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June 4, 2018

VIA ELECTRONIC FILING

M. Lynn Jarvis, Chief Clerk
North Carolina Utilities Commission
4325 Mail Service Center
Raleigh, North Carolina 27699-4300

RE: 2017 Smart Grid Technology Plan - Duke Energy Progress, LLC's Revised AMI Cost-Benefit Analysis
Docket No. E-100, Sub 147

Dear Ms. Jarvis:

Pursuant to the Commission's March 7, 2018 *Order Accepting DENC's and DEC's SGTP Updates, Requiring Additional Information from DEP, and Directing DEC and DEP to Convene a Meeting Regarding Access to Customer Usage Data,* I enclose Duke Energy Progress, LLC's revised AMI cost-benefit analysis for filing in connection with this matter.

Thank you for your attention to this matter. If you have any questions, please let me know.

Sincerely,

Lawrence B. Somers

cc: Parties of Record

DEP NC Smart Grid Technology Plan – NCUC Analysis Requirement

8. **Using the actual historical kilowatt-hour and lost revenue data for energy theft that DEP has experienced and is discovering in North Carolina, including during its AMI deployment, develop an independent estimate of the percent of additional revenues DEP will collect via that deployment that would otherwise be lost due to theft and other non-technical losses.**

Response:

In its original analysis, the Company relied upon an independent industry report (EPRI 1016049: Advanced Metering Infrastructure Technology, Limiting Non-Technical Distribution Losses in the Future) to estimate the total Non-Technical Losses (NTL). Generation minus delivery equals total losses. Total losses include known losses (Technical Losses – generation, transmission, and distribution) and unknown losses. The unknown losses are a combination of NTL (as described by above-mentioned EPRI report) and non-metered rates load (street lighting, etc.). The Company periodically assesses total losses, yet it is not able to precisely isolate NTL from Technical Loss or otherwise measure unknown losses unless all individual cases are identified. It would not be possible to use "the actual historical kilowatt-hour and lost revenue data for energy theft that DEP has experienced," as the Company is only able to measure what has been identified. It is also important to note that past experience of DEP's NTL identification is not necessarily instructive for the Company's anticipated Revenue Protection capabilities with full AMI deployment. Analytics capabilities for Revenue Protection with AMI are continuing to develop as more AMI data becomes available. A full deployment of AMI is expected to further enhance revenue loss identification abilities.

To complete the requested analysis for question 8, the Company compiled actual identified NTL and associated revenue capture data across multiple work streams and performed an analysis of expected revenue capture with full AMI deployment which is detailed below.

It is important to note that many tamper situations are identified during an AMI deployment, although not all result in full revenue capture upon investigation (e.g., customer removes tamper device before a technician visits the premise). Also, there are limitations in identifying revenue loss cases such as slowed or stuck meters, which are not visibly identifiable by field performers, yet are corrected at the time of the new meter installation. For these reasons, the full expected impact of the AMI meter deployment may be understated in the requested analysis.

The analysis resulted in a total NTL percentage of 1.31%. This figure is based on revenue losses identified and projected in DEP by Analytics, Meter Engineering, and Revenue Services. The following assumptions were used to arrive at 1.31%.

- For consistency and simplification of analysis, the percentage of NTL calculations uses DEP 2017 Residential and Commercial revenues as the basis.

- Analytics: Incremental and cumulative revenue capture by the Analytics team from NTL for years 2015-2017 was assessed year over year to estimate the expected total revenue loss identification and capture by Analytics with full AMI deployment in DEP. The expected total revenue loss capture was then divided by the percent of applicable meters (0.995), the collection rate (0.60), the recovery gain rate (0.80), and DEP's 2017 total residential and commercial revenues to estimate NTL as a percent of revenues for this work stream (~1.12%).

