DUKE ENERGY

Winter Peak Demand Reduction Potential Assessment

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1 WINTER PEAK DSM POTENTIAL MODELING OVERVIEW

Duke Energy North Carolina and South Carolina engaged Dunsky Energy Consulting, as part of the Tierra Inc team to model the winter peak demand reduction potential in the Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) systems.

The objectives of this modelling exercise were to

1) Capture the potential for new programs and measures to reduce the winter peak demand in each of DEP and DEC, via Demand Side Management (DSM) programs target to residential and commercial customers
2) Quantify the degree to which this potential is incremental to the current Duke DSM program impacts, and compare the findings to the Market Potential Study, recently conducted by Nexant[1].
3) Provide insights that can help Duke prioritize winter peak DSM approaches in the short term, as well as identify the potential for longer term strategies.

Following on Tierra's work to identify and characterize new rate structures and mechanical solutions, the winter peak DSM potential assessed the ability of behavioral measures, equipment controls and industrial and commercial curtailment to reduce Duke's overall system peak in each system.

The report includes an introduction to the modelling methodology, followed by a step-by step description of the model findings. The overall potential assessment is then provided in section 3 of this report, followed by a concluding section containing key take-aways. Finally, a set of detailed results and input assumptions is appended.

1.1 DSM POTENTIAL ASSESSMENT APPROACH

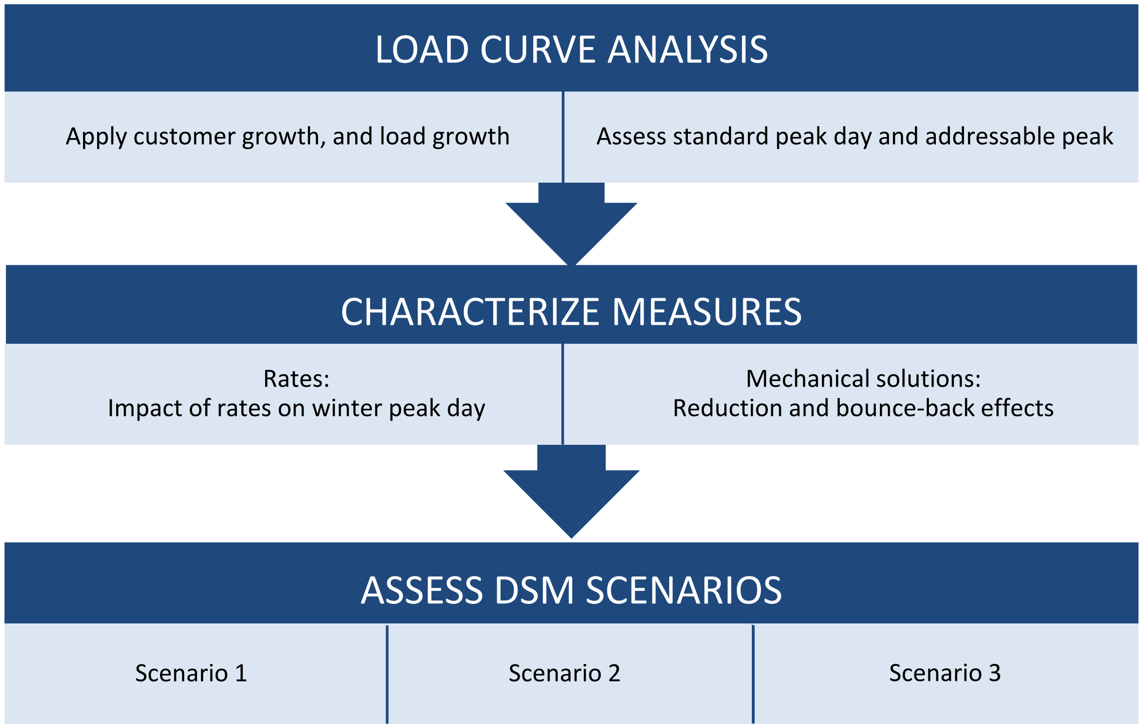
The DSM potential is assessed against Duke's hourly system load curves and winter peak demands. Figure 1 below presents an overview of the steps applied to assess the DSM potential in this study.

Key to this assessment is the treatment and consideration Duke's DEC and DEP winter system peak-day hourly load curve. As part of this process, standard peak day 24-hour load curves are identified and adjusted to account for projected load growth over the study period. This allows the model to assess each measure's net reduction in the annual peak, considering possible shifts in the timing and duration of the annual winter peak in each system.

In some cases, this may lead to results that are contrary to initial expectations, especially when DSM programs such as dynamic rates or equipment direct load control (DLC) measures are looked at only from the perspective of how they may impact individual customer peak loads at the originally identified peak hour.

[1] Nexant, *Duke Energy North Carolina EE and DSM Market Potential Study,* and *Duke Energy South Carolina EE and DSM Market Potential Study*, May 2020

Figure 1 - DSM Potential Assessment Approach



The achievable potential is assessed under three scenarios corresponding to varied DSM approaches or strategies (Figure 2). These scenarios were developed with the goal of assessing the impacts of different rate structures and a selected set of mechanical solutions on the load curve of both DEC and DEP. More details on the scenarios can found in the section 3.3 of this report.

Figure 2. Demand Response Program Scenario Descriptions

LOW	Applies a limited number of rate structures with conservative adoption or incentive levels in conjunction with a defined set of mechanical solutions.
MID	Introduces an additional rate structure into the residential market and increases C&I adoption or incentive levels. Mechanical solutions are adapted to the new rate structures.
MAX	Applies a variety of residential rate structures and more aggressive C&I adoption and incentive levels to estimate maximum achievable potential. Mechanical solutions are adapted to the new rate structures.

1.2 SEGMENTATION

Market segmentation is essential to accurately estimate the DSM potential and is one of the first step of the modelling. Customer information provided was broken down by rate class for both DEC and DEP. As rates patterns and DSM savings vary by customer characteristics, DEC and DEP customers were segmented in three ways:

- **By market sector**: Residential, Commercial and Industrial

- **By rate class**: Within each sector, customers can choose a variety of rate classes, depending on their overall size (assessed by annual peak kW power draw) and rate structure preference. By segmenting customers according to their applicable rate classes, the model can assess the impact of customers moving to new or adjusted rate structures. The key rates classes in both DEP and DEC and presented in Table 1. Both "other" rates encompass all the other rates not specifically mentioned that are available in each system.

Table 1 – Rate Class Segmentation

DEC - Rates	DEP - Rates
SGS	SGS
LGS	MGS
OPTC	LGS
OPTI	RTP
RS	Res
RE	Other
Other	

- **By customer segment:** Within each market sector/rate class segment, Duke's commercial and industrial customers were further segmented by business type (i.e., offices, schools, retail etc.) using U.S. Energy Information Agency's (EIA) Commercial Buildings Energy Consumption Survey (CBECS - 2012) and Residential Energy Consumption Survey (RECS - 2015).

2 DSM POTENTIAL ASSESSMENT

2.1 STEP 1 - LOAD CURVE ANALYSIS

The peak load analysis is the first step in the DSM potential analysis, through which key constraints are defined to identify the solutions that will be deployed, and the scenarios modelled to reduce winter peak demands.

First, the winter season standard peak day load curve is defined, and the impacts of load growth projections are applied. The standard peak day load curve for the electric system is defined by taking an average of the load shape from each of the top ten winter peak days in the forecasted hourly load data provided[2] (Figure 3 for DEC and Figure 4 for DEP).

Figure 3 - DEC Standard Peak Day (incl. wholesale) Based on Historical Data – 2020

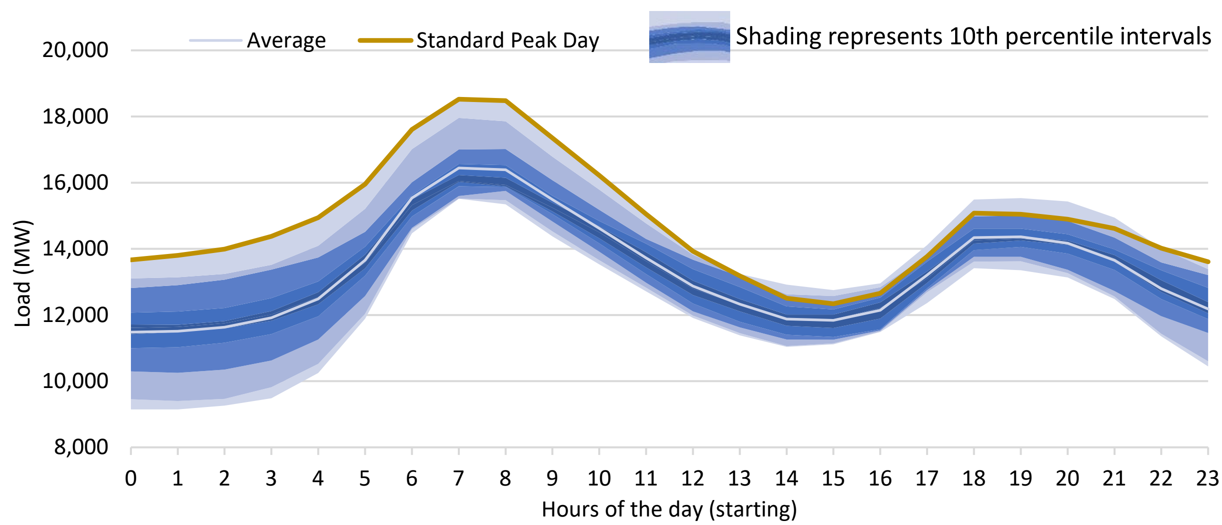
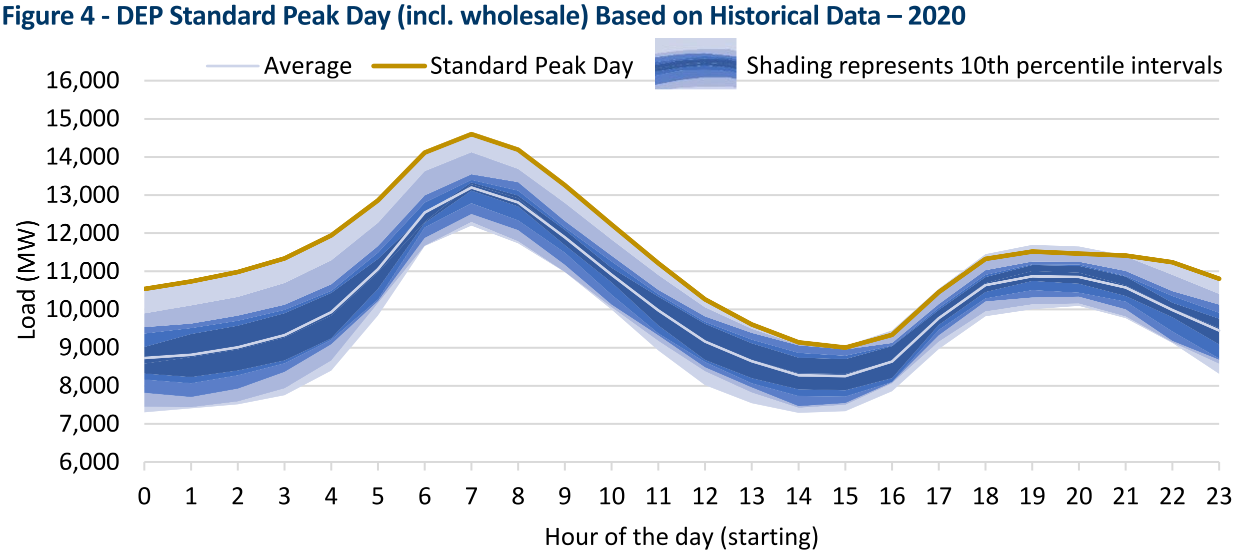


Figure 4 - DEP Standard Peak Day (incl. wholesale) Based on Historical Data – 2020



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[2] Provided forecast included years between 2020 and 2045.

