 DOEHLER JARVIS/GRIGGS 3	2018	345
28967510	WD0241 DOELHER-JARVIS REPL 177 & 277 SW	2018	330
30420981	LN071M EASTWOOD CMSTK JCT 46 KV REPL 2 SW	2018	330
TBD	DISTA18 CUTLERVILLE-GAINES LOOP SCHEME	2018	273
28321784	LN069H SUMMIT 46 KV REPL 3 SWS	2018	270
17356330	WD0480 PELLSTON DSCADA & REPL RCLRS	2018	266
20372232	WD0548 LEONARD - DSCADA & REPL RCLR	2018	261
21905882	WD0369 COOLEY - DSCADA & REPL REGS	2018	251
TBD	DISTA18 BARRYTON/BARRYTON	2018	244
31024245	DISTAYLOAD-LKLEANN-LKLEANN-CONST ORDER	2018	219
21905893	WD0765 LOVELL - DSCADA & REPL REGS	2019	327

CONSUMERS ENERGY ELECTRIC DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN

22884219	WD1120 HOGSBACK-ADD DSCADA	2019	285
21765397	WD0706 BOWEN - DSCADA & REPL REGS	2019	240
21905763	WD0275 OAKWOOD - DSCADA & REPL REGS	2019	233
30147877	WD0416 Whittum - INST DSCADA	2019	225
21755867	WD0726 MAYNARD - DSCADA & REPL REGS	2019	184
21905260	WD0501 EASTWOOD - DSCADA & REPL RCLRS	2019	165
22783172	WD0338 HARRISON-ADD DSCADA	2019	152
22879352	WD0020 GREENWOOD-ADD DSCADA	2019	129
21906424	WD1063 HANSEN - DSCADA & REPL REGS	2019	120
22848987	WD1273 WHITTEMORE-ADD DSCADA	2019	117
22918843	WD0380 FAIRFIELD-ADD DSCADA	2019	113
22918607	WD1145 CADMUS-ADD DSCADA	2019	113
21905570	WD0212 PHILLIPS - INST DSCADA	2019	109
22918383	WD1088 GOLDEN-ADD DSCADA	2019	108
22887695	WD1150 GRAND RIVER-ADD DSCADA	2019	105
31290679	LN072VV METRO 46 KV LINE MOABS SCADA REPL	2019	90
31293092	WD0411 KELLOGGSVL RP 277 & 377 MOABS CTRL	2019	90
31492685	WD0116 HURLEY 177 & 188 MOABS SCADA & REP	2019	90
21895769	WD0634 KILGORE - INST DSCADA	2019	90
22927328	WD0748 WEBB RD-Repl trf & ADD DSCADA	2020	480
22925548	WD0418 NORTH ADAMS-ADD DSCADA	2020	300
17358692	WD0581 SHELBY - DSCADA & REPL RCLRS	2020	266
22925886	WD0298 PALMYRA-ADD DSCADA	2020	255
22926358	WD0377 WAMPLERS-ADD DSCADA	2020	225
22926306	WD0309 WALDRON-ADD DSCADA	2020	222
21904830	WD0530 WHITE CLOUD - DSCADA & REPL REGS	2020	211
21895578	WD1146 ATWATER - DSCADA & REPL RCLRS	2020	191
20372520	WD0411 KELLOGGSVILLE - DSCADA & REPL REG	2020	189
22883878	WD0090 CHARLOTTE-ADD DSCADA	2020	180
21902989	WD0664 TRAVIS - INST DSCADA	2020	169
21904822	WD0047 SPRING DR - DSCADA & REPL RCLRS	2020	161
22917974	WD0676 McGRAW-ADD DSCADA	2020	158
22787368	WD0304 WEIDMAN-ADD DSCADA	2020	156
21888530	WD0141 GRANDVILLE - DSCADA & REPL REGS	2020	146
21910112	WD0566 BALDWIN - DSCADA & REPL RCLRS	2020	136
22927323	WD1113 SHERMAN-ADD DSCADA	2020	135
22887068	WD1303 WEST ROAD-ADD DSCADA	2020	129
22876407	WD1031 COGGINS-ADD DSCADA Scope:	2020	129
22887079	WD0340 DIMONDALE-ADD DSCADA	2020	126

