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Colorado Springs Utilities 2020 Demand-Side Management Potential Study

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1. Executive Summary

1.1. *Overview*

This report presents the results of an independent assessment of the technical and achievable technical potential for electric and natural gas demand-side management (DSM) resources in the service territory of Colorado Springs Utilities' (Springs Utilities) service territory. The assessment addressed a 20-year planning horizon, from 2020 to 2039. This DSM potential study, commissioned by Springs Utilities as part of its Short-Term Energy Plan, Electric Integrated Resource Plan, and Gas Integrated Resource Plan (GIRP) processes, seeks to identify DSM potential from the perspectives of energy efficiency, demand response (DR), customer-sited renewables (including solar photovoltaics [PVs] and battery storage), and electric vehicles. The assessment's results will help Springs Utilities to identify cost-effective DSM and to design future programming.

The study builds on previous DSM potential assessments in Springs Utilities' service territory, most recently the 2016 Demand Side Management Potential Study (2016 DSM Study), also performed by Cadmus. Study updates include the addition of natural gas energy efficiency and natural gas DR, customer-sited renewables, and electric vehicles. The methods used to evaluate the technical and achievable technical potential drew upon best utility industry practices and remained consistent with the methodology used in the previous 2016 Study.

1.1.1. Scope of the Analysis and Approach

Energy Efficiency

The energy efficiency analysis included estimates of the technical and achievable technical potential for more than 300 unique electric and natural gas energy efficiency measures. Cadmus relied on Springs Utilities' program data, Xcel Energy's (CO) 2019/2020 Demand-Side Management Plan, and other measure databases to determine savings, costs, and applicability for each measure.

Cadmus prepared 20-year forecasts of potential electric energy, peak demand, and natural gas energy savings for each energy efficiency measure. The assessment considers multiple vintages (new and existing), distinguishes between lost opportunity and replace-on-burnout measures, and accounts for building energy codes as well as future federal equipment standards.

Demand Response

DR programmatic options strive to reduce peak demand during system emergencies or periods of extreme market prices and to promote improved system reliability. Cadmus' analysis focused on program options that included residential and nonresidential direct load control (DLC) and nonresidential load curtailment for Springs Utilities' electric and natural gas customers. These DR strategies included price- and incentive-based options for all major customer segments and end uses within Springs Utilities' service territory.

To estimate DR potentials, the study applied a hybrid, top-down, and bottom-up approach, beginning by using utility system loads, disaggregated into sectors, segments, and applicable end uses. For each program, Cadmus first assessed potential impacts at the end-use level, and then aggregated these to obtain estimates of technical potentials. This allowed us to apply market factors (such as likely program and event participation) to technical potentials to obtain market potential estimates.

Customer-Sited Renewables

Cadmus analyzed technical and achievable technical potential for two types of customer-sited renewables:

- Distributed solar PV
- Distributed battery storage

The solar PV analysis used power-density forecasts and estimates of total available roof areas for solar PV, designed to develop forecasts of nameplate capacity. Cadmus determined solar PV achievable technical potential using a bass diffusion equation that incorporated data on adoption of solar PV in Springs Utilities' service territory.

Cadmus determined achievable technical potential for residential, behind-the-meter, energy storage in three separate categories: potential based on the sum of the nameplate capacity; total time-shifted energy potential, based on a time-of-use (TOU) rate structure, and demand potential as part of a DR program.

Electric Vehicles

Cadmus utilized scenario modeling to support Springs Utilities in understanding and preparing for a range of potential electric vehicles futures. To estimate the potential of electrical vehicles, Cadmus established a historical adoption baseline, projected three scenarios of continued adoption out to 2050 (a low-growth scenario, a medium-growth scenario, and a high-growth scenario), and estimated new load growth, demand impacts, and EV charging infrastructure associated with each of those scenarios.

1.2. Summary of Results

Table 1 shows the technical and achievable technical potential for each resource considered in this study. Electric DSM potential, representing nearly 701 gigawatt-hours (GWh) of achievable technical potential, could produce approximately 105 MW of coincident summer peak demand savings. All electric potential estimates in this report are presented at the generator, meaning they include line losses, assumed to be 4.03% on average across Springs Utilities' transmission and distribution system. Cadmus identified natural gas, cumulative, achievable, technical potential of approximately 49 million therms.

Table 1. Summary of Energy and Demand Savings Potential

Resource	Energy (MWh/Million Therms)		Summer Coincident Peak Capacity (MW)	
	Technical Potential	Achievable Technical Potential	Technical Potential	Achievable Technical Potential
Electric Resources				
Energy Efficiency	1,109,594	700,922	169	105
Demand Response	N/A	N/A	N/A	92
Electric Resources Total	**1,109,594**	**700,922**	**169**	**197**
Natural Gas Resources				
Energy Efficiency	87	49	N/A	N/A

Figure 1 and Figure 2 present respective electric and natural gas achievable technical potential forecasts. More savings are achievable in the study's first 10 years (2020 through 2029) than in the last 10 years due to most discretionary measures (i.e., measures that retrofitted existing homes and equipment) being acquired over the first 10 years. During this time, additional savings came primarily from lost opportunity measures, such as equipment replacement and new construction.

Figure 1. Electric Achievable Technical Potential Forecast

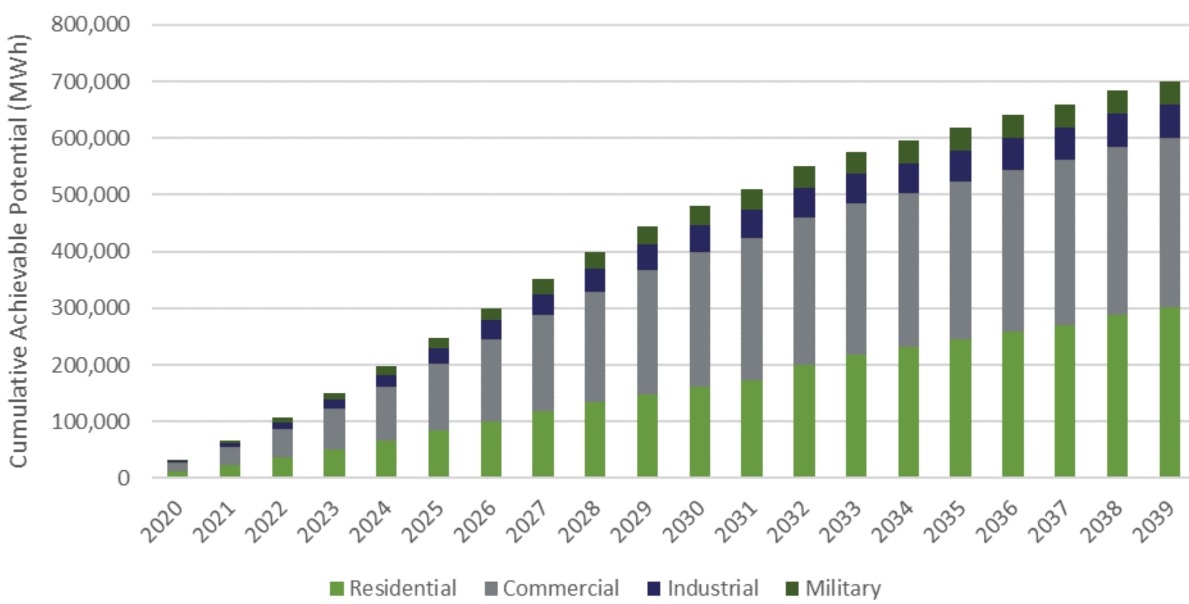


Figure 2. Natural Gas Achievable Technical Potential Forecast

1.2.1. Energy Efficiency

Table 2 shows forecast baseline electric sales and achievable technical energy efficiency potential for each sector. Overall, if all 20-year achievable potential could be realized it, would produce a load reduction equivalent to 16% of Springs Utilities' baseline electric sales. Approximately 43% of this potential falls within the residential sector, with another 43% percent in the commercial sector.

Table 2. Electric Energy Efficiency by Sector, Cumulative 2039

Sector	2039 Baseline Sales (MWh)	Achievable Technical Potential		
		MWh	Percentage of Baseline Energy Sales	MW
Residential	1,564,870	301,541	19%	39
Commercial	2,025,091	299,322	15%	53
Industrial	551,859	57,995	11%	6
Military	292,229	42,065	14%	7
Total	**4,434,050**	**700,922**	**16%**	**105**

Table 3 shows forecasted natural gas baseline sales and achievable technical potential by sector. Cadmus identified approximately 49 million therms of natural gas, energy efficiency potential, with 55% of these savings occurring in the residential sector. Overall, natural gas achievable potential equaled 19% of Springs Utilities' forecasted natural gas sales.

Table 3. Natural Gas Energy Efficiency by Sector, Cumulative 2039

Sector	2039 Baseline Sales (MM Therms)	Achievable Technical Potential	
		MM Therms	Percentage of Baseline Sales
Residential	159	27	17%
Commercial	74	16	22%
Industrial	12	2	22%
Military	17	3	20%
Total	**262**	**49**	**19%**

Comparison to 2016 DSM Potential Study – Electric Energy Efficiency

The 2019 energy efficiency analysis incorporated the following changes since completion of Springs Utilities' most recent DSM potential study (2016):

- Uses Springs Utilities' most recent electric energy and customer forecasts
- Calculates new baseline end-use energy forecasts for each major end use within each sector, accounting the effects of federal appliance standards and local building energy codes
- Updates energy efficiency measure savings, costs, and effective useful lives assumptions, derived primarily from Xcel Energy's (CO) 2019–2020 Demand Side Management Plan
- Derives the levelized costs of electric energy efficiency potential on a total resource cost (TRC) test basis
- Estimates the technical and technical achievable potential for the 20-year study horizon

Because the previous study estimated technical, economic, and achievable potential, direct comparisons of achievable technical potential are not possible. However, Table 4 compares the overall technical potential, expresses as a percentage of baseline sales, as identified in the 2019 and 2016 DSM potential studies. Overall, the 2019 DSM Potential Study identified lower electric, achievable, technical potential.

Table 4. Energy Efficiency Comparison to 2016 DSM Potential Study

Study	20-Year Technical Potential (Percent of Sales)				Total Technical Potential (MWh)
	Residential	Commercial	Industrial	Military	
Electric Resources					
2019 DSM Study	31%	24%	14%	23%	1,109,594
2016 DSM Study	40%	28%	16%	25%	1,537,947

The following elements contribute primarily to decreases in electric energy efficiency potential:

- Each 20-year sector sales forecast was lower compared to the 2016 Study
- Updated federal energy efficiency standards, including the 2020 Federal Light Bulb Efficiency Standard, reduced the amount of available technical potential
- Increased baseline efficiencies, including for commercial lighting technologies, also reduced the amount of available technical potential

1.2.2. Demand Response

Table 5 presents the summer peak coincident achievable potential for electric DR programs, with the total 20-year summer peak coincident potential at approximately 92 MW, equivalent to a 12.7% reduction in Springs Utilities' summer peak.

Table 5. Electric Demand Response Potential by Program, 2039

Product	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer
Res DLC Smart Thermostat Direct Install	23.8	3.3%
Res DLC Smart Thermostat BYOT	18.8	2.6%
Res DLC EV Charger	7.6	1.0%
Res Critical Peak Pricing Opt-In	6.5	0.9%
Com DLC BYOT	25.8	3.5%
Com Curtailment (Peak Savings)	8.7	1.2%
C&I Critical Peak Pricing Opt-In	1.3	0.2%
Total	**92**	**12.7%**

Table 6 shows the winter peak-hour and peak-day achievable potential for natural gas DR. The total, 20-year winter peak, coincident achievable potential, is 721 deka-therms (Dth) per peak hour and 2,261 Dth per peak day.

Table 6. Natural Gas Demand Response Potential by Program, 2039

Product	Winter Achievable Potential (Dth per peak hour)	Percent of System Peak Hour - Winter	Winter Achievable Potential (Dth per peak day)	Percent of System Peak Day - Winter
Res Gas DLC Smart Thermostat Direct Install	105	0.7%	206	0.1%
Res Gas DLC Smart Thermostat BYOT	114	0.8%	224	0.1%
Res Gas DLC Water Heat	92	0.6%	546	0.2%
Res Critical Peak Pricing Opt-In	293	2.0%	1,204	0.4%
Com Gas DLC BYOT	25	0.2%	81	0.0%
Total	**721**	**4.3%**	**2261**	**0.8%**

1.2.3. Customer-Sited Renewables

Solar Photovoltaics

Table 7 presents the 20-year solar PV achievable potential in energy (MWh) and capacity (MW) for residential and commercial sectors, addressing each of four primary scenarios. For each of these, the residential sector represents the vast majority of solar PV achievable potential.

Table 7. Solar Photovoltaic Achievable Potential by Scenario and Sector, 2039

Scenario	2039 Achievable Potential (MW)			2039 Achievable Potential (MWh)		
	Residential	Commercial	Total	Residential	Commercial	Total
Low Incentive	239	10	249	455,640	18,626	474,266
Business as Usual	301	11	311	572,244	19,793	592,037
Extended Investment Tax Credit (ITC)	480	12	491	908,693	21,673	930,366

Scenario	2039 Achievable Potential (MW)			2039 Achievable Potential (MWh)		
	Residential	Commercial	Total	Residential	Commercial	Total
Best Case	533	12	545	1,007,977	22,738	1,030,715

Battery Storage

Table 8 shows the 20-year, residential battery storage, achievable potential results.

Table 8. Residential Battery Storage Achievable Potential Results

Potential Type	2039 Achievable Potential	
	Energy (MWh)	Capacity (MW)
Nameplate Storage Capacity	NA	34
Energy Time-Shift	24,021	NA
Demand Response Event	344	9

Cadmus also performed a tipping-point analysis for residential battery storage under three different future-cost scenarios. The low-cost scenario reaches a net positive value to customers between 2025 and 2030; the medium-cost scenario reaches a positive value between 2030 and 2035; and the high-cost scenario reaches a positive value between 2035 and 2039.

1.2.4. Electric Vehicles

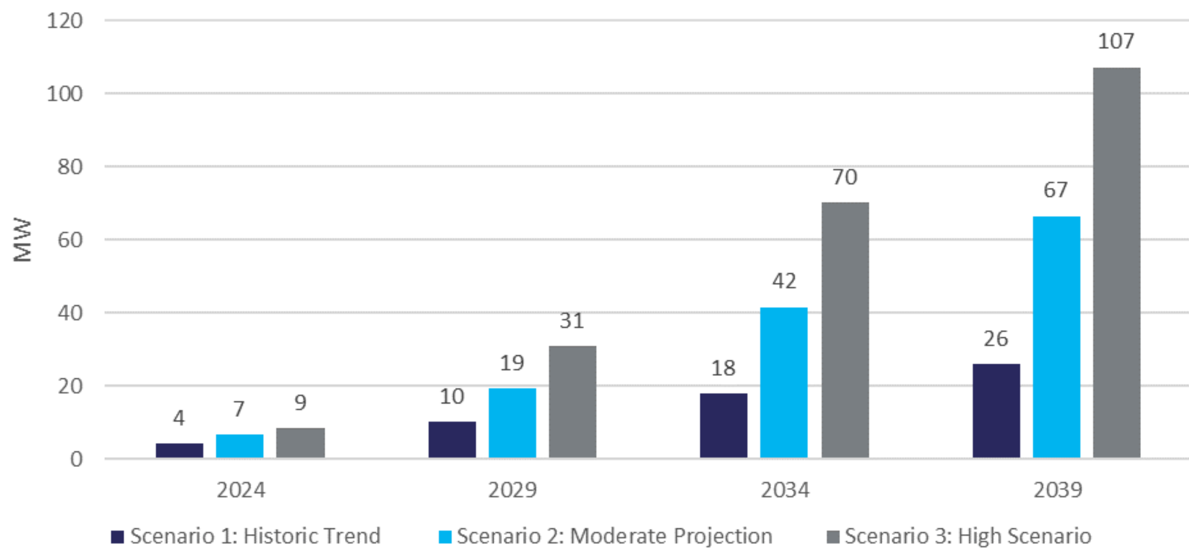
Cadmus estimated the percentage of electric vehicles in the total light duty vehicle fleet, using the three scenario models corresponding to low, medium, and high growth. As shown in Table 9, medium-growth scenarios indicate electric vehicles will account for 8.9% of total light duty fleet vehicles in year 10 of the study (2029).

Table 9. Percent Electric Vehicles of Total Light Duty Vehicle Fleet Milestones

Scenario	2024	2029	2034	2039
Scenario 1: Low Growth	2.1%	4.8%	7.7%	10.8%
Scenario 2: Medium Growth	3.3%	8.9%	17.6%	27.3%
Scenario 3: High Growth	4.3%	14.1%	29.7%	44.2%

Figure 3 presents the estimated peak demand from light-duty EVs for each of the three adoption scenarios for years five, 10, 15, and 20 of the study. The moderation adoption scenario indicates that, by 2029, approximately 19 additional MW of peak-coincident demand would accrue to light-duty electric vehicle charging.

Figure 3. Estimated Peak Demand from Light Duty EVs in El Paso County by Scenario, Horizon Year



1.3. *Incorporation of DSM into Springs Utilities' IRP*

The achievable technical potential estimates shown above have been grouped by the levelized cost of conserved energy for inclusion in Springs Utilities' integrated resource plan (IRP) model. These costs have been calculated over a 20-year program life; the calculated levelized costs section provides additional detail on the levelized cost methodology. Bundling resources into a number of distinct cost groups allowed the model to select optimal choices regarding DSM potential, based on expected load growth, energy prices, and other factors.

Cadmus and Springs Utilities spread the annual savings estimates over 8760-hour end use load shapes to produce hourly DSM bundles. Figure 4 and Figure 5 show the annual cumulative combined potential for electric and natural gas energy efficiency, respectively, by each cost bundle considered in Springs Utilities' 2020 IRP.

Figure 4. Electric Supply Curve—Cumulative 20-Year Achievable Technical Potential

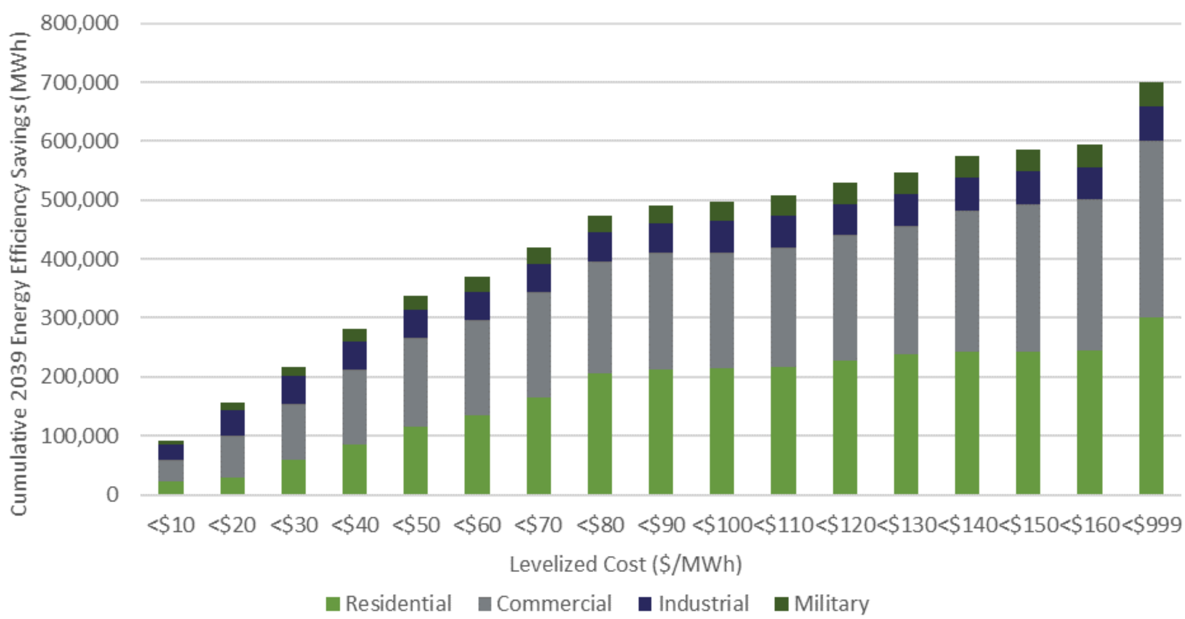
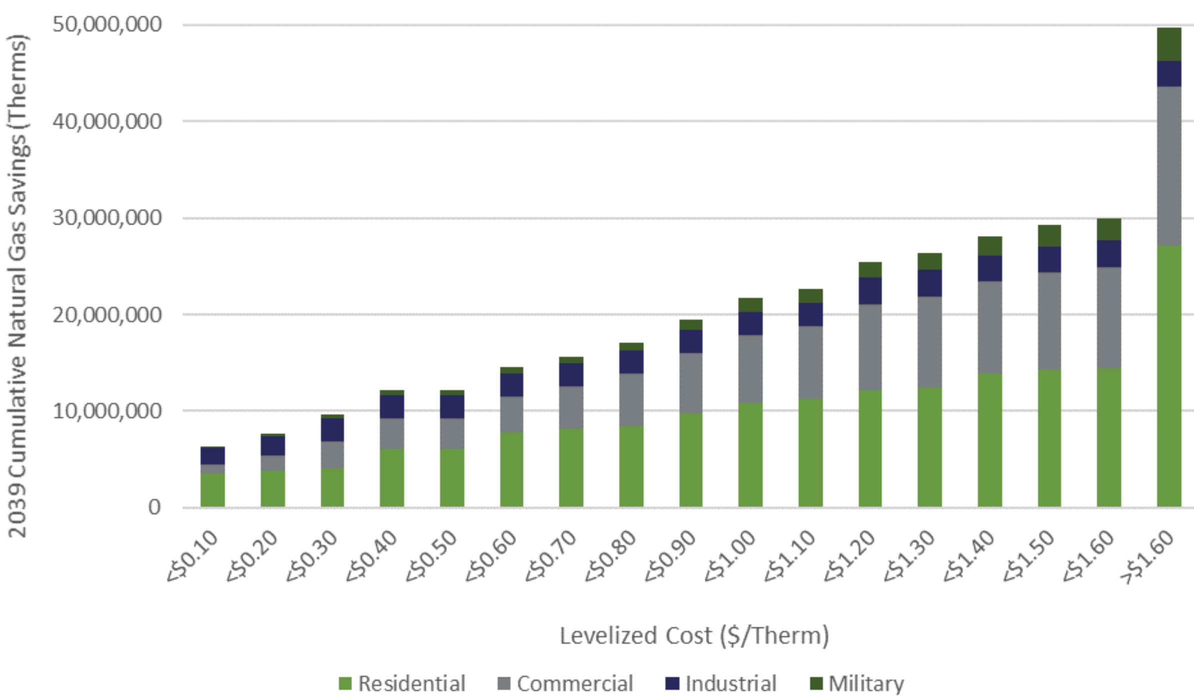


Figure 5. Natural Gas Supply Curve—Cumulative 20-Year Achievable Technical Potential



1.4. Organization of this Report

This study's presents its findings in two volumes: Volume I (this document) provides methodologies and findings; and Volume II contains the report's appendices, and it provides detailed study results and supplemental materials. **Volume I** includes the following sections:

General Approach and Methodology describes the technologies, data inputs, data sources, data collection processes, and assumptions used in calculating technical and achievable technical long-term potentials for energy efficiency, DR, customer-sited renewable energy, and electric vehicles.

Energy Efficiency

- **Methodology** provides an overview of the methodology Cadmus used to estimate technical, economic, and achievable potential. The section includes a discussion of Cadmus' approach to the following:
  - **Developing Baseline Forecasts** to provide an overview of Cadmus' approach to producing baseline end-use forecasts for each sector
  - **Measure Characterization** describes Cadmus' approach to developing a database of energy conservation measures, from which we derived conservation potential estimates
  - **Estimating Conservation Potential** discusses assumptions and underlying equations used to calculate technical and technical achievable potential
- Developing Baseline Forecasts provides detailed sector-level results for Cadmus' baseline end-use forecasts.
- Energy Efficiency Potential provides detailed sector, segment, and end-use-specific conservation potential estimates as well as a discussion of the top energy-saving measures in each sector.

Demand Response

- Methodology
- Potential Results

Customer-Sited Renewable Energy

- Methodology
- Potential Results

Electric Vehicles

- Methodology
- Potential Results

Volume II (the appendices) includes the following sections:

- Appendix A: Baseline Data
- Appendix B: Energy Efficiency Measure Descriptions
- Appendix C: Detailed Assumptions and Energy Efficiency Potential
- Appendix D: Measure Details

2. General Approach and Methodology

This report describes the technologies, data inputs, data sources, data collection processes, and assumptions used in calculating technical and achievable technical long-term potentials.

2.1. General Approach

The demand-side resources analyzed in this study differ with respect to technology, availability, types of load impact, and target consumer markets. Analysis of their potentials, therefore, requires using customized methods to address the unique characteristics of each resource.

The methods, however, spring from the same conceptual frameworks, and they seek to estimate two distinct types of potential—technical and achievable technical, defined as follows:

- Technical potential assumes that all technically feasible resource opportunities may be captured, regardless of their costs or other market barriers. Notably, the concept of technical potentials proves less relevant to some resources (such as DR) as, from a strictly technical point of view, nearly all end-use loads may be subject to interruption or displacement by on-site generation.
- Achievable technical potential is defined as the portion of technical potential that might be assumed achievable in the course of the planning horizon, regardless of the acquisition mechanism. (For example, savings may be acquired through direct utility acquisition programs, improved building energy codes, federal, state, and local standards, or market transformation.)

In addition to the quantity of achievable technical potential, the resource availability's timing presents a key consideration. For this analysis, resources split into two distinct categories:

- Discretionary resources: retrofit opportunities in existing facilities that, theoretically, remain available at any point over the course of the study period.
- Lost opportunity resources have pre-determined availability, such as replacements after equipment failures and opportunities in new construction.

2.1.1. About Levelized Costs

Cadmus grouped the achievable technical potential by levelized cost over the 20-year study horizon, allowing the Springs Utilities integrated resource planning (IRP) model to select the optimal DSM amount, given various assumptions regarding future resource requirements and costs. The 20-year levelized cost calculation incorporates numerous factors, which remain consistent with the values shown in Table 10.

Table 10. Levelized Cost Components

Type	Component
Costs	Incremental Measure Cost
	Incremental O&M Cost*
	Administrative Adder
Benefits	PV of Non-Energy Benefits
	Present Value of T&D Deferrals
	Secondary Energy Benefits

*Some measures may have a reduction in O&M costs, effectively treated as a benefit in the levelized cost calculation.

In addition to upfront capital costs and annual energy savings, the levelized cost calculation incorporates several other factors:

- Incremental Measure Costs. This study considers costs required to sustain savings over a 20-year horizon, including reinstallation costs for measures with useful lives less than 20 years. If a measure's useful life extends beyond the end of the 20-year horizon, Cadmus incorporates an end effect that treats the measure's levelized cost over its effective useful life (EUL)[1] with an annual reinstallation cost for the remainder of the 20-year period.[2]
- For example, Figure 6 shows the timing of initial and reinstallation costs for a measure with an eight-year EUL in the context of a 20-year study. The measure's final lifetime in this study ends after the study horizon; so the final four years (Year 17 through Year 20) will be treated differently by levelizing measure costs over the eight-year EUL, and treating these as annual reinstallation costs.

Figure 6. Illustration of End Effects

	Year																			
Cost Component	**1**	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**
Initial Capital Cost																				
Re-installation Cost																	End Effect			

- **Incremental Operations and Maintenance (O&M)** Costs or Benefits. As with incremental measure costs, O&M costs are considered annually over the 20-year study horizon. The present value is used to adjust the levelized cost upward for measures with costs above baseline technologies and downward for measures that decrease O&M costs.
- **Administrative adder**. Cadmus assumed a program administrative cost equal to 20% of incremental measures' costs for electric and gas measures across all sectors.

1 This refers to levelizing over the measure's useful life, the equivalent to spreading incremental measure costs over its EUL in equal payments, assuming a discount rate of Springs Utilities' weighted average capital cost.

2 This method is applied to measures with a useful life greater than 20 years and to those with a useful life extending beyond the 20th year at the time of reinstallation.

- Non-energy benefits are treated as a reduction in levelized costs for measures that save resources (such as water or detergent). For example, the value of reduced water consumption due to installations of low-flow showerheads reduce levelized costs of that measure.
- Secondary energy benefits are treated as a reduction in levelized costs for measures saving energy on secondary fuels. This treatment is necessitated by Cadmus' end-use approach to estimate technical potential. For example, consider the cost for of R-60 ceiling insulation for a home with a gas furnace and an electric cooling system. For the gas furnace end use, Cadmus considers energy savings that R-60 insulation produces for electric cooling systems, conditioned on the presence of a gas furnace, as a secondary benefit that reduces the levelized cost of the measure. This adjustment impacts only the measure's levelized costs; the magnitude of energy savings for the R-60 measure on the gas supply curve is not impacted by considering secondary energy benefits.

2.1.2. Data Sources

Conducting a full assessment of resource potential required compilation of a large set of measure-specific, technical, economic, and market data, obtained through secondary sources and primary research. The study's main data sources included the following:

- ***Springs Utilities internal data***. These include historical and projected sales and customers, hourly load profiles, and historic and projected DSM accomplishments.
- ***Primary data***. The study relied on several data sources specific to Springs Utilities' service territory and customers, including data collected via surveys and site visits as part of Springs Utilities' 2015/2016 DSM Potential Study.
- ***Secondary Colorado sources***. The study relied upon Xcel Energy's (CO) 2019/2020 Demand-Side Management Plan.
- ***Additional secondary sources***. The study relied on a number of secondary sources to characterize measures, assess baseline conditions, and benchmark results against other utilities' experiences. These sources included the California Energy Commission's Database of Energy Efficiency Resources (DEER), ENERGY STAR®, the Energy Information Administration (EIA), and various utilities' annual and evaluation reports on energy efficiency and DR programs.