This analysis shows that Duke's systems, in winter, have a steep morning peak, which is driven predominantly by residential and commercial space heating. The duration and steepness of the peak curve indicate that measures with bounce-back or pre-charge effects are not likely to pose a real problem in winter by creating new peaks when shifting load from one hour to another.

An hourly load forecast was provided, for each year from 2021 to 2041, thus the winter peak load curve assessment was repeated for each year to determine the annual winter peak in each of the year of the study period (2021-2041), resulting in the peak day characteristics listed in Table 2 below.

Table 2 – Standard Peak Day Key Metrics

Year	Peak Demand (MW) excl. wholesale	
	DEC	DEP
2021	16,533	10,551
2026	16,611	10,661
2031	17,242	11,020
2036	18,191	11,593
2041	19,315	12,332

Once defined, the standard peak day utility load curve is then used to characterize the DSM solution set measures, by defining the peak load reduction possible at each hour of the day. These are then used to assess the measure-specific peak demand reduction potentials at the technical and economic potential levels.

2.2 STEP 2 - SOLUTION SET CHARACTERIZATION

Based on the load analysis and detailed review of Duke's current program and rates[3], a solution set was developed to reduce the winter peak demand in both DEP and DEC. The mechanical solutions and rate structures considered are described below.

2.2.1 MECHANICAL SOLUTIONS

As outlined in Tierra's Winter Peak Analysis and Solution Set report, a solution set was identified to specifically address the DEC and DEP winter peak. Once selected, measures were characterized individually. Measure characterization is the process of determining the hourly load curve impacts (kW reductions in each hour), as well as the measure costs, applicable markets and EULs. The measure characterizations leverage a range of secondary sources, including energy modelling profiles and empirical data from relevant jurisdictions to determine the resulting load curve impacts.

Based on the Winter Peak Analysis and Solution Set report analysis, a total of eight technologies/programs were chosen to be integrated into the modelling.

[3] More details are provided in Tierra's Winter Peak Analysis and Solution Set report.

- **Residential**
  - Bring Your Own Thermostat (BYOT)
  - Rate Enabled Thermostats (RET)
  - Rate Enabled Residential Hot Water Heating Controls (RE-HWH)
  - Winter Heat Pump Tune-up
  - Battery Energy Storage[4]
- **Small and Medium C&I**
  - Bring Your Own Thermostat (BYOT)
  - Rate Enabled Thermostats (RET)
  - Winter Heat Pump Tune-up
- **Large C&I**
  - Automated Demand Response (ADR) for larger C&I flat rate customers selecting advanced rates

More details on the key measure inputs are provided in the Winter Peak Analysis and Solution Set report.

2.2.2 RESIDENTIAL RATES

Close attention was paid to the rates structure as they not within the scope covered by Nexant's 2020 MPS study, and thus they provided an opportunity to determine if and where further potential for winter peak reductions may lie. Rates are used to encourage customers to modify their behavior and change consumption patterns. Four specific rates structures were designed for the study, applying the three common residential dynamic rate structures: Time-Of-Use Rate (TOU), Critical Peak Pricing (CPP) and Peak Time Rebate (PTR). Based on the load curve analysis, the peak hour charges were applied from 5:00 am to 9:59 am on weekdays only.

- **TOU Rate**
- **TOU Rate with CPP**
- **Bill Certainty with PTR**
- **Flat Volumetric with CPP**

Further details on the Residential DSM rates are provided in the appendix.
[5]

2.2.3 COMMERCIAL & INDUSTRIAL RATES

Commercial rates were derived for customer segments small, medium, and large annual consumption profiles. Both CN&I rates apply PTR rates to attract customers by providing a benefit for demonstrated

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[4] The forecast of residential Battery Energy Storage represents a conservative view based on uncertainties about market adoption for this technology and is discussed in more detail in the Winter Peak Plan report completed as part of this same research effort.

[5] The reports produced by the Winter Peak Study, including the Winter Peak Demand Reduction Potential Assessment report, use the term Commercial and Industrial to discuss rates used by the non-residential market sectors and is intended to help define the significant difference in load shapes between commercial and industrial customers and also define DSM opportunities targeting each market segment, Commercial and Industrial rates and customers may be referred to as "Non-residential" or "General Service" rates in other Duke publication and communications.

peak event demand reductions. By using a rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times

- **Small C&I Customers – Bill Certainty with PTR**
- **Medium and Large - C&I Customers - PTR**

For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count. Further details on the C&I DSM rates are provided in the appendix.

2.3 STEP 3 - SCENARIOS

As a final analysis step, three defined adoption scenarios are applied, and the winter peak impacts are assessed. Three scenarios were developed to be viable in both DEC and DEP systems, with key program inputs defined for each. This section summarizes the selected scenarios and main program inputs.

2.3.1 LOW SCENARIO

The low scenario includes a solution set that includes the most straight-forward combination of rate options. A new residential TOU rate structure would be offered along with a TOU+CPP option. On the C&I side, a PTR rate would be deployed with a conservative adoption rate for SGS customers and a low PTR incentive for medium and large C&I.

Table 3 – Overview of the Low Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Low adoption (10%) • Medium and Large C&I - PTR Low incentive (30$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I- BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.2 MID SCENARIO

The Mid scenario aims to expand on the Low scenario by including a new residential Bill Certainty rate option and increase adoption and PTR incentives in the C&I sector.

Table 4 – Overview of the Mid Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates	• Small C&I - Bill Certainty + PTR Mid adoption (15%)

	• Bill Certainty + PTR Rates	• Medium and Large C&I - PTR Mid incentive (60$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.3 MAX SCENARIO

The Max scenario aims to maximize demand response potential by adding a new CPP option, maximizing adoption in small C&I, and increasing medium and large C&I PTR incentives to approach the limits that still render the programs cost effective (i.e., the incentive levels that yield UCT results of 1.2 or higher).

Table 5 – Overview of the Max Scenario DSM Rates and Mechanical Solution Set

	Residential	C&I
DSM Rates	• TOU Rates • TOU + CPP Rates • Bill Certainty + PTR Rates • Flat Volumetric + CPP Rates	• Small C&I - Bill Certainty + PTR High adoption (20%) • Medium and Large C&I - PTR High incentive (90$/kW/yr)
Mechanical Solutions	• Res - BYOT • Res - Rate Enabled T-Stat • Res - Rate Enabled HWH • Res - HP Tune-up • Res - Battery Energy Storage	• Small C&I - BYOT • Small C&I - Rate Enabled T-Stat • Medium & Large C&I - ADR (Automated Demand Response)

2.3.4 KEY VARIABLES FOR DSM POTENTIAL ASSESMENT

The variables below are key to the DSM assessment as they feed the achievable potential and costs calculation. These assumptions were developed based on Duke's inputs, jurisdictional scans and professional judgment.

RESIDENTIAL PARTICIPATION RATES

Table 6 below summarizes adoption levels for each DSM rate per under each scenario treatment.

Table 6 – Adoption for Residential Rates*

	Low Scenario			Mid Scenario			Max Scenario		
Target Rate	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**	**DEC RS**	**DEC RE**	**DEP Res**
TOU	2%	10%	5%	2%	10%	5%	4%	20%	11%
TOU + CPP	10%	15%	12%	10%	15%	12%	6%	9%	7%
Bill Certainty + PTR	-	-	-	8%	20%	13%	10%	25%	16%
Flat Volumetric + CPP	-	-	-	-	-	-	4%	11%	7%
Total residential Market	***12%***	***25%***	***18%***	***21%***	***45%***	***31%***	***25%***	***65%***	***42%***

*Due to rounding, numbers may not add up

Adoption levels were first determined for the DEC all-electric residential rate class (RE). It is expected that this rate class would benefit the most from the selected rates structures (higher electric bills and peak demand) and therefore, the rate with the highest adoption levels. Adoption levels for all-electric residential rate are derived from Brattle's Time-Varying Price Enrollment Rates Study[6], a study that bundles results from six market research studies and fourteen full-scale deployments. Based on this study findings, for an opt-in residential dynamic rate, TOU rates can reach on average 28% of the customers, CPP rates can achieve an average of 17% and PTR rates average 21%.

For the Low scenario, it is therefore assumed that a total of 25% of RE customers would enroll in a TOU rate structure after full deployment of the rates. Of those customers willing to join a TOU rate, it is estimated that 15% would prefer a TOU+CPP version of the rate. For the Mid scenario, the adoption for PTR was assumed to be 20% of RE customers. It is important to note that to keep conservative estimates, the averages for all residential customers from the Brattle study were applied as our highest adoption estimates for the RE rate class only.

Finally, for the Max scenario, the objective was to reach a maximum of customers through large-scale deployment and intensive marketing. It is estimated that a total of 28.5% of customers will be interested in a TOU rates structure, corresponding to the average from the Brattle's Time-Varying Price Enrollment Rates Study. Based on findings from Sacramento Municipal Utility District's Consumer Behavior Study[7], it is assumed that the participation rates between TOU+CPP and a CPP rate would be similar with a slightly preference for a CPP rate structure[8]. This was further corroborated through the preliminary survey results from Duke's Flex Savings Options Pilot. As for PTR, adoption levels as high as 56% were achieved in other jurisdictions. Taking into consideration the multiple rates offered conjointly in this scenario, a maximum adoption of 25% has been selected.

Once RE rate class adoption levels were established, those levels were used to determine the potential adoption for DEC standard residential rate (RS) which mainly includes non-electric heated customers. The adoption levels were assumed to be proportional to the average bill savings. The lower the bill savings, the lower the adoption. Load impact results from the Flex Savings Options Pilot were used to assess the level of achievable savings.

Finally, adoption rates for customers under the DEP residential rates were prorated based on the number of customers all electric versus non-electric heated.

C&I PARTICIPATION RATES

Table 7 below present the incentives and adoption level used for the C&I DSM rate scenarios.

Table 7 – Adoption for C&I Rates

C&I	Low Scenario	Mid Scenario	Max Scenario

[6]Adoption for opt-in dynamic rates from R. Hledik, A. Faruqui and L. Bressan, *Demand Response Market Research: Portland General Electric, 2016 to 2035 – Appendix A: Participation Assumptions*, 2016.

[7] SMUD, *SmartPricing Options Final Evaluation*, 2014. Retrieved at: https://www.smud.org/-/media/Documents/Corporate/About-Us/Energy-Research-and-Development/research-SmartPricing-options-final-evaluation.ashx

[8] The TOU+CPP rate structure had a higher percentage of drop-out customers than the CPP rate structure (7.7% vs 5.7% - Figure 1.2). Our estimates use drop-out percentages rather than acceptance rates because acceptance rates reflect decisions made at the beginning of the pilot, before experiencing the rate.

Bill Certainty + PTR (Small C&I) Adoption	10%	15%	20%
PTR (Medium & Large C&I) Incentives	30$/kW/yr	60$/kW/yr	90$/kW/yr

Small C&I Customers
Adoption levels were also based on Brattle's Time-Varying Price Enrollment Rates, with again a reduction factor to account for the low elasticity of the small C&I sector. Since there is uncertainty in this approach, three scenarios, with various adoption levels were modelled to see the impact of adoption on demand response potential.