- Meter Engineering: Non-technical losses on transformer-rated meters and AMI polyphase meters are identified and tracked by the Meter Engineering group. This group leverages AMI data to identify the majority of these losses. To estimate the total non-technical losses for this work stream, the revenue loss amounts for each case identified were divided by the number of months the revenue loss took place to arrive at a monthly revenue impact. The monthly revenue impact was multiplied by 12 to arrive at the annual revenue impact. The total annual revenue impact was then divided by the percent of applicable meters (0.995), the recovery gain rate (0.80), and DEP's 2017 total residential and commercial revenues to estimate NTL as a percent of revenues for this work stream (~0.18%).

- Revenue Services: The billing group identifies cases of revenue loss through billing exceptions. Average annual revenue capture from this work stream from 2015-2017 was then divided by the percent of applicable meters (0.995), the collection rate (0.60), the recovery gain rate (0.80), and DEP's 2017 residential and commercial revenues to estimate NTL as a percent of revenues (~0.01%).

NTL Analytics (~1.12%) + NTL Meter Engineering (~0.18%) + NTL Revenue Services (~0.01%) = Total NTL (~1.31%)

For the requested analysis, see Exhibit 1 – DEP AMI Revenue Capture Benefit NCUC Q8 attached. The revised analysis of revenue capture benefits of AMI results in a higher total net increased revenue capture than what DEP estimated in its original analysis, since the original analysis assumed that the Company would only be able to claim half of the 2% total non-technical losses cited by EPRI in the DEP AMI deployment business case. The more conservative assumption was used to ensure the business case accurately reflected the direct revenue protection impacts specifically attributable to the DEP AMI meter deployment.

9. Provide a revised 20-year AMI cost-benefit analysis that includes: (a) the costs of replacing AMI meters at the end of their 15-year lives, (b) the most recent estimate of the costs of cellular direct connect meters, (c) the cost of replacing other components and software at reasonable intervals, and (d) the non-technical revenue loss estimate (rather than the EPRI 2% estimate) developed pursuant to question 8.

Response:

DEP filed the supporting cost-benefit analysis for its AMI meter deployment in the October 2, 2017 SGTP Update. Witness Donald L. Schneider, Jr. testified to the similar additional AMI cost-benefit analysis the Commission requested and considered from Duke Energy Carolinas, LLC ("DEC") during the recently-concluded DEC general rate case hearing in Docket No. E-7, Sub 1146.

When developing cost-benefit analyses, Duke Energy does not include full asset replacement of major technology deployments at the end of the asset's useful life. Likewise, the benefits in the years following the expected asset life are not included in analyses. The Company expects a separate analysis for any follow-on deployments or replacements of the assets.

The technology landscape is ever changing, thus a full replacement of AMI technology like-for-like is not expected, and any future technology deployment would require a standalone analysis to be evaluated upon its own merits (cost-benefit analysis). In addition, the inclusion of a full meter replacement at the end of the meters' expected 15-year life would warrant an extended analysis to reflect the costs and benefits of the replacement AMI meters for the following 15 years. A 20-year analysis that includes asset replacement in Years 17-19 will thus overstate capital deployment costs and understate the on-going costs and benefits. However, in response to the Commission's questions, the requested analysis modifications were performed.

The creation of a cost estimate for work to be done 15 years in the future requires that several assumptions be made, as there are many unknowns. The assumptions used for this analysis are described below.

The cost estimate to replace the AMI meters at end-of-life (EOL) assumes reduced project support and overhead for Network Design, Data and Mapping Management, Change Management, Business Process Management, Meter Route Analysis, Network Mitigation, Itron Professional Services, Business Case Development, IT Architecture, and Billing Support. The estimate also does not include the replacement of Cisco Connected Grid Routers, as these devices have a 10-year life and their associated replacement costs are already included in the original business case at EOL (Years 12-14).

By adding the costs to replace the AMI meters at EOL, the benefits were extended throughout the 20-year analysis.

Direct Connect meter costs are based on the current Itron meter pricing and the current/expected total Direct Connect meters needed for the full deployment. Total meter costs were updated pursuant to existing contractual pricing with the vendor.