2.2. Energy Efficiency

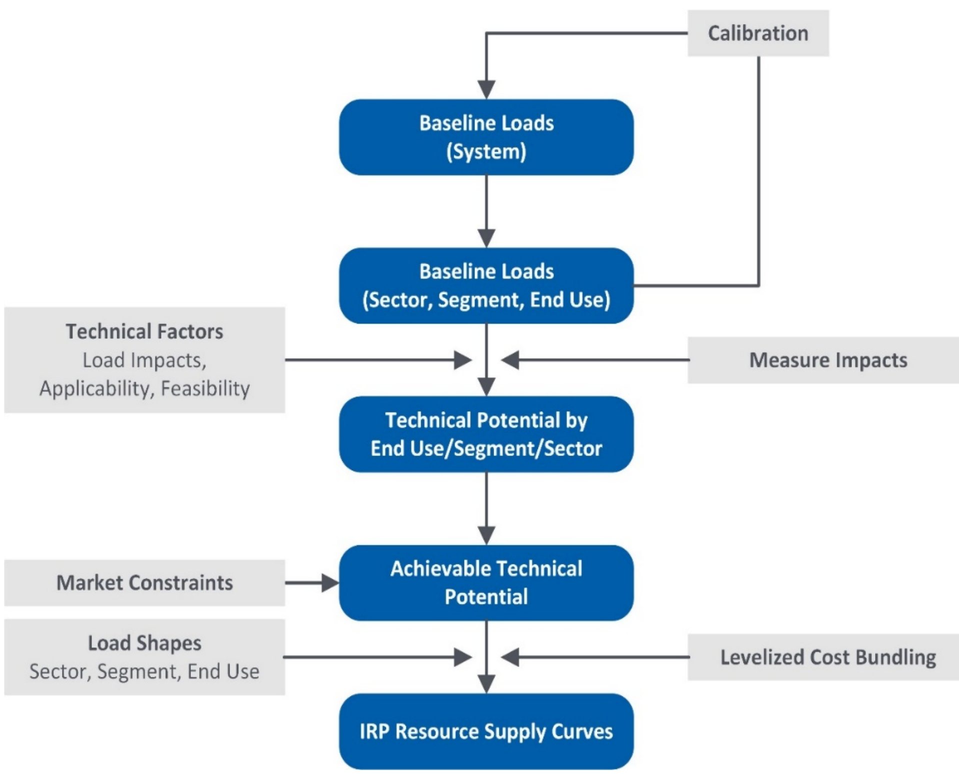
The methodology used for estimating technical and achievable technical energy efficiency potential drew upon standard industry practices and proved largely consistent with Cadmus's previous assessment of energy efficiency potentials for Colorado Springs Utilities' 2016 Demand-Side Management Potential Assessment. The general approach, shown in Figure 7, illustrates how baseline and efficiency data have been combined to develop potential estimates for use in Springs Utilities' IRP process. The study considered three types of potential—naturally occurring, technical, and achievable potential.

Naturally occurring conservation refers to reductions in energy use occurring due to normal market forces (such as technological change, energy prices, market transformation, improved building energy codes, and federal, state, and local equipment standards. The analysis accounted for naturally occurring conservation in three ways:

- First, the assessment accounted for gradual efficiency increases due to retirement of older equipment in existing buildings and subsequent replacements with units meeting minimum standards at that time. For some end uses, the technical potential associated with certain energy-efficient measures assumed a natural adoption rate. For example, savings associated with ENERGY STAR appliances accounted for current trends in customer adoption.
- Second, energy consumption characteristics of new construction reflected current building codes.
- Third, the assessment accounted for improvements in pending equipment efficiency standards that will take effect during the planning horizon. The assessment did not, however, forecast changes to standards that have not passed; rather, it treated these at a “frozen” efficiency level.

These impacts resulted in changed baseline sales, from which technical and achievable technical potential could be estimated.

Figure 7. General Methodology for Assessment of Energy Efficiency Potentials



Technical potential includes all technically feasible energy-efficient measures, regardless of costs or market barriers. Technical potential divides into two classes: discretionary (retrofits) and lost opportunities (new construction and replacement of equipment on burnout).

The study’s technical potential estimations for energy efficiency resources drew upon best-practice research methods and typical utility industry analytic techniques. Such techniques remained consistent with conceptual approaches and methodologies used by other planning entities as well as with methods used in Springs Utilities' 2015/2016 DSM Potential Study.

Achievable technical potential represents the portion of technical potential that might be reasonably achievable in the course of the 20-year planning period, given the possibility that market barriers could impede customer adoption. At this point, the examination did not consider cost-effectiveness as identified achievable technical potential levels principally serve as planning guidelines and information sources for the IRP process.

Developing sound utility IRPs requires a knowledge of alternative resource options and reliable information on the long-run resource potential of achievable technologies. DSM potential studies principally seek to develop reasonably reliable estimates of the magnitude, costs, and timing of resources likely available over the planning horizon's course. They do not, however, provide guidance regarding how or by what means identified resources might be acquired. For example, identified potential for electrical equipment or building shell measures might be attained through utility incentives, legislative action instituting more stringent efficiency codes and standards, or other means.

2.2.1. Overview to Estimating Energy Efficiency Potential

Estimating energy efficiency potential drew on a sequential analysis of various energy-efficient measures in terms of technical feasibility (technical potential) and expected market acceptance, considering normal barriers could possibly impede measure implementation (achievable technical potential). The assessment followed three primary steps:

- ***Baseline*** forecasting: determining 20-year future energy consumption by sector, market segment, and end use. The study calibrated the base year (2019) to Springs Utilities' sales forecasts. As discussed above, the baseline forecasts shown in this report include the Cadmus team's estimated impacts of naturally occurring potential.[3]
- Estimation ***of alternative forecasts of technical potential:*** estimating technical potential, based on alternative forecasts that technical impacts of specific energy-efficient measures.
- Estimation ***of achievable technical potential:*** achievable technical potential, calculated by applying ramp rates and an achievability percentage to the technical potential, as detailed later in this section.

This approach offered two advantages:

- First, savings estimates would be driven by a baseline calibrated to Springs Utilities' base year (2019) sales. Although subsequent baseline years may differ from Springs Utilities' sales forecast, comparisons to Springs Utilities'' sales forecast helped control for possible errors. Other approaches may simply generate total potential by summing estimated impacts of

[3] The Cadmus team's baseline forecast accounted for codes and standards not embedded in Springs Utilities' load forecast. Due to these adjustments, 2039 baseline sales presented in this report may not match Springs Utilities' sales forecasts.

individual measures, which can result in total savings estimates, representing unrealistically high or low baseline sales percentages.

- Second, the approach maintained consistency among all assumptions underlying the baseline and alternative (technical and achievable technical) forecasts. The alternative forecasts changed relevant inputs at the end-use level to reflect impacts from energy-efficient measures. As estimated savings represented the difference between baseline and alternative forecasts, they could be directly attributed to specific changes made to analysis inputs.

2.2.2. Developing Baseline Forecasts

The first step entailed creating a baseline (no-DSM) forecast. In the residential and commercial sectors, the analysis relied on a bottom-up forecasting approach, beginning with annual consumption estimates by segment, end use, and equipment efficiency level. Average base-year use per customer could then be calculated from saturations of equipment, efficient equipment, and fuel. Comparisons to historical use per customer validated these estimates, and a forecast of future energy sales could then be created, based on expected new construction and equipment turnover rates.

As standard practice in the industrial sector, Springs Utilities' industrial forecast has been disaggregated to end uses, based on primary data collected from Springs Utilities' 2015/2016 DSM Potential Study and on secondary data available from the EIA'S Manufacturing Energy Consumption Survey.[4]

To bundle potential by cost, Cadmus collected data on measure costs, savings, and market sizes at the most granular levels possible. Within each fuel and sector, the study distinguished between customer segments or facility types and their respective applicable end uses. Cadmus then conducted the analyses for the following customer segments:

- Four residential segments (existing and new construction for single-family and multifamily)
- Twenty commercial segments (10 building types within the existing and new construction vintages)
- Seventeen industrial segments (17 facility types, treated only as an existing construction vintage)
- Twenty military segments (10 building types within existing and new construction vintages)

2.2.3. Estimating Technical Potential

An important aspect of technical potential arises from it assuming installation of the highest-efficiency equipment, wherever possible. For example, this study examined solar water heaters, heat pump water heaters (HPWH), and efficient storage water heaters in residential applications with technical potential, assuming that, as equipment fails or new homes are built, customers will install solar water heaters wherever technically feasible, regardless of cost. Where applicable, HPWHs are assumed installed in

[4] Energy Information Administration. "Manufacturing Energy Consumption Survey (MECS)." Available online: http://www.eia.gov/consumption/manufacturing/index.cfm

homes ineligible for solar water heaters. The same proved true for efficient storage water heaters assumed to be installed in homes becoming ineligible for neither solar water heaters nor HPWHs. The study treats competing non-equipment measures in the same way, assuming installations of the highest-saving measures, where technically feasible.

In estimating technical potential, one cannot merely sum up savings from individual measure installations as significant interactive effects can result from installing complementary measures. For example, upgrading a heat pump in a home where insulation measures have already been installed can produce fewer savings than in an uninsulated home.

Analysis of technical potential accounted for two types of interactions:

- ***Interactions between equipment and non-equipment measures.*** As equipment burns out, technical potential assumes it will be replaced with higher-efficiency equipment, reducing average consumption across all customers. Reduced consumption causes non-equipment measures to save less than they would have the equipment remained at a constant average efficiency. Similarly, savings realized by replacing equipment decreased upon installation of non-equipment measures.
- ***Interactions between non-equipment measures.*** Two non-equipment measures applying to the same end use may not affect one another's savings. For example, installing a low-flow showerhead would not affect savings realized from installing a faucet aerator. Insulating hot water pipes, however, would cause water heaters to operate more efficiently, thus reducing savings from either measure. This assessment accounted for this interaction by "stacking" interactive measures—iteratively reducing baseline consumption as measures were installed, thus lowering savings from subsequent measures.

Although, theoretically, all retrofit opportunities in existing construction (often called "discretionary" resources) could be acquired in a study's first year, skewing the potential for equipment measures and providing an inaccurate picture of measure-level potential.

Therefore, the study assumed realizations for these opportunities in equal annual amounts, over the 20-year planning horizon. By applying this assumption, natural equipment turnover rates, and other adjustments (described above), the study estimated annual incremental and cumulative potential by sector, segment, construction vintage, end use, and measure.

To estimate technical potential, Cadmus developed a comprehensive list of measures for all sectors, segments, and end uses. For all sectors (i.e., residential, commercial, military, and industrial), the study began with a review of a broad range of energy-efficient measures. These measures were then screened to include only measures fitting the following criteria:

- Commonly available
- Based on a well-understood technology
- Applicable to Springs Utilities' buildings and end uses

As shown in Table 11, the study encompassed 568 unique electric, energy-efficient measures and 273 unique gas, energy-efficient measures. When expanded across segments, end uses, and construction vintages, this results in over 14,086 measures. (Appendix B provides a comprehensive list of measures included in the analysis, and Appendix C provides inputs and outputs.)

Table 11. Energy-Efficient Measure Counts by Fuel

Sector	Electric Measure Counts	Gas Measure Counts
Residential	121 unique 812 permutations across segments	75 unique 41 permutations across segments
Commercial	191 unique 3,886 permutations across segments	89 unique 2,104 permutations across segments
Industrial	65 unique 681 permutations across segments	20 unique 203 permutations across segments
Military	191 unique 3,886 permutations across segments	89 unique 2,104 permutations across segments

For every measure permutation contained in the study, Cadmus compiled the following key inputs, varying by segment and end use:

- ***Measure savings.*** Energy savings associated with a measure as a percentage of the total end-use consumption. Sources include engineering calculations and secondary sources, such as Xcel Energy's (CO) 2019/2020 Demand-Side Management Plan, the Regional Technical Forum (RTF), ENERGY STAR, DEER, the Northwest Power and Conservation Council, and various other state technical reference manuals (TRMs).
- ***Measure costs.*** Per-unit cost (full or incremental, depending on the application) associated with measure installations. Sources include the Xcel's 2019/2020 DSM Plan, the RTF, DEER, RS Means, and merchant websites.
- ***Measure life.*** The measure's expected useful life (EUL). Sources include Xcel Energy's (CO) 2019/2020 Demand-Side Management Plan, the RTF, ENERGY STAR, DEER, the Northwest Power and Conservation Council, and various state technical reference manuals (TRMs).
- ***Measure applicability.*** A general term encompassing multiple factors (such as the technical feasibility of installation, the measure's current saturation, measure interactions, competition, and projected market shares). Where possible, applicability factors drew upon Springs Utilities' data.

The study created an alternate sales forecast, incorporating the effects of all technically feasible measures; the difference between this forecast and the baseline forecast represented the technical potential. This method allowed for long-term technical potential estimates by measure, while accounting for changes in baseline conditions inherent in the baseline forecast.

2.2.4. Incorporation of Upcoming Codes and Standards

Although Cadmus' analysis does not attempt to predict how energy codes and standards may change, it captures information about enacted legislation, even if the legislation does not take effect for several years. Compared with Springs Utilities' 2015/2016 DSM potential study, the number of upcoming federal equipment standards proved much lower. The most notable, recent efficiency regulation incorporated into the study was the 2020 EISA backstop provision As the study's first year is 2020, the baseline technology is LEDs for residential and commercial screw-based lighting. Capturing the effects of this legislation proved especially important, as residential lighting has played a large role in Springs Utilities' energy efficiency programs over the past several years.

Table 12 provides a list of standards (starting in 2020) that Cadmus considered in this study. Standards enacted prior to 2020 have been accounted for equipment such as residential clothes washers, dryers, freezers, linear fluorescent lamps, microwaves, furnace fans (electrically commutated motors), and water heaters, each of which have been enacted since 2015.

Table 12. Pending Standards Accounted For—Electric End Uses

Equipment Type	Existing (Baseline) Standard	New Standard	Sectors Impacted	Study Effective Year
Air-Source Heat Pump	Federal standard 2015 (SEER/ EER 14/12 and HSPF 8.2)	Federal standard 2023 (SEER/EER 15/12.5 and HSPF 8.8)	Residential	2023
Central Air Conditioner	Federal standard 2015 (SEER/ EER 13/11.2)	Federal standard 2023 (SEER/EER 14/12)	Residential	2023
General Service Lamps	EISA Standard 2020 General Service Lamp	EISA Standard 2020 General Service Lamp	Residential Commercial	2020
Cooling (Direct Expansion)	Federal standard 2018 (12.9 IEER)	Federal standard 2023 (14.1 IEER, 3.4 COP)	Commercial	2023
Heat Pumps	Federal standard 2018 (12.9 IEER)	Federal standard 2023 (14.1 IEER, 3.4 COP)	Commercial	2023

To ensure an accurate assessment of remaining potential, Cadmus created a new forecast, netting out the effects of future standards. This forecast drew upon a strict interpretation of the legislation, assuming affected end uses would be replaced with technologies meeting minimum federal standards.

2.2.5. Naturally Occurring Conservation

Cadmus' baseline forecast includes naturally occurring conservation, referring to reductions in energy use occurring due to normal market forces (e.g., technological change, energy prices, market transformation efforts, improved energy codes and standards). These impacts changed baseline sales, from which the technical and achievable technical potential were estimated.

This analysis accounted for naturally occurring conservation in four ways:

- The potential associated with certain energy-efficient measures assumes a natural adoption rate, net of current saturation. For example, total potential savings associated with ENERGY STAR appliances account for current trends in customer adoption. As such, the total technical potential from ENERGY STAR appliances is reduced from the 2013 IRP, with these savings reflected in the baseline energy forecast.
- The assessment has accounted for gradual efficiency increases due to the retirement of older equipment in existing buildings, followed by replacement with units meeting or exceeding minimum standards at the time of replacement.

- The assessment has accounted for pending improvements to equipment efficiency standards, which will take effect during the planning horizon, as discussed above. The assessment does not, however, forecast changes to standards that have yet to be passed.

2.2.6. Achievable Technical Potential

Achievable technical potential can be defined as the portion of technical potential expected to be reasonably achievable over the course of a planning horizon. This estimate accounts for likely acquisition rates and market barriers to customer adoption, but it does not address cost-effectiveness or acquisition mechanisms (e.g., utility programs, codes and standards, market transformation). Thus, savings that a utility can expect to acquire cost-effectively may be substantially less than the achievable technical potential estimate.

Although estimating technical potential remains a fundamental engineering endeavor, based on industry-standard practices and methodologies, achievable potential proves more difficult to quantify and reliably predict as it depends on a large number of behavioral factors that tend to change unpredictably over time.

For this study, Cadmus drew upon survey results from Springs Utilities' 2016 DSM Potential Study to assess customers' willingness to adopt energy-efficiency measures at four levels, depending on the fraction of a measure's incremental cost covered by Springs Utilities incentives: (1) no incentive; (2) 50% incentive, 75% incentive, and 100% incentive. Each of these incentive levels corresponded to an achievable potential scenario, representing percent of long-run (20 years) technical potential considered achievable. To determine the *annual rate of deployment* of achievable potential over the study horizon, Cadmus relied on the same set of sigmoid-curve based ramp rates from the 2015/2016 DSM Potential Study.

2.3. Demand Response

DR programmatic options seek to achieve the following:

- Help reduce peak demand during system emergencies or periods of extreme market prices
- Promote improved system reliability
- In some cases, balance variable-load resources (particularly wind energy)

DR resource benefits accrue by providing incentives for customers to curtail loads during utility-specified events (e.g., direct load control [DLC]), or by offering pricing structures to induce participants to shift load away from peak periods (e.g., critical peak pricing programs).

To estimate electric DR market potential for Springs Utilities, Cadmus employed a similar, two-pronged approach (i.e., top-down and bottom-up methods) to that Cadmus employed for electric DR in the previous study. In contrast to that study, Cadmus also estimated several natural gas DR products in Springs Utilities' service territory. In its 2015 Gas IRP, Springs Utilities projected that natural gas demand would exceed supply, starting in the 2017–2018 heating season, and would continue to increase over the next 10 years. In this study, Cadmus analyzed gas DR as an option to sustainably curtail future peak-day and peak-hour customer gas demand.

Table 13 lists electric and gas DR products within this study's scope. For electric DR, Cadmus included several products in addition to those assessed in the previous study: residential and commercial DLC smart thermostat products with a bring-your-own-thermostat structure; and a residential DLC product controlling electric vehicle chargers. The resulting product list includes price- and incentive-based options for all major customer segments and end uses within Springs Utilities' service territory.

For gas DR, Cadmus evaluated five prototypical products (e.g., residential and commercial DLC smart thermostat products targeting gas space heating, residential gas DLC water heat, residential critical peak pricing). Due to the nascency of gas DR in the United States, this list captures almost all gas DR products in existing pilots and programs from other utilities.

Table 13. Electric and Gas Demand Response Products

Sector	Electric	Gas
Residential	DLC Smart Thermostat Direct Install*	Gas DLC Smart Thermostat BYOT
	DLC Smart Thermostat BYOT	Gas DLC Smart Thermostat Direct Install
	DLC EV Charger	Gas DLC Water Heat
	Critical Peak Pricing Opt-In*	Critical Peak Pricing Opt-In
Nonresidential	DLC BYOT	Commercial Gas DLC BYOT
	Load Curtailment*	
	CPP Opt-In*	

*These products were also assessed in the 2016 study.

2.3.1. Electric Demand Response

This study utilizes a two-pronged approach employing top-down and bottom-up methods for estimating electric DR potentials. Where appropriate, Cadmus updated assumptions from the previous Spring Utilities study, incorporating recent DR program experience and program plans as well as new benchmarked sources (including those in the region, such as Xcel's 2019–2020 DSM Plan and Black Hills Energy's 2018 Potential Study).

Top-Down Method

The top-down method estimates technical potential as a fraction of a participating facility's total peak-coincident demand. The calculation begins with disaggregating system electricity sales by sector, market segment, and end use, and then estimates technical potential as a fraction of the end-use loads. Total potential can then be estimated by aggregating the estimated load reductions of applicable end uses. The top-down estimation method is applied to DR products that target entire facilities or loads (rather than specific equipment): residential critical peak pricing (CPP), commercial load curtailment, and C&I CPP.

General analytic steps involved in estimating potential include the following:

1. **Disaggregate sales forecast by sector, segment, and end use.** The study first defined customer sectors and customer segments (listed in Table 14), disaggregating the 20-year forecast of total system electricity sales by sector and segment. Sales at the sector-segment level are then further broken out by the following end uses: cooking, cooling, heat pumps, heating, HVAC aux, lighting, plug load, refrigeration, and water heating. The customer segmentation and sales forecast data used in this step aligned with those used for energy efficiency.

Table 14. Electric Customer Sectors and Segments

Residential	Commercial	Industrial
Multifamily	Assembly	Chemical Manufacturing
Single-Family	Data Center	Electrical Equipment Manufacturing
	Education	Fabricated Metal Products
	Grocery	Food Manufacturing
	Health Care	Industrial Machinery
	Lodging	Miscellaneous Manufacturing
	Office	Nonmetallic Mineral Products
	Other	Paper Manufacturing
	Restaurant	Plastics Rubber Products
	Retail	Printing-Related Support
	Warehouse	Transportation Equipment Mfg.
		Wastewater
		Water

2. **Estimate utility-specific, peak-coincident, end-use loads.** Cadmus used Springs Utilities' summer peak period definition (June to August from 5:00 pm to 8:00 pm) and modeled the top 10 four-hour events within the peak period. Using the 40 selected hours and end-use load shapes employed in the previous study, Cadmus calculated the peak-coincident load (in megawatts) for every end use over the 20-year horizon.
3. **Screen customer segments for eligibility.** This step involved applying an eligibility percent to applicable peak-coincident end use loads for a specific program. For example, only nonresidential customers with maximum monthly demand of at least 100 kW could be considered eligible for the load curtailment program.
4. **Estimate technical potential.** Technical potential for a product was estimated as the sum of all eligible peak-coincident end-use load reductions from eligible customers.
5. **Estimate market potential.** Market potential accounted for customers' ability and willingness to participate in a program. Market potential estimates are derived from adjusting the technical potential by two factors—expected program participation rates (the percentage of customers likely to enroll in the program) and expected event participation rates (the percentage of customers that will participate in a DR event).
6. **Estimate levelized costs and develop supply curves.** The levelized cost ($/kW-year) of each program option was calculated using estimates of program development, technology, incentive, ongoing maintenance, administration, and communications costs. All economic inputs used are

aligned with those used in the energy efficiency analysis, including discount rate of 5.0% and line loss rate of 4.03%.

Bottom-Up Method

The bottom-up method differs from the top-down method in estimating ***technical potential***. In this study, Cadmus used this method for all DLC products as they affect a piece of equipment in a specific end use. In the bottom-up method, technical potential is determined as the product of three variables: the number of eligible customers, the equipment saturation rate, and the expected per-unit (kW) peak load impact:

1. **Gather customer count**. The bottom-up method starts with a 20-year customer count forecast of each sector-segment, derived from this study's energy efficiency analysis and—for the electric vehicles forecast—from this study's electric vehicles analysis.
2. **Apply eligibility and equipment saturation rates**. Equipment saturation represents the percentage of customers eligible for participating in the program (i.e., to participate in the residential DLC smart thermostat BYOT program, a customer have had a central air conditioner or air-source heat pump, along with an existing smart thermostat). Equipment saturation rates for residential customer segments were consistent with saturations used to estimate energy efficiency potential.
3. **Apply the per-unit impact to determine technical potential**. A program's technical potential was calculated as the product of the number of eligible pieces of equipment and the per-unit kilowatt peak load impacts. Where appropriate, Cadmus supplemented the per-unit kilowatt impacts assumed in the previous study with new benchmarked sources.

2.3.2. Gas Demand Response

The methodology to estimate electric DR potential broadly applies to gas DR potential. However, while electric DR potentials were presented in megawatts, gas DR potentials were presented in dekatherms during event peak-hours and event peak-days.

Gas DR serves as a relatively new strategy to curtail gas demand around the country; at the time of the study, only a few pilots and programs have been established. Cadmus conducted thorough benchmarking to compile the latest pilot results and program plans on gas DR, and used these sources to design the five prototypical products assessed in this study. These sources included the following:

- Southern California Gas 2017–2018 pilots (Nexant 2018), and 2019–2022 program plan (Hanway 2019)
- ConEdison 2017 potential study and 2018–2021 pilot plan (Navigant 2017)
- National Grid 2019 pilots in NY and MA (Roth 2019)

Almost all gas DR products in this study were DLC products targeting a single equipment piece. Consequently, Cadmus assessed them using the bottom-up method. In contrast to electric DR, however, gas DR is designed to alleviate gas pipeline congestion issues, which may occur during a single peak hour or last several hours during a peak day. Therefore, Cadmus analyzed gas DR potential by modeling a three-hour morning event during a winter peak day, and reported both peak-hour impacts and the peak-day impacts due to the event.

Peak Hour Impact

For each product, Cadmus began with a targeted piece of equipment's annual consumption in therms (from this study's energy efficiency analysis) and applied a peak-day factor and peak-hour factor to derive peak-hour consumption in therms. Cadmus based the peak-day factor (1.16%) and peak hour-factor (5.1%) on Springs Utilities' analysis of its gas peak.

With per-unit, peak-hour consumption, Cadmus applied a percent peak-hour impact (from benchmarking) to derive the per-unit technical potential for a single piece of equipment. Then, akin to the bottom-up method used for electric DR, aggregate technical potential across Springs Utilities' service territory was calculated as the product of customer count, equipment saturation, and per-unit technical potential. Lastly, achievable potential was derived by applying a program participation and event-participation rate to technical potential.

Peak-Day Impact

The peak-day impacts were calculated in a manner similar to peak-hour impacts, except per-unit technical potential was the product of per-unit annual consumption, the peak-day factor, and a percent peak-day impact (from benchmarking).

2.4. Customer-Sited Renewable Energy

2.4.1. Solar PV

Technical Potential Approach

Solar PV's technical potential depends on available rooftop areas of residential and commercial buildings, suitable for solar PV installation as well as for the power density of solar PV arrays, which become increasingly efficient and can be installed on available rooftop square areas. Cadmus assessed these factors using the following methods.

Available Roof Area

Cadmus calculated the available roof area, based on building square footage (from the residential customer survey[5] and the EIA's Commercial Building Energy Consumption Survey [CBECS]),[6] the number of floors (obtained from the CBECS), and a count of Springs Utilities' customer premises (to facilitate analysis of achievable technical potential, Cadmus estimated the number of commercial accounts with and without time-of-use [TOU] rates).

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[5] Residential building square feet are based on the customer survey conducted for Springs Utilities' 2016 DSM Study.

[6] Based on CBECS 2012 microdata analysis.

By dividing the overall square footage of each building category (e.g., single-family residential, education, office) by the average number of floors, Cadmus estimated the roof area available for each building type, as shown in Table 15.

Table 15. Available Roof Area by Building Type

Building Type	Average Building Area (sq. ft.)	Average Estimated Floors	Average Roof Area per Building (sq. Ft.)	Total Customer Premise Counts by 2039
Education	32,658	1.18	27,701	532
Grocery	5,509	1.21	4,547	331
Health Care	17,394	1.50	11,599	648
Lodging	45,529	2.26	20,141	882
Other	7,192	1.12	6,396	14,035
Assembly	13,801	1.43	9,671	1,171
Office	12,939	1.64	7,876	8,450
Restaurant	4,820	1.18	4,073	704
Retail	9,292	1.26	7,394	3,954
Warehouse	12,812	1.24	10,346	1,657
Total Commercial				**32,366**
Multifamily[1]	918	5.63	163	84,894
Single-Family	2,108	1.91	1,166	162,610
Total Residential				**247,504**

[1] Cadmus estimated the number of floors in multifamily buildings using data from EIA's 2009 Residential Energy Consumption Survey. As Cadmus received multifamily data by multifamily dwelling unit, we calculated the average roof square footage at the unit level.

Adjusted Available Area

Available raw area cannot be used directly for estimating technical potential as not every roof proves suitable for solar PV. To account for factors such as unsuitable roof orientation, shading, and obstructions, Cadmus relied on publicly available data from the Google Project Sunroof and Engineering analysis.[7] While Google Project Sunroof accounts for most unsuitable conditions, the likelihood of residential homeowners installing solar PV panels facing north, east, or west may not be practical. To avoid overestimation, Cadmus limited the feasible orientation to south (100%), west (50%), east (50%), and north (0%).

[7] Google Project Sunroof (https://www.google.com/get/sunroof) indicates that technical potential can vary by 25%, depending on definitions used and assumptions. "This tool estimates the technical solar potential of all buildings in a region. Technical potential includes electricity generated by the rooftop area suitable for solar panels assuming economics and grid integration are not a constraint. There are many definitions of technical potential, and other definitions may affect results by 25% or more." Cadmus adjusted potential downward by 25% to account for these variations within Google Project Sunroof data.

To derive the technical constraints assumptions illustrated in Table 16, Cadmus calculated the total available, suitable, rooftop square footage for the residential and commercial sectors using Google Project Sunroof data, dividing the suitable square footage by total available rooftop square footage for the residential and commercial sectors. Cadmus applied these constraints to the total available Roof Area Square footage for residential and commercial customers in Springs Utilities' service area.

Table 16. Technical Constraints Assumptions by Sector

Sector/Building Type	Technical Constraints Assumptions
Residential	29%
Commercial	62%

Module Power Density

Cadmus determined the solar PV-module power density using assumptions from the National Renewable Energy Laboratory's (NREL) 2018 national rooftop solar potential assessment (160 peak watts/square meter in 2017, which Cadmus converted to 14.86 watts per square foot).[8] Cadmus developed estimates for solar PV modules' future efficiency, according to trends from the International Technology Roadmap for Photovoltaic.[9] In 2039, the assumed Colorado module power density is 18.27 watts per square foot, indicating a 23% increase in efficiency over 22 years.

Electricity Generation

Upon establishing potential solar PV capacity, Cadmus converted this figure into annualized electricity (kilowatt-hour) generation. To approximate the generation profile for a typical solar PV system within Springs Utilities 's service territory, Cadmus used a capacity factor, calculated using existing solar installations from Springs Utilities' solar PV metering data. This resulted in using an average capacity factor of 0.224 to estimate electric generation.

Calculation of Technical Potential

Cadmus calculated technical potential for solar PV installations in Springs Utilities' service area by multiplying customer counts for each building type by the average, adjusted, available roof area for each building type, and then multiplying the total available rooftop area for the commercial and residential sectors by the module power densities. Estimates for each study year varied, according to customer-count forecasts for each building type, and to improvements in module efficiencies (and converted installed capacity to technically achievable electric generation, as described above).

8 Estimating rooftop solar technical potential across the United States using a combination of GIS-bases methods, lidar data, and statistical modeling: https://iopscience.iop.org/article/10.1088/1748-9326/aaa554/pdf

9 International Technology Roadmap for Photovoltaic: https://itrpv.vdma.org/en/ueber-uns

Program Accomplishments

Springs Utilities tracks solar PV system installations within its territory. To account for historical solar PV installation activities and to avoid overestimating potential, Cadmus summarized Springs Utilities' tracking data from 2006 through May 2019. During this period, over 1,800 residential and commercial solar PV systems were installed, resulting in roughly 10 MW of solar PV capacity. To avoid overcounting the available potential, the potential study analysis removed program accomplishments for installed capacity.

Achievable Potential Approach

After calculating the technical potential, providing a theoretical upper bound on solar PV capacity growth, Cadmus considered relevant market factors (e.g., current costs, projected future cost trends, past adoption) to determine likely solar PV installations in Springs Utilities' service territory. To assess achievable potential, Cadmus examined sector and customer economics for solar PV adoption in terms of simple paybacks, followed by considering the impacts of federal tax credits, incentives, policies, and avoided electric utility charges to calculate achievable potential for multiple policy-based and rate scenarios.