Medium & Large C&I Customers
For the medium and large C&I rates, the model determines the expected maximum program participation based on the incentive offered, the level of marketing, and the total number of eligible customers, by applying DR program propensity curves developed by the Lawrence Berkeley National Laboratory[9]. The propensity curve was calibrated to the existing participation level from DRA and PowerShare.

OTHER PROGRAM OUTPUTS

The modelling includes several program inputs. Below are presented a few of these key variables. More detailed are included in Appendix A.2.

Participation and Enrollment Ramp up: Participation and enrollment ramp ups are applied to every modelled solution. The BYOT program is assumed to be deployed in 2021 while all other programs are not assumed to start before 2022 at least. The low scenario assumed a 5-year ramp up for each rate solution while the Mid and Max scenarios assume an 8-year ramp up.

Program Costs: For every DSM program, a one-time fixed cost is applied for program development. For recurring costs, an annual fixed cost is assumed along with a variable cost per customers. Program costs also include sign-up and/or annual incentives.

Program Lifetime: For mechanical solutions, programs are assumed to last for the whole measure life.

[9] Lawrence Berkeley National Laboratory, *2025 California Demand Study Potential Study: Phase 2 - Appendix F*, March 2017. Retrieved at: http://www.cpuc.ca.gov/General.aspx?id=10622

3 DSM ACHIEVABLE POTENTIAL RESULTS

The overall achievable winter DSM potential in each year for each scenario is presented below, and in all cases the values are presented are incremental to current DSM program winter peak impacts. These results represent the overall winter peak load reduction potential when all constituent programs are assessed together against the DEP and DEC load curves, accounting for combined interactions among programs and reasonable roll-out schedules.

Measures that cost-effectively deliver sufficient peak load reductions individually are retained and applied in the achievable potential scenario analysis. Consistent with the other savings modules in this study, only cases where the measure yields a Utility Cost Test (UCT) value greater than 1.1 are retained in the economic and achievable potential.

Under the Low scenario, which represents the most conservative scenario, the winter potential is estimated to reach **1,079 MW in 2041** (651 MW in DEC and 428 MW in DEP), which represents 3.4% and 3.5% of DEC and DEP peak, respectively. Under the Mid and Max scenarios, the achievable potential estimates respectively achieve **1,273 MW** (766 MW in DEC and 507 MW in DEP) and **1,378 MW** (834 MW in DEC and 544 MW in DEP) **in 2041**, translating into 4.0% (DEC) and 4.1% (DEP) for the Mid scenario and 4.3% (DEC) and 4.4% (DEP) for the Max scenario of the systems peaks. Based on these results, the scenario analysis indicates that DSM rate structures that have been piloted by Duke (TOU and TOU+CPP) can capture a little over 45% of the expected potential from DSM rates, while the rest of the potential lies in new rates offers (PTR and CPP).

Figure 5 – DEC potential, by scenario

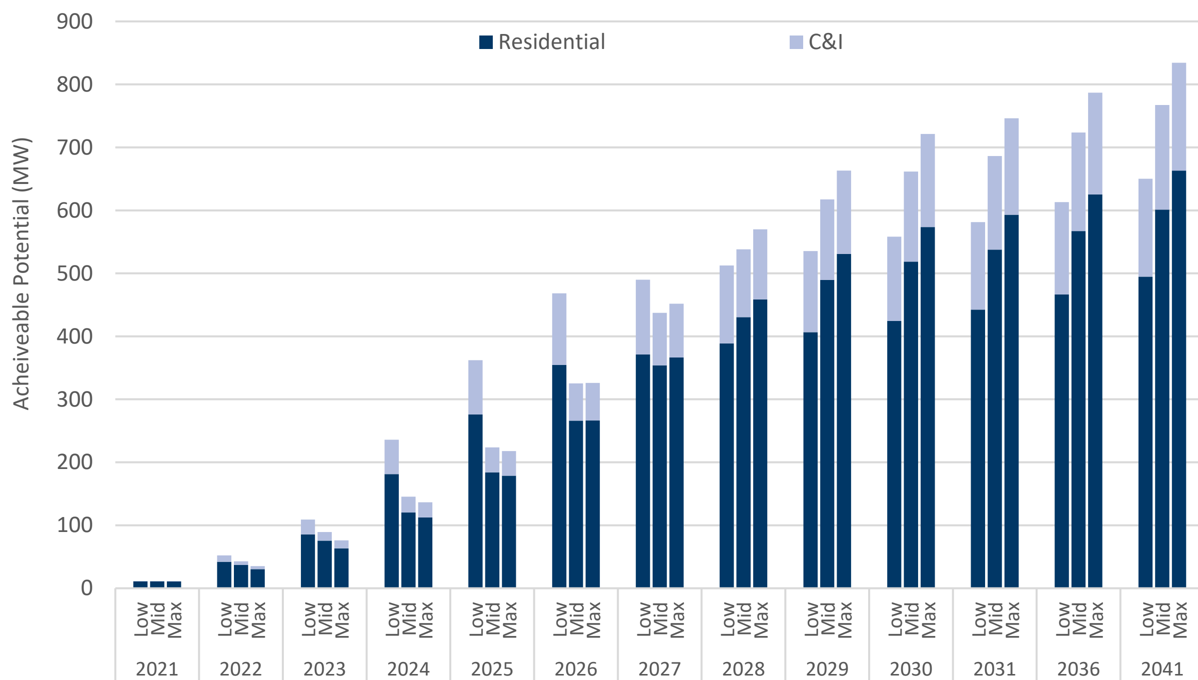


Figure 6 – DEP potential in each study year by scenario

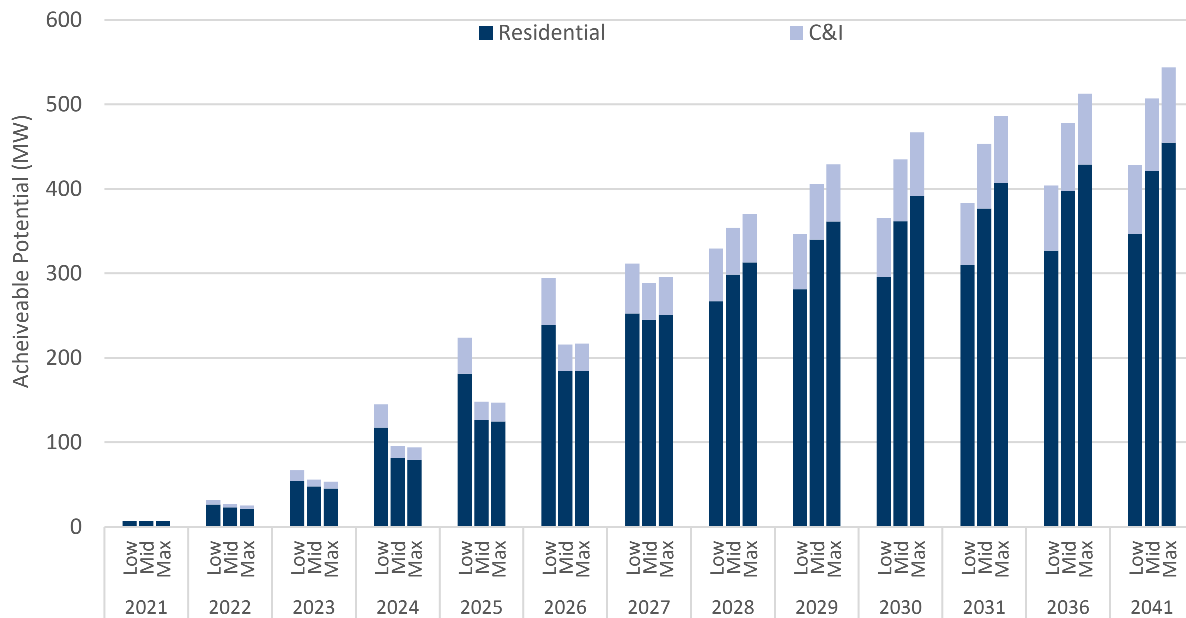
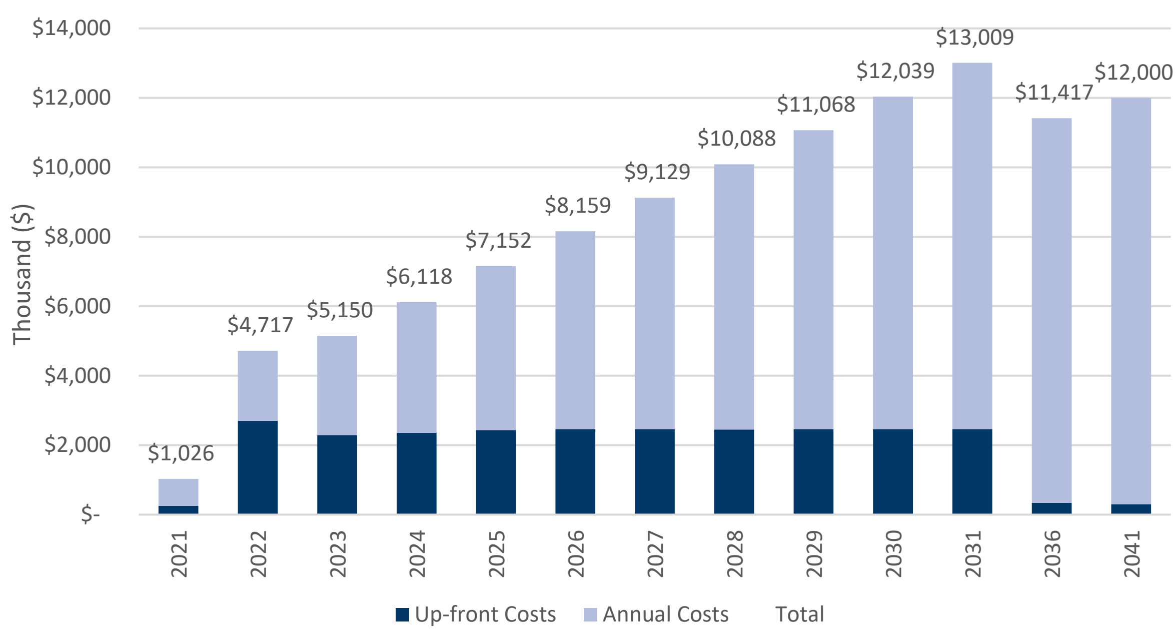


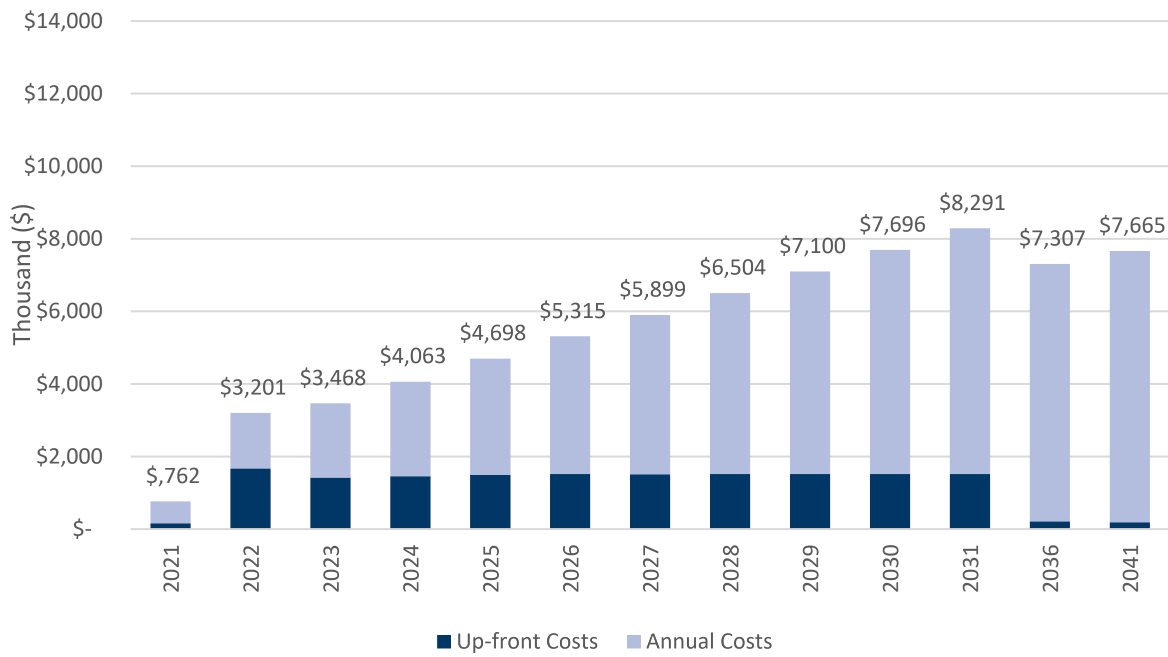
Figure 7 and Figure 8 below provide the program costs for mechanical solutions, broken down by upfront measure costs[10], and program administration costs and customer incentives. The set of mechanical solutions measures are constant throughout all scenarios. The results show higher up-front costs in the initial development years as new programs are developed, new customers are enrolled in the programs and new controls systems are put in place.