The original business case included costs to replace meters related to on-going failures, thus not all meters deployed during the initial deployment timeframe will be at their EOL. For the purpose of this analysis, the cost estimate assumes that all meters in scope of the original deployment would be replaced regardless of whether the meter has truly reached its EOL, despite the fact that a percentage of the meters would have been replaced post-deployment and would be less than 15 years old.

For the 20-year AMI cost-benefit analysis with the requested modifications, see Exhibit 2 - DEP Costs and Benefits Summary - Revised NCUC Q9 for the revised summary view of the DEP cost and benefit estimates. The Company did not originally perform a consolidated cost-benefit analysis for DEP in the same format that it was performed for DEC. For consistency, the Company here provides a version of its original DEP cost-benefit analysis in the DEC format as Exhibit 3 - DEP AMI Cost-Benefit Original and a version of its revised DEP cost-benefit analysis based on Commission requests in the DEC format as Exhibit 4 - DEP AMI Cost-Benefit Revised.

Duke Energy Progress

Analysis of Revenue Capture Benefits with AMI Utilizing an Internal Analysis Requested by NCUC in SGTP Order, Question #8

Year	2017 Revenues Residential & Commercal (1)	Revenue Leakage Percentage (2)	AMI Recovery Gain (3)	Collection Percentage (4)	Gross Increased Revenue Capture	Applicable Meters (5)	Benefit Realization/ "Phase-In" Schedule(6)	Net Increased Revenue Capture
1	3,002,853,191	1.31%	80.0%	60.0%	18,881,941	99.5%	0.0%	$ -
2	3,017,867,457	1.31%	80.0%	60.0%	18,976,351	99.5%	10.0%	$ 1,888,147
3	3,032,956,794	1.31%	80.0%	60.0%	19,071,232	99.5%	43.0%	$ 8,159,627
4	3,048,121,578	1.31%	80.0%	60.0%	19,166,588	99.5%	80.0%	$ 15,256,604
5	3,063,362,186	1.31%	80.0%	60.0%	19,262,421	99.5%	99.0%	$ 18,974,448
6	3,078,678,997	1.31%	80.0%	60.0%	19,358,734	99.5%	100.0%	$ 19,261,940
7	3,094,072,392	1.31%	80.0%	60.0%	19,455,527	99.5%	100.0%	$ 19,358,250
8	3,109,542,754	1.31%	80.0%	60.0%	19,552,805	99.5%	100.0%	$ 19,455,041
9	3,125,090,468	1.31%	80.0%	60.0%	19,650,569	99.5%	100.0%	$ 19,552,316
10	3,140,715,920	1.31%	80.0%	60.0%	19,748,822	99.5%	100.0%	$ 19,650,078
11	3,156,419,500	1.31%	80.0%	60.0%	19,847,566	99.5%	100.0%	$ 19,748,328
12	3,172,201,597	1.31%	80.0%	60.0%	19,946,804	99.5%	100.0%	$ 19,847,070
13	3,188,062,605	1.31%	80.0%	60.0%	20,046,538	99.5%	100.0%	$ 19,946,305
14	3,204,002,918	1.31%	80.0%	60.0%	20,146,770	99.5%	100.0%	$ 20,046,036
15	3,220,022,933	1.31%	80.0%	60.0%	20,247,504	99.5%	100.0%	$ 20,146,267
16	3,236,123,048	1.31%	80.0%	60.0%	20,348,742	99.5%	100.0%	$ 20,246,998
17	3,252,303,663	1.31%	80.0%	60.0%	20,450,485	99.5%	100.0%	$ 20,348,233
18	3,268,565,181	1.31%	80.0%	60.0%	20,552,738	99.5%	100.0%	$ 20,449,974
19	3,284,908,007	1.31%	80.0%	60.0%	20,655,502	99.5%	100.0%	$ 20,552,224
20	3,301,332,547	1.31%	80.0%	60.0%	20,758,779	99.5%	100.0%	$ 20,654,985
20 Year Total					$ 396,126,417			$ 343,542,870