The examination included the following scenarios:

- **Low-Incentive Scenario (residential and commercial potential)**: The low-incentive scenario assumed no extension of federal investment tax credits, no Colorado sales tax exemption, and no Springs Utilities incentives for solar PV installations. The scenario assumed avoided residential electric cost savings at the residential E1R rate. Cadmus calculated commercial avoided electric savings as a blend of avoided commercial TOU (ECT)[10] and standard commercial rates (E2C). Cadmus calculated the percent of customers on TOU rates from Springs Utilities' 2018 nonresidential customer billing data.
- **Business-as-Usual Scenario:** The business-as-usual scenario did not assume extension of the federal investment tax credit, continued sales tax exemptions, and continued Springs Utilities incentives. Rather, the scenario assumed avoided electric cost savings as described in the low-incentive scenario, above.
- **Extended Investment Tax Credit (ITC) Scenario (residential and commercial potential)**: The extended ITC scenario assumed a continued 30% ITC for the remainder of the program period, continued sales tax exemptions, and continued Springs Utilities incentives. The scenario assumed avoided electric cost savings, as described above.
- **Best-Case Scenario (residential and commercial potential):** The best-case scenario assumed a continued 30% ITC for the remainder of the program period, continued sales tax exemptions,

[10] Cadmus calculated an avoided TOU rate as the average avoided electric rate, based on solar PV generation patterns calculated from NREL's Hourly PV Performance data for Colorado Springs. Available online: https://pvwattt.nrel.gov

and doubled Springs Utilities incentives. The scenario assumed avoided electric cost savings as described above.

- **Rate Case Scenario A (residential only):** Scenario A assumed two rate periods, with the peak period from 6:00 pm to 10:00 pm and current customer charges. Other assumptions derived from the Business-as-Usual Scenario.
- **Rate Case Scenario B (residential only):** Scenario B assumed the same structure as the two peak-period scenarios, with increased daily customer charges. Other assumptions drew upon the Business-as-Usual Scenario.
- **Rate Case Scenario C (residential only):** Scenario C assumed three rate periods, with a critical peak period from 6:00 pm to 9:00 pm in June, July, and August; and a peak period from 5:00 pm to 6:00 pm and 9:00 pm to 10:00 pm year-round. Other assumptions drew upon the Business-as-Usual Scenario.
- **Rate Case Scenario D (residential only):** Scenario D assumed the same structure as the three peak period scenario, including an increased daily customer charge. Other assumptions drew upon the Business-as-Usual Scenario.

While Cadmus did not model rate scenarios for commercial potential, it did account for commercial customers on TOU (or standard plans) by modeling market adoption rates separately for each commercial rate class, and applying those rates to estimated technical potential per class. Cadmus weighted this technical potential based on the number of customers in each rate class and the available roof area square footage.

Customer payback. A metric commonly used in selling energy efficiency and renewable energy technologies, annualized simple payback (ASP) is a simplistic calculation that customers can easily and intuitively understand, providing a key factor in their financial decision-making processes. For this analysis, Cadmus calculated simple payback using the following equation for each scenario described above:

$$ASP = \frac{Net\ Costs\ (after\ applicable\ incentives\ and\ avoided\ electric\ charges)}{Annual\ Energy\ Savings\ (avoided\ electric\ costs)}$$

Although conceptually simple, the mix of incentives and cost projections added complexity to the calculations.

Installed costs. Cadmus based these assumptions regarding Solar PV system costs on a variety of public data sources, reviewing cost forecasts for residential and commercial solar installations. These costs did not include any incentives; they are based on full costs of an installation. Cadmus developed the solar PV dollars per watt cost estimates for this study from three major sources:

- 2018 Lazard Levelized Cost of Energy analysis for national solar prices[11]
- 2017 and 2018 NREL forecasts for residential- and commercial-scale PV pricing to 2050[12]
- 2019 EnergySage reported costs for installed residential solar systems in Colorado's state[13]

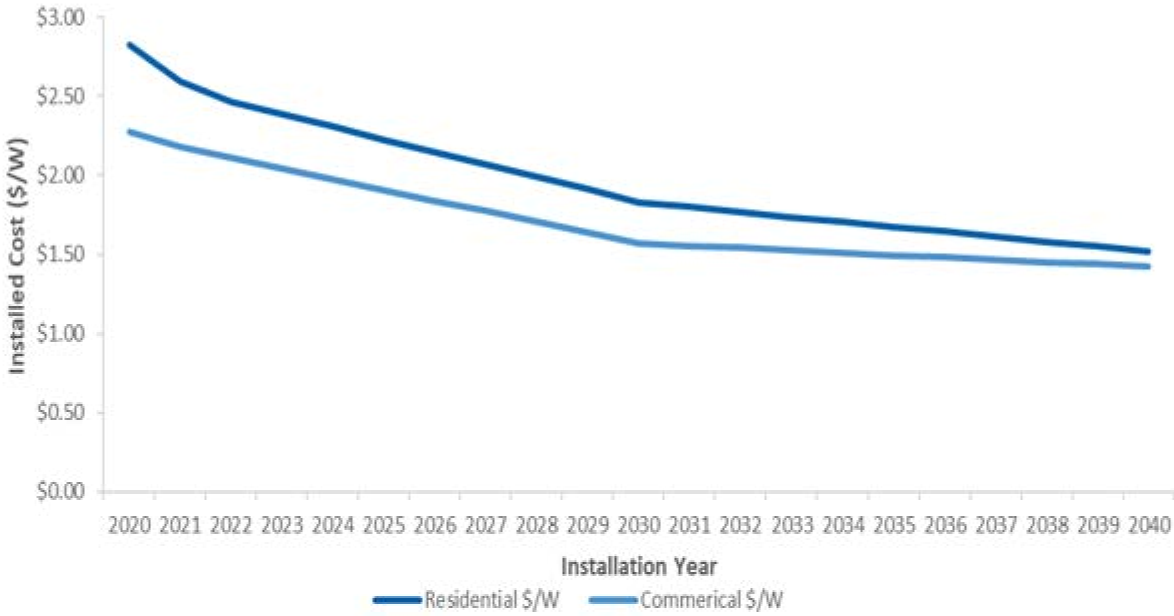
Using a combination of these sources to forecast solar PV dollars per watt. Cadmus employed Energy Sage data as a first-year $/watt value for residential installations, and projected cost changes using NREL cost forecasts. The 2019 installation cost for residential systems was $3.17/watt. For commercial installations, Cadmus used Lazard Levelized Cost of Energy Analysis data as the first year (2019) value, and applied NREL cost data to forecast installation cost changes. This resulted in a first-year installation cost of $2.58/watt for commercial Solar PV systems. Figure 8 shows the projected, installed $/watt forecast for residential and commercial systems over the planning horizon.

[11] Lazard's Levelized Cost of Energy Analysis, Version 12, November 2018. Available online: https://www.lazard.com/media/450784/lazards-levelized-cost-of-energy-version-120-vfinal.pdf

[12] NREL provides an annual set of modeling input assumptions for energy technologies; known as the Annual Technology Baseline, this includes residential and commercial PV. Available online: https://atb.nrel.gov

[13] EnergySage is an online marketplace for residential solar installations that gathers actual quotes from installers. Available online: https://www.energysage.com/solar-panels/solar-panel-cost/co/

Figure 8. Projected Installed PV Costs by Sector (2020–2039)



Cadmus did not include O&M costs in the simple payback calculation as these costs rarely reflected the solar PV system sales process. As the market penetration model uses simple payback to predict customer purchasing-decisions, and O&M costs occur after a purchase has been made, Cadmus deliberately excluded these costs from analysis.

Market penetration rates. Predicting which portion of technically feasible sites will install solar PV systems during the assessment period follows a complex process, driven by many policy, economic, and technical factors beyond the direct control of Springs Utilities. Cadmus modeled these factors using their impacts on a quantitative metric (such as customer simple paybacks), running these for a variety of prototypical scenarios.

This model estimates (a percentage of) market penetration as a function of customer payback. The following equation provided the curve used in the analysis:

$$MP = A * e^{-B*ASP}$$

where MP equals the annual percentage of technically feasible solar PV potential adopted in the commercial and residential sectors; ASP equals the annual simple payback (years).

For this analysis, Cadmus calculated ASP from the customers' perspectives, including all relevant incentives and fitting the curve to historical adoption rates from Springs Utilities' solar PV metering data. This curve-fitting process allowed Cadmus to account for, broadly speaking, regional attitudes and bias that might lead end-use customers to adopt solar PV at a given ASP level (the above equation shows these empirical factors as A and B).

2.4.2. Battery Storage

Technical Potential Methodology

Cadmus determined the technical potential for residential, behind-the-meter energy storage in three separate categories:

- Potential based on the sum of nameplate capacity
- Total time-shifted energy potential, based on a TOU rate structure
- Demand potential as part of a DR program
- In the following sections, Cadmus documents the methodology for each potential category.

For the potential analysis, Cadmus identified the Tesla Powerwall as a representative, behind-the-meter, storage technology for residential applications. In 2015, the Powerwall provided the first mass-market lithium-ion residential battery storage device, making up the large majority of residential battery installations in Springs Utilities' service territory in recent years. By using a single battery technology, Cadmus could reduce technological and financial variability, thereby simplifying the analysis.

Cadmus excluded the multifamily market, focusing on the single-family housing market for this analysis. Since creation of the market in 2015, residential-scale, lithium-ion, battery storage systems have been exclusively marketed to single-family customers. As battery companies have not yet started marketing battery systems configured to meet the needs of multifamily customers that incorporate solar PV systems, Cadmus did not analyze the multifamily segment's potential at this time.

Nameplate Storage Technical Potential

Cadmus determined the total nameplate, residential, storage capacity potential by using data from the solar PV potential study, identifying the total number of single-family homes considered viable for a solar PV system. Applying additional technical feasibility factors of 90% and 95%, Cadmus accounted for the fraction of solar PV-viable homes containing (respectively) the necessary electrical infrastructure and space limitations to install an energy storage system. Table 17 shows the single-family home forecast used for the technical potential study.

Table 17. Single-Family Homes Forecast Applied to Technical Potential

Study Year	Total Single-Family Homes	Solar PV Viable Homes	Solar-Plus-Storage Viable Homes
2020	131,658	38,262	32,714
2021	133,167	38,701	33,089
2022	134,699	39,146	33,470
2023	136,249	39,597	33,855
2024	137,807	40,050	34,242
2025	139,380	40,507	34,633
2026	140,971	40,969	35,029
2027	142,566	41,433	35,425
2028	144,165	41,897	35,822
2029	145,760	42,361	36,219
2030	147,363	42,827	36,617

Study Year	Total Single-Family Homes	Solar PV Viable Homes	Solar-Plus-Storage Viable Homes
2031	148,985	43,298	37,020
2032	150,623	43,774	37,427
2033	152,280	44,256	37,839
2034	153,955	44,742	38,255
2035	155,649	45,235	38,676
2036	157,361	45,732	39,101
2037	159,092	46,235	39,531
2038	160,841	46,744	39,966
2039	162,610	47,258	40,405

While a single Powerwall has a nameplate capacity of 5 kW, multiple batteries can be stacked to create a larger system. Tesla's marketing materials recommend two batteries for a 2,100 square foot home (the average single-family home size in the Springs Utilities service territory), but customers can purchase systems up to 50 kW in size. To determine an average system size, Cadmus used historical battery installation data, provided by Springs Utilities. We calculated an average system size of 1.57 batteries or a nameplate capacity of 7.85 kW. We determined the final nameplate technical potential by multiplying the number of homes viable for solar-plus storage systems with the average nameplate storage system capacity.

Time-Shift Energy Technical Potential

Cadmus determined the technical potential in terms of total time-shifted energy capacity by modelling the annual storage dispatch of a residential, solar-plus-storage system using StorageVET 1.1 modeling software.[14] StorageVET (i.e., Storage Value Estimation Tool) is a free, open-source software, developed by the Electric Power Research Institute. The technical potential analysis considered all homes with an installed storage system to be a part of Springs Utilities' TOU residential rate structure. Although the current fraction of Springs Utilities' residential customers on the TOU rate structure is very small, this rate structure allows significant financial benefits for any home with a storage energy system. Therefore, customers purchasing a battery system would likely switch voluntarily to this rate structure.

Using a solar-plus-storage system with the TOU rate structure allows two separate revenue streams for a homeowner. When the solar array produces electricity during off-peak hours (when energy prices are lower), this electricity can be stored in the battery bank and for use during on-peak hours, when energy prices are higher. The battery bank can also charge directly from the grid during off-peak hours for use in the home or for sale back to the grid during on-peak hours. For this revenue stream, the home's battery bank acts essentially to extend the period that the home can use less expensive off-peak electricity.

StorageVET

Cadmus modelled the solar-plus storage system's interaction with the TOU rate structure using StorageVET V1.1., which relies on user inputs. This includes the battery system's technical specifications,

[14] StorageVET Version 1.1. Electric Power Research Institute. Available online: www.storagevet.com

load profile, solar PV production profile, and rate structure to calculate a time-series dispatch, based on economic optimization of battery usage for each hour in the system's lifetime.

For battery system technical specification inputs, Cadmus used values from the Tesla Powerwall specification sheet and, where necessary, default values from StorageVET. These inputs can be found in Table 18 for a 5 kW Powerwall system. For the hourly site load input data, we used the average residential system customer load profile (rate class E1R), provided by Springs Utilities. For the PV load profile, we used NREL's online PVWatts calculator to calculate hourly power production for an average-sized 4.39 kW residential PV system, located within the Springs Utilities service territory. Cadmus used Springs Utilities' current residential TOU rate structure to determine future residential customer rates by applying an average escalation rate of 2.9%.[15]

Table 18. StorageVET Technical Inputs for a 5 kW Powerwall System

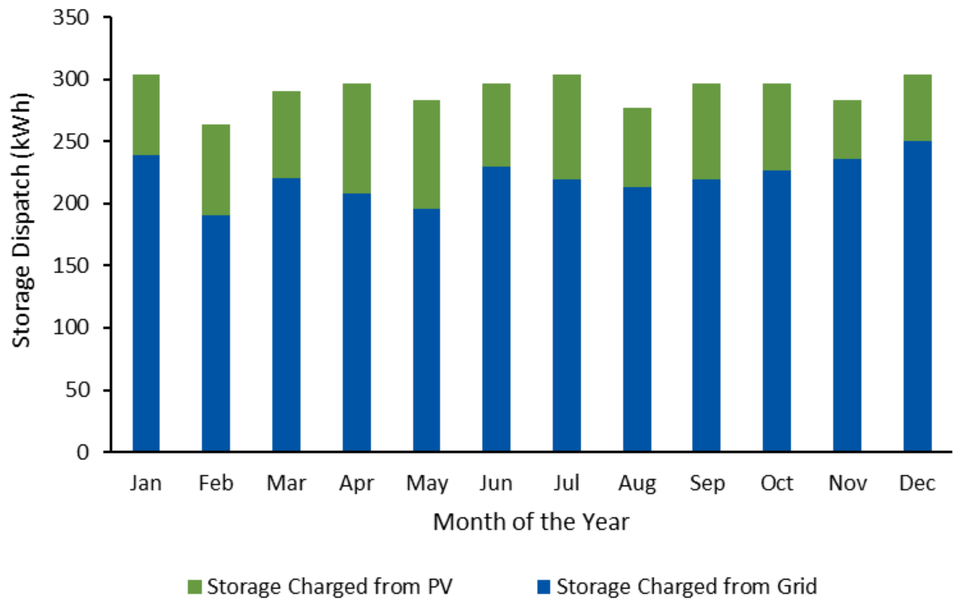
Input	Value	Source
Charge Capacity	5 kW	EnergySage
Discharge Capacity	5 kW	Tesla Powerwall datasheet
Energy Storage Capacity	13.5 kW	Tesla Powerwall datasheet
Round Trip Efficiency	90%	Tesla Powerwall datasheet
Charge Efficiency	94.9%	Engineering judgement, assuming equal charge and discharge efficiency
Discharge Efficiency	94.9%	Engineering judgement, assuming equal charge and discharge efficiency
Self-Discharge Rate	0%/hour	StorageVET default
Calendar Life Degradation	3%/yr	StorageVET default
Minimum Discharge Capacity	0%	EnergySage

StorageVET can generate a range of outputs that cover hourly operations of a modeled solar-plus-storage system. For this potential study, Cadmus used the hourly storage dispatch, paired with the monthly charge allocation to calculate total annual time-shifted energy dispatched by the battery system.

By multiplying the hourly storage dispatch with the fraction charging from the grid or from the PV array, Cadmus could separate out the fraction of battery dispatch used to time-shift energy from the grid or from the PV array. Figure 9 shows the time-shifted energy dispatch for a 5kW Powerwall system, split into energy charged from the grid and from the PV array over the course of a year.

[15] Projection was calculated from Colorado state historical retail rates for the past 10 years, derived from EIA Form 861 data.

Figure 9. Monthly Storage Dispatch for a 5 kW Powerwall System



Cadmus conducted this analysis in StorageVET for a home with a 4.39 kW solar PV system and a 5 kW, 10 kW, and 20 kW storage system. We then weighted the results produced by these three simulations using system sizes of all Powerwall systems installed in the Springs Utilities territory in 2018 and 2019. Table 19 shows the analysis results for an average battery system of 1.57 batteries.

Table 19. Annual Time-Shift Energy Discharge for Residential Solar-Plus-Storage Systems

Simulation Output	5-kW System	10-kW System	20-kW System	Average System (1.57 Batteries)
Discharge (kWh, from Grid)	2,648	6,133	13,122	4,619
Discharge (kWh, from PV)	846	855	855	850
Discharge (kWh, Total)	3,494	6,988	13,977	5,469
Weight	52%	43%	4%	

Demand Response Technical Potential

To calculate the technical potential of a DR program, based on residential battery storage, Cadmus used a bottom-up DR approach, described in section 2.3.1, to assess potential for DR products affecting a specific piece of equipment in a home. While typically used for products such as water-heating equipment or smart thermostats, the same approach can be applied to a home battery system. Using modeling inputs such as the average DR event duration, customer participation rate, available power from the customer, and events per year, we can estimate the technical potential of a single DR event in kW and the technical potential of an annual program in MWh.

Table 20 lists input assumptions used for the bottom-up DR approach. Cadmus designed this DR model as a typical peak-shaving program, though a battery DR program could be expanded with additional DR events to address grid services besides critical peaking.

Table 20. Modeling Inputs for Residential Battery Storage DR Program

Input	Value	Source
DR Program Ramp Years	7	Assumption. Aligns with other residential electric DR DLC products.
DR Event Duration in Hours	4	
DR Event Customer Available Power (kW)	4	Assumption. Based on nameplate capacity in a Powerwall battery.
DR Events Per Year	10	Assumption. Aligns with other residential electric DR direct load control products.
DR Program Customer Participation	30%	
DR Program Event Participation	100%	
DR Program Switch Success Rate	100%	
Line Loss	4.03%	Springs Utilities-provided value for the 2019 DSM Potential Study.

Achievable Potential Methodology

The technical potential analysis results detailed above represent a theoretical upper limit on the growth of the residential solar-plus-storage market in Springs Utilities' service territory. After calculating the technical potential, Cadmus determined the achievable potential, based on projected growth trends in the residential storage market. We purchased the market growth forecast from the Q2 2019 U.S. Energy Storage Monitor published by Wood Mackenzie.

This report shows the expected residential storage market size projected to 2024. Using these values, Cadmus further projected them to the end of the study period. We then applied the annual growth rate for each study period year to the current number of Powerwall battery systems installed in Springs Utilities' service territory to determine an expected battery system count for each study period year. Table 21 shows the cumulative battery and system forecast for each study period year, with the system count calculated by dividing the battery count by the average system size of 1.57 batteries.

Table 21. Cumulative Achievable Battery Installation Forecast

Study Year	Achievable Battery Installation Forecast	Achievable System Installation Forecast
2020	125	80
2021	239	153
2022	345	220
2023	490	313
2024	688	440
2025	904	578
2026	1,148	733
2027	1,421	908
2028	1,722	1,100
2029	2,052	1,311
2030	2,411	1,540
2031	2,798	1,788
2032	3,214	2,053
2033	3,658	2,337
2034	4,131	2,639
2035	4,632	2,959
2036	5,162	3,298
2037	5,721	3,655
2038	6,308	4,030
2039	6,924	4,424

Nameplate Storage Achievable Potential

Using the battery installation forecast provided in Table 21, Cadmus determined the achievable nameplate residential storage capacity potential by applying the 5-kW nameplate capacity of a Powerwall system. Additionally, we applied a 96% factor to account for the fraction of battery system installations that do not include solar PV. Though most residential storage systems are installed alongside a solar PV array, a small fraction are not. Battery installation data provided by Springs Utilities did not indicate whether systems were installed alongside solar PV; so Cadmus used the Interconnection Queue Summary from the New York State Department of Public Service.

Time-Shift Energy Achievable Potential

Cadmus determined achievable potential in terms of total time-shifted energy capacity using the same methods as the technical potential analysis. We multiplied annual time-shift energy discharge values (shown in Table 19) with the achievable system installation forecast (shown in Table 21) to derive total achievable potential of time-shifted energy charged from the grid, both from the PV array and for the total system.

Demand Response Achievable Potential

Cadmus calculated the achievable potential of a DR program, based on residential battery storage using the same process as the technical potential analysis. This combined the Cadmus bottom-up DR approach and the modelling inputs in Table 20. By replacing the number of customer counts from the technical potential with the forecast of achievable system installations (Table 21), Cadmus determined the achievable DR potential for the study period.

Tipping Point Analysis Methodology

Cadmus conducted a tipping point analysis to determine at what point during the study period residential storage systems became cost-effective in Springs Utilities' service territory. For projects starting at seven different years during the study period, we calculated the total capital cost of a solar-plus-storage system and the total net present benefits from this system. Using these two values, Cadmus calculated the participant cost-test ratio to determine when the system would become cost-effective and can pay for itself without additional incentives.

Cadmus then calculated total capital costs using all available incentives, including the federal investment tax credit (assumed to fully expire by 2022). Using StorageVET, Cadmus extrapolated the benefits for each year in the battery system's lifetime, and then calculated the net present value of these future benefits using the Springs Utilities-provided discount rate of 5%. For all StorageVET simulations, Cadmus used an average solar PV system size of 4.39 kW and a battery system of one 5 kW Powerwall, in addition to a battery system size of 5 kW for the tipping point analysis as reliable installation cost data are only available at this size and not for a stacked system of 10 kW or larger.

Battery System Cost Estimates

Cadmus purchased a residential battery storage report from Wood Mackenzie that detailed the complete material costs bill for a 5 kW Powerwall system, projected for each year to 2022. These costs could be broken down further by category, including battery, solar-ready inverter, labor, and balance of system costs. We used these cost trends to project costs for a Powerwall system for the remainder of the study period. We also used an EnergySage 2019 market review of the Tesla Powerwall as a source for the most realistic estimate for an array installation labor costs.

To cover a wide range of future outcomes, Cadmus conducted the tipping-point analysis around three cost scenarios: a low, middle, and high (shown in Table 22). We varied these cost scenarios, based on different labor cost estimates, keeping all other costs equal to values found in the EnergySage market review. The low-cost scenario uses labor costs from the Wood Mackenzie report. The middle-cost scenario uses a labor cost that is an average of the Wood Mackenzie value and the midpoint of the EnergySage labor cost range. The high-cost scenario uses the upper limit of the EnergySage cost range.

Table 22. Tipping Point Cost Scenarios

Labor Cost Estimate	Labor Price	Total System Price
Low Cost	$2,031	$9,831
Middle Cost	$3,516	$11,316
High Cost	$8,000	$15,800

Vanadium Flow Batteries

Cadmus reviewed all available materials to determine how to incorporate vanadium flow batteries into the tipping-point analysis. What discovered that vanadium flow technology remains too early in its development stage to accurately predict future costs. Currently, no battery companies offer a residential vanadium flow product on the market for purchase. With the technology in such an early stage, this means no cost research is available from which Cadmus could derive future cost estimates. Without sources for current or future costs, we cannot conduct a tipping-point analysis of vanadium flow at this time.

2.5. Electric Vehicles

Given the uncertainty about future transportation behaviors and EV market dynamics due to ongoing technology improvements and cost reductions, the increasing availability of affordable used EVs, and shifts in the EV policy environment, past trends in EV adoption, car ownership, and vehicle miles traveled (VMT) likely will not predict the future.

This analysis utilizes scenario modeling to support Springs Utilities' understanding and preparing for a range of potential futures. To estimate the potential of electrical vehicles, Cadmus established a historical adoption baseline, projecting three scenarios of continued adoption out to 2050 (a low-growth scenario, a medium-growth scenario, and a high-growth scenario), estimated new load growth, demand impacts, and EV charging infrastructure associated with each of those scenarios.

According to the Alliance of Auto Manufacturers' Advanced Technology Vehicles Sales Dashboard, Colorado experienced the fifth-highest EV market share in the nation in 2018, due in part to their strong EV policies and programs, which include substantial tax credits for new EVs, and incentive programs for charging infrastructure.[16]

Additional programs and incentives exist throughout the state, including sales tax exemptions for alternative fuel vehicles, "right-to-charge" legislation for tenants, HOV lane exemptions, and education campaigns. On top of these policies, Colorado recently became the latest state to adopt California's ZEV mandate. The strength of the state's policy environment, and in particular the statewide target set in 2018 for EVs on the road by 2030, informed development of the high-growth scenario. In addition to serving as a strong policy environment, technology improvements and cost reductions likely to drive market growth. The International Council on Clean Transportation estimates shorter-range EVs will reach upfront cost parity with conventional vehicles in Colorado between 2024 and 2026, with longer-range EVs between 2027 and 2029.[17]

EV Adoption Baseline

Cadmus first established an EV growth baseline in El Paso County and Colorado by analyzing EV registration data from Colorado Interactive's database of DMV records and the CO's Statewide ZEV Sales Dashboard. Total registered vehicles data were included in the analysis to account for the entire

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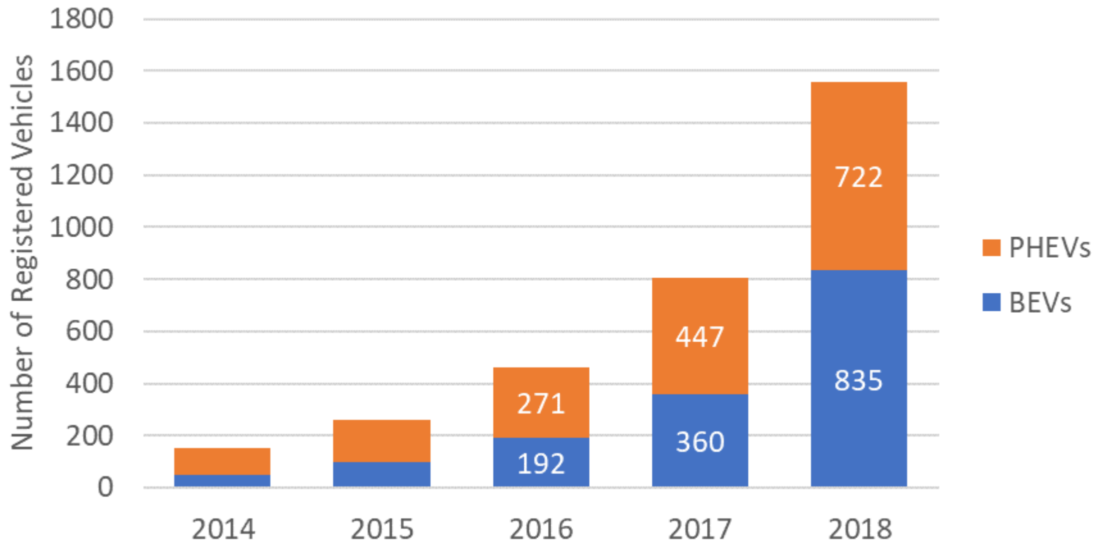
16 EV Market Share by State. 2018. Available online: https://evadoption.com/ev-market-share/ev-market-share-state/

17 ICCT. Electric Vehicle Costs and Consumer Benefits in CO in the 2020–2030 Time Frame. Available online: https://theicct.org/sites/default/files/publications/ev_Colorado_cost_2020_20190613.pdf

county's fleet. EV registration data in El Paso County ranged from 2014 to 2018, broken into Battery Electric Vehicles (BEVs) and Plug-in Hybrid Electric Vehicles (PHEV). Figure 10 shows the growth in the number of EVs registered over the past five years.

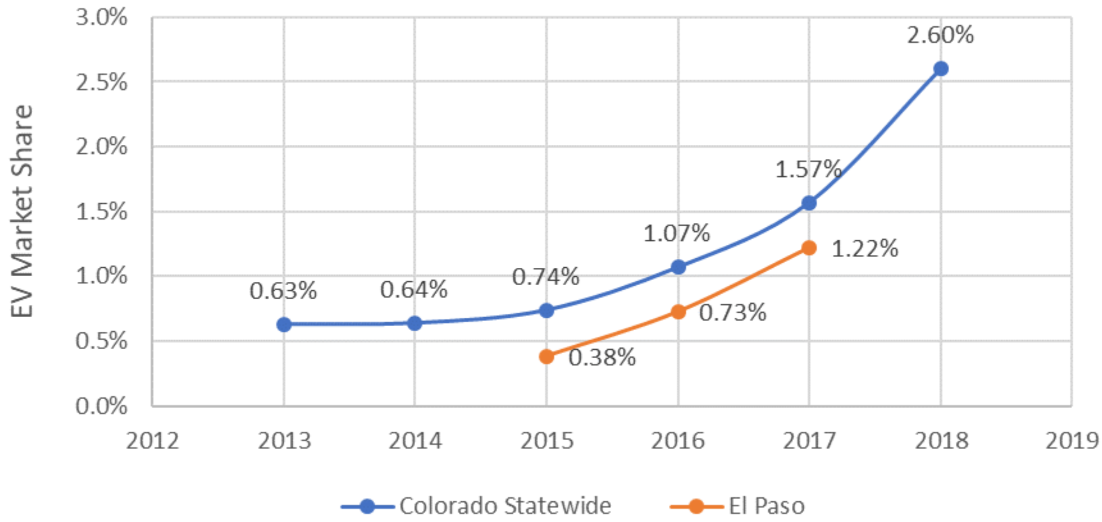
Figure 10. Number of Registered EVs in El Paso County



Due to changes in DMV data collection, El Paso County new vehicle sales were available only through 2017, enabling comparisons of countywide market shares to Colorado statewide market shares over three years.[18] Between 2015 and 2017, El Paso County EV market shares slightly trailed statewide market shares, though has been trending closer to the statewide figures. The EV market share from 2017, the last year of full data from El Paso County, was 1.22%, compared to 1.57% statewide. Figure 11 shows the trend in EV market shares in Colorado and El Paso County.