Figure 7 – DEC Mechanical Solutions Costs



[10] Upfront measure costs include sign-up (enrollment) incentive costs, as well as controls and equipment installation costs.

Figure 8 – DEP Mechanical Solutions Costs



The Utility Cost Test (UCT) results assume that participants will stay enroll for 10 or 11 years, depending on the expected measure life. Table 8 provides cost-effectiveness results based on a program lifetime basis.

Table 8 – DEC Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	3.2
Residential BYOT	4	4.9
Residential Rate-Enabled HWH	11	1.3
WP/HP Tune-up	10	2.0
Commercial Rate-Enabled T-Stat	10	2.7
Commercial BYOT	4	3.6
Residential BYOB	10	0.5
ADR	10	4.1

Table 9 – DEP Demand Response UCT Results

Programs	Measure/Program Life	UCT (at full deployment - 2026)
Residential Rate-Enabled T-Stat	11	2.3
Residential BYOT	4	3.7
Residential Rate-Enabled HWH	11	1.0
WP/HP Tune-up	10	1.2
Commercial Rate-Enabled T-Stat	10	1.6
Commercial BYOT	4	2.2
Residential BYOB	10	0.3
ADR	10	2.8

All modelled measures were cost-effective on a lifetime basis except for residential battery energy storage. This measure is cost-effective at measure level but fails the test at program level due to the costs required for running the program (fixed program costs) because it is assumed that there are a small number of residential battery systems currently installed among Duke's residential customers.

The impacts assessed for each scenario on the standard winter peak day in 2031 are shown in Figure 9 and Figure 10, where all programs are at full deployment. The assessment reveals that the combined impacts of the DSM rates and measures are not sufficient to alter the timing of the winter peak on the standard peak day. Thus, the net potential, is assessed as the achieved load reduction at the identified peak hours. For DEC, the load is nearly flat from 7:00 to 8:59, emphasizing the importance to target not only the peak hour, but the whole peak.[11]

[11] Our definition of peak did not consider wholesale transactions because the EE and DSM programs included in the solution set will not be available to this market

Figure 9 – DEC: Scenario Impact on Peak Day Load Shape (2031)

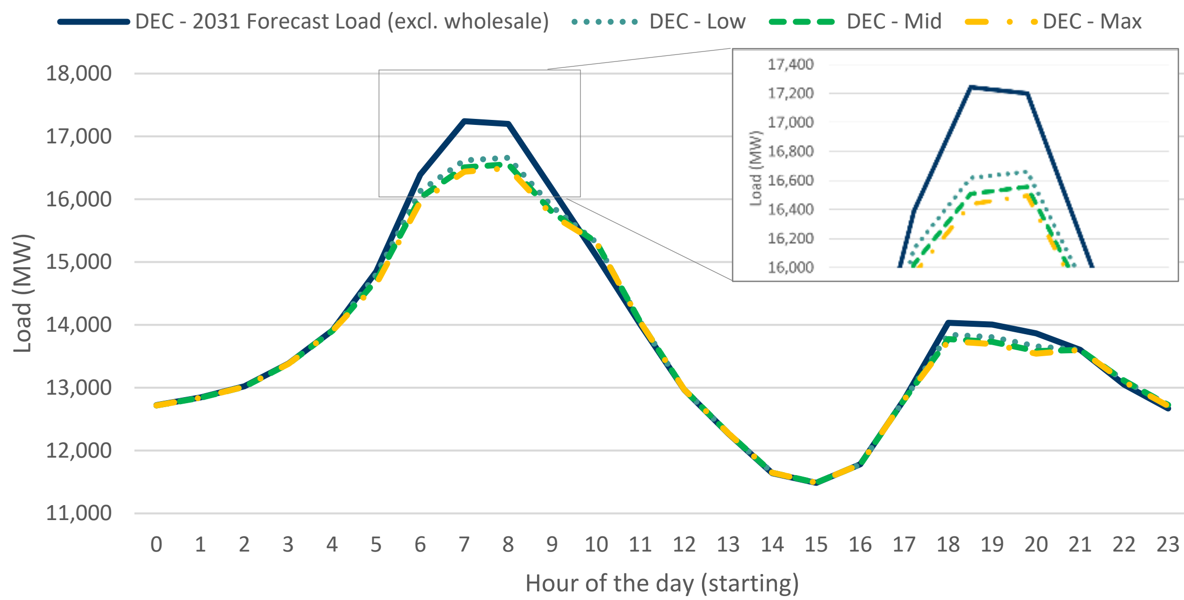
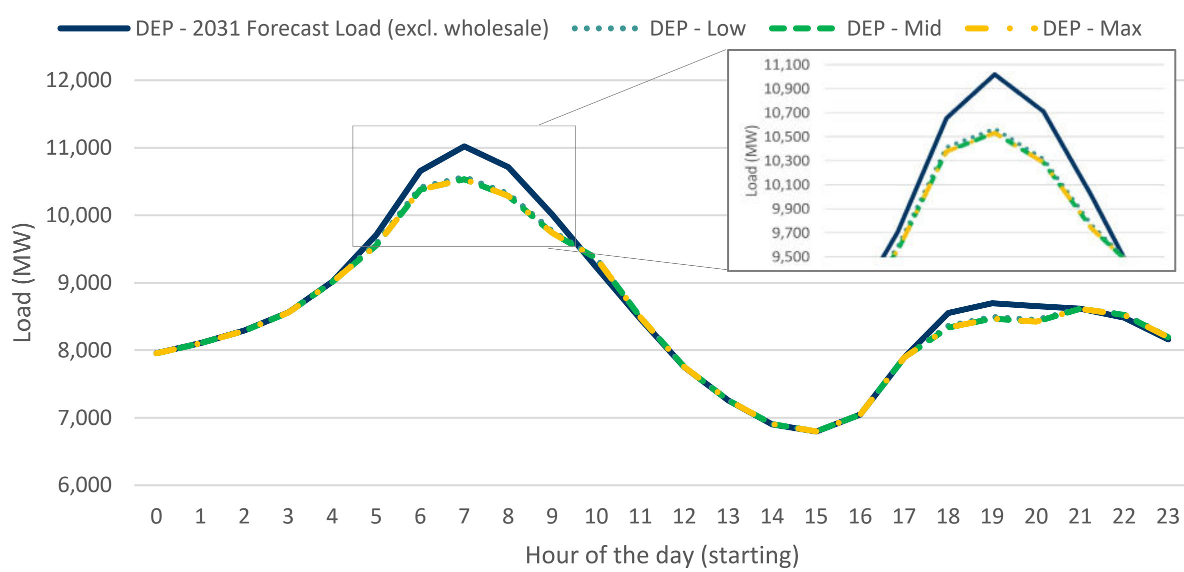


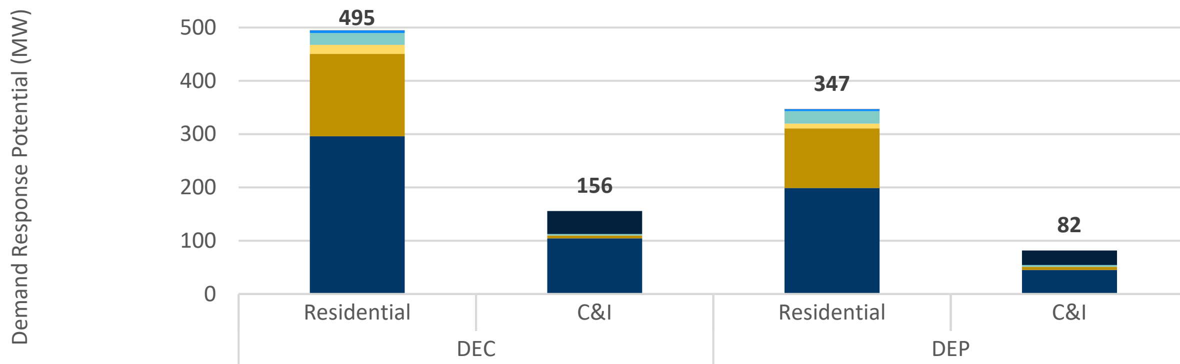
Figure 10 – DEP: Scenario Impact on Peak Day Load Shape (2031)



3.1 LOW SCENARIO

The Low scenario captures the DSM potential from two DSM rates options evaluated under the Flex Savings Options Pilot: TOU and TOU+CPP, in combination with the proposed set of mechanical solutions, thereby assessing rates that can be relatively quickly deployed. Figure 11 shows that DEC and DEP can respectively achieve 651 MW and 428 MW in winter peak reductions by 2041. Overall, the rate solutions and the residential Bring Your Own Thermostat (BYOT) program together account for more than 80% of the DSM potential.

Figure 11 – Low Scenario Achievable DSM Potential (2041) *



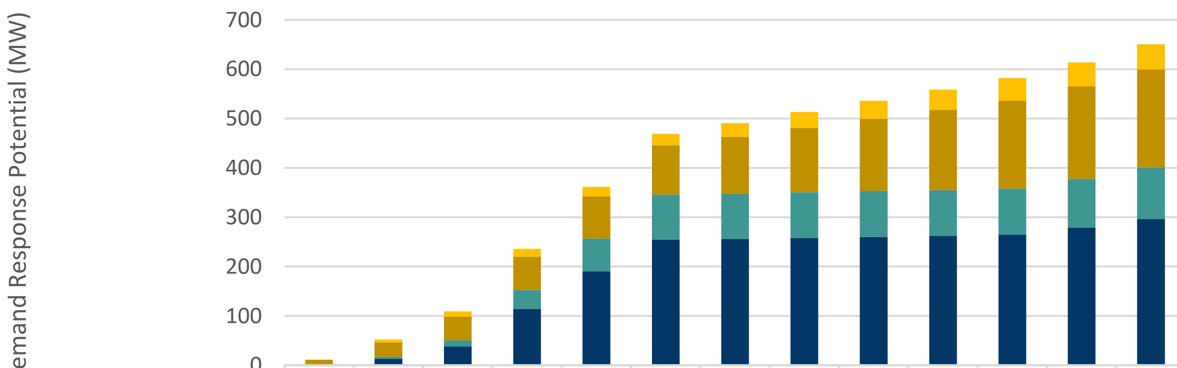
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	495	156	347	82
ADR		43		27
Battery Storage	0.4		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	22	3	23	3
Rate-enabled HWH	17		9	
BYOT	154	5	112	6
Rate Solution	296	105	199	45

* Due to rounding, numbers may not add up

Reviewing of the above chart, along with the detailed results provided in the appendix, a range of observations to focus on become apparent regarding future opportunities for Duke DSM programs. Although the TOU+CPP rate option accounts for 60% of the customer enrollment, it composed about 85% of the residential DSM rate savings, providing significantly more savings per customer than TOU. High savings from TOU+CPP participants are consistent with the preliminary results from the Flex Savings Options Pilot. Rate-enabled solutions, for both thermostats and water heaters account for a further 7% for the savings, reaching 72 MW in 2041. The residential BYOT program is already offered for summer peak reduction purposes and is in-process of being expanded to the winter season, offering an immediate expansion of winter peak reductions until new DSM rates can be successfully deployed.