Annual load growth percent = 0.50%
Year 1 = 2017

NOTES: (1) 2017 DEP Residential/Commercial revenue
(2) Amount of revenue subject to erosion from non-technical losses based on requested analysis
(3) Amount of revenue erosion identifiable through AMI deployment and use of AMI data
(4) Amount to be collected from identified revenue erosion
(5) Applicable meters = Percent of meter population to be converted to AMI
(6) Alignment of benefits to proposed installation schedule

DEP Costs & Benefits Summary - Revised NCUC (Question 9)

	Actuals	Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-20	Total
Total Cost ($ in Millions)	2016	2017	2018	2019	2020	2021		
Capital Project Costs	$ 0.05	$ 4.72	$ 71.86	$ 97.14	$ 92.31	$ 8.50	$ 225.98	$ 500.56
Capital Recurring Costs	$ -	$ -	$ 0.21	$ 0.49	$ 0.77	$ 1.03	$ 39.39	$ 41.89
O&M Program Costs	$ -	$ -	$ 0.02	$ -	$ -	$ -	$ 0.02	$ 0.04
O&M Recurring costs	$ -	$ -	$ 0.85	$ 1.83	$ 2.62	$ 3.04	$ 51.43	$ 59.76
Total Capital	**$ 0.05**	**$ 4.72**	**$ 72.06**	**$ 97.64**	**$ 93.08**	**$ 9.52**	**$ 265.38**	**$ 542.45**
Total O&M	**$ -**	**$ -**	**$ 0.87**	**$ 1.83**	**$ 2.62**	**$ 3.04**	**$ 51.45**	**$ 59.80**
Total Annual Costs	**$ 0.05**	**$ 4.72**	**$ 73.55**	**$ 100.73**	**$ 97.06**	**$ 12.71**	**$ 316.82**	**$ 602.26**

		Year 1	Year 2	Year 3	Year 4	Year 5	Years 6-20	Total
Total Benefits ($ in Millions)		2017	2018	2019	2020	2021		
Expense Reduction	Meter Reading Cost Reduction	$ -	$ -	$ 0.40	$ 0.85	$ 3.12	$ 59.77	$ 64.14
	Field Metering (Temp to Capital)	$ -	$ 0.98	$ 1.40	$ 1.40	$ -	$ 5.88	$ 9.66
	Reduced Meter Operations Costs	$ -	$ 0.03	$ 0.10	$ 0.10	$ -	$ -	$ 0.23
	Consumer Order Cost Reduction	$ -	$ 0.13	$ 1.52	$ 2.91	$ 3.70	$ 71.69	$ 79.95
	Consumer Order Cost Reduction (DNP)	$ -	$ -	$ -	$ 0.73	$ 0.94	$ 18.13	$ 19.80
	Cellular Cost Reduction (SSN APs)	$ -	$ -	$ 0.01	$ 0.06	$ 0.12	$ 2.26	$ 2.45
Avoided Costs - O&M	Restoration Cost Reduction - OK on Arrival	$ -	$ 0.05	$ 0.22	$ 0.43	$ 0.55	$ 10.61	$ 11.86
	Restoration Cost Reduction - Major Storms	$ -	$ 0.06	$ 0.29	$ 0.81	$ 0.98	$ 18.79	$ 20.93
	Miscellaneous O&M Savings	$ -	$ 0.04	$ 0.37	$ 0.87	$ 1.06	$ 20.27	$ 22.61
Avoided Costs - Capital	Miscellaneous Capital Savings	$ -	$ 0.01	$ 0.12	$ 0.29	$ 0.35	$ 6.76	$ 7.53
	Reduced Legacy Meter Failures	$ -	$ 0.01	$ 0.06	$ 0.11	$ 0.14	$ 2.67	$ 2.99
Increased Revenue	Non-Technical Line Loss Reduction	$ -	$ 1.89	$ 8.16	$ 15.26	$ 18.97	$ 299.26	$ 343.54
	Total O&M Expense Reductions	**$ -**	**$ 1.13**	**$ 3.43**	**$ 6.05**	**$ 7.88**	**$ 157.72**	**$ 176.21**
	Total Avoided O&M Costs	**$ -**	**$ 0.15**	**$ 0.89**	**$ 2.11**	**$ 2.59**	**$ 49.67**	**$ 55.41**
	Total Avoided Capital & Increased Revenue	**$ -**	**$ 1.91**	**$ 8.34**	**$ 15.66**	**$ 19.47**	**$ 308.69**	**$ 354.07**
	Total Annual Benefits	**$ -**	**$ 3.20**	**$ 12.65**	**$ 23.82**	**$ 29.93**	**$ 516.09**	**$ 585.69**