[18] El Paso County, CO. DMV Statistical Data. Available online: https://clerkandrecorder.elpasoco.com/motor-vehicle-department/statistical-data/

Figure 11. EV Market Share in Colorado and El Paso County



Cadmus also determined a baseline for public EV charging infrastructure already built in El Paso County, utilizing data available through the Alternative Fuels Data Center (AFDC).[19] EV chargers vary by charging speeds and access. Chargers listed on AFDC include Level 2 or DCFC, and some have different access levels to different types of drivers. Table 23 lists the current state of publicly listed charging infrastructure available in El Paso County.[20]

Table 23. EVSE Plugs Listed on AFDC (as of July 30, 2019)

Access	Level 2	DCFC	Total
Public	18	6	24
Public with restrictions	16	8	24
Private	15	0	15
Tesla	9	8	17
Total	**58**	**22**	**80**

EV Adoption Scenarios

Three scenarios were projected forward to 2050: a low-growth scenario, a medium-growth scenario, and a high-growth scenario. Cadmus utilized its custom vehicle stock-turnover model to identify impacts

19 U.S. Department of Energy. Energy Efficiency and Renewable Energy, Alternative Fuels Data Center – Electric Vehicle Charging Station Locations. Available online: https://afdc.energy.gov/fuels/electricity_locations.html#/find/nearest?fuel=ELEC

20 Though public chargers are available to everyone, some have restrictions, such as the time of day that the charger is available, or availability only to an establishments' customers. Private chargers may only be available to a workplace's employees (for example). Tesla chargers are only compatible with Tesla vehicles.

of different EV adoption scenarios for the overall vehicle fleet over time, focused on the light-duty vehicle fleet, including passenger cars and light trucks (e.g., vans, SUVs, and pickups with gross vehicle weight ratings under 8,500 pounds). Scenarios for medium- or heavy-duty vehicle electrification were not modeled. The light-duty vehicle model utilized national scrappage rates,[21] adapting many inputs to El Paso County, modeling the fuel types, efficiencies, miles driven, and energy needs and emissions of the in-use light duty vehicle fleet each year.

The low-growth scenario used a linear extrapolation, based on historical EV adoption data from El Paso County. A linear trend was fitted to the data and extended out to 2050, estimating total EVs purchased every year. This scenario modeled a conservative 0.63% increase per year in EV sales, reaching 22% of new sales by 2050.

The medium-growth scenario was modeled based on a portfolio of independent forecasts that factor in customer-preference models, cost-parity projections, manufacturer-profitability considerations, and fuel-efficiency standards, aligning closely with a November 2018 Edison Electric Institute forecast for the U.S.[22]

The high-growth scenario assumed that EV sales in El Paso County accelerated sufficiently to meet their portion of Colorado's statewide target (940,000 EVs by 2030). The county would reach 113,000 EVs by 2030, and EV sales would then level off at 60% of the market by 2050.

Key Data Sources

Table 24 lists data sources used to complete this analysis.

Table 24. Key Data Sources for Fleet Stock-Turnover Model

Data Point	Sources
EV Registrations	El Paso County: CO Interactive CO Statewide: ZEV Sales Dashboard
Total Registered Vehicles	Historic: El Paso County Clerk and Recorder Projected: Based on DOLA population projections and current vehicle per capita ratios Share of cars vs light trucks: the U.S. DOT Volpe Center's Corporate Average Fuel Economy (CAFE) Model
EV Charging	Existing EV Chargers: Alternative Fuels Data Center (AFDC) Estimated EV Charger Needs: NREL EVI-Pro Lite tool Percent drivers with Level 1 or 2 charging at home: 75%, estimate based on Census data, RECS survey data

21 NHTSA. Vehicle Survivability and Travel Mileage Schedules. 2006. Available online: https://crashstats.nhtsa.dot.gov/Api/Public/ViewPublication/809952

22 Edison Electric Institute. Electric Vehicle Sales Forecast and Charging Infrastructure Required through 2030. Available online: https://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20Report_Nov2018.pdf

Data Point	Sources
Vehicle Scrappage Rates	U.S. National Highway Traffic Safety Administration (NHTSA). Vehicle Survivability Tables
VMT	U.S. National Highway Traffic Safety Administration (NHTSA). Travel Mileage by Vehicle Age Tables
Fuel Economy	Conventional vehicle fuel economy: CAFE Standards per 40 CFR 86.1818-12(h) BEV and PHEV efficiencies: mixture of assumptions from www.fueleconomy.gov and the AFLEET tool, combined with a 1% increase in efficiency per year

To estimate the amount of public-charging infrastructure required to support different EV adoption levels, Cadmus utilized the NREL Electric Vehicle Infrastructure Projection tool (EVI-Pro Lite).[23] This tool uses demographic and travel behavior data from major cities and metropolitan areas to estimate the number and type of chargers (DCFC, L2 Workplace, L2 Public) needed to support the number of EVs input by users. A key model input was the number of drivers with access to EV charging at home. Cadmus estimated the percentage of EV-owning households in El Paso County likely to lack access to charging at home (estimated 25%), based on American Community Survey data for the number of households living in multifamily buildings and owning or renting their homes.[24]

The model then estimated the expected number of Level 1 and Level 2 chargers used by those drivers who charge at home. Based on the Edison Electric Institute's report "Electric Vehicle Sales Forecast and the Charging Infrastructure Required through 2030," not all EV drivers who can charge at home are expected to install a Level 2 charger: one-half are expected to install Level 2 chargers, while the rest are anticipated to use Level 1 charging (i.e., a typical wall outlet).[25]

The American Community Survey also provided data on the number of employees commuting to El Paso County jobs by car, which Cadmus used to calibrate estimates of workplace plugs.

[23] U.S. Department of Energy and NREL. Alternative Fuels Data Center, EVI-Pro tool. Available online: https://afdc.energy.gov/evi-pro-lite

[24] United States Census Bureau. American Community Survey. Available online: https://factfinder.census.gov/faces/nav/jsf/pages/index.xhtml

[25] Edison Electric Institute. Electric Vehicle Sales Forecast and Charging Infrastructure Required through 2030. Available online: https://www.edisonfoundation.net/iei/publications/Documents/IEI_EEI%20EV%20Forecast%20Report_Nov2018.pdf

3. Energy Efficiency Potential

3.1. Scope of Analysis

Springs Utilities requires accurate estimates of available energy efficiency potential as these are essential for its electric IRP, GIRP, short-term energy plan, and program planning efforts. Springs Utilities bundles these potentials in terms of levelized costs of conserved energy; so, its IRP models can determine the optimal amount of energy efficiency potential that Springs Utilities should select.

To support these efforts, Cadmus performed an in-depth assessment of technical potential and achievable technical potential for electric and natural gas resources in the residential, commercial, industrial, and military sectors.

This section divides into two parts: the first summarizes resource potentials by fuel and sector; and the second presents detailed results by fuel and sector.

3.2. Summary of Resource Potentials—Electric

Table 25 shows 2039 forecasted baseline electric sales and potential by sector.[26] Cadmus' analysis indicated that 1,110 GWh of technically feasible electric energy efficiency potential would be available by 2039, the end of the 20-year planning horizon and translating to an achievable technical potential of 701 GWh. Should all of this potential prove cost-effective and realizable, it would result in a 16% reduction in 2039 forecasted retail sales.

Table 25. Electric 20-Year Cumulative Energy Efficiency Potential

Sector	2039 Baseline Sales (MWh)	2039 Technical Potential (MWh)	Technical Potential as a Percent of Sales	2039 Achievable Technical Potential (MWh)	Achievable Technical Potential as a Percent of Sales
Residential	1,564,870	487,072	31%	301,541	19%
Commercial	2,025,091	479,112	24%	299,322	15%
Industrial	551,859	75,743	14%	57,995	11%
Military	292,229	67,666	23%	42,065	14%
Total	**4,434,050**	**1,109,594**	**25%**	**700,922**	**16%**

Figure 12 shows the 20-year achievable technical potential, represented as a supply curve of conserved energy. The supply curve indicates the relationship between each sector's cumulative (through 2039) electric, energy efficiency, achievable technical potential and the corresponding cost of conserved electricity. For example, approximately 473,451 MWh of achievable technical potential exists, at a cost of less than $80 per MWh.

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[26] These savings derive from future consumption forecasts, absent utility program activities. Note that consumption forecasts account for savings that Springs Utilities has acquired in the past, but the estimated potential is inclusive of—not in addition to—current or forecasted program savings.

Figure 12. Electric 20-Year Cumulative Energy Efficiency Supply Curve

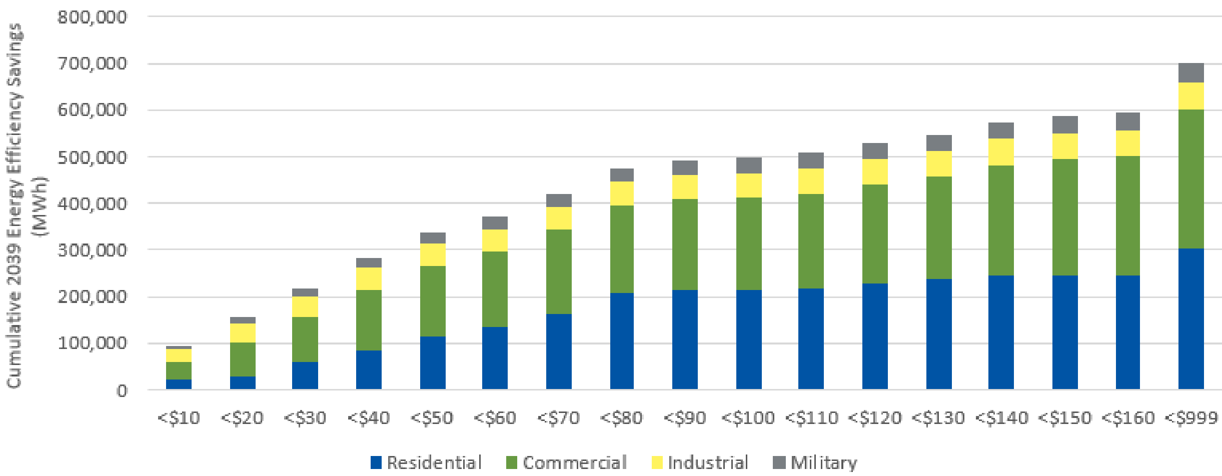
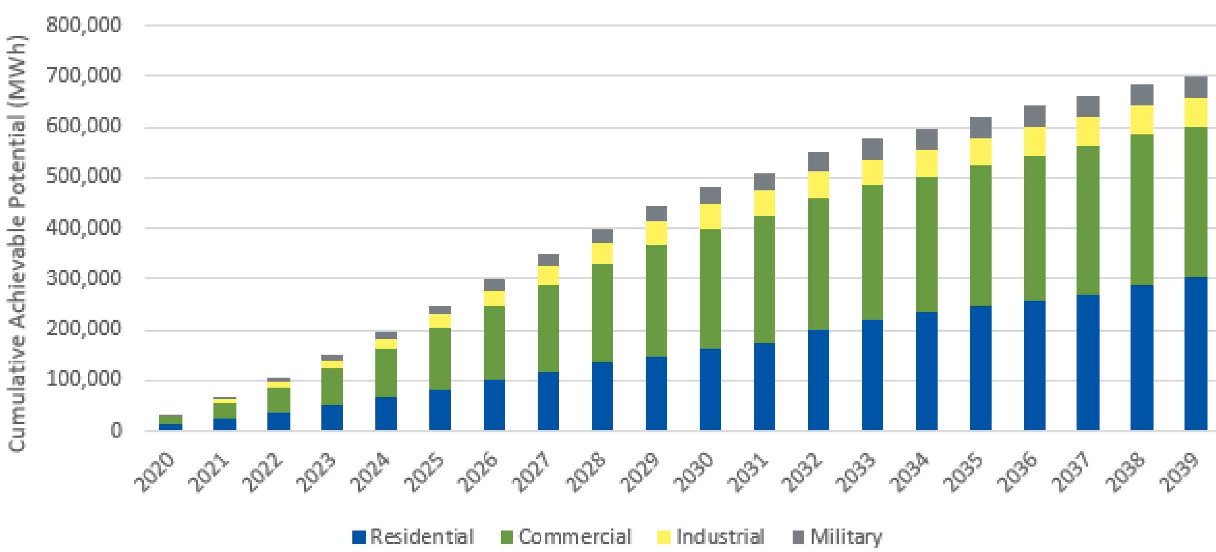


Figure 13 illustrates cumulative potential annually available in each sector. The slight change in slope depends on the discretionary and lost opportunity resources rate in which savings will be acquired. For example, most discretionary resources will be acquired within the first 10 years (2020 and 2029), and the majority remaining potential after 2029 will be achieved by lost opportunity resources.

Figure 13. Electric Energy 20-Year Efficiency Potential Forecast



3.3. Summary of Resource Potentials – Gas

Table 26 lists the 2039 forecasted baseline natural gas sales and potential by sector. The study results indicate roughly 49.4 million therms of achievable technical energy efficiency potential by 2039, the end of the 20-year planning horizon. Should all of this potential prove cost-effective and realizable, it will amount to a 19% reduction in 2035 forecasted retail sales.

Table 26. Natural Gas 20-Year Cumulative Energy Efficiency Potential

Sector	2039 Baseline Sales (Therms)	2039 Technical Potential (Therms)	Technical Potential as a Percent of Sales	2039 Achievable Technical Potential (Therms)	Achievable Technical Potential as a Percent of Sales
Residential	158,575,723	49,136,275	31%	27,150,308	17%
Commercial	73,938,458	28,765,607	39%	16,425,582	22%
Industrial	12,309,336	2,979,269	24%	2,409,227	20%
Military	17,304,963	6,069,078	35%	3,449,981	20%
Total	**262,128,480**	**86,950,229**	**33%**	**49,435,098**	**19%**

The supply curve shown in Figure 14 indicates the relationship between identified, achievable technical potential and the corresponding costs of conserved energy. For example, roughly 19.5 million therms of achievable technical potential will be available at a cost of less than $0.90 per therm.

Figure 14. Natural Gas 20-Year Cumulative Energy Efficiency Supply Curve

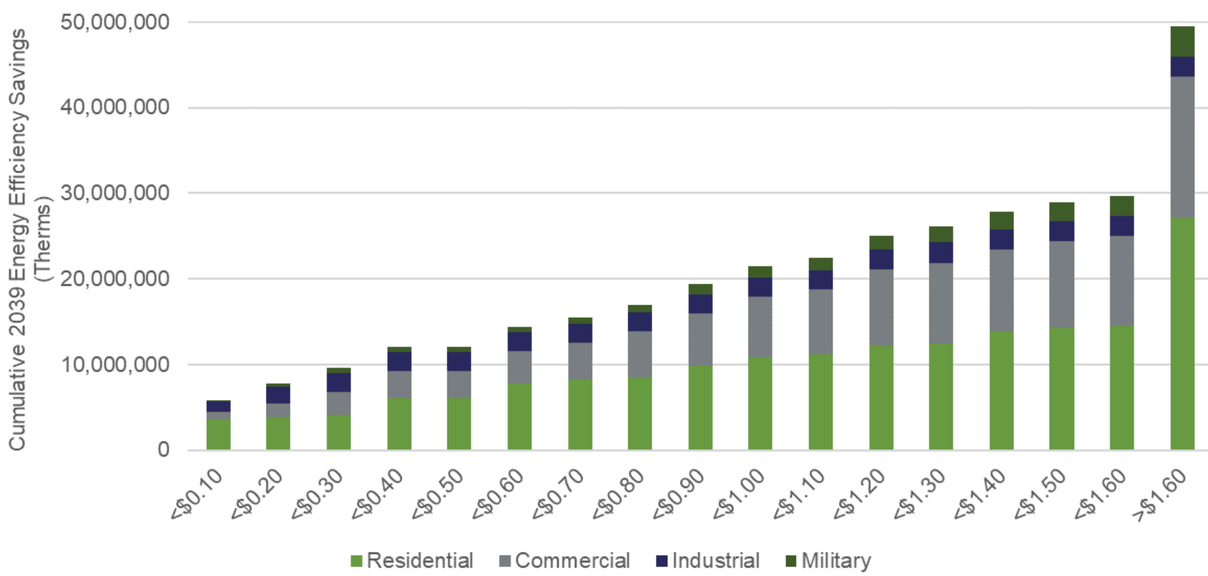
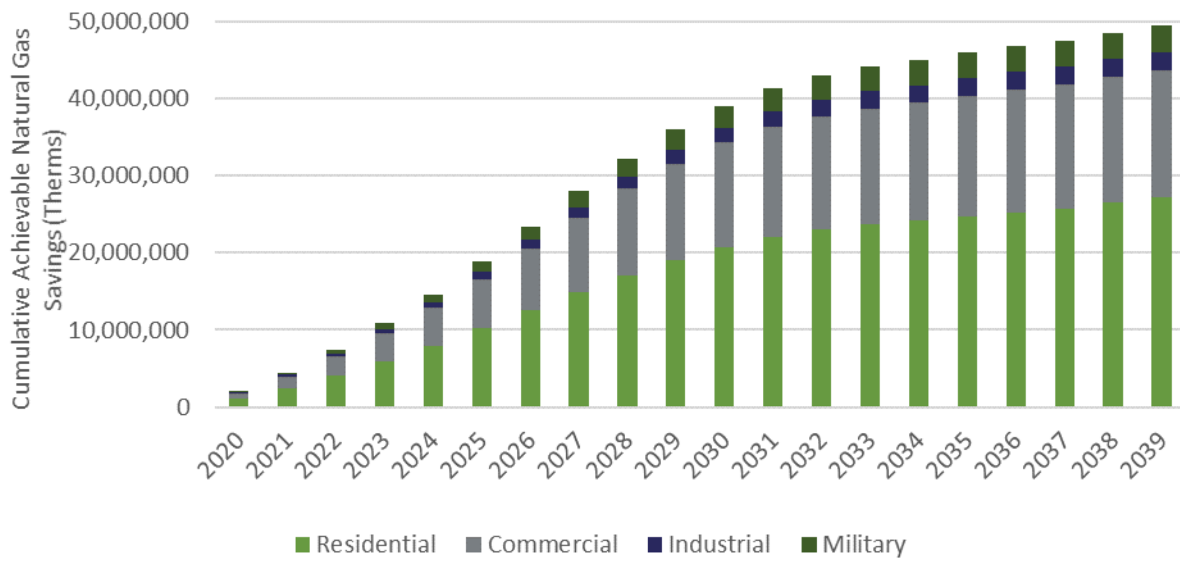


Figure 15 shows cumulative potential annually available in each sector. As with electric potential, the study assumes most achievable discretionary opportunities will be acquired within the first 10 years of the study, from 2020 through 2029.

Figure 15. Natural Gas 20-Year Energy Efficiency Potential Forecast



3.4. Detailed Resource Potential—Electric

3.4.1. Residential Sector—Electric

By 2039, residential customers in Springs Utilities' service territory will likely account for 35% of baseline electric retail sales. The single-family and multifamily dwellings in this sector present a variety of potential savings sources, including equipment-efficiency upgrades (e.g., heat pumps, refrigerators), improvements to building shells (e.g., insulation, windows, air sealing), and increases in lighting efficiency (e.g., LEDs). As described in the General Approach and Methodology section, the expected impacts of new lighting standards established through EISA have diminished the available lighting potential.

As shown in Figure 16, single-family homes represent 66% of the total achievable, technical, residential electric potential by 2039, with the remaining potential achieved by multifamily (34%). Each home type's proportion of baseline sales served as the primary driver of these results, but other factors—such as heating fuel sources and equipment saturations—play important roles in determining potential.

For example, a higher percentage of multifamily buildings use electric heat than single-family building, increasing their relative share of potential. Multifamily dwellings, however, are typically smaller than detached, single-family homes, *and* they experience lower per-customer energy. Therefore, the same measure may save less in a multifamily dwelling than in a single-family home. (Volume II, Appendix C provides a comprehensive list of factors affecting segment-level energy efficiency potential.)

Figure 16. Residential Electric Achievable Technical Potential Forecast by Segment

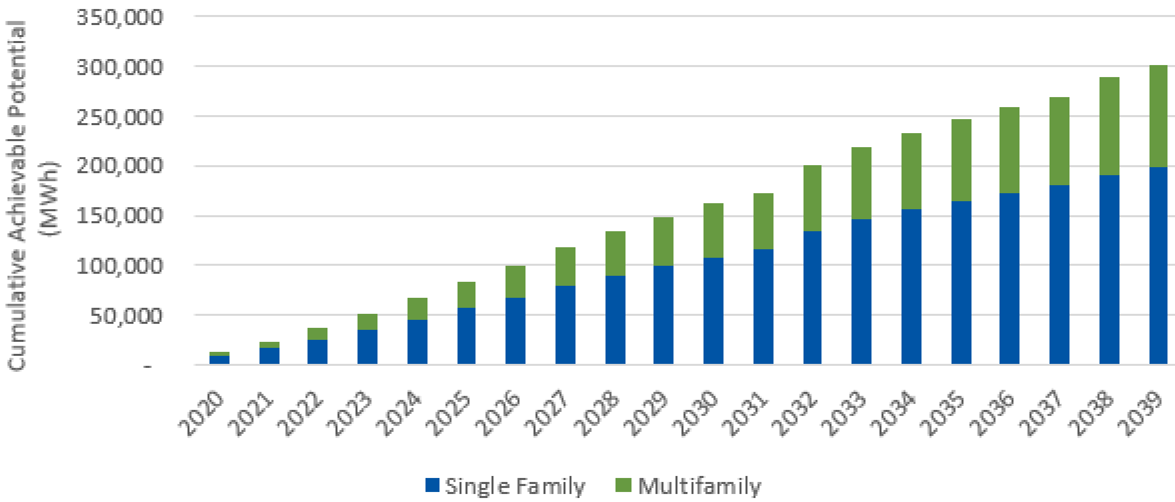


Figure 17 shows cumulative, achievable technical potential by residential end use. Water heating end uses represent the largest portion (28%) of achievable technical potential, with space heating end uses representing the second-largest portion (24%). Appliances (17%) and plug loads (13%) represented most of the remaining achievable technical potential. Historically speaking the lighting end use has typically seen considerably higher energy efficiency potential amounts in prior potential assessments across the country, including the previous Springs Utilities study. The lighting end use comprises only 8% of total residential electric energy efficiency potential due to the 2020 EISA backstop standard. (Volume II, Appendix C provides additional details on savings associated with specific measures assessed in each end use.)

Figure 17. Residential Electric Achievable Technical Potential by End Use

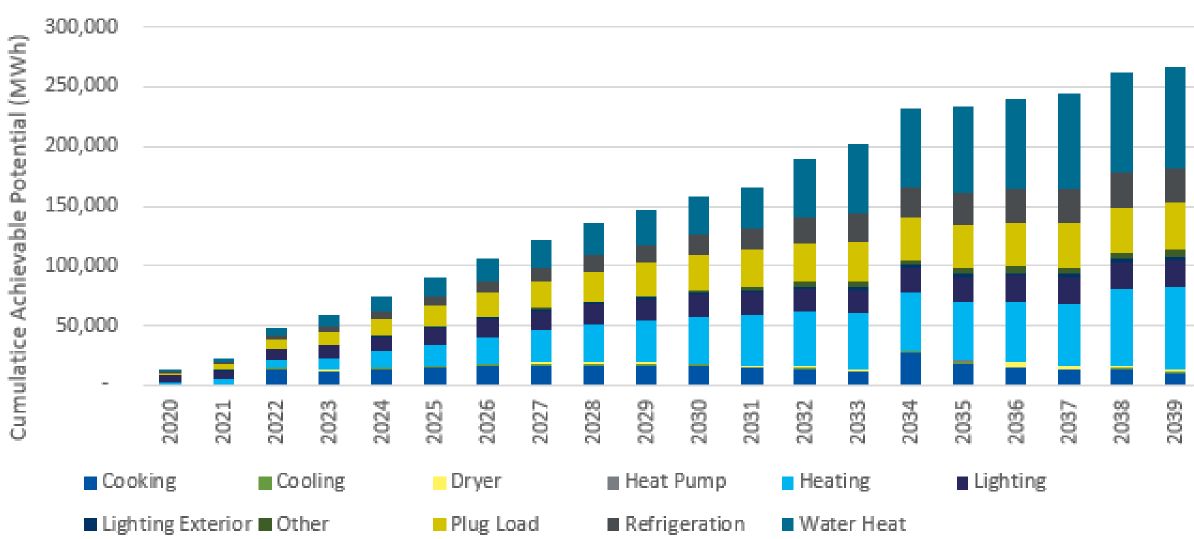


Table 27 lists the top 15 residential, electric, energy efficiency measures, ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for 218.5 GWh, or approximately 72% of the total residential achievable technical potential, although Tier 2 HPWHs represent the single measure with the highest energy savings, with six of the top 15 measures reducing electric heating loads. These measures include equipment measures (i.e., ductless heat pumps and air-source heat pumps) and retrofit measures (i.e. air sealing, learning Wi-Fi thermostats, attic insulation, the HVAC portion of indirect energy feedback/behavioral measure).

Table 27. Top Residential Electric Measures

Measure Name	Weighted Average Levelized Cost ($/kWh)	Achievable Technical Potential (MWh)	
		20-Year Achievable Technical	10-Year Achievable Technical
Heat Pump Water Heater - CEE Advanced Tier	$0.075	39,623	9,061
Conversion Electric Furnace to Air Source Heat Pump	$0.073	30,789	9,548
Indirect Energy Feedback	$0.036	27,087	24,038
Heat Pump Water Heater - CEE Tier 2	$0.063	21,837	4,970
Dryer - Heat Pump Dryer	$0.177	15,442	4,117
Refrigerator - CEE Tier 3	$0.041	14,190	3,316
Lighting Specialty Lamp - LED - CEE Tier 2	$0.041	10,456	8,738
Air Sealing	$0.203	8,911	7,399
Ductless Mini-Split HP / AC - ENERGY STAR 2019 Most Efficient	$0.022	8,787	2,692
Refrigerator Recycling without Replacement	$0.031	8,543	7,094
Dryer - CEE Advanced Tier	$0.240	8,020	1,804
Air Purifier - ENERGY STAR	$0.000	6,442	1,645
Learning Wi-Fi Thermostat	$0.083	6,425	4,200
Ceiling / Attic Insulation	$0.374	6,240	5,091
Showerhead Low Flow	$0.002	5,786	5,102

3.4.2. Commercial Sector—Electric

Based on energy efficiency measure resources used in this assessment, electric, energy efficiency, achievable technical potential in the commercial sector will likely be 299 GWh over 20 years, approximately a 15% reduction in forecasted 2039 commercial sales.

Figure 18 represents the commercial, electric, achievable technical potential by segment type through the 20-year planning horizon. The office, retail, and other segments represent 30%, 14%, and 11%, respectively, of total commercial achievable technical potential; no other single commercial segment represents more than 7% of commercial, achievable technical potential. The other segment includes customers that do not fit into other categories, along with customers producing insufficient information for classification.

Figure 18. Commercial Electric Achievable Technical Potential Forecast by Segment

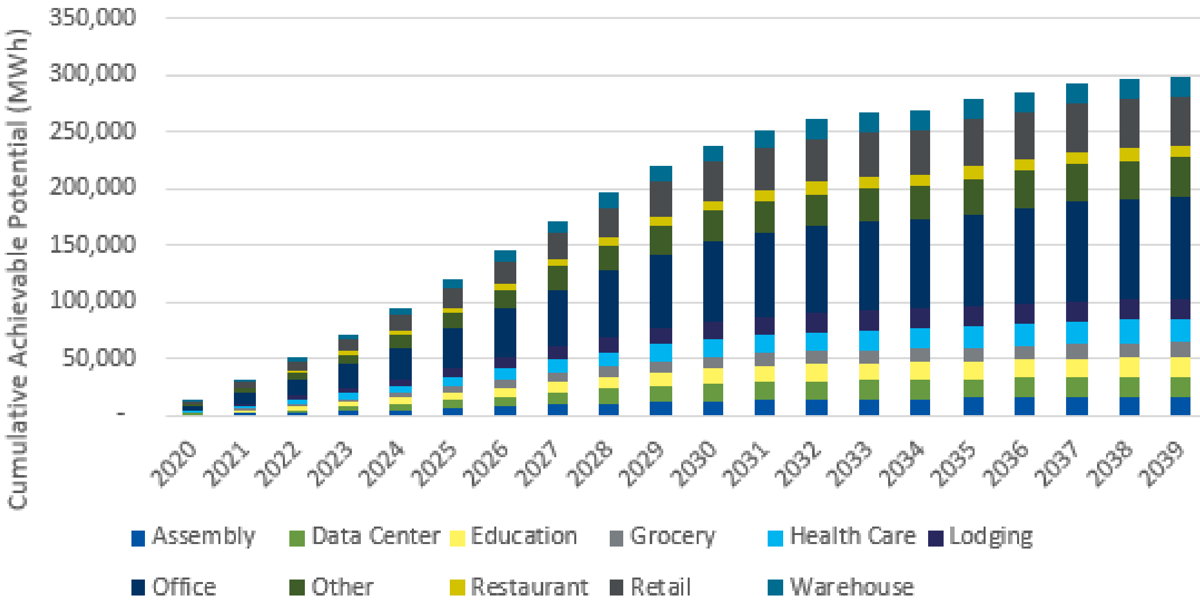


Figure 19 presents the cumulative, electric, commercial end use, achievable technical by end use. By far, lighting efficiency improvements represent the largest portion of achievable technical potential in the commercial sector (38% interior, 7% exterior), followed by cooling (21%), ventilation (7%), and refrigeration (7%) end uses. Lighting potential includes bringing existing buildings up to code and exceeding code in new and existing structures.

Figure 19. Commercial Electric Achievable Technical Potential by End Use

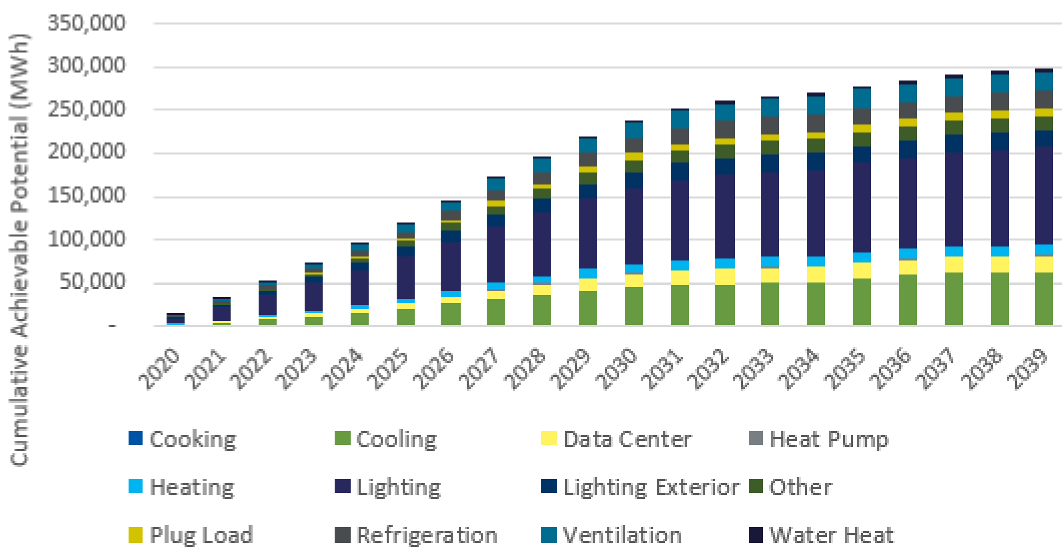


Table 28 lists the top 15 commercial electric energy efficiency measures, ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for 199.7 GWh or approximately 67% of total electric commercial achievable technical potential. Commercial LED lighting measures, including linear fixtures and lamps as well as "other" applications, account for approximately 64 GWh or 22% of total commercial, electric, energy efficiency potential. Lighting controls represent a large portion of the potential, with approximately 59.6 GWh or 20% of total commercial potential.