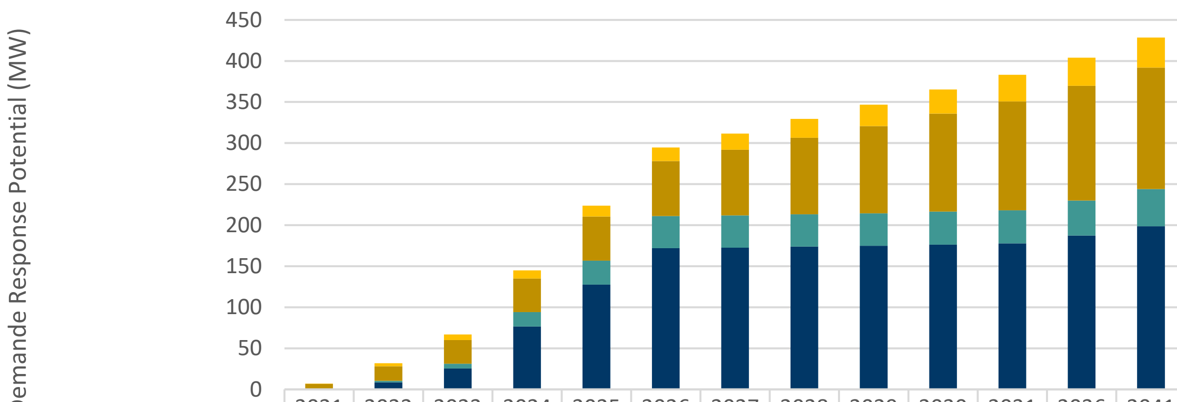
Figure 12 and Figure 13 below present the DSM solution ramp-up from 2021 to 2031, where all programs are at full deployment. The programs then continue to scale with load growth until 2041.

Figure 12 – DEC - Low Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	11	16	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	67	85	99	115	131	146	162	178	188	199
C&I - Rates	0.0	4.3	12.9	38.8	66.3	91.3	91.6	92.1	92.7	93.0	93.5	98.6	104.6
Residential - Rates	0	13	38	114	190	255	256	258	260	262	265	279	296

Figure 13 – DEP - Low Scenario Deployment

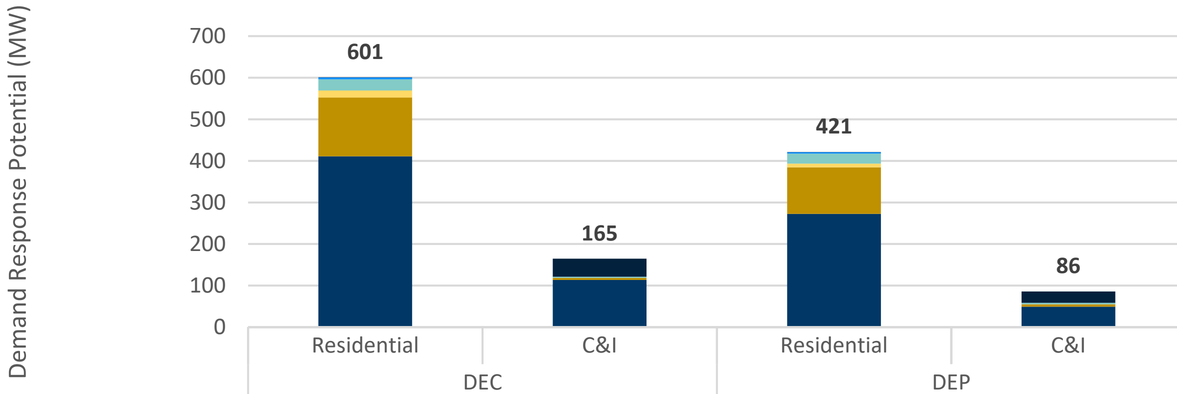


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	80	93	106	119	132	140	148
C&I - Rates	0.0	1.9	5.8	17.5	29.3	39.2	39.3	39.5	39.6	40.3	40.5	42.7	45.2
Residential - Rates	0	8	25	77	128	172	173	174	175	176	178	187	199

3.2 MID SCENARIO

The Mid scenario includes the DSM potential from the Low scenario, while adding a new residential rate option (Bill certainty with PTR) which targets risk averse customers. Adoption from small C&I is also increased, while PTR incentives for medium and large customers are doubled to $60/kW. Figure 14 below shows the breakdown of savings from the Mid scenario, wherein the overall achievable potentials for DEC and DEP in 2041 are 766 MW and 507 MW, respectively. With the addition of a new residential rate, rate solutions (residential and C&I) and BYOT now collectively account for over 85% of the DSM potential.

Figure 14 – Mid Scenario Demand Response Potential (2041) *



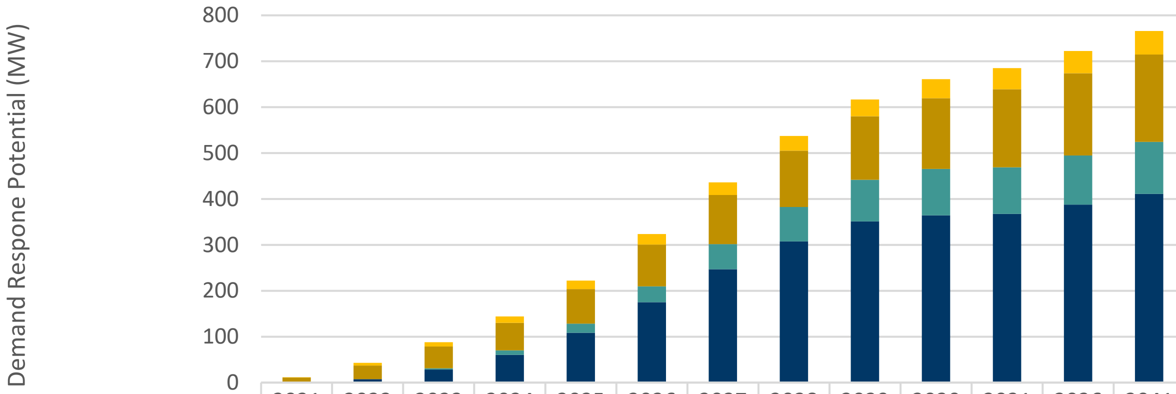
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	601	165	421	86
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	141	5	112	6
Rate Solution	411	113	272	49

* Due to rounding, numbers may not add up

The new Bill certainty with PTR rate option, accounts for a little under 30% of the residential rate savings potential and for most of the additional potential under residential rate solution in the Mid scenario. Despite the increase to the potential for the small C&I segment (i.e., from 9.0 MW in the Low scenario to 13.4 MW in the Mid scenario), overall, it has a limited impact on the total potential, which may not make this market segment a strong candidate for short-term program expansion. Finally, doubling the incentives to $60/kW for the medium and large C&I PTR program has limited impact, increasing the PTR potential by just 10%, while program costs increased by over 80%.

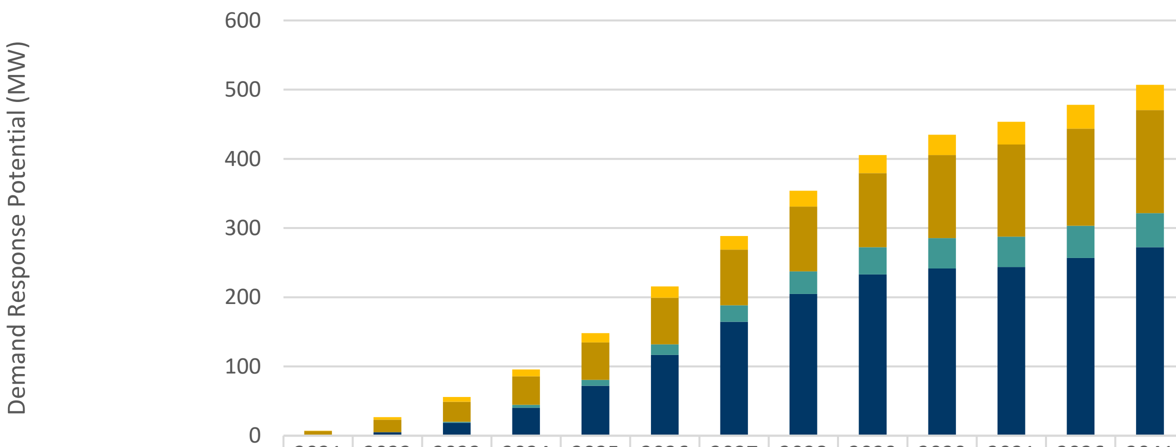
Figure 15 and Figure 16 below present the annual achievable potential, from 2021 to 2041. Program roll-out is extended compared to the Low scenario, to account for the time needed to implement the new rate option.

Figure 15 – DEC - Mid Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	1	6	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	29	47	60	75	91	107	123	138	154	170	179	190
C&I - Rates	0.0	0.0	2.9	9.8	19.7	34.6	54.7	74.9	90.4	101.0	101.4	106.9	113.4
Residential - Rates	0	8	28	61	109	175	247	308	351	364	368	388	411

Figure 16 – DEP - Mid Scenario Deployment

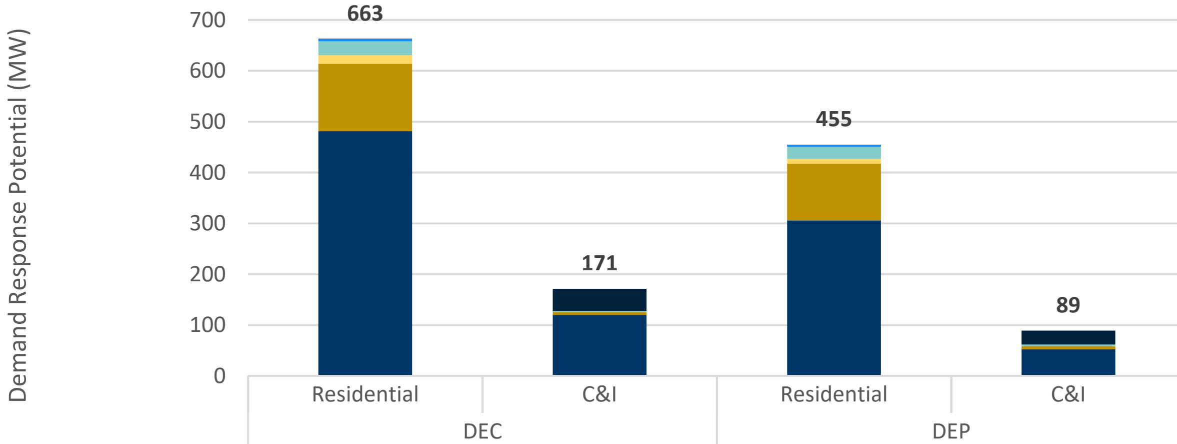


	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0.0	0.0	1.3	4.3	8.6	15.1	23.8	32.6	39.3	43.9	44.0	46.4	49.2
Residential - Rates	0	5	19	40	72	117	165	205	233	242	244	257	272

3.3 MAX SCENARIO

The Max scenario aims to maximize the DSM rates potentials, and to assess the impact of offering the highest possible PTR incentives. A new CPP with flat volumetric rate is added to complement the residential rates included in the Mid scenario. In the Max scenario a complete set of residential rates options is offered ranging from low risk (Bill certainty with PTR) to high risk (TOU+CPP). In the C&I sector, the small C&I adoption was raised while incentives for medium and large C&I PTR were raised to their maximum level, while maintaining program cost-effectiveness. Figure 17 shows that DEC and DEP can respectively achieve 834 MW and 544 MW by 2041. With the addition of another new residential rate, collectively the rate solutions (residential and C&I) and BYOT now account for over 87% of the DSM potential.