Exhibit No. 3
Docket No. E-100, Sub 147

Duke Energy Progress Advanced Metering Infrastructure Cost-Benefit Analysis

May 2018 - NCUC Data Request - SGTP Order

Original Business Case

		AMI Program Costs ($000s)				AMI Program Benefits ($000s)												NPV
		Total Capital Program Costs	Total Capital Recurring Costs	Total O&M Program Costs	Total O&M Recurring costs	Meter Reading Cost Reduction	Customer Order Cost Reduction (e.g. dis/reconnects)	Customer Order Cost Reduction (Non-Pay Disconnect)	Field Metering Labor Cost Reduction	Meter Operations Cost Reduction	Outage Restoration Cost Reduction - OK on Arrival	Outage Restoration Cost Reduction - Major Storms	Misc O&M Savings	Reduced Legacy Meter Failures	Misc Capital Savings	Cellular Cost Reduction	Non-Technical Loss Reduction	**Net Benefits and (Costs)**
-	2016	- 49	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**- 49**
1	2017	- 4,721	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	**- 4,721**
2	2018	- 72,467	- 214	- 20	- 848	-	128	-	975	25	51	60	35	13	12	-	1,680	**- 70,570**
3	2019	- 98,390	- 511	-	- 1,829	400	1,517	-	1,400	100	224	294	373	57	124	15	7,259	**- 88,968**
4	2020	- 93,645	- 800	-	- 2,621	850	2,907	735	1,400	100	430	811	873	109	291	59	13,573	**- 74,929**
5	2021	- 8,870	- 863	-	- 2,976	3,120	3,705	937	-	-	548	981	1,058	139	353	118	16,880	**15,130**
6	2022	-	- 1,070	-	- 3,157	3,214	3,855	975	-	-	570	1,010	1,090	143	363	121	17,136	**24,250**
7	2023	-	- 1,344	-	- 3,199	3,310	3,970	1,004	-	-	587	1,041	1,122	148	374	125	17,222	**24,361**
8	2024	-	- 1,558	-	- 3,240	3,409	4,089	1,034	-	-	605	1,072	1,156	152	385	129	17,308	**24,542**
9	2025	-	- 1,632	-	- 3,281	3,512	4,212	1,065	-	-	623	1,104	1,191	157	397	132	17,394	**24,874**
10	2026	-	- 1,658	-	- 3,323	3,617	4,338	1,097	-	-	642	1,137	1,227	161	409	136	17,481	**25,266**
11	2027	-	- 1,661	-	- 3,364	3,725	4,469	1,130	-	-	661	1,171	1,263	166	421	141	17,569	**25,691**
12	2028	-	- 8,185	-	- 3,405	3,837	4,603	1,164	-	-	681	1,207	1,301	171	434	145	17,657	**19,608**
13	2029	-	- 6,473	-	- 3,447	3,952	4,741	1,199	-	-	701	1,243	1,340	176	447	149	17,745	**21,773**
14	2030	-	- 3,729	-	- 3,488	4,071	4,883	1,235	-	-	722	1,280	1,380	182	460	154	17,834	**24,983**
15	2031	-	- 1,407	-	- 3,530	4,193	5,029	1,272	-	-	744	1,318	1,422	187	474	158	17,923	**27,784**
16	2032	-	- 1,411	-	- 3,571	4,319	5,180	1,310	-	-	766	1,358	1,465	193	488	163	18,012	**28,272**
17	2033	-	- 1,829	-	- 3,556	3,858	4,628	1,170	-	-	685	1,213	1,308	172	436	146	15,701	**23,933**
18	2034	-	- 2,025	-	- 3,465	2,192	2,629	665	-	-	389	689	743	98	248	83	8,704	**10,950**
19	2035	-	- 842	-	- 3,352	416	499	126	-	-	74	131	141	19	47	16	1,612	**- 1,115**
20	2036	-	- 337	-	- 3,275	-	-	-	-	-	-	-	-	-	-	-	-	**- 3,612**
		- 278,143	- 37,549	- 20	- 58,927	51,996	65,382	16,115	3,775	225	9,705	17,120	18,489	2,443	6,163	1,988	258,690	**77,452**
																	Net Present Value of Benefits & Costs	**- 39,015**
																	Duke Energy Progress Weighted Average Cost of Capital	6.7%