TABLE 117 – 5.1 LVD LINES CAPACITY – 20 LARGEST WORK ORDERS BY YEAR

LVD Lines Capacity 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
29513454	DARE16 Oriole/Hamlin LCP 5128 PH 2	2018	875
TBD	NBUS17 FREELAND/RURAL LCP 904	2018	621
TBD	DARE14 WEST CLARK LAKE/GRAND - JEFFERSON	2018	568
TBD	DARE18 ABBE_ABBE LCP 328 PART 1	2018	534
TBD	NBUS17 FOREMAN/VERGENNES.Foreman St PH2	2018	503
31670991	DARE18 PEACH RIDGE/BALLARD CONV PT3	2018	499
TBD	DARE17 MILTON/FEDERAL SCRW LCP077 OHL P1	2018	496
TBD	DARE18 LONG LAKE SUB NEW CKT	2018	433
31638294	DARE18ASHRDSUB-SIMPSON ckt01 URD	2018	395
31299556	DARE18 PEACH RIDGE/BALLARD CONV PT3 B	2018	384
TBD	DARE17 Benston Sub WD 1635 LOC 1-37	2018	372
TBD	DARE17 Benston Sub WD 1635 LOC 38-71	2018	357
31238438	DARE16 FIELD RD SUB (LINDEN RD RECOND)	2018	346
31735828	NBUS17 FOREMAN VERGENNES Foreman St.Ph 1	2018	338
TBD	DARE18 STEVENS/STEVENS NEW CIRCUIT 2	2018	302
31510664	DARE18 JAMESTOWN-JAMESTWN FOREST GROVE A	2018	289
31337352	DARE18 PEACH RIDGE/KENOWA ISOLATORS	2018	287
31075678	NBUS17 GRANDVILLE GRANDVILLE 2	2018	286
29665958	DARE17 NEW RIDGEVIEW SUB 2	2018	267
TBD	DARE18 NEW BUCHANAN SUB - CIRCUIT 1A	2018	258

TABLE 118 – 5.2 HVD LINES AND SUBS CAPACITY – 20 LARGEST WORK ORDERS BY YEAR

HVD Lines and Subs Capacity 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
29197689	WD0136 EDENVILLE RBLD SUB TB1	2018	2531
25561247	LN063J JACKMAN LINE RBLD 3.3 MI 46 KV	2018	1725
29068110	WD1248 FARR RD INST RLY PROTECTION METC	2018	810
29946060	WD0083 BLACKSTONE ST REPL 2 VARMASTERS	2018	728
28899686	LN033BZ ROSEBUSH R/W 46 KV 6MI	2018	720
28350976	FOREST GROVE - NEW 138 kv SPUR	2018	600
31456430	LN071H COOLEY 1.3MI RBLD 46 KV RR %	2018	600
30949399	WD1211 BARD RD RPL MOAB/SOGS W/ CKT SWI	2018	460
29056946	LN070G MENDON WAKESHM 46 KV ACQ R/W 5.3MI	2018	443
30349791	WD0131 GREY IRON CH SPACE MODIFICATIONS	2018	428

CONSUMERS ENERGY ELECTRIC DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN

27367582	LN082A KELLOGGSVILLE 46 kV RBLD 0.81 MI	2018	390
29334847	LN033Y FROST 46 KV NEW 1 MI	2018	365
29945956	WD0064 BEECHER REPL 156 VARMASTER	2018	308
26263038	WD0980 SPAULDING METC RLY & INST CKTSW	2018	301
29353729	LN100A_ PETERSON SPUR - ACQR LINE RIGHTS	2018	300
28618903	LN081U NORTH KENT 46 KV ADD MOABS %	2018	288
28367132	LN072_ BUCHANAN - NEW 46 kV TAP	2018	225
30913192	LN_ LINCOLN SUB 138 KV LINE R/W	2018	225
28511504	LN086E SHELBY 46 kV ADD MOABS	2018	210
29353727	WD1647 PETERSON SUB - ACQR PROPERTY	2018	210
31021217	WD0560 RIVERVIEW NEW 46 KV CCH WORK SPACE	2019	1875
29314019	WD1489 VERNON ADD 4 BKRS 46KV	2019	1778
28599346	LN063E STERNS RD LINE RBLD 2.1 MI 46KV	2019	1725
31676745	LN_ SEVEN MILE SUB 138 KV LINE R/W	2019	968
28899835	LN033CA ROSEBUSH R/W 46 KV 8MI	2019	915
31011343	Summerton-Rosebush Line Removal	2019	663
29916620	LN0008AO_ KROMDYKE - NEW 138 kV SPUR	2019	600
29816001	WD1249 ALGOMA INST DUAL PILOT RLY & CCVT	2019	570
29924867	WD0999 RICKERT INST NEW CCH & REPL PNLS	2019	420
29946246	WD0190 MORROW REPL 156 VARMASTER	2019	383
31021278	WD0560 RIVERVIEW REPL 156 VARMASTER	2019	338
23882615	LN019W MECOSTA RBLD 1.1 MI 46 kV %	2019	285
31443977	WD1085 AMBER REPL 156 VARMASTER	2019	255
29263652	LN033Y FROST R/W 46KV 1 MI	2019	167
30788158	LN018_ HIGH BRIDGE, NEW 46 kV TAP	2019	165
10007735	LN044AF RANKIN NEW 46 kV TAP & SW	2019	150
30884371	LN018C ONEKAMA, NEW 46 kV SWS	2019	135
17946205	LN001J ACUGLAS - RELO FOR SUB EXPN	2019	75
31712106	LN071K PHILLIPS#1 STR#875-876 GRADE B %	2019	75
29209617	LN033E COLEMAN 46 KV RELO TERMINATION	2019	62
30610587	WD0605 WEXFORD INST NEW CCH	2020	1950
31011356	ROSEBUSH-WARREN SUB LINE REMOVAL	2020	930
24635465	WD0190 MORROW MODIFY RELAYING FOR METC	2020	300
25376726	WD0190 MORROW RELO FENCE FOR METC\$	2020	135

TABLE 119 – 5.3 LVD SUBSTATIONS CAPACITY – 20 LARGEST WORK ORDERS BY YEAR

LVD Substations Capacity 20 Largest Work Orders by Year			
Order #	Description	Year Complete	Estimated Loaded Cost (values in \$ thousands)
26941628	WD0856 FORT CUSTER - REPL TB1 & TB2	2018	2700

CONSUMERS ENERGY ELECTRIC DISTRIBUTION INFRASTRUCTURE INVESTMENT PLAN

27903099	WD1574 FOREST GROVE - NEW 138 kV SUB	2018	1800
28348140	WD1635 BENSTON - NEW 138 kV SUB	2018	1800
29266301	WD1663 ASH ROAD NEW SUB	2018	1800
27903636	WD1589 BUCHANAN - NEW 46 kV SUB	2018	1500
28558303	WD403 Long Lk -Repl trf <(>&<)>conv to c	2018	1500
18646603	WD0487 PEACH RIDGE - CAPACITY INCREASE	2018	1350
28519253	WD0797 GRAYLING - REPL TRF & ADD CKT REG	2018	1350
28939069	WD0618 LAGRAVE REPL TRF #1	2018	900
26988247	WD0109 ELLSWORTH - INST TRANSFER BUS	2018	750
29673365	WD0362 WASHINGTON - INST TRF #2	2018	450
29254209	WD0109 ELLSWORTH - DISTRIBUTION EXITS	2018	450
17402798	WD0109 ELLSWORTH - INST BUS-TIES/CNTRLS	2018	150
22918617	WD0630 DEERFIELD REPL TRF & ADD CKT REG	2018	105
30911909	WD0170 HARVEY STREET - REPL 6-6 REGS	2018	75
30911697	WD0934 CALVIN - REPL 4-6 REGS	2018	75
30022913	WD0275 OAKWOOD - REPL 1-6 REGS	2018	60
30859553	WD0109 ELLSWORTH - REPL DSCADA SYSTEM	2018	38
29916053	WD1664 KROMDYKE - NEW 138 kV SUB	2019	2400
27903484	WD1548 HAWTHORNE - NEW 138 kV SUB	2019	1800
18737988	WD1267 TAMARACK CAPACITY INCREASE	2019	1650
10008066	WD1535 CASE LAKE NEW 46 SUB	2019	1500
30341757	WD1284 MILLERS POINT - TEMP SUB (MDOT)	2019	375
31590169	WD0619 BROADWAY - INST NEW CKT #4	2019	188
31590163	WD0776 KEATING - REPL 4-6 REG	2019	75
31225884	WD1672 CREYTS ROAD NEW SUB	2020	1800
27962015	WD0982 LEFFINGWELL - REPL TRF #2	2020	600