Figure 17 – Max Scenario Demand Response Potential (2041) *



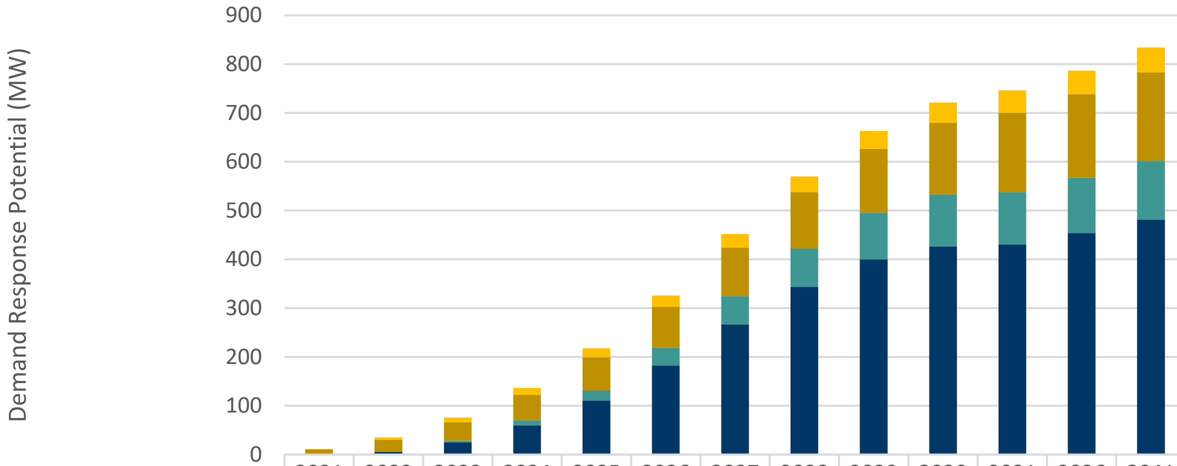
	DEC Residential	DEC C&I	DEP Residential	DEP C&I
Total	663	171	455	89
ADR		43		27
Battery Storage	0.5		0.3	
HP Tune-Up	5		4	
Rate-enabled T-stats	27	3	24	3
Rate-enabled HWH	17		9	
BYOT	133	5	112	6
Rate Solution	481	120	306	53

* Due to rounding, numbers may not add up

Like the Mid scenario findings, the increase in adoption among small C&I customers and the increase in PTR incentives for the medium and large C&I customers resulted in limited additional uptake. The C&I sector potential reaches just 265 MW under the Max scenario (DEC and DEP combined) compared to the 241 MW in the Low scenario. The Max scenario residential rate potential presents a 39% increase over the Low scenario and a 17% increase compared to the Mid scenario. The breakdown of savings among the DSM rates is similar for both DEC and DE, with the TOU+CPP rate and Bill certainty with PTR each accounting for over 30% of the overall DSM rates savings.

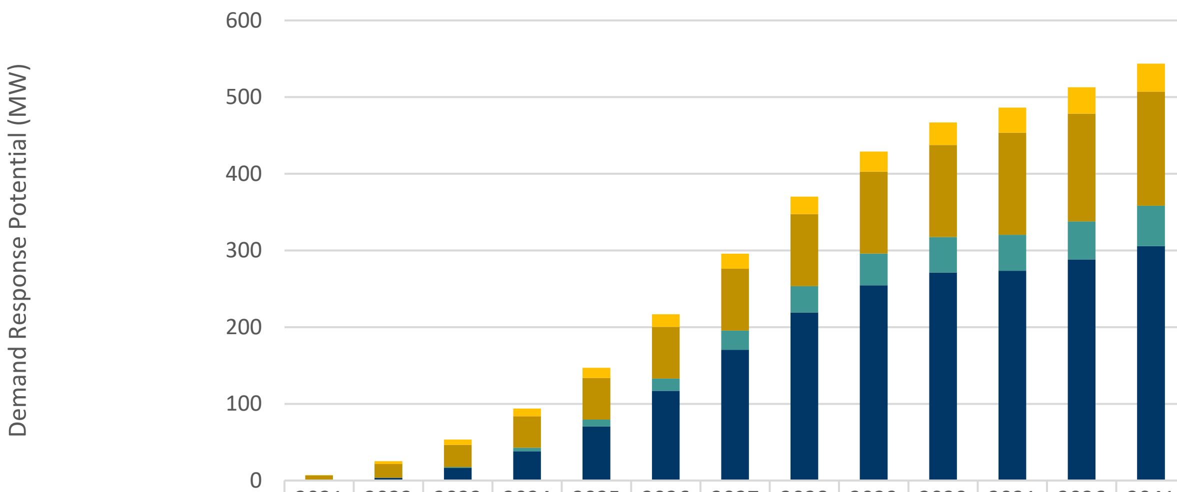
Figure 18 and Figure 19 below present the in each year from 2021 to 2041. As for the Mid scenario, program roll-out is extended to allow for the time needed to deploy additional new rate options.

Figure 18 – DEC - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	5	9	14	19	23	28	32	37	41	46	48	51
Residential - Mechanical	11	25	38	52	68	84	100	115	131	147	163	171	182
C&I - Rates	0	0	3	10	21	37	58	79	95	107	107	113	120
Residential - Rates	0	6	25	60	111	183	267	343	400	427	430	454	481

Figure 19 – DEP - Max Scenario Deployment



	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2036	2041
C&I - Mechanical	0	4	7	10	13	16	20	23	26	29	33	34	36
Residential - Mechanical	7	18	29	41	54	67	81	94	107	120	133	140	149
C&I - Rates	0	0	1	5	9	16	25	34	41	46	47	50	53
Residential - Rates	0	4	16	38	70	117	170	219	255	271	273	288	306

3.4 COMPARISON WITH DUKE'S MARKET POTENTIAL STUDY (MPS)

The goal of this study is to assess possible strategies that could allow Duke Energy to expand its winter peak reduction potential. To that end, it focuses on a small set of specific mechanical and rates solutions specifically selected for their ability to address winter peak loads. It is important to note that the study does not include all available mechanical solutions and therefore differs from the MPS conducted by

Nexant. Conversely, the MPS study focused on the achievable potential related to all mechanical solutions and did not assess any rate structure impacts.

Table 10 and Table 11 below show a high-level comparison between the MPS[12],[13] results and the modelled solution set. In both studies, the DSM potentials assessed are incremental to Duke's current winter peak DSM program impacts.

Table 10: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEC)

	DEC - 2041 Max Scenario	MPS – DEC (Base – 2041)	MPS – DEC (Enhanced – 2041)
Potential Total (MW)	**834**	**403**	**488**
C&I	Rates: 120 Mechanical: 51	38	69
Residential	Rates: 481	0	0
	Mechanical: 182	365	419

Table 11: Achievable Potential Comparison - Max Scenario and MPS Enhanced scenario (DEP)

	DEP - 2041 Max Scenario	MPS – DEP (Base – 2041)	MPS – DEP (Enhanced – 2041)
Potential Total (MW)	**544**	**273**	**307**
C&I	Rates: 53 Mechanical: 36	3	5
Residential	Rates: 306	0	0
	Mechanical: 149	270	302

For the C&I market, this study estimates rate and mechanical potential separately and shows the impact mechanical solutions and rates not considered in the MPS and are therefore incremental to that study. For the residential sector, the potential in this study is also incremental to the MPS and outlines a plan to operationalize a more specific set of high value technologies and new rates not considered in the MPS. Additionally, the MPS excluded DSM rider opt-out customers while this study considers that a PTR rate structure could potentially attract some of those customers (between 5% and 9% depending on the rate class and scenario).

[12] DEC values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-21 DEC DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-20 DEC DSM Summer Peak Capacity Program Potential

[13] DEP values are from is Duke Energy North Carolina EE and DSM Market Potential Study, May 2020, Figure 7-23 DEP DSM Winter Peak Capacity Program Potential and Duke Energy South Carolina EE and DSM Market Potential Study, April 2020. Figure 7-23 DEP DSM Summer Peak Capacity Program Potential

4 KEY TAKE-AWAYS

Based on the results of the winter peak demand reduction potential assessment, there is an apparent 1,378 MW (Max Scenario –DEC and DEP combined) of winter season DSM potential by 2041 representing 4.3% and 4.4% of the DEC and DEP forecasted load, respectively.

As shown in Table 12, most of this potential can be achieved via the residential sector using new rates and expanding mechanical solutions. A smaller portion of the DSM potential can be achieved by increasing incentives to drive program adoption and by diversifying rate structures.

Table 12 – Achievable DSM Potential in 2041, by Scenario (MW)

	Low Scenario	Mid Scenario	Max Scenario
Total Achievable Potential	**1,079 MW**	**1,273 MW**	**1,378 MW**
DEC Achievable Potential	651 MW (495 Res/156 C&I)	766 MW (601 Res/165 C&I)	834 MW (663 Res/171 C&I)
DEP Achievable Potential	428 MW (347 Res/82 C&I)	507 MW (421 Res/86 C&I)	544 MW (455 Res/89 C&I)

Table 13 below benchmarks the achievable DSM potential from the Mid and Max scenarios to DSM potential study findings in other jurisdictions. Overall, these show that the Duke DSM potential is like other winter peaking jurisdictions, where the industrial portion of the utility peak load is moderate and avoided costs are low, as is the case for Duke Energy.

Table 13 – Benchmarking of the Achievable DSM Potential (Mid-Max Scenarios) to Winter Peaking Jurisdictions

	Duke Energy (2020)	Newfoundland and Labrador (2019)	Puget Sound Energy (2017)	Northwest Power & Cons. Council (2014)
Portion of Peak Load	DEC: 4.0% - 4.3% DEP: 4.1% - 4.4% (2041)	10.4%[14] (15-year outlook)	3.7% (20-year outlook)	8.8% (15-year outlook)

Based on the findings in this report three key take-aways emerge:

- **Residential sector programs are key to achieve significant winter demand reduction potentials.** Across all scenarios, the residential sector shows three to four times more potential than the C&I

[14] The share of curtailable industrial load contributing to the utility peak load in Newfoundland and Labrador is high.

sector. This is driven primarily by seasonal variation in the residential sector demand curves, which results from the relatively high penetration of electric heating in the residential sector, while the C&I sector exhibits flatter variations on a daily and inter-seasonal basis.

Duke's current winter residential DSM offering is limited to DEP NC in the Company's Western Region service territory in the area surrounding Asheville[15] and the results of this study indicate that there is potential to expand residential Duke's winter DSM programs. Residential savings are derived from both mechanical and DSM rate solutions, and will likely take time to implement, in some cases requiring regulatory approval for new rates and pilots and programs.