Table 28. Top Commercial Electric Measures

Measure Name	Weighted Average Levelized Cost ($/kWh)	Achievable Technical Potential (MWh)	
		Cumulative 10-Year	Cumulative 20-Year
Lighting Interior—TLED/LED Panel—Above Standard	$0.134	25,487	43,206
Dimming of Fluorescent Fixtures	$0.047	22,930	27,615
Occupancy Sensor Control	$0.050	21,093	25,403
DX Package 65 to 135 kBtuh—CEE Advanced Tier	$0.417	3,304	15,488
Retrocommissioning	$0.060	9,823	11,830
Motor - Pump & Fan System—Variable Speed Control	$0.019	9,164	11,705
Re-Commissioning	$0.060	7,293	8,783
Wi-Fi Thermostat	$0.006	6,763	8,387
LED Exterior Wall Pack	$0.030	7,768	8,217
Server virtualization/consolidation	$0.020	6,205	7,807
Convert Constant Volume Air System to VAV	$0.281	6,258	7,537
Daylighting Controls, Outdoors (Photocell)	$0.018	5,534	6,665
Lighting Interior—Screw Base LED—Above Standard	$0.004	6,267	6,383
Lighting Package—Advanced Efficiency	$0.023	2,568	6,234
Direct Digital Control System-Installation	$0.031	3,725	4,486

3.4.3. Industrial Sector—Electric

This study estimates technical and achievable technical, energy efficiency potential for major end uses in 14 major industrial sectors (including street lighting). Across all industries, achievable technical potential is approximately 58 GWh over the 20-year planning horizon, corresponding to a 11% reduction of forecasted 2039 industrial consumption.

Figure 20 shows 20-year cumulative, electric, industrial achievable technical potential by segment. The electrical equipment manufacturing industry represents 38% of the total, electric, industrial achievable technical potential, followed by street lighting (22%), miscellaneous manufacturing (11%) and fabricated metal products (9%). No other industry represents more than 5% of industrial electric potential.

Figure 20. Industrial Electric Achievable Potential Forecast by Segment

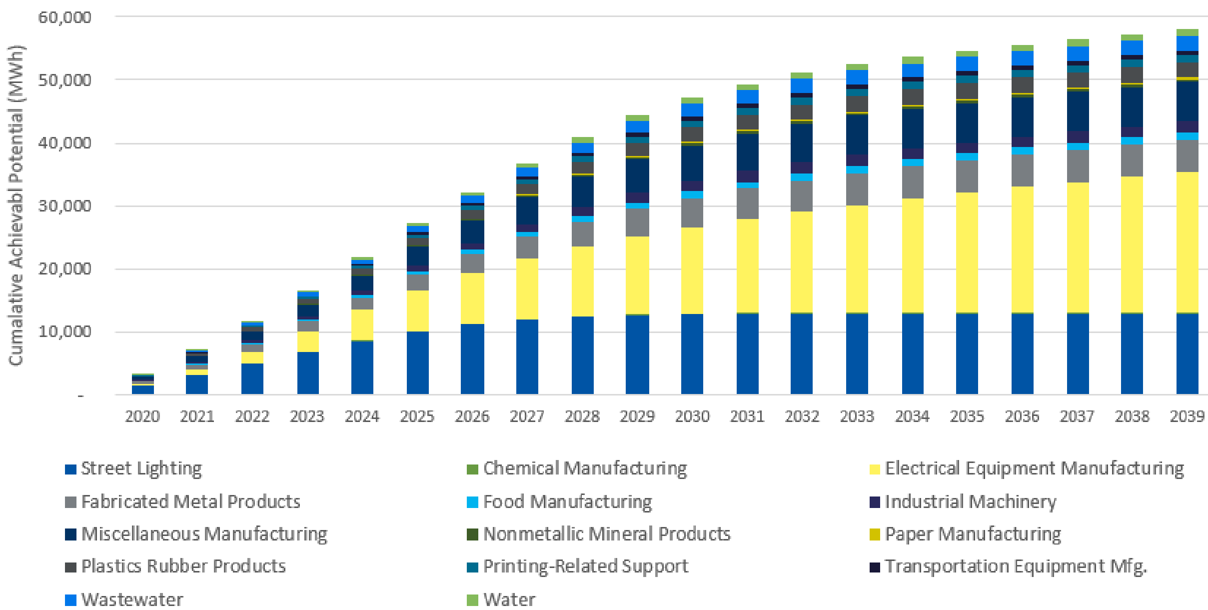


Figure 21 presents the cumulative, electric, industrial end use achievable technical by end use (including street lighting). Process improvements represent the largest portion of achievable technical potential in the industrial sector (27%), followed by HVAC (22%), street lighting (22%), and lighting (10%) end uses. The combined end uses of motors, fans, and pumps represent roughly one-seventh (14%) of the achievable technical potential.

Figure 21. Industrial Electric Potential by End Use

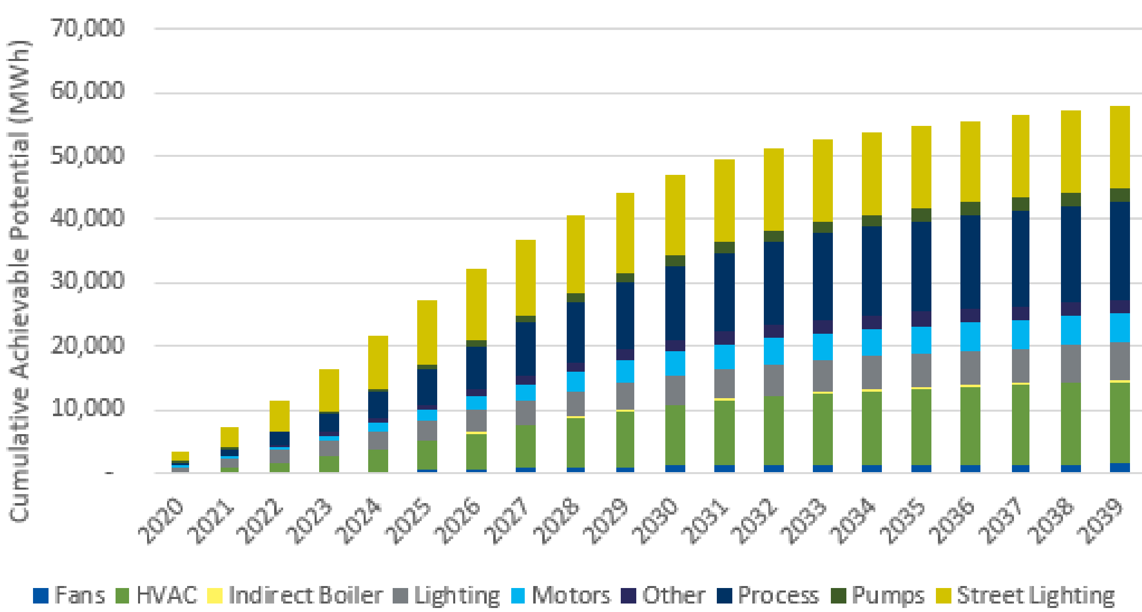


Table 29 presents cumulative, electric, 20-year, achievable technical potential for the top 15 measures in the industrial sector. Besides various process improvement measures in the top 15 electric measures, LED industrial lighting packages and LED street lighting measures represented a large portion of the 20-year, achievable technical potential (15,358 MWh).

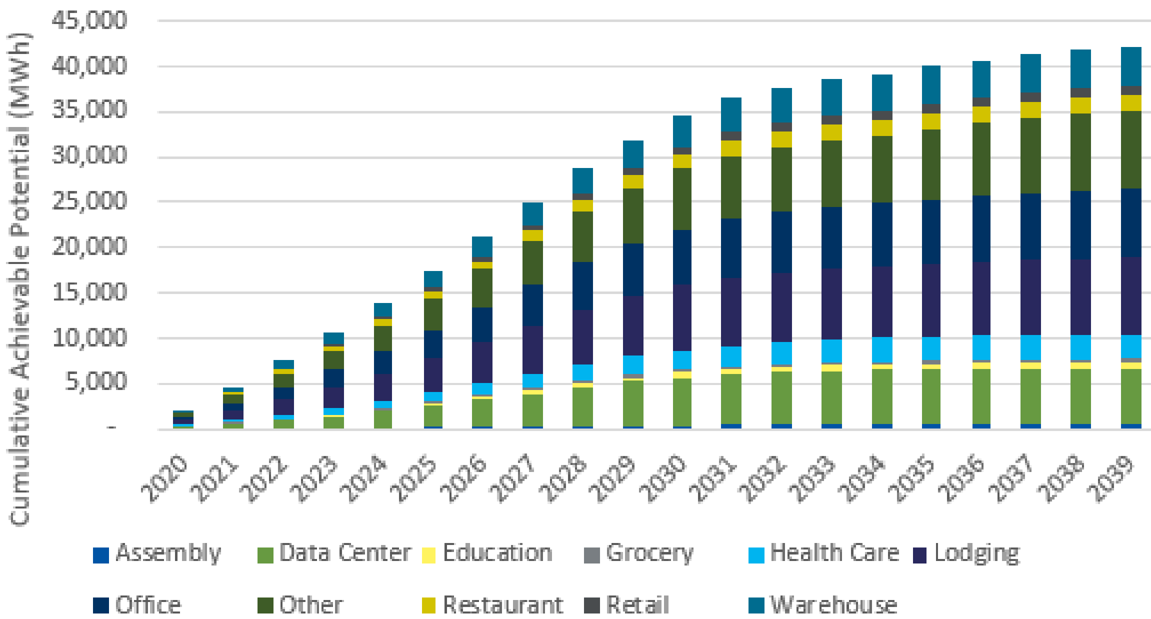
Table 29. Top Industrial Electric Measures

Measure Name	Weighted Average Levelized Cost ($/kWh)	Achievable Technical Potential (MWh)	
		Cumulative 10-Year	Cumulative 20-Year
Lighting—Linear LED Packages	-$0.038	3,720	4,025
LED 49-watt Replacement of HPS—100-watt COBRA HEAD	$0.000	3,636	3,717
LED 52-watt Replacement of DECORATIVE HPS—100-watt ACORN	$0.099	3,522	3,600
Upgrade Equipment—Replace Existing HVAC Unit with High-Efficiency Model	$0.029	2,619	3,154
Equipment Upgrade—Replace Existing HVAC Unit with High-Efficiency Model	$0.430	2,619	3,154
Thermal Systems Recover Heat and Use for Preheating, Space Heating, Power Generation, Steam Generation, Transformers, Exhausts, Engines, Compressors, Dryers, and Waste Process Heat	$0.015	2,526	3,042
Thermal Systems Add Insulation to Equipment	$0.005	1,994	2,401
Building Envelope Infiltration, Insulation, and Duct System Improvements	$0.006	1,966	2,368
Install Adjustable Frequency Drive for Variable Pump, Blower, and Compressor Loads	$0.011	1,847	2,224
LED 58-watt Replacement of DECORATIVE HPS—100-watt COLONIAL	$0.131	2,015	2,060
LED 138-watt Replacement of HPS—250-watt COBRA HEAD	$0.012	1,913	1,955
Utilize an Evaporative Air Pre-Cooler or Other Heat Exchanger in AC System	$0.016	1,620	1,951
Install Outside Air Damper/Economizer on HVAC Unit	$0.010	1,524	1,835
Install Compressor Controls	$0.007	1,435	1,728
Optimize Space Cooling Zone and Schedule	$0.019	1,284	1,547

3.4.4. Military Sector—Electric

Cadmus estimated military achievable technical potential by the 11 commercial segments shown in Figure 22. The lodging segment accounts for 20% (8,373 MWh) of the total 20-year military achievable technical potential, with other representing another 20%, followed by offices (18%), data centers (15%), and retail (10%).

Figure 22. Military Electric Achievable Potential Forecast by Segment



Similar to the commercial sector overall, light is the end use with the greatest achievable technical potential within the military sector, accounting for 47% (interior and exterior lighting) of the potential, followed by data center technologies (15%) and HVAC auxiliary/ventilation (7%), as shown in Figure 23.

Figure 23. Military Electric Potential by End Use

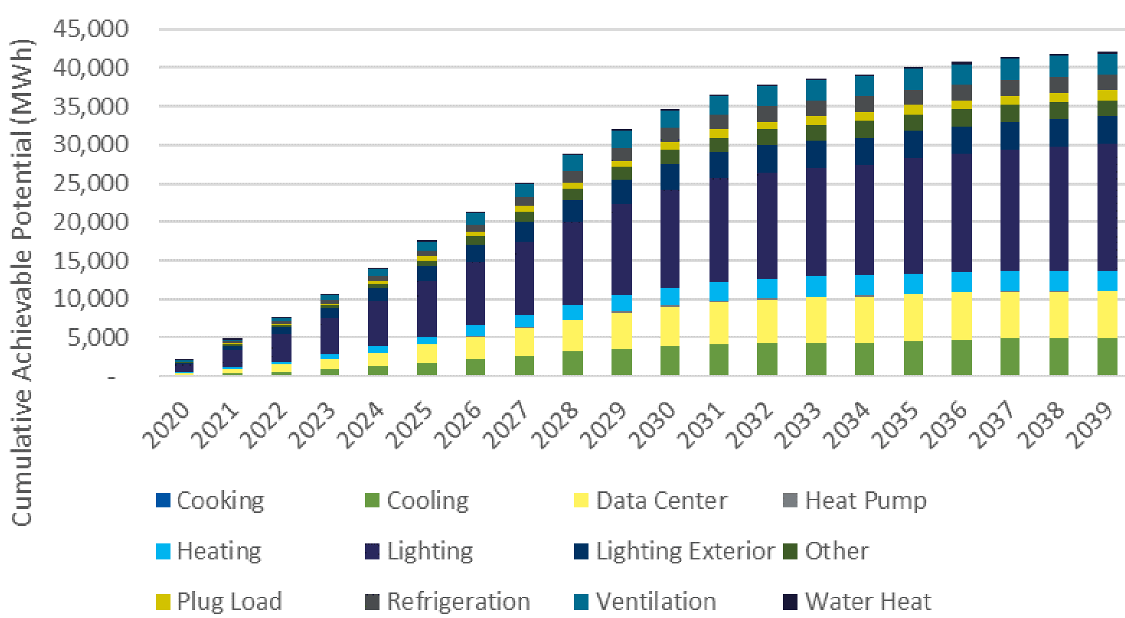


Table 30 lists the top 15 military electric energy efficiency measures ranked in order of cumulative, 20-year achievable technical potential. Similar to commercial sector results, military LED lighting measures (including linear fixtures, lamps, controls, and "other" lighting applications) account for the majority of energy efficiency potential. These top lighting measures and lighting controls approximately represent 18 GWh, or 43% of total military, electric, energy efficiency potential.

Table 30. Top Military Electric Measures

Measure Name	Weighted Average Levelized Cost ($/kWh)	Achievable Technical Potential (MWh)	
		Cumulative 10-Year	Cumulative 20-Year
Lighting Interior—TLED/LED Panel—Above Standard	$0.104	2,762	5,100
Occupancy Sensor Control	$0.043	3,817	4,597
Dimming of Fluorescent Fixtures	$0.056	2,834	3,413
Server Virtualization/Consolidation	$0.020	2,174	2,738
Motor—Pump & Fan System—Variable Speed Control	$0.021	1,157	1,490
Lighting Interior—Screw Base LED—Above Standard	-$0.025	1,448	1,468
Retrocommissioning	$0.073	1,185	1,427
LED Exterior Wall Pack	$0.030	1,323	1,394
Lighting Package—Advanced Efficiency	$0.011	579	1,163
Daylighting Controls, Outdoors (Photocell)	$0.015	925	1,114
Convert Constant Volume Air System to VAV	$0.344	767	924
Decommissioning of Unused Servers	$0.007	536	675
Automated Ventilation VFD Control (Occupancy Sensors/CO2 Sensors)	$0.058	501	603
Windows—High-Efficiency	$0.668	435	533
Energy Efficient Data Storage Management	$0.017	421	531

3.5. *Detailed Resource Potential—Gas*

3.5.1. Residential Sector—Gas

By 2039, residential customers will likely account for 60% of Springs Utilities' natural gas sales. Unlike residential electricity consumption, this includes relatively few natural gas-fired end uses (primarily space heating, water heating, and appliances, including dryers and stove tops). Nevertheless, significant available energy-savings opportunities remain. Based on the energy efficiency measures used in this assessment, achievable technical potential in the residential sector will likely provide about 27 million therms over 20 years, corresponding to a 17% reduction of forecasted 2039 sales.

Single-family homes account for 80% of identified achievable technical potential, as shown in Figure 24. The remaining achievable technical potential resides in multifamily residences (20%).

Figure 24. Residential Gas Potential by Segment

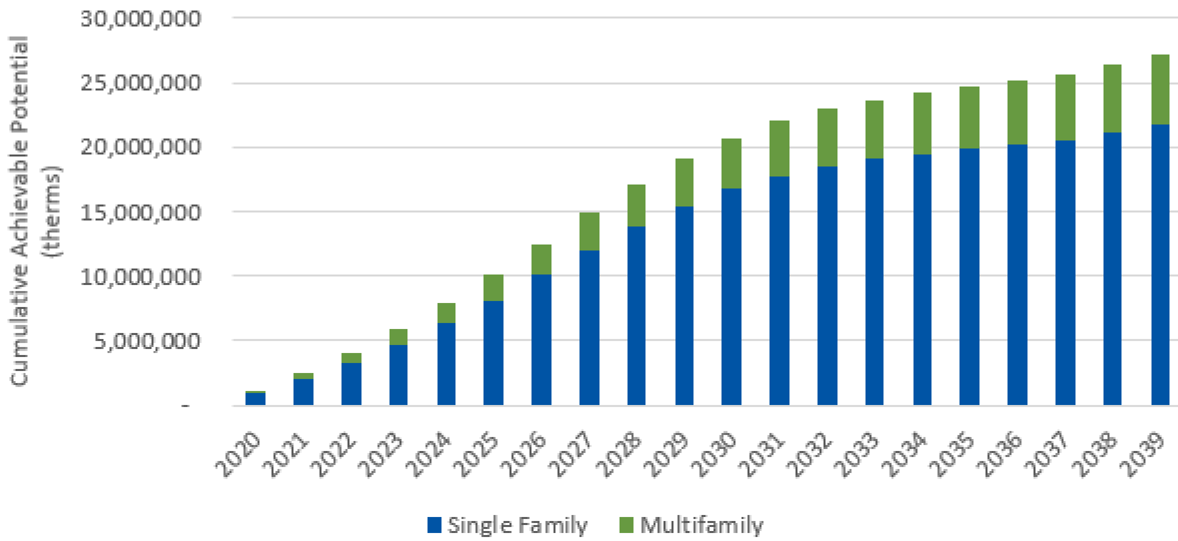


Figure 25 shows cumulative, natural gas, achievable technical potential by residential end use. Space heating (80%) and water heating (19%) end uses account for 99% of identified, achievable, technical potential, combining high-efficiency equipment (e.g., condensing furnaces, water heaters) and retrofits (e.g., shell measures, duct and pipe insulation, low-flow showerheads).

Figure 25. Residential Gas Potential by End Use

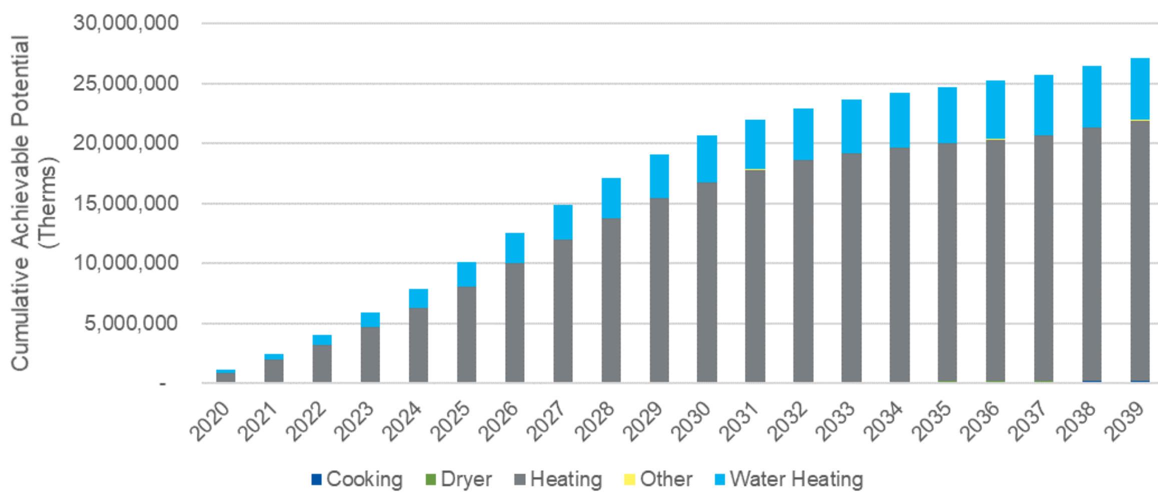


Table 31 shows the top 15 residential, natural gas, energy efficiency measures ranked in order of cumulative, 20-year, achievable technical potential. Combined, these 15 measures account for 22 million therms, or approximately 82% of total residential achievable technical potential.

Table 31. Top Residential Gas Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Furnace - ENERGY STAR 2019 Most Efficient	$5.60	856,810	2,512,883
Air Sealing	$3.17	2,594,891	3,125,065
Ceiling / Attic Insulation	$3.05	2,359,485	2,877,650
Combination Gas Space and Water Heat	$1.10	1,567,671	2,071,613
Furnace - Maintenance	$0.49	900,820	1,801,640
Indirect Energy Feedback	$0.79	1,485,800	1,607,857
Air-to-Air Heat Exchangers	$2.71	994,029	1,459,432
Floor Insulation	$1.80	942,159	1,161,243
Furnace - Quality Install	$1.04	512,366	1,044,415
Learning Wi-Fi Thermostat	$1.83	672,239	937,487
Showerhead Low Flow	$0.04	767,491	869,114
Wall Insulation - 2x6	$2.56	543,616	759,888
Duct Sealing and Insulation Combined	$1.11	629,157	757,703
Windows - Storm - ENERGY STAR	$1.00	514,887	620,086
Windows	$5.43	496,562	619,122

3.5.2. Commercial Sector—Gas

The natural gas, cumulative, achievable technical potential in the commercial sector will likely amount to 16.4 million therms over 20 years, a 22% reduction in forecasted 2039 commercial sales, and about 33% of total identified potential across all sectors. As shown in Figure 26, for natural gas customers, office buildings represent the largest portion of potential (20%), followed by other commercial facilities (17%), lodging (13%), and education (11%).

Figure 26. Commercial Gas Potential by Segment

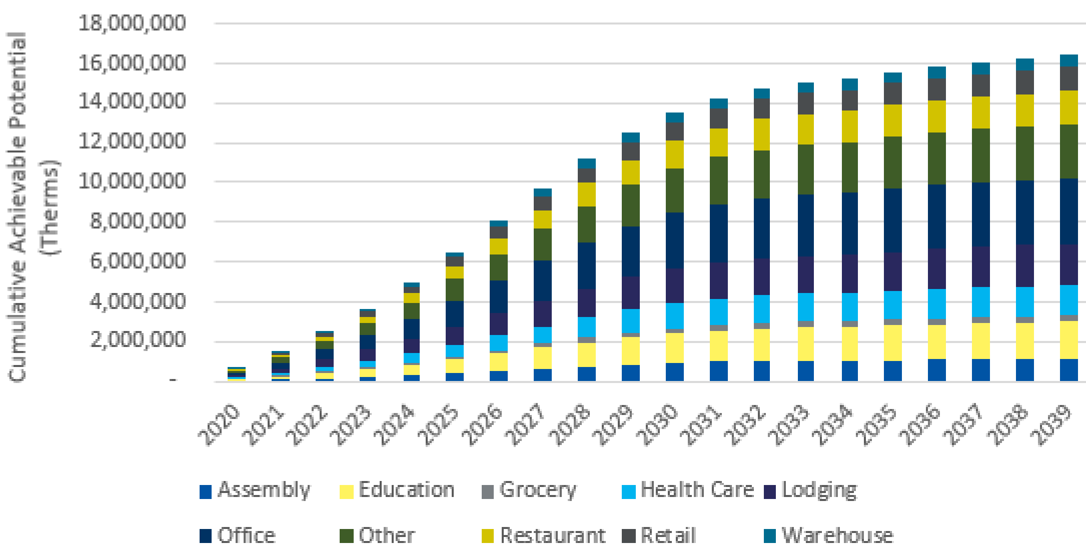


Figure 27 shows commercial, natural gas, annual, cumulative, achievable technical potential by end use. As in the residential sector, far fewer gas-fired end uses exist compared to electric end uses. Space heating (e.g., HVAC equipment upgrades, shell improvements) accounts for 72% of identified potential; the remaining potential is mostly water heating (20%), cooking (7%), and other (<1% pool heating).

Figure 27. Commercial Gas Potential by End Use

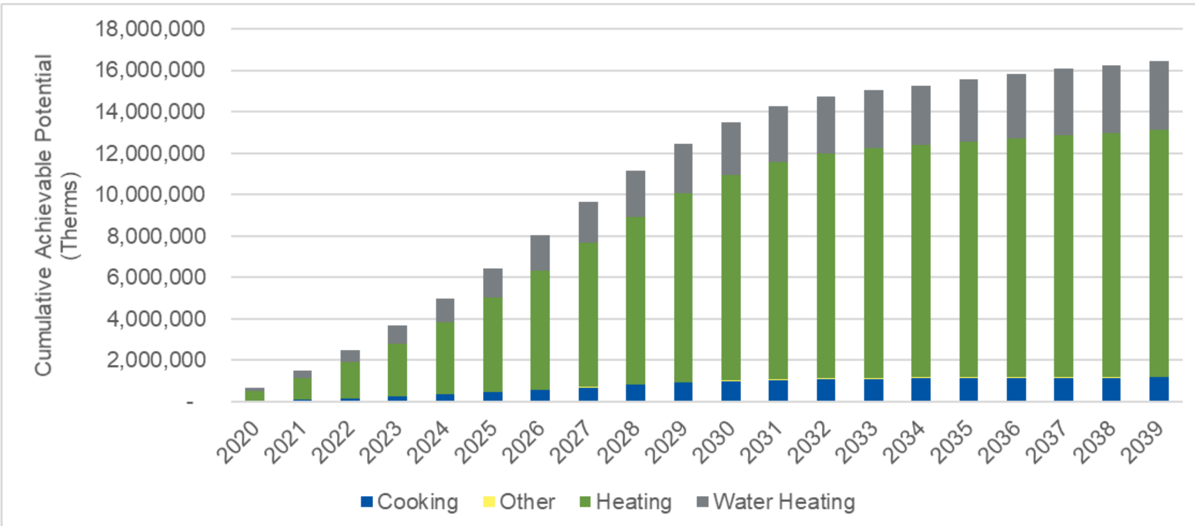


Table 32 shows the top 15, commercial, natural gas, energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 11.3 million therms, or about 69% of total, natural gas, commercial, achievable technical potential. Over 10 of the measures contribute to reducing commercial building natural gas space heating.

Table 32. Top Commercial Gas Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Retrocommissioning	$1.25	2,394,135	2,883,292
Combination Gas Space and Water Heat	$1.30	1,378,401	1,756,117
Automated Ventilation VFD Control (Occupancy Sensors / CO2 Sensors)	$1.21	691,610	832,916
Convert Constant Volume Air System to VAV	$5.17	669,705	806,536
Direct Digital Control System-Installation	$0.85	569,992	686,450
Wi-Fi Thermostat	$0.38	524,464	651,491
Solar Hot Water (SHW)	$6.92	157,312	566,376
Furnace < 225 kBtuh - ENERGY STAR 2019 Most Efficient	$6.27	137,693	475,387
Re-Commissioning	$1.22	390,386	470,147
Windows-High Efficiency	$30.21	362,759	450,565
Insulation - Ceiling	$10.75	357,284	440,852
Strategic Energy Management (SEM)	$0.60	285,158	355,746
Exhaust Air to Ventilation Air Heat Recovery	$6.48	259,329	333,053
Low-Flow Faucet Aerators (Private Use)	$0.04	297,062	312,806
Broiler	$0.41	245,541	312,232

3.5.3. Industrial Sector – Gas

Across all industries, achievable technical potential totals approximately 2.4 million therms over 20 years. Although this represents 20% of forecasted 2039 industrial sales, it accounts for only 6% of achievable technical potential across all sectors. As shown in Figure 28, substantial achievable technical potential occurs in electrical equipment manufacturing (28%), miscellaneous manufacturing (18%), nonmetallic mineral products (14%), fabricated metal products (13%), and food manufacturing (11%).

Figure 28. Industrial Gas Potential by Segment

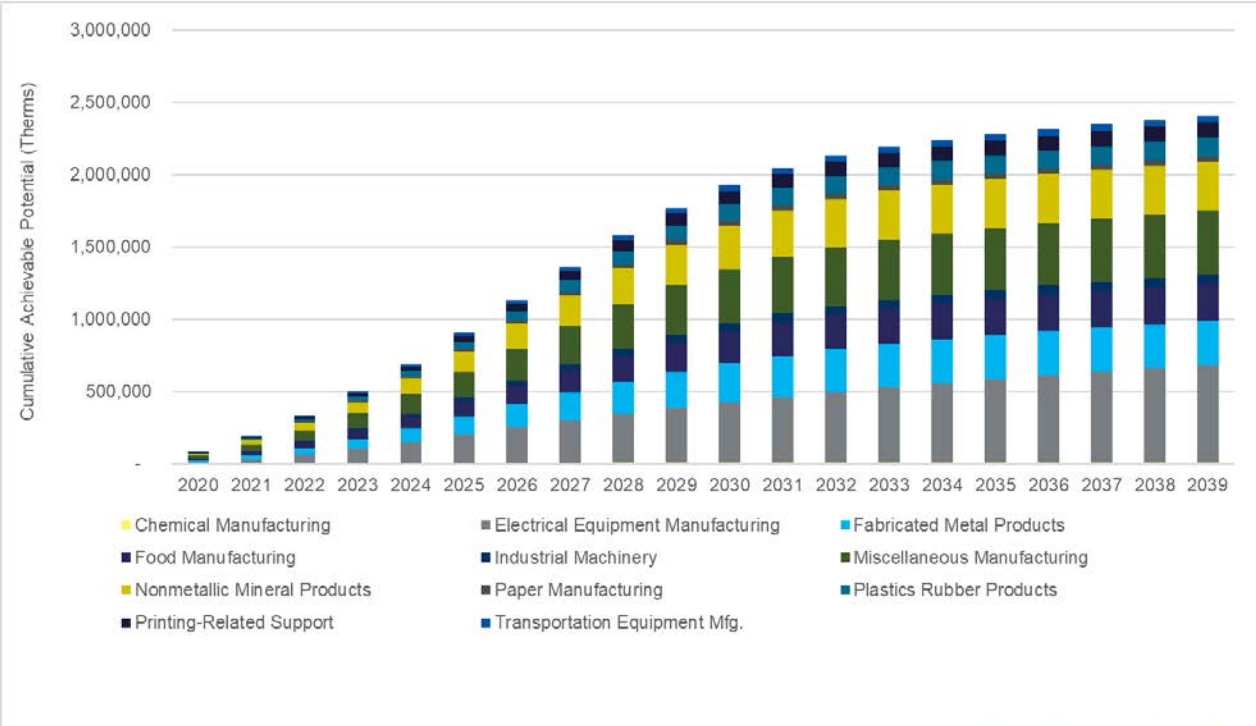


Figure 29 shows cumulative, natural gas, achievable, technical potential by industrial end use. Indirect boiler (43%), process improvements (39%), and HVAC (17%) end uses account for identified achievable technical potential.