Duke Energy Progress Advanced Metering Infrastructure Cost-Benefit Analysis

May 2018 - NCUC Data Request - SGTP Order

Revised Business Case

AMI Program Costs ($000s)

		Total Capital Program Costs	Total Capital Recurring Costs	Total O&M Program Costs	Total O&M Recurring costs	*Capital Recurring - Deployment*	*O&M Recurring - Deployment*	*Capital Recurring - IT Hardware*	*Capital Recurring - Software*	*O&M Recurring - Software*
-	2016	- 49	-	-	-	-	-	-	-	-
1	2017	- 4,721	-	-	-	-	-	-	-	-
2	2018	- 71,857	- 206	- 20	- 848	- 206	- 848	-	-	-
3	2019	- 97,144	- 494	-	- 1,829	- 494	- 1,829	-	-	-
4	2020	- 92,309	- 773	-	- 2,621	- 773	- 2,621	-	-	-
5	2021	- 8,498	- 1,025	-	- 3,038	- 834	- 2,976	- 192	-	- 62
6	2022	-	- 3,456	-	- 3,220	- 1,036	- 3,157	- 2,348	- 72	- 62
7	2023	-	- 1,693	-	- 3,294	- 1,305	- 3,199	- 316	- 72	- 96
8	2024	-	- 1,631	-	- 3,240	- 1,516	- 3,240	- 115	-	-
9	2025	-	- 1,590	-	- 3,329	- 1,590	- 3,281	-	-	- 48
10	2026	-	- 1,836	-	- 3,371	- 1,616	- 3,323	- 173	- 48	- 48
11	2027	-	- 3,805	-	- 3,460	- 1,620	- 3,364	- 2,113	- 72	- 96
12	2028	-	- 5,802	-	- 3,405	- 5,493	- 3,405	- 285	- 24	-
13	2029	-	- 5,111	-	- 3,495	- 5,008	- 3,447	- 104	-	- 48
14	2030	-	- 5,161	-	- 3,536	- 5,113	- 3,488	-	- 48	- 48
15	2031	- 49	- 1,569	-	- 3,625	- 1,366	- 3,530	- 155	- 48	- 96
16	2032	- 833	- 3,295	-	- 3,571	- 1,369	- 3,571	- 1,902	- 24	-
17	2033	- 59,457	- 1,620	- 20	- 3,604	- 1,340	- 3,556	- 256	- 24	- 48
18	2034	- 80,897	- 1,808	-	- 3,513	- 1,666	- 3,465	- 93	- 48	- 48
19	2035	- 81,619	- 728	-	- 3,448	- 680	- 3,352	-	- 48	- 96
20	2036	- 3,127	- 287		- 3,316	- 287	- 3,316	-	-	-
		- 500,562	- 41,891	- 39	- 59,764	- 33,312	- 58,969	- 8,052	- 527	- 796