- **Duke should consider pursuing some quick wins in the immediate term, followed by the addition of more complex and varied rate options.**

  On the residential side, a winter BYOT program can likely be implemented as the lowest-hanging fruit option, by adapting the existing summer peak BYOT program to include winter peak events.

  Following that, TOU and TOU+CPP rate designs could be implemented, pending positive results from the Flex Savings Options Pilot conclusions. Bill certainty + PTR and a Flat volumetric + CPP rate option can also be developed as near-term options to capture residential winter peak reduction potential.

  On the C&I side, implementing a PTR rate structure can achieve higher potential reduction than adding other new DSM programs. As a second step, adding Automated Demand Response solutions could enhance current DSM programs.

- **Changes to PTR incentive levels have very little impact on medium and large C&I customer potentials.** Most of the achievable DSM potential (91%) for medium and large customers is achievable with the low scenario incentives ($30 per kW).

Overall, it appears that expanding to new programs and rates could have an important role in increasing Duke winter peak DSM potential in both the DEC and DEP systems.

[15] This program, funded through Rider LC-WIN-2B, installs controls to (1) interrupt service to all resistance heating elements installed in approved central electric heat pump units with strip heat and/or (2) interrupt service to each installed, approved electric water heater. In addition, a winter BYOT filing has been made but has not yet been operationalized as of the time of this study being published

APPENDIX

A.1 RESULTS BREAKDOWN BY RATE CLASS

Table A-1 – Scenario 1 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	9	15	21	21	21	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	7	22	67	112	151	152	153	154	155	156	158	159	161	163	165	167	169	171	173	175
		Businesses	PTR - SGS	0.0	0.1	0.4	1.2	2.0	2.6	2.6	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8	2.9	2.9	2.9	3.0	3.0	3.0
			PTR - Medium and Large C&I	0	2	5	16	27	37	37	37	37	38	38	38	38	39	39	40	40	41	41	42	42
	DEC	Residential	TOU - RE	0	2	5	15	25	33	34	34	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	7	21	64	106	142	143	144	145	146	148	149	150	152	154	156	157	159	161	163	165
			TOU - RS	0.0	0.3	0.9	2.7	4.5	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	4	11	33	55	73	74	74	75	75	76	77	78	78	79	80	81	82	83	84	85
		Businesses	PTR - SGS	0.0	0.3	0.8	2.3	3.8	5.1	5.1	5.2	5.2	5.2	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			PTR - Medium and Large C&I	0	4	12	37	62	86	86	87	87	88	88	89	90	91	92	93	94	95	96	98	99
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	12	14	16	19	21	21	21	21	22	22	22	22	23	23	23
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	9	10	9	12	14	16	18	20	20	20	20	21	21	21	21	22	22	22
			Res. Wi-Fi T-Stat	11	23	37	51	67	80	91	103	115	126	138	139	141	142	144	146	147	149	151	153	154
			Res. HP Tune-up	0	1.6	2.0	2.4	2.7	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.5	3.8	5.2	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	1.1	1.5	1.8	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	2.0	2.7	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-2 – Scenario 2 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	2	4	7	11	16	19	21	21	21	22	22	22	22	22	23	23	23	24	24
			TOU+CPP - Res	0	4	15	30	52	83	114	138	154	155	156	158	159	161	163	165	167	169	171	173	175
			Bill Certainty + PTR - Res	0	0	2	6	13	22	35	48	58	65	66	66	67	68	69	69	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.1	0.4	0.8	1.4	2.2	3.0	3.6	4.1	4.1	4.1	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	36	40	40	40	41	41	42	42	43	43	44	44	45
	DEC	Residential	TOU - RE	0	1	3	7	12	18	25	30	34	34	35	35	35	36	36	37	37	37	38	38	39
			TOU+CPP - RE	0	4	14	28	50	78	107	130	145	146	148	149	150	152	154	156	157	159	161	163	165
			Bill Certainty + PTR - RE	0	0	2	8	15	27	43	59	71	80	80	81	82	83	84	85	86	87	88	89	90
			TOU - RS	0.0	0.2	0.6	1.2	2.1	3.3	4.5	5.5	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.6	6.7	6.8	6.8	6.9	7.0
			TOU+CPP - RS	0	2	7	15	26	40	55	67	75	75	76	77	78	78	79	80	81	82	83	84	85
			Bill Certainty + PTR - RS	0	0	1	2	4	8	12	17	20	22	23	23	23	23	24	24	24	24	25	25	25
		Businesses	PTR - SGS	0.0	0.0	0.2	0.8	1.5	2.7	4.2	5.8	7.0	7.9	7.9	8.0	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9
			PTR - Medium and Large C&I	0	0	3	9	18	32	51	69	83	93	93	94	95	96	97	99	100	101	102	103	104
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	3	6	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	23	36	46	58	69	81	92	103	115	126	127	128	130	131	133	135	136	138	140	141
			Res. HP Tune-up	0	1.6	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.2	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.7	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.6	1.3	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

Table A-3 – Scenario 3 Potential (MW) by Sector and Rate Class

Measure Type	System	Sector	Measure	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041
Rates	DEP	Residential	TOU - Res	0	1	3	6	10	16	23	27	30	31	31	31	31	32	32	33	33	33	34	34	35
			TOU+CPP - Res	0	3	9	18	32	51	69	84	94	95	95	96	97	98	99	101	102	103	104	106	107
			Bill Certainty + PTR - Res	0	0	2	8	16	27	43	59	72	80	81	82	83	83	84	85	86	87	89	90	91
			Flat Volumetric + CPP - Res	0	0	2	6	13	22	35	48	58	65	66	67	67	68	69	70	70	71	72	73	74
		Businesses	Bill Certainty + PTR - SGS	0.0	0.0	0.2	0.5	1.0	1.8	2.9	4.0	4.8	5.4	5.4	5.5	5.5	5.6	5.7	5.7	5.8	5.9	6.0	6.0	6.1
			PTR - Medium and Large C&I	0	0	1	4	8	14	22	30	37	41	42	42	42	43	43	44	44	45	45	46	46
	DEC	Residential	TOU - RE	0	1	4	9	15	24	33	39	44	44	45	45	46	46	47	47	48	48	49	50	50
			TOU+CPP - RE	0	3	9	18	32	51	70	84	94	95	96	97	98	99	100	101	102	104	105	106	107
			Bill Certainty + PTR - RE	0	0	3	10	19	34	53	73	89	100	100	101	102	103	105	106	107	108	110	111	112
			Flat Volumetric + CPP - RE	0	0	3	8	17	30	47	64	78	87	88	89	90	91	92	93	94	95	96	98	99
			TOU - RS	0.0	0.2	0.6	1.3	2.3	3.6	4.9	5.9	6.6	6.7	6.7	6.8	6.9	6.9	7.0	7.1	7.2	7.3	7.4	7.5	7.5
			TOU+CPP - RS	0	1	4	9	16	25	34	41	46	46	46	47	47	48	48	49	50	50	51	51	52
			Bill Certainty + PTR - RS	0	0	1	3	6	10	16	21	26	29	29	30	30	30	31	31	31	32	32	32	33
			Flat Volumetric + CPP - RS	0	0	1	2	4	6	10	14	16	18	19	19	19	19	19	20	20	20	20	21	21
		Businesses	PTR - SGS	0.0	0.0	0.3	1.0	2.0	3.6	5.6	7.7	9.4	10.5	10.6	10.7	10.8	10.9	11.0	11.2	11.3	11.4	11.6	11.7	11.8
			PTR - Medium and Large C&I	0	0	3	9	19	33	52	72	86	96	97	98	98	100	101	102	103	104	106	107	108
Mech-anical	DEP	Residential	Res. Rate-Enabled T-Stat	0	2	4	6	8	10	13	15	17	19	22	22	22	22	22	23	23	23	24	24	24
			Res. Wi-Fi T-Stat	7	14	22	31	41	51	61	71	80	90	100	101	102	103	104	106	107	108	109	111	112
			Res. HP Tune-up	0	1.0	1.2	1.5	1.7	2.0	2.2	2.4	2.7	2.9	3.2	3.2	3.2	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6
			Res. Rate-Enabled HWH	0	0.8	1.5	2.3	3.1	4.0	4.8	5.6	6.4	7.3	8.1	8.1	8.2	8.3	8.4	8.5	8.6	8.7	8.8	8.9	9.0
			Res. Battery Energy Storage	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.7	0.9	1.2	1.5	1.8	2.1	2.3	2.6	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.2	3.2	3.2
			Comm. Wi-Fi T-Stat	0.4	0.8	1.3	1.7	2.2	2.7	3.3	3.8	4.3	4.8	5.3	5.3	5.4	5.4	5.5	5.6	5.6	5.7	5.8	5.9	5.9
			Comm. ADR	0	2	5	7	10	12	15	17	20	22	24	25	25	25	25	26	26	26	27	27	27
	DEC	Residential	Res. Rate-Enabled T-Stat	0	2	4	7	9	11	14	16	19	21	24	24	24	25	25	25	26	26	26	27	27
			Res. Wi-Fi T-Stat	11	19	29	39	51	62	73	85	96	107	119	120	121	122	123	125	126	128	130	131	133
			Res. HP Tune-up	0	1.3	1.6	1.9	2.3	2.6	2.9	3.2	3.6	3.9	4.2	4.2	4.3	4.3	4.4	4.4	4.5	4.5	4.6	4.7	4.7
			Res. Rate-Enabled HWH	0	1.4	2.9	4.4	6.0	7.5	9.1	10.7	12.2	13.8	15.3	15.5	15.6	15.8	16.0	16.2	16.4	16.6	16.8	17.0	17.2
			Res. Battery Energy Storage	0	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.5	0.5
		Businesses	Comm. Rate-Enabled T-Stat	0	0.4	0.6	0.8	1.1	1.3	1.5	1.8	2.0	2.3	2.5	2.5	2.6	2.6	2.6	2.6	2.7	2.7	2.7	2.8	2.8
			Comm. Wi-Fi T-Stat	0.3	0.7	1.1	1.5	1.9	2.4	2.8	3.3	3.7	4.1	4.6	4.6	4.7	4.7	4.8	4.8	4.9	5.0	5.0	5.1	5.1
			Comm. ADR	0	4	8	12	16	19	23	27	31	35	39	39	39	40	40	41	41	42	42	43	43

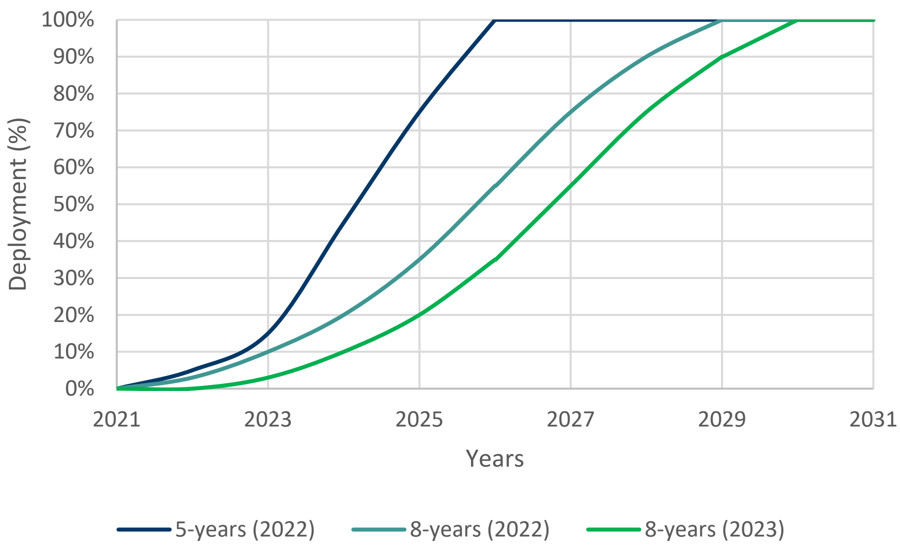
A.2 PROGRAM RAMP-UP AND COSTS

RAMP-UP

Ramp-up rates were created using s-curves over 5 and 8 years.