Figure 29. Industrial Gas Potential by End Use

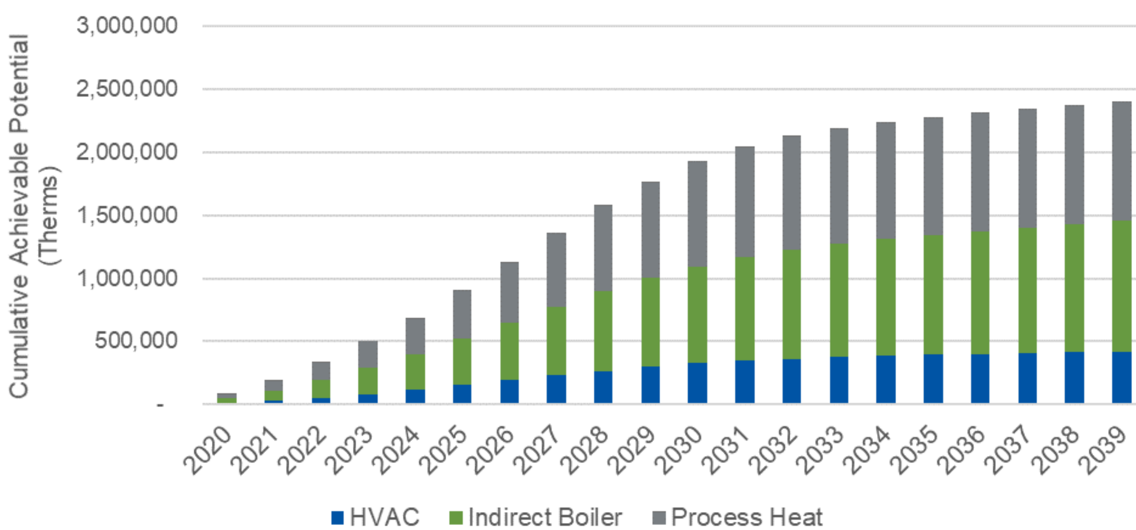


Table 33 shows the top 15, industrial, natural gas, energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. These 15 measures represent almost all natural gas, industrial, achievable technical potential (over 92%—the potential study included a total of 20 natural gas industrial measures).

Table 33. Top Industrial Gas Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (Therms)	
		Cumulative 10-Year	Cumulative 20-Year
Waste Heat from Hot Flue Gases to Preheat	$0.13	282,580	351,164
Heat Recovery and Waste Heat for Process	$0.10	237,353	293,935
Isolate and Prevent Infiltration of Heat Loss from Equipment	$0.07	199,438	247,545
Optimize Heating System to Improve Burner Efficiency, Reduce Energy Requirements and Heat Treatment Process	$0.06	130,661	181,929
Analyze Flue Gas for Proper Air/Fuel Ratio	$0.10	117,373	164,278
Improve Combustion Control Capability and Air Flow	$0.07	115,647	161,266
Equipment Upgrade - Boiler Replacement	$1.20	63,485	121,045
Repair or Replace Steam Traps	$0.05	78,944	110,475
Optimize Ventilation System	$0.21	69,822	98,559
HVAC Equipment Scheduling Improvements - HVAC Controls, Timers or Thermostats	$0.03	64,176	90,590
Building Envelope Insulation Improvements	$0.24	63,456	89,574
Boiler - Operation, Maintenance, And Scheduling	$0.12	45,105	86,483
Repair and Eliminate Steam Leaks	$0.04	56,629	78,109
Building Envelope Infiltration Improvements	$0.07	51,412	72,572
Equipment Upgrade - Replace Existing HVAC Unit with High Efficiency Model	$1.14	49,815	70,297

3.5.4. Military Sector—Gas

Cadmus estimated natural gas, military, achievable technical potential by the 11 commercial segments included in Figure 30. The other segment accounts for 32% of total 20-year, military, achievable technical potential, followed by offices (31%), lodging (11%), and health care (9%).

Figure 30. Military Gas Potential by Segment

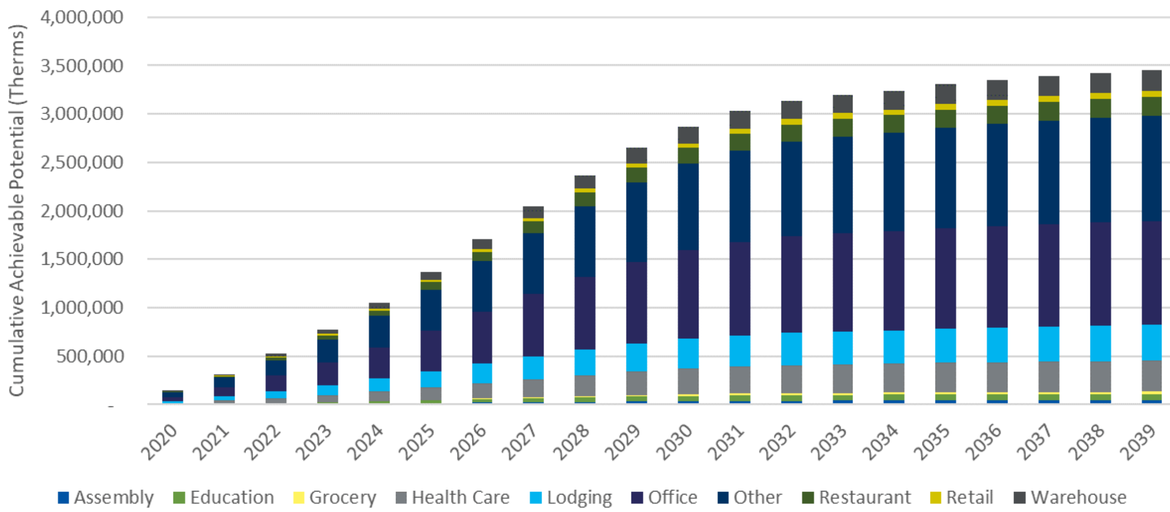


Figure 31 shows military, natural gas, annual, cumulative and achievable technical potential by end use. Similar to the commercial sector overall, the end use with the greatest achievable technical potential within the military sector is space heating (e.g., HVAC equipment upgrades and shell improvements), accounting for 79% of identified potential; the remaining potential is mostly water heating (17%), cooking (4%), and other (<1% pool heating).

Figure 31. Military Gas Potential by End Use

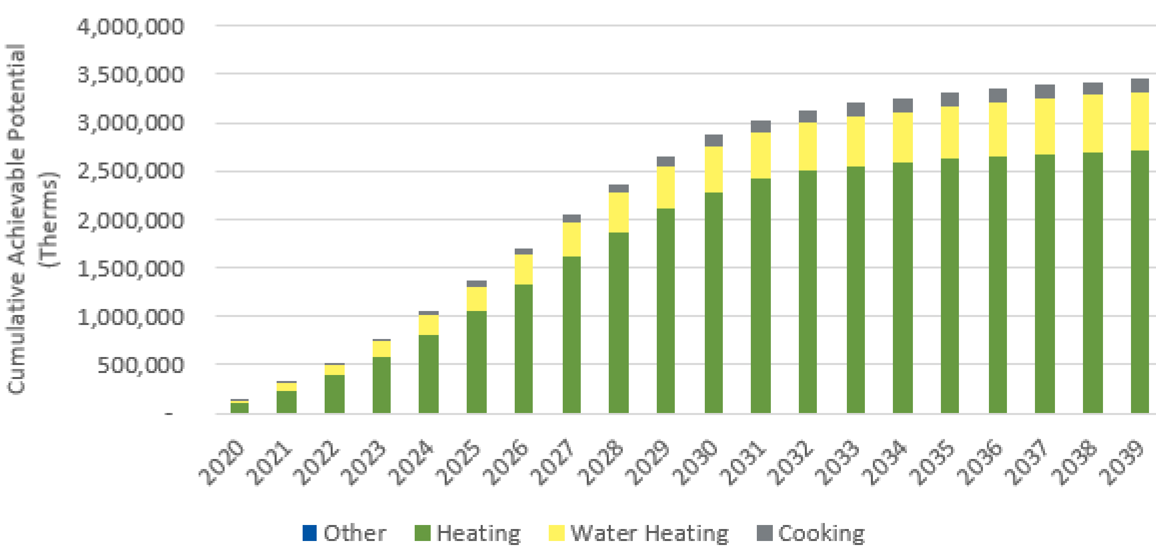


Table 34 shows the top 15, commercial, natural gas, energy efficiency measures ranked in order of cumulative 20-year achievable technical potential. Combined, these 15 measures account for approximately 2.5 million therms, or about 73% of total natural gas, commercial, achievable technical potential.

Table 34. Top Military Gas Measures

Measure Name	Weighted Average Levelized Cost ($/therm)	Achievable Technical Potential (MWh)	
		Cumulative 10-Year	Cumulative 20-Year
Retro-commissioning	$1.217	515,840	621,233
Combination Gas Space and Water Heat	$1.206	261,873	323,455
Automated Ventilation VFD Control (Occupancy Sensors/ CO2 Sensors)	$1.446	194,026	233,669
Direct Digital Control System—Installation	$1.207	164,816	198,490
Convert Constant Volume Air System to VAV	$4.660	149,582	180,144
Wi-Fi Thermostat	$0.591	108,131	135,110
Re-Commissioning	$1.190	90,197	108,626
Furnace < 225 kBtuh—ENERGY STAR 2019 Most Efficient	$2.805	31,003	106,258
Solar Hot Water (SHW)	$8.125	29,845	103,424
Strategic Energy Management (SEM)	$0.620	83,184	101,556
Insulation—Ceiling	$10.532	81,421	99,466
Windows-High Efficiency	$31.907	76,051	93,116
Exhaust Air to Ventilation Air Heat Recovery	$5.718	58,702	77,355
Infiltration Reduction	$0.301	61,199	73,703
Duct Repair and Sealing	$1.862	57,074	68,735

4. Demand Response Potentials

4.1. Scope of Analysis

Cadmus estimated electric and gas DR market potential for Springs Utilities. For electric DR, Cadmus considered four residential products and three nonresidential products, all of which reduce Springs Utilities' summer peak load. Table 35 lists electric DR in this assessment's scope.

Table 35. Electric Demand Response Products

Sector	Product	Eligibility
Residential	DLC Smart Thermostat Direct Install*	Central cooling and does not currently own smart thermostat
	DLC Smart Thermostat BYOT	Central cooling and smart thermostat
	DLC EV Charger	Does not have a Level 2 DC charger (program will install a connected level 2 DC Charger)
	CPP Opt-In*	Assumes full AMI by 2023
Nonresidential	DLC BYOT	Cooling DX or ASHP and smart thermostat
	Load Curtailment*	On-peak demand >100kW (excludes ELG customers)
	CPP Opt-In*	Assume full AMI by 2023

*These products were also assessed in the 2016 study.

New to the DR potential assessment is consideration of gas DR, which reduces gas pipeline congestion in winter. Gas DR programs in the country are nascent; Table 36 lists five prototypical gas DR products that Cadmus assessed in this study.

Table 36. Gas Demand Response Products

Sector	Product	Eligibility
Residential	Gas DLC Smart Thermostat BYOT	Central gas heating and smart thermostat
	Gas DLC Smart Thermostat Direct Install	Central gas heating and does not currently own smart thermostat
	Gas DLC Water Heat	Gas storage water heaters
	Critical Peak Pricing Opt-In	Assume full AMI by 2023
Nonresidential	Commercial Gas DLC BYOT	Gas furnace or boiler and smart thermostat

Note: Gas Interruptible Tariff is an existing Springs Utilities resource to manage gas demand. It is included elsewhere in Springs Utilities' Gas Integrated Resource Plan and thus not assessed as part of this study.

4.2. Summary of Demand Response Potentials—Electric

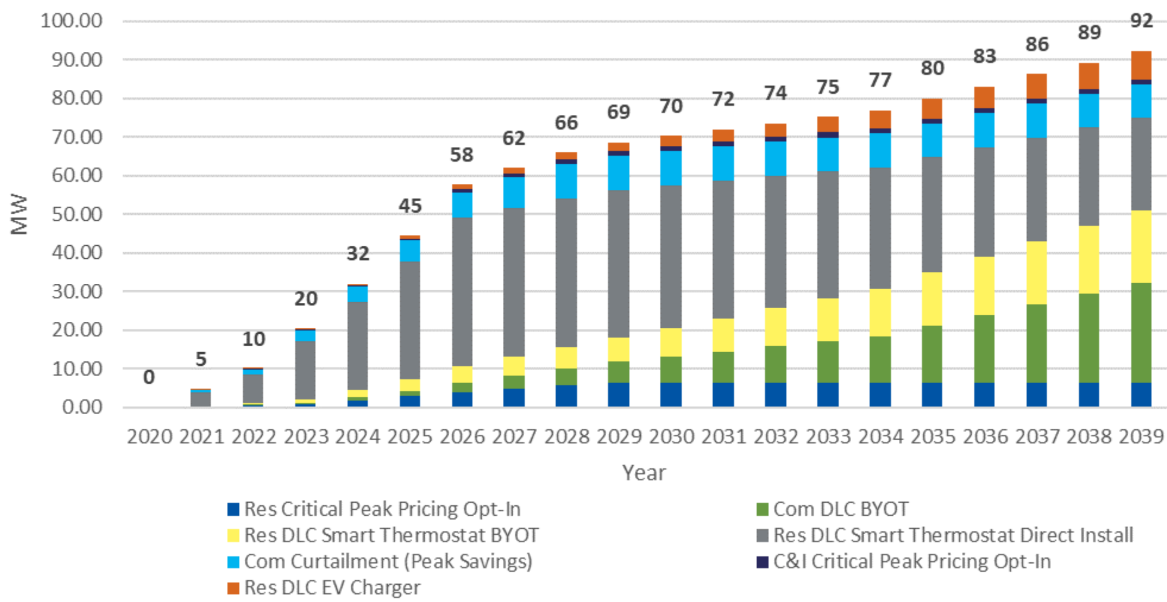
Table 37 presents each electric DR product's achievable potential (in megawatts and as a percentage of summer system peak) and the associated levelized cost. Providing almost 57 MW of achievable potential by 2039, the residential sector accounts for 61% of total electric DR achievable potential. Residential DLC smart thermostat products across residential and nonresidential sectors present the highest potential levels at relatively inexpensive costs.

Table 37. Electric Demand Response Achievable Potential and Levelized Cost, 2039

Product	Summer Achievable Potential (MW)	Percent of Area System Peak - Summer	Levelized Cost ($/kW-year)
Res DLC Smart Thermostat Direct Install	23.81	3.3%	$69
Res DLC Smart Thermostat BYOT	18.78	2.6%	$57
Res DLC EV Charger	7.55	1.0%	$291
Res Critical Peak Pricing Opt-In	6.52	0.9%	$42
Com DLC BYOT	25.80	3.5%	$46
Com Curtailment (Peak Savings)	8.67	1.2%	$112
C&I Critical Peak Pricing Opt-In	1.25	0.2%	$131

Figure 32. charts the annual, product-level, achievable potential from the lowest-cost product (Residential Critical Peak Pricing Opt-in) to the highest-cost product (Residential DLC EV Charger).

Figure 32. Electric Demand Response 20-Year Achievable Potential, Ranked by Levelized Cost



4.2.1. Residential Electric Demand Response Products

The following sections present the program description, study assumptions, and potential results for each residential electric DR product.

Residential DLC Smart Thermostat Direct Install

Program Description. During peak events, Springs Utilities controls participating, residential, air-conditioning loads by changing temperature setpoints on smart thermostats. These summer peak events occur in early evenings in June, July, and August. The potential study assumes that events last up to four hours, with about 10 events per season. Participants may opt-out of an event by adjusting the temperature on the smart thermostat. Participants receive a free smart thermostat and a $25 annual incentive. This product is similar to Springs Utilities' existing ECO program (Springs Utilities 2019a).

Eligibility. All residential customers with central air-conditioners or air-source heat pumps, but not owning an existing smart thermostat, become eligible for the Residential DLC Smart Thermostat Direct Install program.

Table 38 provides other study assumptions used to estimate potential and levelized costs for Residential DLC Smart Thermostat Direct Install.

Table 38. Residential DLC Smart Thermostat Direct Install: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program. Springs Utilities is currently making improvements to an existing program (Springs Utilities 2019a) that is similar to this product.
O&M Cost	$ per participant per year	$20	Xcel (2019): $18 per participant. Springs Utilities may use its Commercial Load Curtailment vendor for this product as well.
Equipment Cost	$ per new participant	$250	Xcel (2019): equipment and installation incremental cost of $249. The 2015 potential study assumed $293 (Springs Utilities 2016).
Marketing Cost	$ per new participant	$25	Springs Utilities (2016): $25; Xcel (2019): $6.
Incentives (annual)	$ per participant per year	$25	Springs Utilities planning assumption. Xcel (2019): $25.
Incentives (one time)	$ per new participant	$0	There is no one-time incentive, unlike the BYOT option.
Attrition	% of existing participants per year	1.5%	Springs Utilities (2016).
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	kW per participant (at meter)	0.98	Springs Utilities (2016): 0.935kW (1.1 kW * 85% event participation); Xcel (2019b): 1.03 kW.
Program Participation	% of eligible customers	30%	Springs Utilities (2016): low rate of 20% for direct install option; Xcel (2019b): 55% across direct install and BYOT options.
Event Participation	%	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Springs Utilities planning assumption: enrollment starting in 2021. This study assumes that ramp rates are 10%, 20%, 40%, 60%, and 80% from 2021 to 2025 before reaching steady-state achievable potential in 2026.

Results. At a levelized cost of $69/kW-year, the Residential DLC Smart Thermostat Direct Install program can provide about 24 MW of summer peak load reduction in 2039.

Residential DLC Smart Thermostat BYOT

Program Description. The Residential DLC Smart Thermostat BYOT is identical to the Residential DLC Smart Thermostat Direct Install program, except that it requires that participants have already installed a smart thermostat. Thus, the potential study assumes no equipment or installation costs for smart thermostats, but pays participants a $50, one-time incentive in addition to the $25 annual incentive.

Eligibility. All residential customers with central air-conditioners or air-source heat pumps that already own an installed smart thermostat become eligible for the Residential DLC Smart Thermostat BYOT program.

Table 39 provides other study assumptions used to estimate potential and levelized costs for the Residential DLC Smart Thermostat BYOT.

Table 39. Residential DLC Smart Thermostat BYOT: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$20	This study assumes the direct install and BYOT options have the same vendor; assumption aligns with the direct install option.
Equipment Cost	$ per new participant	$0	Assuming participant already has a smart thermostat.
Marketing Cost	$ per new participant	$25	Aligned with direct install option.
Incentives (annual)	$ per participant per year	$25	Aligned with direct install option.
Incentives (one time)	$ per new participant	$50	Southern California Gas program plan (Hanway 2019) assumed $50 of one-time incentive (aligned with assumption for the Res Gas DLC Smart Thermostat BYOT product). Xcel (2019): $75.
Attrition	% of existing participants per year	1.5%	Springs Utilities (2016).
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	kW per participant (at meter)	0.98	Aligned with direct install option.
Program Participation	% of eligible customers	30%	Aligned with direct install option.
Event Participation	%	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with direct install option.

Results. At a levelized cost of $57/kW-year, the Residential DLC Smart Thermostat BYOT can provide about 19 MW of summer peak load reduction in 2039. This product is slightly less expensive than its direct-install counterpart.

Residential DLC EV Charger

Program Description. During peak events, Springs Utilities may communicate with connected, Level 2, EV chargers to reduce EV charging output power. Connected Level 2 chargers predominantly communicate via Wi-Fi or cellular service and can reduce 0% to 100% of output power in response to a DR event. As with other DLC products, the potential study assumes that events last up to four hours, for about 10 events during June, July, and August.

Cadmus assumed EV owners could charge their EVs at home, though not all were expected to install a Level 2 charger. We also assumed that most existing Level 2 chargers were not *connected*. Therefore, we designed this Residential DLC EV Charger program study to target EV owners that currently charge at home, but do not have a Level 2 charger installed. The program would pay for the incremental cost of installing a connected Level 2 charger.

Eligibility. All residential customers owning an electric vehicle, but currently without a Level 2 charger installed at home, are eligible for the Residential EV Charger program.

Table 40 provides other study assumptions used to estimate potential and levelized costs for the Residential DLC EV Charger program.

Table 40. Residential DLC EV Charger: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$20	Aligned with other residential DLC products in this study.
Equipment Cost	$ per new participant	$300	RTF (2019): incremental equipment cost of networked 240V level 2 charger compared to non-networked level 2 charger is $287.
Marketing Cost	$ per new participant	$25	Aligned with other residential DLC products in this study.
Incentives (annual)	$ per participant per year	$25	Aligned with other residential DLC products in this study.
Incentives (one time)	$ per new participant	$0	This study assumes there is no one-time incentive.
Attrition	% of existing participants per year	1.5%	Aligned with other residential DLC products in this study.
Population	Customer count	Varies by segment	Electric vehicle forecast from this study.
Eligibility	% of customer count (e.g. equipment saturation)	36%	The proportion of electric vehicle owners that already have a residential 240V AC level 2 charger (64%) is from RTF (2019), which used 2017 national vehicle survey data. Therefore, the percentage of EV owners without an existing level 2 charger is estimated to be 36%.
Peak Load Impact	kW per participant (at meter)	Varies by year	Electric vehicle forecast from this study produced annual kWh consumption that varies by year (see *Potential EV Load Growth*). This study applied a national electric vehicle load profile (U.S. Department of Energy 2013) to the annual kWh consumption derive a peak load impact around 0.3 to 0.35 kW per participant. This level of impact is in line with results from Avista's recent EV DLC pilot study (SEPA 2019).
Program Participation	% of eligible customers	30%	Aligned with other residential DLC products in this study.
Event Participation	%	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with other residential DLC products in this study.

Results. Though a residential DLC EV Charger can provide 7.5 MW of summer peak load reduction by 2039, it is an expensive product—with a levelized cost of $291/kW-year—due to necessary purchases of a connected Level 2 charger with DR capabilities.

Residential Critical Peak Pricing

Program Description. Under Residential CPP Opt-In, customers voluntarily opt in to receive a discount on their normal retail rates during noncritical peak periods in exchange for paying predetermined, premium prices during critical peak events. The basic rate structure is a TOU tariff, with the rate using fixed prices during different blocks of time (typically on-, off-, and mid-peak prices by season).

This study assumes that Springs Utilities may call critical peak events lasting four hours, for up to 10 events in June, July, and August. During these events, the normal peak price under a TOU rate structure is increased to a much higher price to incentivize participants to shift energy use out of the event period.

Eligibility. All residential customers are eligible for the Residential CPP, assuming full AMI deployment for Springs Utilities' residential customers by end of 2023.

Table 41 provides other study assumptions used to estimate potential and levelized costs for Residential CPP.

Table 41. Residential Critical Peak Pricing: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program. Springs Utilities (2016): $400,000; BHE (2018): $150,000.
O&M Cost	$ per year	$50,000	Assume one-third FTE. BHE (2018): $57,000 shared with commercial CPP.
Equipment Cost	$ per new participant	$0	Springs Utilities planning assumption: AMI will be fully deployed by the end of 2023.
Marketing Cost	$ per new participant	$25	Springs Utilities (2016): $25; BHE (2018): $50.
Incentives (annual)	n/a	$0	None per program definition.
Incentives (one time)	n/a	$0	None per program definition.
Attrition	% of existing participants per year	10%	SMUD (2014) for opt-in CPP: 9%.
Eligibility	% of segment load	100%	Springs Utilities planning assumption: AMI will be fully deployed by the end of 2023.
Peak Load Impact	% of eligible segment load	20%	Springs Utilities (2016): 20%; BHE (2018): 19%; SMUD (2014): 21%.
Program Participation	% of eligible segment load	15%	Springs Utilities (2016): low rate of 20%; BHE (2018): 13%; SMUD (2014): 19%.
Event Participation	n/a	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	10	With AMI fully deployed by the end of 2023, this study assumes this product will start enrolling in 2022. This study assumes that enrollment will begin in 2022, and ramp rates are 10%, 15%, 30%, 45%, 60%, 75%, and 90% from 2022 to 2028 before reaching steady-state achievable potential in 2029.

Results. At a levelized cost of $42/kW-year, Residential CPP can provide 6.5 MW of summer peak load reduction by 2039. Compared to smart thermostat products, Residential CPP does not provide much potential, although it is being less expensive.

4.2.2. Nonresidential Electric Demand Response Products

The following sections present program descriptions, study assumptions, and potential results for each nonresidential electric DR product.

Commercial DLC BYOT

Program Description. Commercial customers receive incentives to allow the utility to control their central cooling equipment during summer peak events. This study assumes a four-hour event duration, with up to 10 events in the summer. Participants receive an annual incentive of $50 in addition to a one-time incentive of $75 upon signing up.

Eligibility. All commercial customers with a direct-expansion air-conditioning unit or an air-source heat pumps with an existing smart thermostat are eligible for the Commercial DLC BYOT program.

Table 42 provides other study assumptions used to estimate potential and levelized costs for Commercial DLC BYOT.

Table 42. Commercial DLC BYOT: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$75	Aligned with assumption for the Commercial Gas DLC BYOT product.
Equipment Cost	$ per new participant	$0	Assuming participant already has a smart thermostat.
Marketing Cost	$ per new participant	$0	Included in O&M cost.
Incentives (annual)	$ per participant per year	$50	This study assumes that the annual incentive is higher than that of Residential DLC BYOT.
Incentives (one time)	$ per new participant	$75	This study assumes that the annual incentive is higher than that of Residential DLC BYOT.
Attrition	% of existing participants per year	1.5%	Aligned with Residential DLC BYOT product.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	kW per participant (at meter)	3.00	Benchmarked values range from 1.2kW (PGE 2016) to 5.4kW (SDG&E 2016).
Program Participation	% of eligible customers	30%	Aligned with Residential DLC BYOT.
Event Participation	%	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with Residential DLC BYOT.

Results. At a levelized cost of $46/kW-year, Commercial DLC BYOT can provide 26 MW of summer peak load reduction by 2039. Compared to other nonresidential products, Commercial DLC BYOT provides the most potential at the lowest cost.

Commercial Load Curtailment

Program Description. Load curtailment programs establish contractual arrangements between the utility, a third-party aggregator that implements the program, and the utility's commercial customers that agree to curtail their operations (in whole or part) for a predetermined period when requested by the utility. This product represents a firm resource as it assumes customers would be penalized for noncompliance. This study assumes that participating customers execute the curtailment after the utility calls the event, curtailing any end-use loads to meet the curtailment agreement. Customers receive payments to remain ready for curtailment, even though actual curtailment requests may not occur. As penalties exist, Cadmus assumes customers will deliver a curtailed load that fulfills their contractual obligations 90% of the time. This product is similar to Springs Utilities' existing Peak Savings program (Springs Utilities 2019b).

Eligibility. Springs Utilities' current Peak Savings program requires that customers can reduce electric use by a minimum of 5% (Springs Utilities 2019b). For modeling purposes, this study assumes that all C&I customers (excluding customers in the ELG rate class), with at least 100 kW of monthly average demand, are eligible. The percentage of load represented by C&I customers meeting this requirement varies across C&I segments.

Table 43 provides other study assumptions used to estimate potential and levelized costs for Commercial Load Curtailment.

Table 43. Commercial Load Curtailment: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per kW pledged per year	$60	BHE (2018).
Equipment Cost	$ per new kW pledged	$0	Assuming participants have necessary equipment to participate or are manually interrupting loads or shutting down equipment.
Marketing Cost	$ per new kW pledged	$0	Included in O&M cost.
Incentives (annual)	$ per kW pledged per year	$50	Annual incentive in SPRINGS UTILITIES Peak Savings (2019a).
Incentives (one time)	$ per new kW pledged	$0	This study assumes no one-time incentives.
Attrition	% of existing participants per year	5%	Based on Springs Utilities' experience with Peak Savings program, this study assumes an annual attrition rate of 5%.
Eligibility	% of segment/end-use load	Varies by segment	This study assumes that customers with minimum on-peak demand of 100kW are able to reduce electric use by a minimum of 5% (Springs Utilities 2019b).
Peak Load Impact	% of eligible segment/end-use load	30%	Springs Utilities (2016): 30%; BHE (2018): 27%.
Program Participation	% of eligible segment/end-use load	10%	Springs Utilities (2016): low case of 15%; BHE (2018): 2%.
Event Participation	%	90%	Springs Utilities Peak Savings program requirement (2019b).
Ramp Period	Number of years to reach maximum achievable potential	9	Based on Peak Savings program experience, Springs Utilities planning assumes that ramp rates are 10%, 15%, 20%, 25%, 30%, 45%, 60%, 75%, and 90% from 2020 to 2027 before reaching steady-state achievable potential in 2028.

Results. Commercial Load Curtailment can provide 9 MW of summer peak load reduction by 2039, at a levelized cost of $112/kW-year. This product provides less potential at a higher cost compared to Commercial DLC BYOT.

C&I Critical Peak Pricing

Program Description. The C&I CPP program is similar to its residential counterpart. Commercial and industrial programs typically have lower participation rates and higher marketing costs.

Eligibility. All commercial and industrial customers are eligible for the C&I CPP, assuming full AMI deployment for Springs Utilities' C&I customers by end of 2023.

Table 44 provides other study assumptions used to estimate potential and levelized costs for C&I CPP.

Table 44. C&I Critical Peak Pricing: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$300,000	This study assumes 1 FTE to set up the program. Springs Utilities (2016): $400,000; BHE (2018): $150,000.
O&M Cost	$ per year	$50,000	Assume one-third FTE. BHE (2018): $57,000 shared with residential CPP.
Equipment Cost	$ per new participant	$0	Springs Utilities planning assumption: AMI will be fully deployed by the end of 2023.
Marketing Cost	$ per new participant	$300	Xcel (2019): $167; BHE (2018): $100; Springs Utilities (2016): $500.
Incentives (annual)	n/a	$0	None per program definition.
Incentives (one time)	n/a	$0	None per program definition.
Attrition	% of existing participants per year	0%	This study assumes minimal attrition for C&I customers once they sign up for this tariff.
Eligibility	% of segment load	100%	Springs Utilities planning assumption: AMI will be fully deployed by the end of 2023.
Peak Load Impact	% of eligible segment load	5%	Springs Utilities (2016): 5%; BHE (2018): 5%; Xcel (2019): 20%.
Program Participation	% of eligible segment load	5%	Springs Utilities (2016): low rate of 5%; BHE (2018): 13%.
Event Participation	n/a	100%	Peak load impact accounts for event participation.
Ramp Period	Number of years to reach maximum achievable potential	10	Aligned with Residential CPP.