Appendix F – Decision Support and Planning Tools

A. Reliability Analytics Engine (RAE)

The RAE is a Microsoft SQL Server database used to analyze outage incident history and electric operations performance. The RAE is similar to the Data Lake in that it combines data from multiple sources, but whereas the lake is intended as a generalized analytics platform, the RAE is focused on reliability analytics. The RAE was developed and put into use in 2013, years before the Data Lake was constructed. However, as additional data sources are brought into the Data Lake, there will eventually be enough overlap that the functionality of the RAE can be migrated to the Data Lake and the RAE as a separate database will be retired.

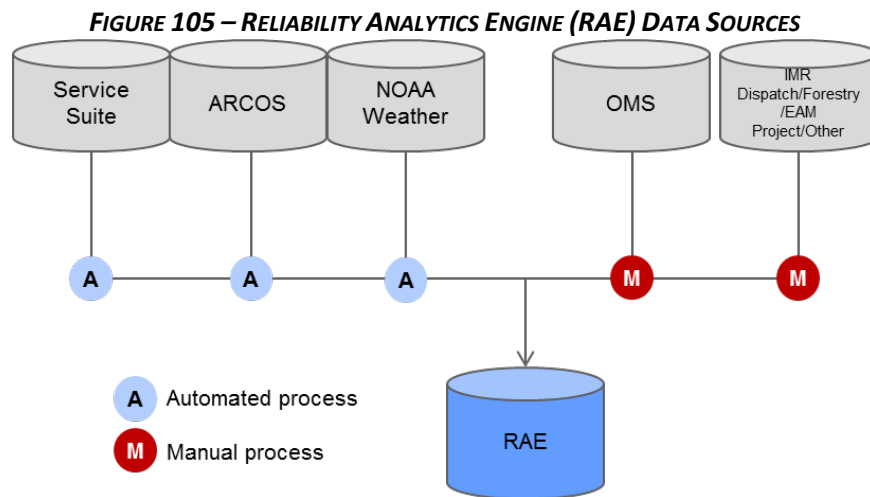
The RAE arranges multiple data points in a manner that allows key reliability metrics (e.g., SAIFI, CAIDI, and CEMI) to be calculated at varying levels of granularity. By combining data from various sources, the RAE can also construct a complete timeline for all incidents from initial outage to final restoration. This detailed timeline breaks down an outage into analysis, dispatch, travel, and repair process steps and calculates the time spent in each step. The RAE also includes other sources such as forestry clearing data, callout success rates, and historic project spending. These can be combined with other data to analyze reliability.

The regularly updated datasets include:

- Outage Management System (OMS) (weekly);
- Service Suite Dispatch Details (SS; formerly OMAR) (weekly);
- Automated Resource Call Out System (ARCOS) Callout Response (weekly);
- Hourly Weather Observation History from the National Weather Service (weekly);
- Electric Asset Management Project Lists (quarterly); and
- Forestry Clearing Dates (yearly).

The RAE may also incorporate other data sources for a particular analysis, but they are not updated on a regular basis.

Figure 105 below provides a high-level diagram of the RAE inputs.



RAE reports are used across multiple departments and in the Electric Reliability Rally Room. RAE outputs were used to create many of the charts in Section IV, which breakdown reliability at a system, headquarter and circuit level. The RAE is also used to identify the worst performing circuits as described in the Planning Process in capital program 4.1 LVD Lines Reliability. There are several standard reports published on a weekly, biweekly, and monthly basis. These include, but are not limited to, dispatch reports, operations reports, reliability metric reports, and on-demand analyses. These automated reports enable the evaluation of system performance throughout the year to help target issues that arise within planning cycles.