The low scenario, which is easier to implement, includes a ramp-up over 5 years. Scenarios Mid and Max, which requires more rates designs, assume a ramp-up over 8 years before full deployment of the rate solutions. Furthermore, rates that where included in the pilot (TOU and TOU+CPP) are estimated to launch in 2022, while bill certainty + PTR and flat volumetric + CPP are starting in 2023. The figure below summarized the ramp-up.

Figure A-1 – Enrollment Ramp-up: Rates



PROGRAM COSTS

Estimated program costs for the mechanical solution set are presented in the table below.

Table A-4: Program Costs

Program Name	Development Costs	Program Fixed Annual Costs	Other Costs ($/customers) for marketing, IT, admin
Residential Rate-Enabled T-Stat	$200,000	$100,000	$40
Residential BYOT	$100,000	$100,000	$40
Residential Rate-Enabled HWH	$175,000	$75,000	$35
WP/HP Tune-up	$175,000	$100,000	$0
Commercial Rate-Enabled T-Stat	$150,000	$75,000	$40
Commercial BYOT	$75,000	$75,000	$40
Residential BYOB	$100,000	$100,000	$30
ADR	$250,000	$150,000	$20

A.3 KEY ASSUMPTIONS

ECONOMIC ASSUMPTIONS

The avoided costs provided by Dukes for South and North Carolina were blended between South and North Carolinas to obtain an average avoided cost for each system. These avoided costs are presented in the table below, in 2021 dollars. This study uses also uses blended discount rates of 6.9% (DEC) and 6.8% (DEP).

Table A-5 – Avoided Costs

Year	DEC - Avoided cost ($/kW)	DEP - Avoided cost ($/kW)
2021	129.5	100.6
2022	131.6	102.1
2023	133.9	103.8
2024	136.3	105.5
2025	138.8	107.2
2026	141.3	108.9
2027	144.0	110.8
2028	146.7	112.6
2029	149.5	114.5
2030	152.3	116.5
2031	155.1	118.4
2032	157.9	120.3
2033	160.7	122.3
2034	163.6	124.3
2035	166.5	126.3
2036	169.5	128.3
2037	172.5	130.4
2038	175.6	132.5
2039	178.8	134.7
2040	182.0	136.9
2041	185.3	139.1
2042	188.6	141.4
2043	192.1	143.8
2044	195.5	146.1
2045	199.1	148.5

SEGMENTATION AND END USE

The follow ratios where used to breakdown the potential by State.

Table A-6 – Segmentation by State

State	DEC	DEP
North Carolina	73.50%	85%
South Carolina	26.50%	15%

To obtain a breakdown per rate and per end use, the latest EIA's CBECS (2012) and RECS (2015) data was used. This data was combined with Duke's 2017 and 2018 annual consumption and average consumption per customer for each rate class to obtain the following tables.

Table A-7 – DEC segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	18,049	324,972
LGS	64%	78%	536,989	11,431
OPTC	64%	78%	745,677	21,133
OPTI	64%	78%	11,394,026	1,642
Other	64%	78%	412,306	7005
RS	24%	52%	12,866	1,295,393
RE	100%	100%	13,485	946,860

Table A-8 – DEP segmentation assumptions

Segment	Share of Primary Space Heating Electric (%)	Share of Primary Hot Water Electric (%)	Average Annual Consumption (kWh)	Population
SGS	64%	78%	14,379	201,554
MGS	64%	78%	372,588	33,267
LGS	64%	78%	17,371,855	255
RTP	64%	78%	68,103,493	90
Other	64%	78%	62,518	1159.44
Res	63%	72%	13,951	1,322,187

The EIA's building archetypes where used to generate 8760h annual load curve to model consumption for each rate class.

Table A-9 – DEC building archetypes included per rates

EIA's Archetypes	Segment						
	RS	RE	SGS	LGS	OPTC	OPTI	Other
Hospital	-	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	-	Yes	-	-	-	-
Industrial	-	-	-	Yes	Yes	Yes	Yes
MF_Elec. Resistance	Yes	Yes	-	-	-	-	-
MF_HP	Yes	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes	Yes
Office Medium	-	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	-	Yes	-	-	-	-
Outpatient Healthcare	-	-	Yes	-	-	-	-
Restaurant Fast Food	-	-	Yes	-	-	-	-
Restaurant Sit Down	-	-	Yes	-	-	-	-
Retail Standalone	-	-	Yes	-	-	-	-
Retail Strip Mall	-	-	Yes	-	-	-	-
School Primary		-	-	Yes	Yes	Yes	Yes
School Secondary	-	-	-	Yes	Yes	Yes	Yes
SF_Elec. Resistance	Yes	Yes	-	-	-	-	-
SF_HP	Yes	Yes	-	-	-	-	-
Supermarket	-	-	-	Yes	Yes	Yes	Yes
Warehouse	-	-	Yes	Yes	Yes	Yes	Yes

Table A-10 – DEP building archetypes included per rates

EIA's Archetypes	Segment					
	Res	SGS	MGS	LGS	RTP	Other
Hospital	-	-	Yes	Yes	Yes	Yes
Hotel Small	-	Yes	Yes	-	-	-
Industrial	-	-	-	Yes	Yes	Yes
MF_Elec. Resistance	Yes	-	-	-	-	-
MF_HP	Yes	-	-	-	-	-
Office Large	-	-	-	Yes	Yes	Yes
Office Medium	-	Yes	Yes	Yes	Yes	Yes
Office Small	-	Yes	-	-	-	-
Outpatient Healthcare	-	Yes	Yes	-	-	-
Restaurant Fast Food	-	Yes	Yes	-	-	-
Restaurant Sit Down	-	Yes	Yes	-	-	-
Retail Standalone	-	Yes	-	-	-	-
Retail Strip Mall	-	Yes	-	-	-	-
School Primary		-	Yes	Yes	-	Yes
School Secondary	-	-	Yes	Yes	-	Yes
SF_Elec. Resistance	Yes	-	-	-	-	-
SF_HP	Yes	-	-	-	-	-
Supermarket	-	-	Yes	Yes	Yes	Yes
Warehouse	-	Yes	Yes	Yes	Yes	Yes

RESIDENTIAL RATE DETAILS

TOU RATES

This rate targets consumers able to vary their daily usage to reduce energy costs. This new TOU structure is based on the Flex Savings Options pilot conducted by Nexant for Duke Energy Carolinas (NC). The pilot went into effect on October 1, 2019 and preliminary results were provided by Duke to inform our analysis. The pilot tested three different rates structures (TOU, CPP, TOUD) across three customer classes including all-electric residential (RE) and standard residential (RS).

- **Peak to off-peak ratio:** 1.7
- **Peak load impact**
    - Based on preliminary Flex Savings Options Pilot findings
    - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
    - Customers in either DEC – RE, DEC – RS or DEP – Res

TOU WITH CPP

This rate targets consumers who are highly attentive to their energy demand and can change their load in a significant manner. The modelled TOU with CPP rate structure is also based on the Flex Savings Options Pilot. Customers are on the previous TOU rate but with higher hourly prices during specific peak hours on about 20 days per year.

- **CPP Peak to off-peak ratios:** 3.2
- **Peak load impact**
    - Based on the preliminary Flex Savings Options Pilot findings
    - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
    - Customers in either DEC – RE, DEC – RS or DEP – Res

BILL CERTAINTY WITH PTR

This rate targets consumers who want to mitigate their billing risk. It offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
    - 3:1 savings ratio for all rates[16]
    - Bill certainty is not expected to increase the winter peak demand compared to a flat volumetric rate
- **Peak load impact**
    - Peak impact reduction was derived from the Arcturus[17] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.

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[16] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[17] Peak reduction from “Arcturus 2.0: A meta-analysis of time-varying rates for electricity”, A. Faruqui, S. Sergici and C. Warner, 2017.

- Bounce back effects are derived from the Flex Savings Options Pilot findings (CPP), adjusted for savings.

- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

FLAT VOLUMETRIC WITH CPP

This rate targets consumers who can change their load in a significant manner but are not willing to modify their everyday usage. It offers a fixed price per unit of energy consumed, with a CPP on peak days.

- **CPP peak to off-peak ratios:** 5.5
- **Peak load impact**
  - Based on the Flex Savings Options Pilot findings
  - Bounce back effects are based on the Flex Savings Options Pilot findings
- **Eligible Market**
  - Customers in either DEC – RE, DEC – RS or DEP – Res

It is important to note that all customers who are enrolled in one of the residential rates above and a rate-enabled mechanical solution (rate-enabled thermostats or hot water heater) have a reduced peak load impact, based on the peak load end use share of heating and hot water usage, to account for the fact that the load impact is considered in mechanical solutions, preventing any double counting.

NON-RESIDENTIAL RATES DETAILS

SMALL C&I CUSTOMERS – BILL CERTAINTY WITH PTR

Being a segment with historically low elasticity to electric demand, this rate was implemented as being the most consumer friendly, hoping to spur demand response. The rate offers a fixed bill per month, with a PTR on peak days.

- **Peak to off-peak ratios**
  - 3:1 saving ratio[18]
  - Peak impact reduction was also derived from the Arcturus[19] analysis on dynamic rates. This analysis evaluates the customer peak reduction to dynamic rates, covering more than 300 pricing treatments from over 60 pilots.
  - Bounce back effects apply the residential PTR shape, adjusted to savings levels derived for C&I customers.
- **Eligible Market**
  - Customers in either DEC – SGS or DEP – SGS

Although the Flex Savings Options Pilot also included customers from the SGS rate class, results were not yet available to integrate into our analysis. Instead, the Arcturus report was used, but savings were

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[18] For example: With an average cost of electricity over the fixed bill is 15¢/kWh, the rebate would be 30¢/kWh, for a total discount of 45¢/kWh, which is three times to initial cost of electricity.

[19] Peak reduction from “Arcturus 2.0: A meta-analysis of time-varying rates for electricity”, A. Faruqui, S. Sergici and C. Warner, 2017.

reduced by 50% compared to residential customer response to account for the historically low elasticity of the small C&I sector.

MEDIUM AND LARGE C&I RATES – PTR

By using a carrot-only rebate approach, PTR rates is particularly attractive to large customers who see in it as a win-win situation. Considering the variety of C&I rates as well as the option for large customers to opt-out from DSM programs, this rate is potentially an opportunity to attract more customers than current DSM programs. The rate consists of offering a rebate for reducing their load below a customer-specific baseline during peak times.

- **Peak load impact**
  - Peak impact reduction was assessed based on an end-use approach where the percentage of achievable load curtailable by customer was evaluated for each major end-use. Baseline load curves are based on hourly average demand per customer class provided by Duke Energy.
- **Eligible Market**
  - All C&I customers can choose to enroll (DEC – LGS, DEC – OPTC, DEC-OPTI, DEC – Other, DEP MGS, DEP – LGS). It is assumed that a small portion of opt-out customers would choose to enroll in the rates (more details in the results section)
  - For modelling assumptions, to avoid any double-counting, participants already enrolled under current DSM programs (DRA or PowerShare) are excluded from the customers count.