Results. C&I CPP can only provide about 1 MW of summer peak load reduction by 2039, at a levelized cost of $131/kW-year. This product does not provide much potential due to low peak load impacts and program participation. Moreover, most summer peak load reduction from the nonresidential sector would already be addressed by Commercial DLC BYOT and Commercial Load Curtailment.

4.3. Summary of Demand Response Potentials—Gas

Table 45 presents each gas DR product's achievable potential (in peak-hour dekatherms and as a percentage of winter system peak-hour deka therms) and the associated dollar-per-therm levelized cost. The two residential, gas, DLC, smart thermostat products provide 219 peak-hour deka therms of achievable potential. Residential Gas CPP is an alternative means of achieving the same impact level, but at a much lower levelized cost level. Unlike the electric Residential CPP, where participants may reduce consumption for a variety of electric end uses, gas Residential CPP participants mostly reduce gas heating and water heating consumption during a winter morning event. Therefore, achievable potential from gas Residential CPP largely overlaps with achievable potential from other residential gas DLC products.

Table 45. Gas Demand Response Achievable Potential (Peak Hour Dth), 2039

Product	Winter Achievable Potential (Dth per peak hour)	Percent of System Peak Hour—Winter	Levelized Cost ($/Therm-hour)
Res Gas DLC Smart Thermostat Direct Install	105	0.7%	$978
Res Gas DLC Smart Thermostat BYOT	114	0.8%	$803
Res Gas DLC Water Heat	92	0.6%	$2,883
Res Critical Peak Pricing Opt-In*	293	2.0%	$95
Com Gas DLC BYOT	25	0.2%	$274

* Note that potential from this product largely overlaps with potential from other residential DLC products.

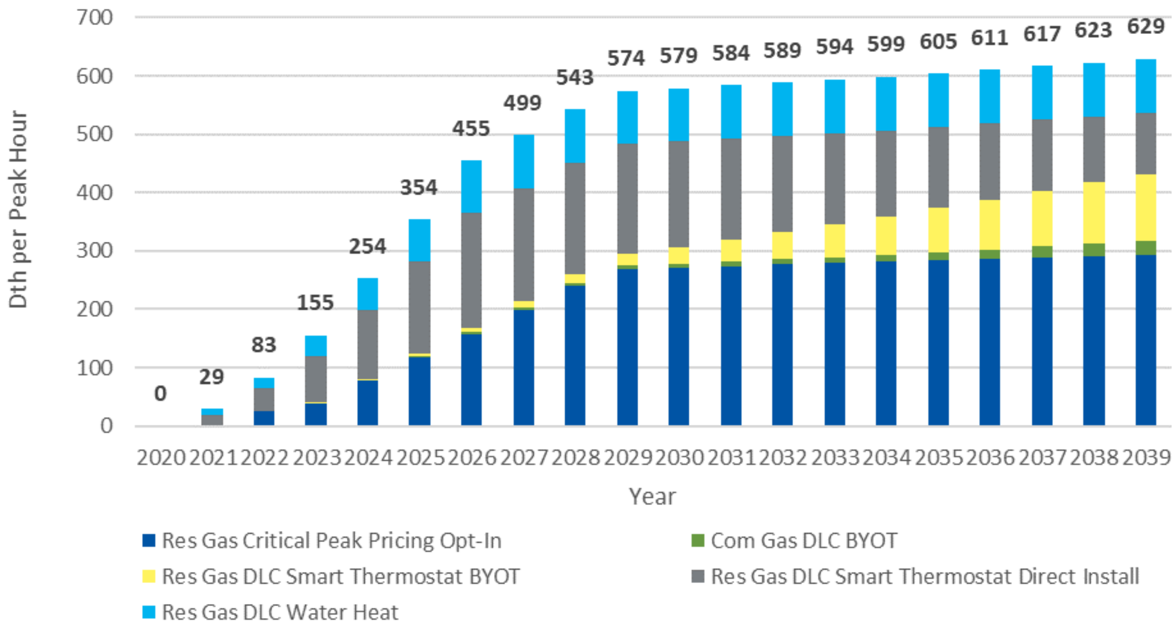
Table 46. Gas Demand Response Achievable Potential (Peak Day Dth), 2039

Product	Winter Achievable Potential (Dth per peak day)	Percent of System Peak Day—Winter	Levelized Cost ($/Therm-Day)
Res Gas DLC Smart Thermostat Direct Install	206	0.1%	$499
Res Gas DLC Smart Thermostat BYOT	224	0.1%	$409
Res Gas DLC Water Heat	546	0.2%	$525
Res Gas Critical Peak Pricing Opt-In	1,204	0.4%	$23
Com Gas DLC BYOT	81	0.0%	$84

* Note that potential from this product largely overlaps with potential from other residential DLC products.

Figure 33. charts the annual, product-level, achievable potential from the lowest-cost product (Residential Gas CPP Opt-in) to the highest-cost product (Residential Gas DLC Water Heat).

Figure 33. Gas Demand Response 20-Year Achievable Potential (Peak Hour Dth), by Levelized Cost*



*Note that potential from this product largely overlaps with potential from other residential DLC products.

4.3.1. Residential Gas Demand Response Products

The following sections present the program description, study assumptions, and potential results for each residential gas DR product.

Residential Gas DLC Smart Thermostat Direct Install

Program Description. The Residential Gas DLC Smart Thermostat Direct Install program is similar to its electric counterpart, except that it targets residential customers with gas central heating. This study assumed winter peak events occur in winter mornings, lasting up to three hours, for up to 10 events per season.

Eligibility. Eligible residential customers have gas central heating equipment, such as a gas furnace or gas boiler, and do not have an installed smart thermostat.

Table 47 provides other study assumptions used to estimate potential and levelized costs for Residential Gas DLC Smart Thermostat Direct Install.

Table 47. Residential Gas DLC Smart Thermostat Direct Install: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$20	Aligned with its electric counterpart.
Equipment Cost	$ per new participant	$250	Aligned with its electric counterpart.
Marketing Cost	$ per new participant	$25	Aligned with its electric counterpart.
Incentives (annual)	$ per participant per year	$25	SoCalGas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$0	There is no one-time incentive, unlike the BYOT option.

Parameters	Units	Values	Notes
Attrition	% of existing participants per year	1.5%	Aligned with its electric counterpart.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	Southern California Gas pilot (2018): 16% to 25% for a morning event.
	% of peak-day load	2%	Southern California Gas pilot (2018): 2.3% to 2.5% of peak day impact with a morning event (neither were statistically significant).
Program Participation	% of eligible customers	15%	Southern California Gas (Hanway 2019): 16% participation of eligible Ecobee thermostats.
Event Participation	%	100%	Peak load impact already takes into account event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with its electric counterpart.

Results. Residential Gas DLC Smart Thermostat Direct Install can provide 105 dekatherms of winter peak-hour reduction in 2039, at a levelized cost of $978/therm-year. In terms of peak-day impact (assuming a three-hour morning event), this product can provide 206 dekatherms of winter peak-day reduction, at a levelized cost of $499/therm-year.

Residential Gas DLC Smart Thermostat BYOT

Program Description. The Residential Gas DLC Smart Thermostat BYOT program is identical to its electric counterpart, except that it targets residential customers with gas central heating. This study assumed winter peak events occurred in winter mornings, lasting up to three hours, for up to 10 events per season.

Eligibility. Eligible residential customers have gas central-heating equipment, such as a gas furnace or gas boiler and an installed smart thermostat.

Table 48 provides other study assumptions used to estimate potential and levelized costs for the Residential Gas DLC Smart Thermostat BYOT program.

Table 48. Residential Gas DLC Smart Thermostat BYOT: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$20	Aligned with its electric counterpart.
Equipment Cost	$ per new participant	$0	Assume participant already has a smart thermostat.
Marketing Cost	$ per new participant	$25	Aligned with its electric counterpart.
Incentives (annual)	$ per participant per year	$25	Southern California Gas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$50	Southern California Gas program plan (Hanway 2019) assumed $50 of one-time incentive.
Attrition	% of existing participants per year	1.5%	Aligned with its electric counterpart.

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	Aligned with the direct install option.
	% of peak-day load	2%	Aligned with the direct install option.
Program Participation	% of eligible customers	15%	Aligned with the direct install option.
Event Participation	%	100%	Peak load impact already takes into account event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with its electric counterpart.

Results. The Residential Gas DLC Smart Thermostat BYOT program can provide 114 dekatherms of winter peak-hour reduction by 2039, at a levelized cost of $803/therm-year. In terms of peak-day impact (assuming a three-hour morning event), this product can provide 224 dekatherms of winter peak-day reduction, at a levelized cost of $409/therm-year. Both in terms of peak-hour and peak-day impacts, this product can provide slightly more potential and at a lower cost compared to the Residential Gas DLC Smart Thermostat Direct Install. Nevertheless, the two products can be implemented together.

Residential Gas DLC Water Heat

Program Description. Residential Gas DLC Water Heat is a DLC program that retrofits existing gas storage water heaters by installing a gas water heater controller. Using the controller, the utility can control participating residential water heating loads. This study assumed that winter peak events occurred in winter mornings, lasting up to three hours, for up to 10 events per season.

Eligibility. Residential customers with gas storage water heaters are eligible to participate. As the Aquanta controller can only be installed on gas storage water heaters with electronic ignition, this study embeds accounts for this restriction in the program participation rate.

Table 49 provides other study assumptions used to estimate potential and levelized costs for Residential Gas DLC Water Heat.

Table 49. Residential Gas DLC Water Heat: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$20	Aligned with other residential gas DLC products.
Equipment Cost	$ per new participant	$300	Aquanta water heater controller cost: $150 (2019). Consolidated Edison (2017) assumed total installed cost: $300.
Marketing Cost	$ per new participant	$25	Aligned with other residential gas DLC products.
Incentives (annual)	$ per participant per year	$25	Southern California Gas program plan (Hanway 2019).
Incentives (one time)	$ per new participant	$0	This study assumes no one-time incentive.
Attrition	% of existing participants per year	1.5%	Aligned with other residential gas DLC products.

Parameters	Units	Values	Notes
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	20%	This study assumes similar impact as other residential gas DLC products.
	% of peak-day load	5%	Consolidated Edison (2017) conservative assumption for annual savings, assumed for peak day savings.
Program Participation	% of eligible customers	15%	Aligned with other residential gas DLC products. Given the Aquanta controller specification, this study assumes that only gas storage water heaters with electronic ignition participate.
Event Participation	%	100%	Peak load impact already takes into account event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with other residential gas DLC products.

Results. Residential Gas DLC Water Heat can provide 92 dekatherms of winter peak hour reduction by 2039, at a levelized cost of $2,883/therm-year. In terms of peak day impacts (assuming a three-hour morning event), this product can provide 546 dekatherms of winter peak-day reduction, at a levelized cost of $525/therm-year.

Residential Gas Critical Peak Pricing

Program Description. Residential Gas CPP is similar to its electric counterpart, except that it encourages residential customers to reduce their overall gas demand.

Eligibility. All residential gas customers are eligible for this program, assuming full AMI deployment for Springs Utilities' residential customers by end of 2023.

Table 50 provides other study assumptions used to estimate potential and levelized costs for Residential Gas CPP.

Table 50. Residential Gas Critical Peak Pricing: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	Assumption aligned with its electric counterpart.
O&M Cost	$ per year	$50,000	Aligned with residential electric CPP product
Equipment Cost	$ per new participant	$0	Colorado Springs assumes that AMI will be fully deployed by the end of 2023.
Marketing Cost	$ per new participant	$25	Aligned with residential electric CPP product
Incentives (annual)	n/a	$0	Aligned with residential electric CPP product
Incentives (one time)	n/a	$0	Aligned with residential electric CPP product
Attrition	% of existing participants per year	10%	Aligned with residential electric CPP product
Eligibility	% of segment load	100%	Aligned with residential electric CPP product
Peak Load Impact	% of peak-hour load	20%	Aligned with residential electric CPP product

Parameters	Units	Values	Notes
	% of peak-day load	4%	Aligned with residential electric CPP product. Assuming a three-hour morning event, normalized to peak day impact.
Program Participation	% of eligible segment load	15%	Aligned with residential electric CPP product
Event Participation	n/a	100%	Aligned with residential electric CPP product
Ramp Period	Number of years to reach maximum achievable potential	10	Aligned with residential electric CPP product

Results. Residential Gas CPP can provide 293 dekatherms of winter peak-hour reduction by 2039, at a levelized cost of $95/therm-year. In terms of peak-day impacts (assuming a three-hour morning event), this product can provide 1,204 dekatherms of winter peak-day reduction, at a levelized cost of $23/therm-year. Note that participants in this product potentially overlap with participants in other residential gas DLC products (especially smart thermostat products). Therefore, this product may resemble a lower-cost approach to incentivizing customers to reduce gas demand during peak winter periods.

4.3.2. Nonresidential Gas Demand Response Products

The following section presents the program description, study assumptions, and potential results for the Commercial Gas DLC BYOT product.

Commercial Gas DLC BYOT

Program Description. Commercial customers receive incentives to allow the utility to control their central gas heating equipment during winter peak events. This study assumes a three-hour event duration, with up to 10 events in the winter. Participants receive an annual incentive of $25 per therm committed to curtailment, in addition to a one-time incentive of $85 upon signing up.

Eligibility. All commercial customers with a gas furnace or gas boiler and an existing learning Wi-Fi thermostat are eligible to participate in this program.

Table 51 provides other study assumptions used to estimate potential and levelized costs for Commercial Gas DLC BYOT.

Table 51. Commercial Gas DLC BYOT: Study Assumptions

Parameters	Units	Values	Notes
Setup Cost	$	$150,000	This study assumes 1 FTE to set up the program.
O&M Cost	$ per participant per year	$75	Estimate based on Southern California Gas program plan (Hanway 2019) for residential and commercial programs combined, less annual incentives.
Equipment Cost	$ per new participant	$0	Assume participant already has a smart thermostat.
Marketing Cost	$ per new participant	$0	Included in O&M cost.
Incentives (annual)	$ per therm pledged per year	$25	National Grid pilot in New York for large boilers: $30/therm (Roth 2019); Southern California Gas program plan (Hanway 2019): $10/therm for core customers.

Parameters	Units	Values	Notes
Incentives (one time)	$ per new participant	$85	Consolidated Edison (2018): $85; Southern California Gas program plan (Hanway 2019): $90.
Attrition	% of existing participants per year	5%	National Grid pilot in New York (Roth 2019): 6%.
Eligibility	% of customer count (e.g. equipment saturation)	Varies by segment	End use saturations for eligible segments are aligned with this study's assumptions for energy efficiency.
Peak Load Impact	% of peak-hour load	50%	National Grid pilot in New York (Roth 2019) for large boilers.
	% of peak-day load	8%	National Grid pilot in New York (Roth 2019) for large boilers for a three-hour event: 50%, normalized to peak day impact, assuming no rebound effect.
Program Participation	% of eligible customers	2.5%	National Grid pilot in New York (Roth 2019) for large boilers.
Event Participation	%	100%	Peak load impact already takes into account event participation.
Ramp Period	Number of years to reach maximum achievable potential	7	Aligned with residential gas DLC products.

Results. Commercial Gas DLC BYOT can provide 25 dekatherms of winter peak-hour reduction in 2039, at a levelized cost of $274/therm-year. In terms of peak-day impacts, assuming a three-hour morning event, this product can provide 81 dekatherms of winter peak-day reduction at a levelized cost of $84/therm-year. This product provides a small amount of potential relative to residential gas products.

5. Customer-Sited Renewable Energy

5.1. *Solar Photovoltaic*

5.1.1. Technical Potential Results

Based on the analysis described in the previous sections, Cadmus estimated 4,093 MW as the total, theoretical, technical potential for solar PV, installed on residential and commercial rooftops in Springs Utilities' service area over 20 years. Almost 72% of this technical potential arose in the commercial sector, with the remaining 28% coming from the residential sector. Each sector's technical potential is a function of the fraction of total roof area suitable for solar PV installation and the total roof area. In this case, the residential sector accounted for a smaller percentage of technical potential, given only a modest proportion of total available roof area for this sector will likely be suitable for solar PV installations; in the residential sector, this proportion was 29%; in the commercial sector, the proportion was 62%. If the full technical potential were installed, it would generate approximately 7,361 GWh.

Table 52 provides the study period resulting in behind-the meter PV technical potential, with growth due to increase in building stock from 2020 to 2039.

Table 52. PV Technical Potential (2020-2039)

Sector	Total 2020 MWh	Installed Capacity 2020 MW	Total 2039 MWh	Installed Capacity 2039 MW
Residential	1,533,111	782	2,090,653	1,157
Commercial	4,461,262	2,276	5,270,084	2,936
Total	**5,994,373**	**3,058**	**7,360,737**	**4,093**

5.1.2. Achievable Potential Results

Historically, the PV market has been heavily influenced by policy and incentive decisions, but, over time, future incentives may play a lesser role. To model the influence of these policy changes on the PV market potential within Springs Utilities' territory, Cadmus developed a series of scenarios reflecting the impact of policy changes on customer paybacks and, by extension, market potentials.

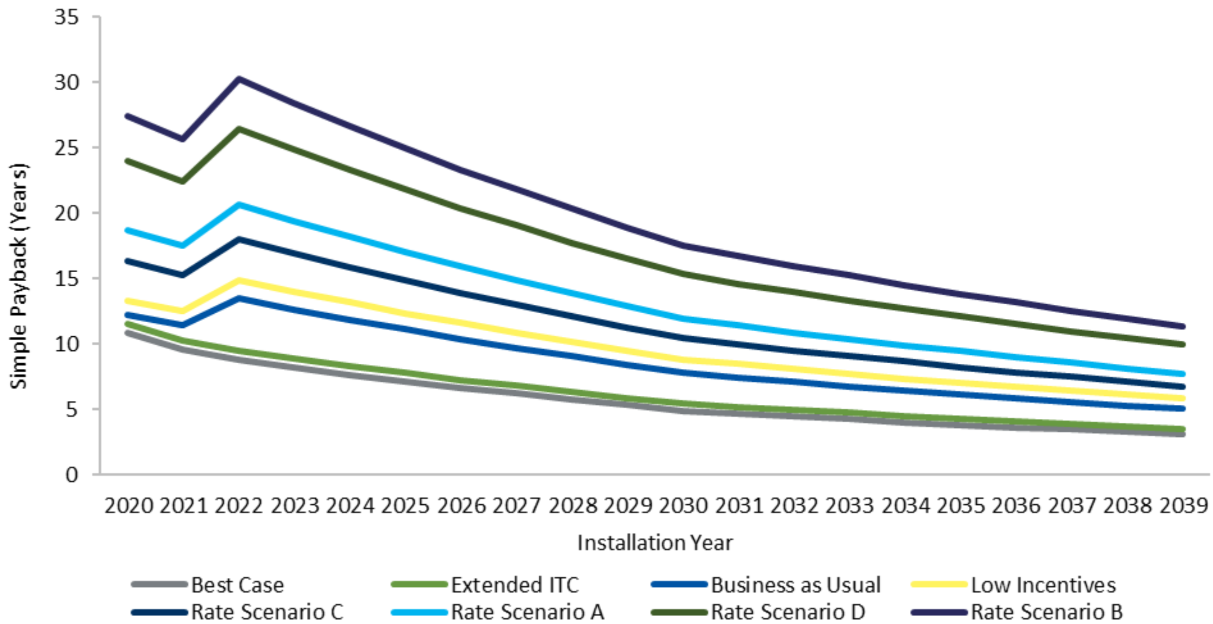
Additionally, rate structures may impact how much utility cost is offset through PV installations. Cadmus developed several residential rate scenarios, as described above, to estimate how various rate options could impact market uptake of PV installations. Unsurprisingly, chosen policy and incentive scenarios heavily influence PV's achievable potential.

In this section, Cadmus summarizes results for each scenario (Base, Extended ITC, Low Incentive, and Best Case). Additionally, Cadmus provides results for several rate-case scenarios for the residential sector (A: two rate periods with current customer charge; B: two rate periods and increased customer charge; C: three rate periods with critical peak rate and current customer charge; D: three rate periods and increased customer charge).

Residential Achievable Potential Results

Error! Reference source not found. shows the impact of various incentive and rate scenarios on expected residential customer paybacks. The shortest payback periods occurred under the Best Case Scenario (i.e., continued ITC and sales tax exemptions, as well as increased incentives), while the longest payback periods occurred under Rate Scenario B (i.e., two rate periods and increased daily customer charge).

Figure 34**. Residential PV Simple Payback Projections Under Eight Policy and Rate Scenarios**



As a result, these varying payback periods impact the likely adoption of PV systems. As discussed in the PV Achievable Potential Approach, Cadmus modeled a percentage of market penetration as a function of customer payback.

Based on historical installation data as well as back cast technical potential and payback periods, Cadmus estimated the achievable market penetration function as:

$$MP = 0.154 * e^{-0.283 * ASP}$$

where MP equals the percentage of market adoption, and ASP equals the annual simple payback (years). Figure 35 shows the relationship between the payback period and achievable market penetration, according to the market penetration function.

Figure 35. Residential Market Penetration Function

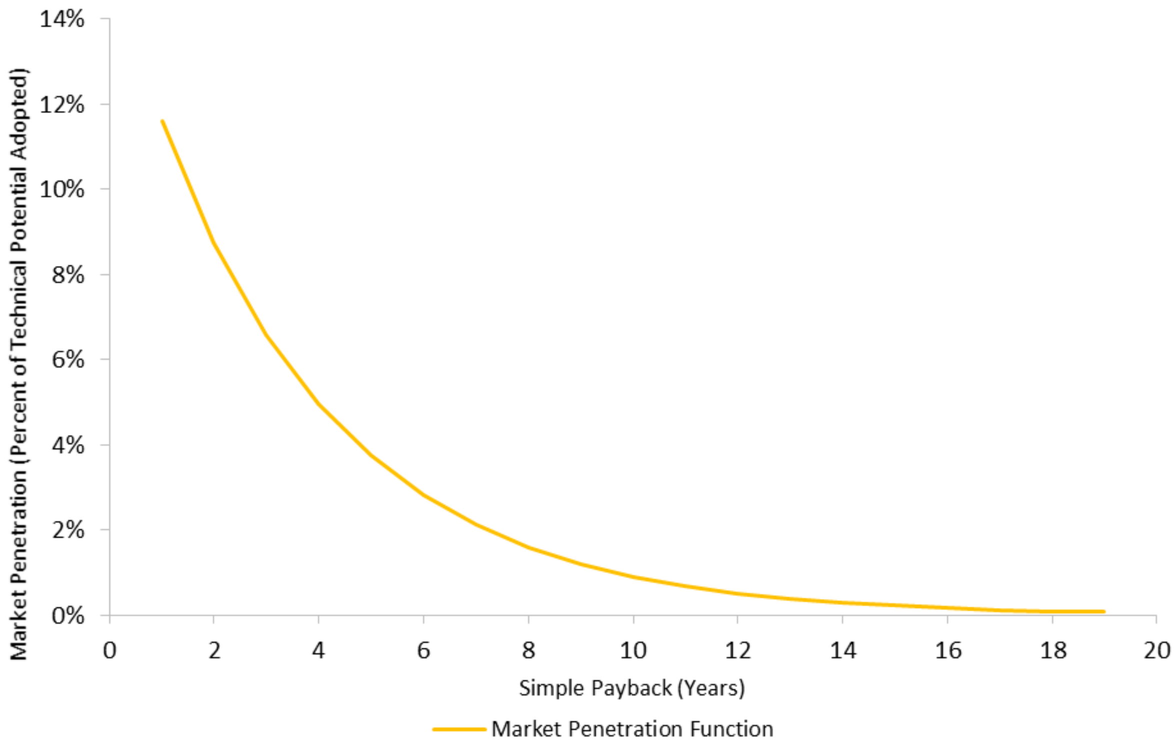
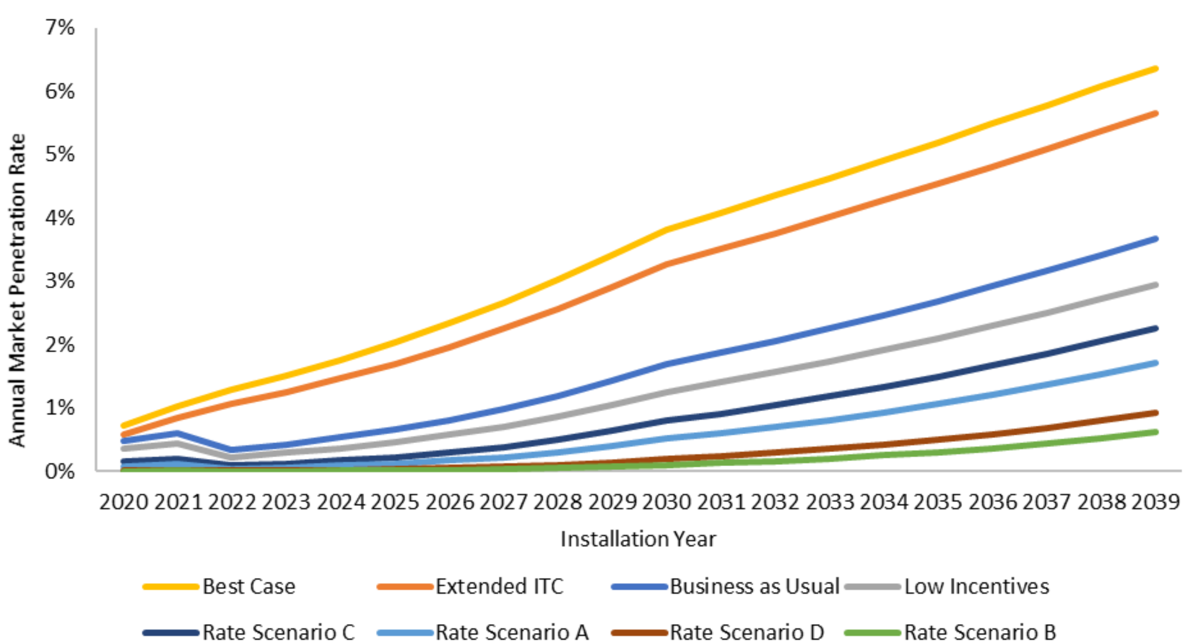


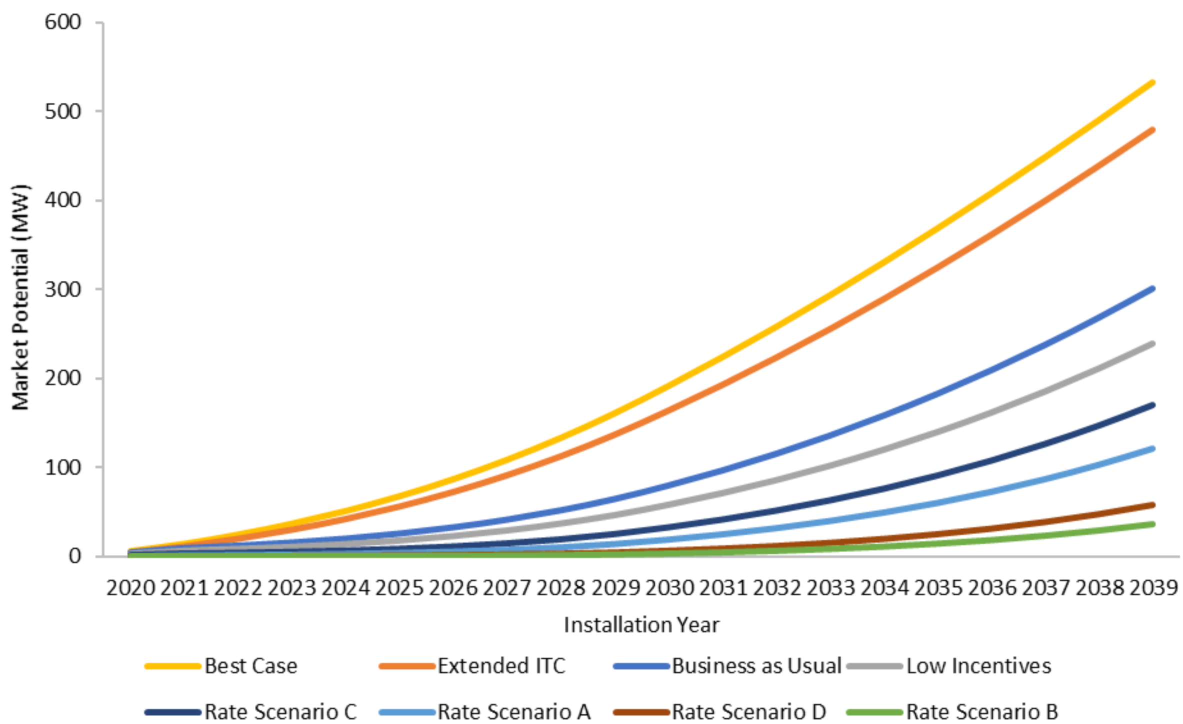
Figure 36. shows the annual market penetration rate for the residential sector of each policy scenario, applying the various payback scenarios to the market penetration functions. As shown, customer incentives and/or lower solar PV costs serve as important drivers to increased market adoption.

Figure 36. Residential Solar PV Annual Market Penetration Rate Under Eight Policy and Rate Scenarios



Overall, across Springs Utilities' service area, achievable potential will remain relatively flat under the various rate scenarios, with increased adoption expected in the late 2030s as simple payback periods fall below 20 years. The highest market adoption rate is seen with Best Case and Extended ITC Scenarios, with a single rate period. Figure 37 shows cumulative market achievable potential under the various scenarios. The Best Case and Extended ITC scenarios show the highest achievable potential, while the rate scenarios show the lowest achievable potential.

Figure 37. Residential Solar PV Total Cumulative Achievable Potential by Scenario (MW)



Commercial Achievable Potential Results

Cadmus estimated that, when weighted by building square footage, approximately 94% of Springs Utilities' commercial customers are on flat rates, while 6% of Springs Utilities' commercial customers are on TOU rates. To account for TOU rate impacts on payback periods, Cadmus estimated payback periods and market adoption rates for TOU and standard rates, then weighted the results for each policy scenario.

Similar to the residential analysis, Cadmus developed a commercial adoption rate, based on historical Springs Utilities installations (2008 through May 2019). According to commercial solar PV tracking data, adoption of solar PV appears less likely to be driven by customer paybacks, rather than be additional barriers.[27] An NREL study also indicated slow growth in the commercial market, noting "a number of key barriers have impeded growth, including tenant and landlord split incentives, contracting challenges, the mismatch in building lease and PV financing terms, and high transaction costs relative to project sizes."[28]

As shown in Figure 38, in a given year, total commercial solar PV installed capacity ranged from 25 kW to 770 kW irrespective to the estimated payback. To avoid overestimation of achievable potential, Cadmus applied a relatively flat market adoption rate that best represented Springs Utilities' historical activity and accounted for the commercial barriers.