There are also a few RAE power users who can access the raw data directly. This provides the freedom to create and test new analytics, and to more quickly answer what-if questions. This philosophy is being carried over into the Data Lake, which will have user “labs.” The Data Lake base tables will be carefully managed, but power users will also have their own lab space to analyze data and run their own data “experiments” without impacting the base tables or other Data Lake users.

B. Restoration Management Systems

Our restoration processes are supported by two major platforms:

- Outage Management System, integrated with Advanced Metering Infrastructure
- Resource Management System (RMS)

Outage Management System

Our OMS is a critical tool used by our engineers, operations and field teams to find, communicate, and manage outages that occur across our system. Customer outages, wire downs, hazards and other key information are received into our map-based OMS via three primary inputs:

- Voice Response Unit (VRU) an automated phone answering system for customers to report outages;
- Customer service representatives through our emergency hotline; and
- The Consumers Energy Outage Center website.

OMS processes this information and, based on the timing of receipt, produces a probable location of where the electric system fault originated or where a protective device may have operated to clear the fault, based on algorithmic modeling. This information is used to locate the problem, communicate information to customers, assign and manage resources to address downed wires, and restore power outages in a more informed, efficient, and timely manner.

Recently we augmented OMS with the capability to receive advanced metering outage information, which provides timely outage information and additional analysis capabilities to quickly locate outage locations.

Resource Management System

During restoration, we perform progress analyses utilizing an RMS known as Catastrophic Crewing. This system is critical for managing resource procurement and allocation among service territories, and tracking resource movements across the state based on the current work in the OMS. The RMS compares available crew resources to OMS demand to establish crew deficiencies or surpluses. This enables us to better understand our resourcing and make critical decisions as to when we engage Mutual Assistance.

Appendix G – Pole Inspection History

Consumers Energy has three inspection programs that evaluate pole conditions:

- The High Voltage Distribution (HVD) pole inspection program is completed on an approximate 12-year cycle using trained contractors.
- The Low Voltage Distribution (LVD) pole inspection program, which began in 2010 and inspected 35 foot poles with primary, was planned to be completed on an approximate 12-year cycle using trained Consumers Energy employees. This program was expanded to all pole configurations using trained contractors starting in August 2011. This program continued through 2015 with the use of trained contractors, moving towards an approximate 12-year inspection cycle.
- The LVD overhead line inspection program is completed on a 6-year cycle. The overhead line inspection program evaluates all equipment on a structure, including the pole, through a visual inspection process.

Table 120 below outlines the pole inspection history from 2012 to 2016. An update including final 2017 values will be reported to the MPSC in 2nd quarter 2018, as part of our annual Year-End Reliability Review process with the MPSC.

TABLE 120 — HVD AND LVD POLE INSPECTIONS

HVD and LVD Pole Inspections					
Inspection Type	Year	Number of Poles Inspected	Number of Poles Identified for Replacement	Number of Poles Replaced	Number of Poles Treated
HVD Pole Inspections ¹	2012	8,580	1,282	321	1,043
	2013	552	74	967	60
	2014	11,704	2,219	788	905
	2015	932	78	888	67
	2016	7,675	915	1,217	823
LVD Pole Inspections	2012	34,792	N/A	3,158	N/A
	2013	129,805	8,523	5,896	N/A
	2014	83,753	5,814	5,130	N/A
	2015	66,407	8,090	3,518	N/A
	2016	0	0	5,969	N/A
LVD Overhead Line Inspections ²	2012	245,000	N/A	574	N/A
	2013	233,600	N/A	429	N/A
	2014	228,900	N/A	470	N/A
	2015	159,420	N/A	224	N/A
	2016	187,260	N/A	312	N/A
Total	2012	288,372	1,282	4,053	1,043
	2013	363,957	8,597	7,292	60
	2014	324,357	8,033	6,388	905
	2015	226,759	8,168	4,630	67
	2016	194,935	915	7,498	823
¹ Only includes poles replaced due to pole inspection. ² Estimating the number of LVD poles inspected is based on the average number of poles per mile for urban and rural circuits.					