AMI Program Benefits ($000s) / **NPV**

		Meter Reading Cost Reduction	Customer Order Cost Reduction (e.g. dis/reconnects)	Customer Order Cost Reduction (Non-Pay Disconnect)	Field Metering Labor Cost Reduction	Meter Operations Cost Reduction	Outage Restoration Cost Reduction - OK on Arrival	Outage Restoration Cost Reduction - Major Storms	Misc O&M Savings	Reduced Legacy Meter Failures	Misc Capital Savings	Cellular Cost Reduction	Non-Technical Loss Reduction	**Net Benefits and (Costs)**
-	2016	-	-	-	-	-	-	-	-	-	-	-	-	**- 49**
1	2017	-	-	-	-	-	-	-	-	-	-	-	-	**- 4,721**
2	2018	-	128	-	975	25	51	60	35	13	12	-	1,888	**- 69,744**
3	2019	400	1,517	-	1,400	100	224	294	373	57	124	15	8,160	**- 86,804**
4	2020	850	2,907	735	1,400	100	430	811	873	109	291	59	15,257	**- 71,882**
5	2021	3,120	3,705	937	-	-	548	981	1,058	139	353	118	18,974	**17,372**
6	2022	3,214	3,855	975	-	-	570	1,010	1,090	143	363	121	19,262	**23,928**
7	2023	3,310	3,970	1,004	-	-	587	1,041	1,122	148	374	125	19,358	**26,052**
8	2024	3,409	4,089	1,034	-	-	605	1,072	1,156	152	385	129	19,455	**26,615**
9	2025	3,512	4,212	1,065	-	-	623	1,104	1,191	157	397	132	19,552	**27,026**
10	2026	3,617	4,338	1,097	-	-	642	1,137	1,227	161	409	136	19,650	**27,208**
11	2027	3,725	4,469	1,130	-	-	661	1,171	1,263	166	421	141	19,748	**25,631**
12	2028	3,837	4,603	1,164	-	-	681	1,207	1,301	171	434	145	19,847	**24,181**
13	2029	3,952	4,741	1,199	-	-	701	1,243	1,340	176	447	149	19,946	**25,288**
14	2030	4,071	4,883	1,235	-	-	722	1,280	1,380	182	460	154	20,046	**25,716**
15	2031	4,193	5,029	1,272	-	-	744	1,318	1,422	187	474	158	20,146	**29,700**
16	2032	4,319	5,180	1,310	-	-	766	1,358	1,465	193	488	163	20,247	**27,789**
17	2033	4,448	5,336	1,349	1,519	-	789	1,399	1,508	198	503	168	20,348	**- 27,135**
18	2034	4,582	5,496	1,390	2,181	-	813	1,441	1,554	204	518	173	20,450	**- 47,417**
19	2035	4,719	5,661	1,431	2,181	-	838	1,484	1,600	211	533	178	20,552	**- 46,407**
20	2036	4,861	5,830	1,474	-	-	863	1,528	1,648	217	549	183	20,655	**31,079**
		64,139	79,948	19,798	9,656	225	11,861	20,938	22,607	2,984	7,536	2,446	343,543	**- 16,573**

Net Present Value of Benefits & Costs	**- 61,020**
Duke Energy Progress Weighted Average Cost of Capital	6.7%

CERTIFICATE OF SERVICE

I certify that a copy of Duke Energy Progress, LLC's Revised AMI Cost-Benefit Analysis, in Docket No. E-100, Sub 147, has been served by electronic mail, hand delivery or by depositing a copy in the United States mail, postage prepaid to the following parties:

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This is the 4th day of June, 2018.

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