Figure 38. Historical Commercial PV Installations and Estimated Payback Period

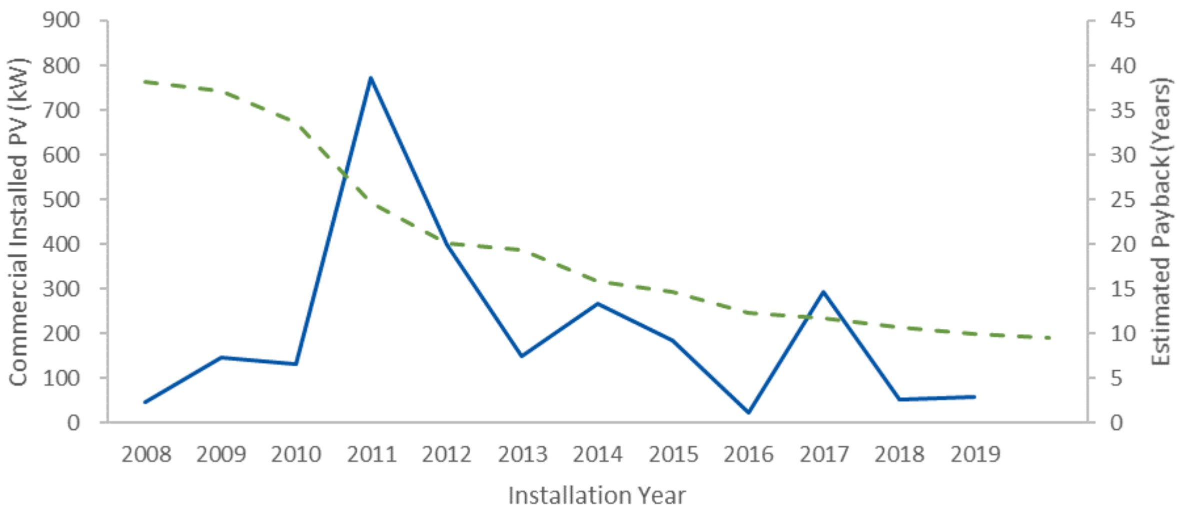


Figure 39 shows the impact of various incentive and rate scenarios on expected commercial customer paybacks. The lowest payback periods were produced by the Best Case Scenario with standard rates, while the highest payback periods were realized under the Low Incentive Scenario with TOU rates.

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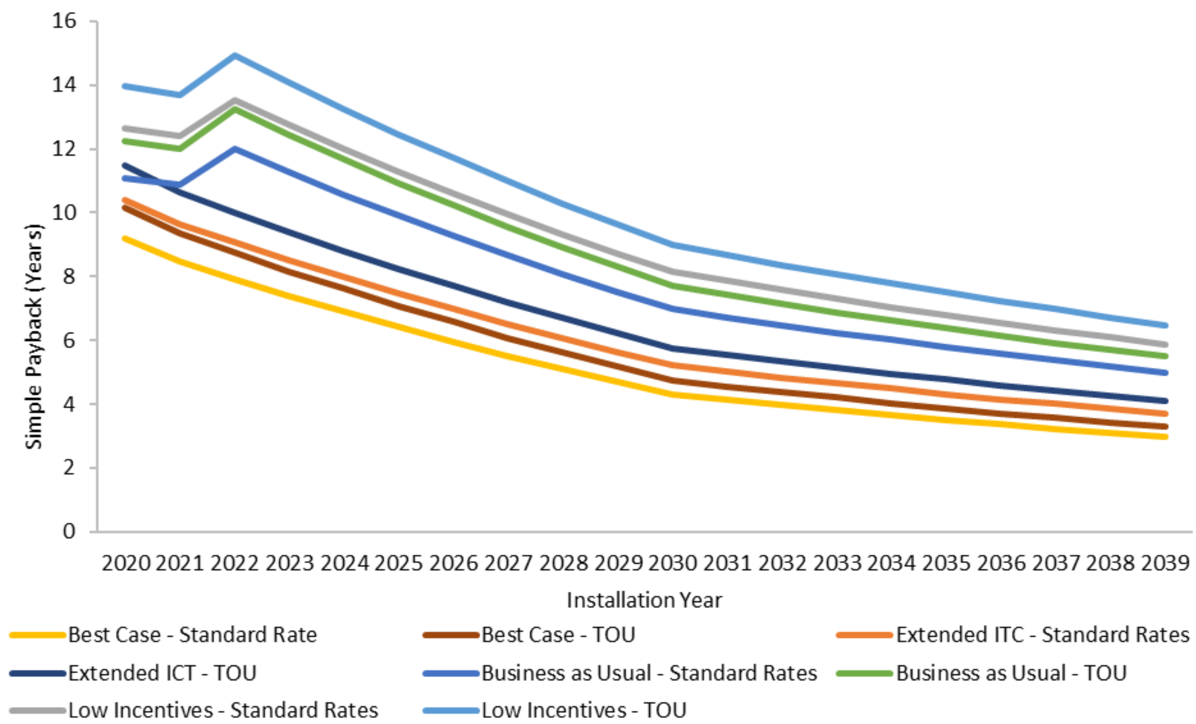
27 Calculating payback periods, Cadmus incorporated changing PV costs, Springs Utilities' incentives, state and federal incentives, and estimated historical commercial customer rates.

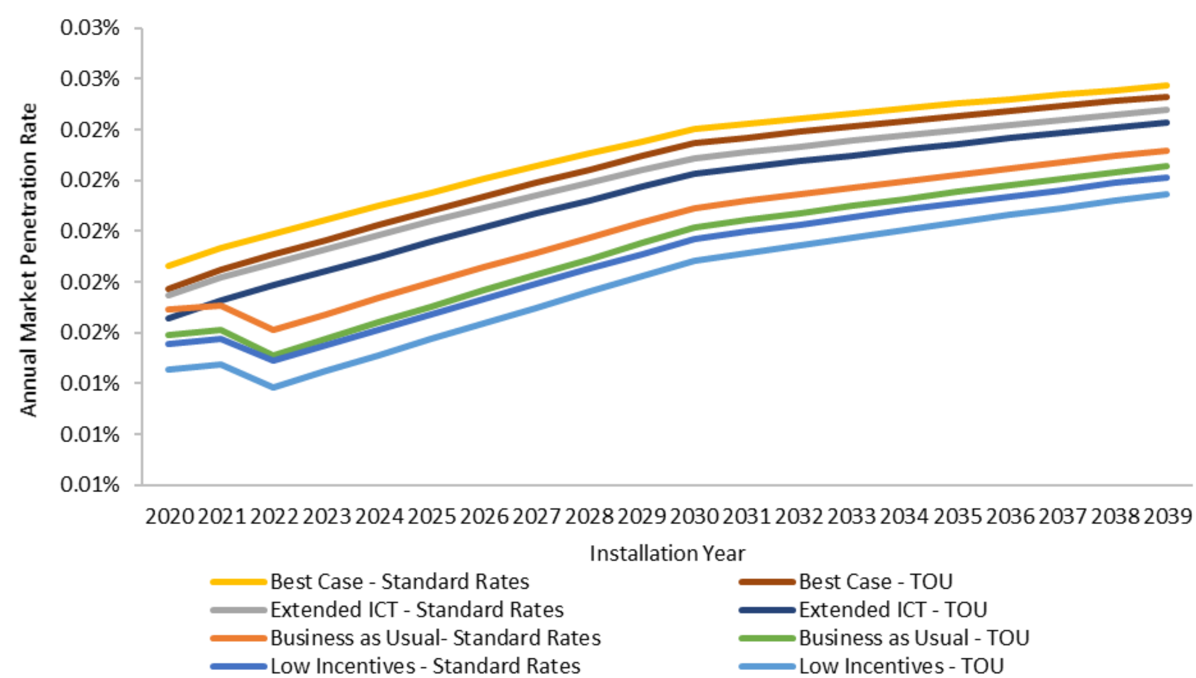
28 Lori Bird, Pieter Gagnon, and Jenny Heeter. NREL. "Expanding Midscale Solar: Examining the Economic Potential, Barriers, and Opportunities at Offices, Hotels, Warehouses, and Universities". September 2016. Available online: https://www.nrel.gov/docs/fy16osti/65938.pdf

Figure 39. Commercial PV Simple Payback Projections Under Eight Policy and Rate Scenarios



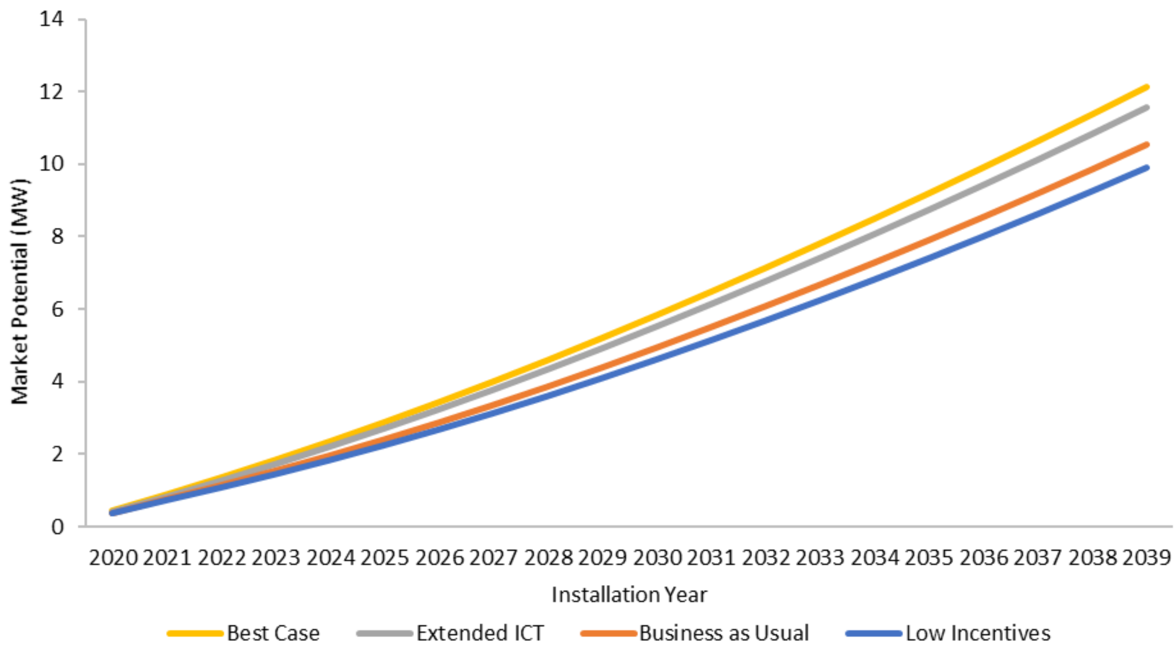
As a result, these varying payback periods affect likely adoption of PV systems. Figure 40 shows the annual market penetration rate for the commercial sector of each policy scenario. Customer incentives and standard rates serve as drivers to increased market adoption.

Figure 40. Commercial PV Annual Market Penetration Rate Under Eight Policy and Rate Scenarios



Overall, commercial achievable potential remained relatively similar, regardless of scenarios, as influence of the payback period was less instrumental in motivating commercial PV adoption. Figure 41 shows commercial, PV, total, cumulative achievable potential (in MWh), representative of current Springs Utilities' trends. Cumulative achievable potential in the figure represents the weighted average commercial rate for the TOU and standard rates.

Figure 41. Commercial Solar PV Total Cumulative Achievable Potential by Scenario



Residential and Commercial Achievable Potential Results

Table 53 summarizes achievable potential results for each scenario.

Table 53. Achievable Potential Results by Scenario and Sector

Scenario	2039 Achievable Potential (MW)			2039 Achievable Potential (MWh)		
	Residential	Commercial	Total	Residential	Commercial	Total
Low Incentive Scenario	239	10	249	455,640	18,626	474,266
Business as Usual Scenario	301	11	311	572,244	19,793	592,037
Extended ITC Scenario	480	12	491	908,693	21,673	930,366
Best Case Scenario	533	12	545	1,007,977	22,738	1,030,715
Rate Scenario A	121	NA	NA	231,741	NA	NA
Rate Scenario B	36	NA	NA	68,582	NA	NA
Rate Scenario C	169	NA	NA	323,756	NA	NA
Rate Scenario D	58	NA	NA	111,078	NA	NA

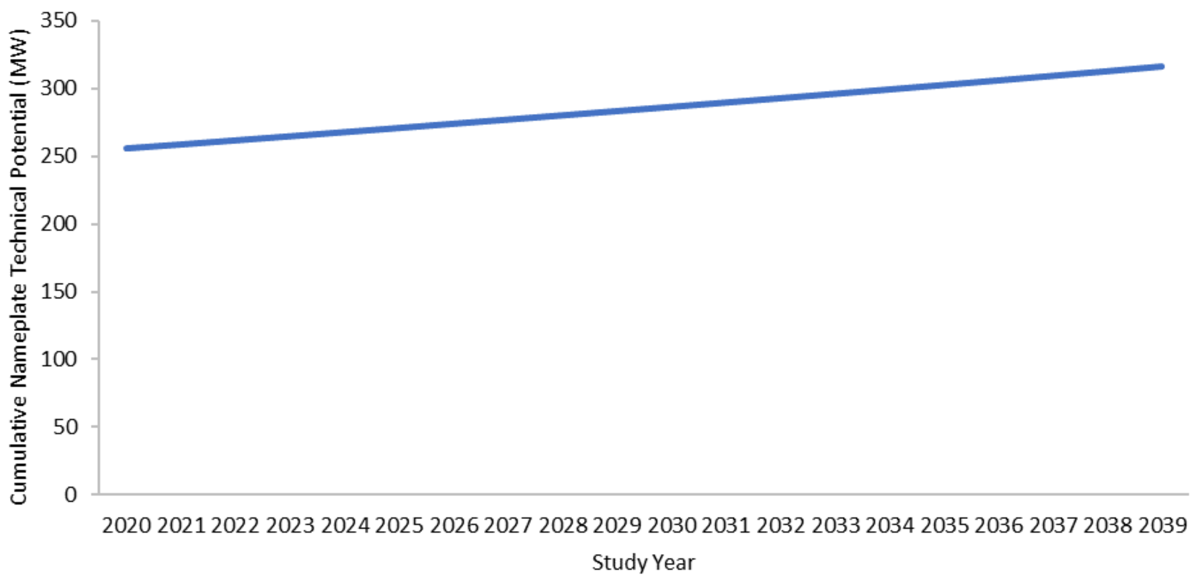
5.2. Battery Storage

5.2.1. Technical Potential Results

Nameplate Storage Technical Potential

Using the methodology outlined in the battery storage Technical Potential Methodology section, Cadmus estimated a technical potential of 316 MW, cumulative, nameplate storage capacity by 2039 for residential solar-plus-storage systems in the Springs Utilities service territory. Figure 42 shows the increase in nameplate storage technical potential during the study period.

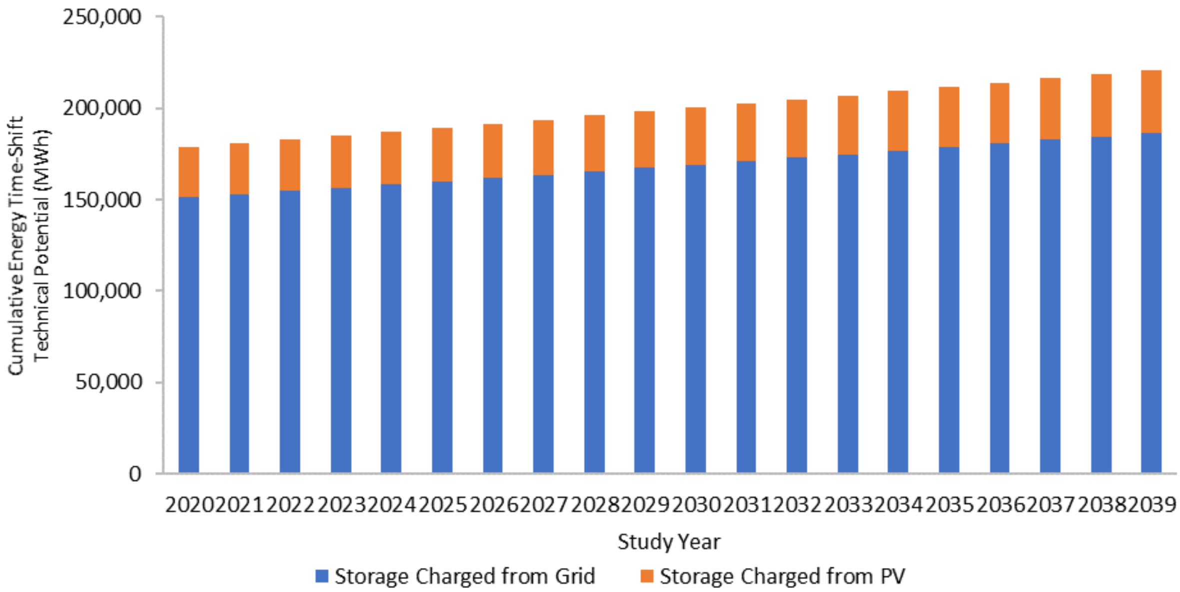
Figure 42. Cumulative Nameplate Storage Technical Potential for Residential Solar-Plus-Storage Systems (MW)



Time-Shift Energy Technical Potential

With these systems integrated into a time-of-day rate structure, the grid could expect to see a total cumulative technical potential of 220,983 MWh of energy time-shift per year by 2039. The majority of this (84%) represents electricity charged to battery banks from the grid during less-expensive off-peak hours for use by customers or sold back to the grid during more expensive on-peak hours. The remaining 16% represents electricity charged to the battery bank from the solar array during off-peak hours for use by customers or sold back to the grid during on-peak hours. Figure 43 shows the cumulative energy time-shift technical potential for the study period's length.

Figure 43. Cumulative Energy Time-Shift Technical Potential (MWh)



Demand Response Technical Potential

If Springs Utilities implemented a DR program making use of residential battery systems, technical potential of 124 MW of DR capacity could be expected per event by 2039, resulting in estimated, annual 4,951 MWh of energy. The cumulative technical potential of a single DR event can be seen in Figure 44 for each year of the study period. Cadmus assumed a linear ramp period of seven years where the storage DR program would develop to its full extent. This ramp period can be seen in the technical potential shift following 2026. After the seven-year ramp period, the DR program is assumed to reach a maximum of 30% of customers with solar-plus-storage systems.

Figure 44. Cumulative Demand Response Event Technical Potential (MW)

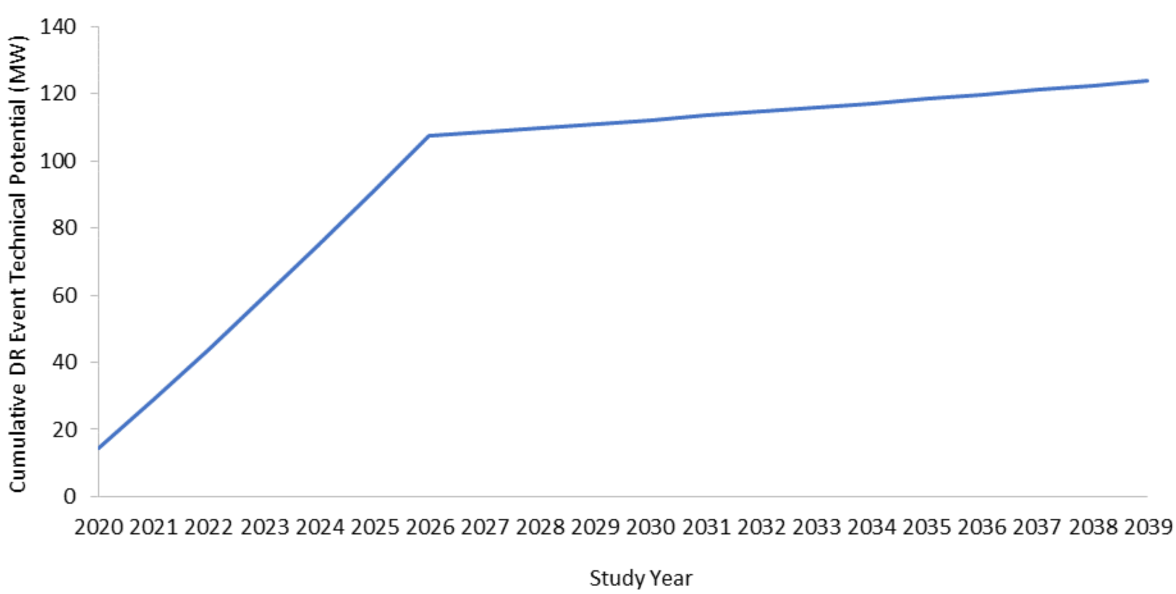
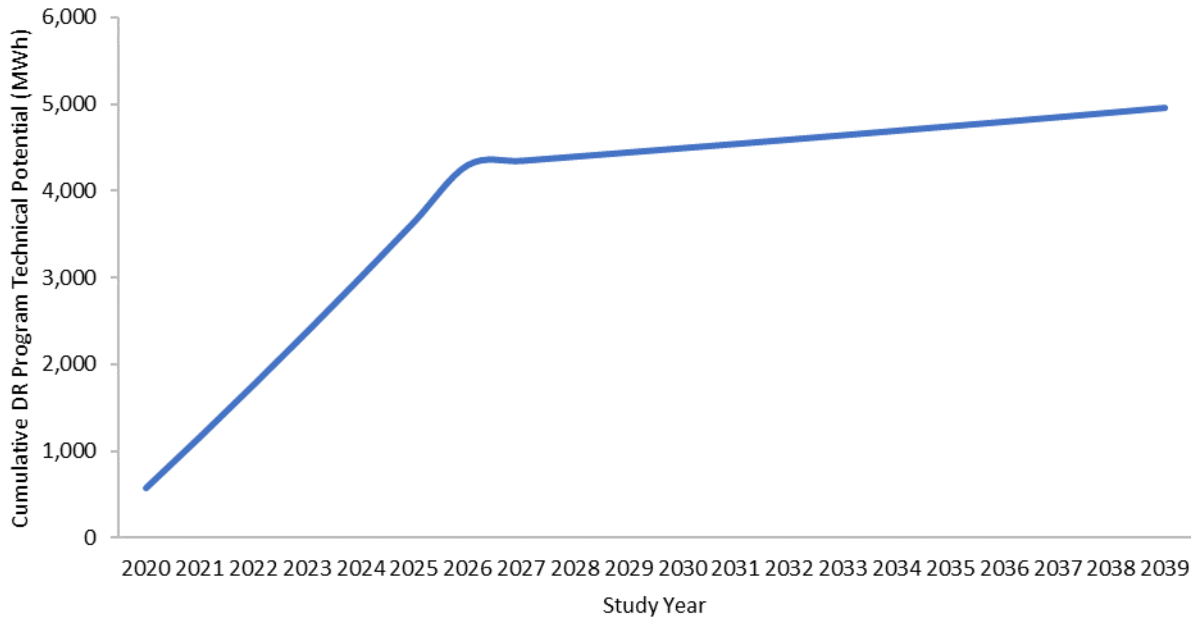


Figure 45 shows the cumulative technical energy potential for all events in the DR program for each year of the study period.

Figure 45. Cumulative Demand Response Program Technical Potential (MWh)

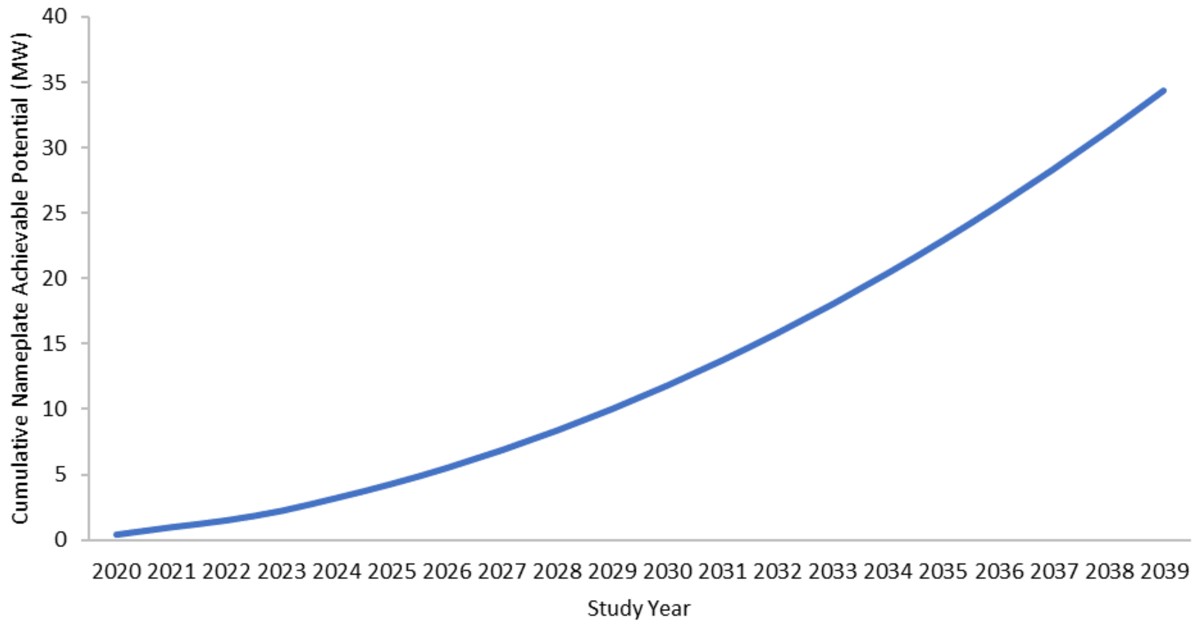


5.2.2. Achievable Potential Results

Nameplate Achievable Potential

By applying market forecasts for residential solar-plus-storage installations to the Springs Utilities' service territory, Cadmus calculated an achievable potential of 34,374 kW (34 MW) cumulative, nameplate storage capacity by 2039. This represents 11% of technical potential. Figure 46 shows the increase in nameplate storage technical potential during the study period.

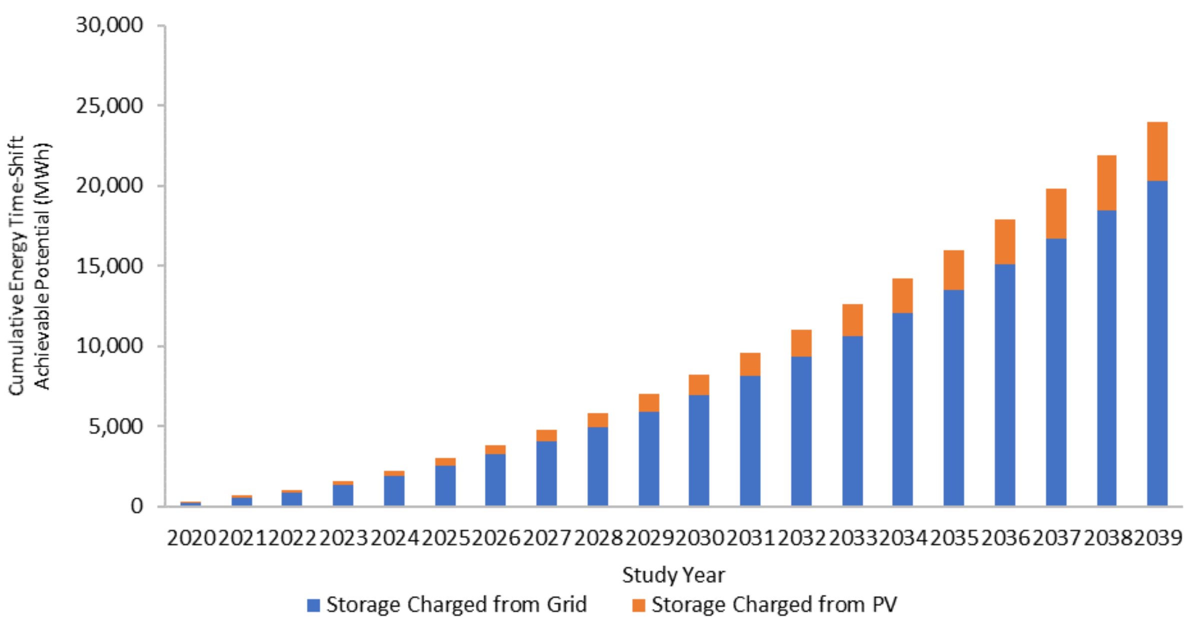
Figure 46. Cumulative Nameplate Storage Achievable Potential for Residential Solar-Plus-Storage Systems (MW)



Time-Shift Energy Achievable Potential

Integrating these storage systems into a residential time-of-day rate structure would produce cumulative, energy time-shift, achievable potential of 24,021 MWh by 2039 with 20,287 MWh of this energy charged from the grid and another 3,734 MWh charged from solar PV. Figure 47 shows the cumulative, energy time-shift, achievable potential for the length of the study period.

Figure 47. Cumulative Energy Time-Shift Achievable Potential (MWh)



Demand Response Achievable Potential

As part of a residential DR program, these storage systems could reach achievable potential of 8,596 kW in DR capacity per event and annual 344 MWh of energy by 2039. Figure 48 shows the cumulative achievable potential of a single DR event for each year of the study period.

Figure 48. Cumulative Demand Response Event Achievable Potential (kW)

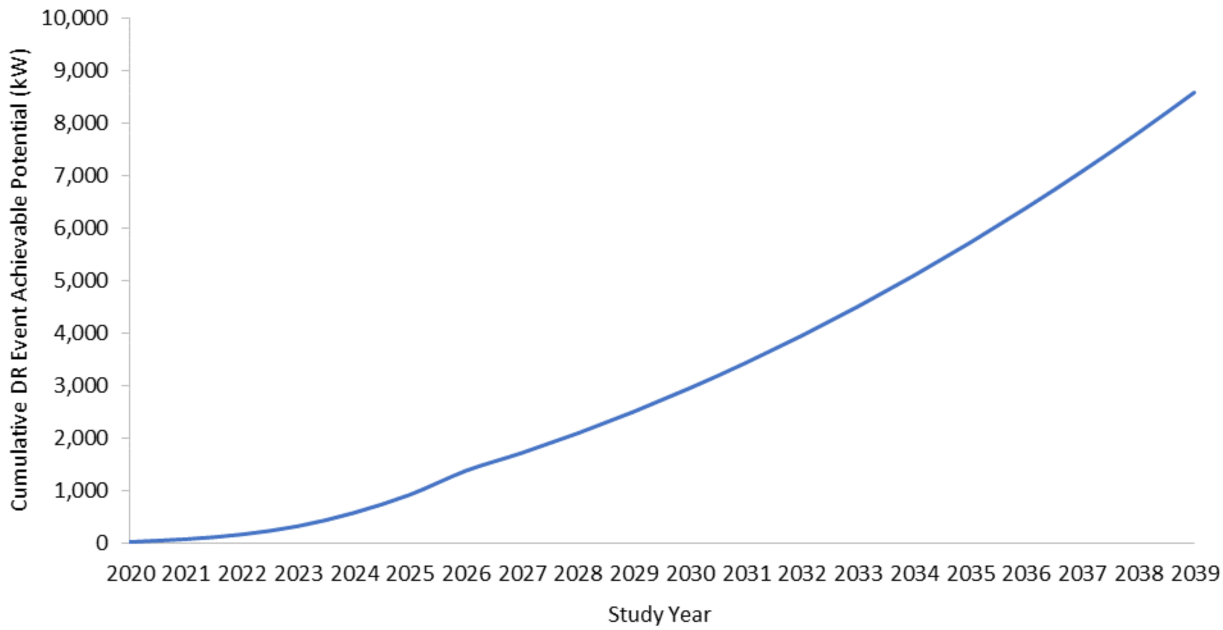
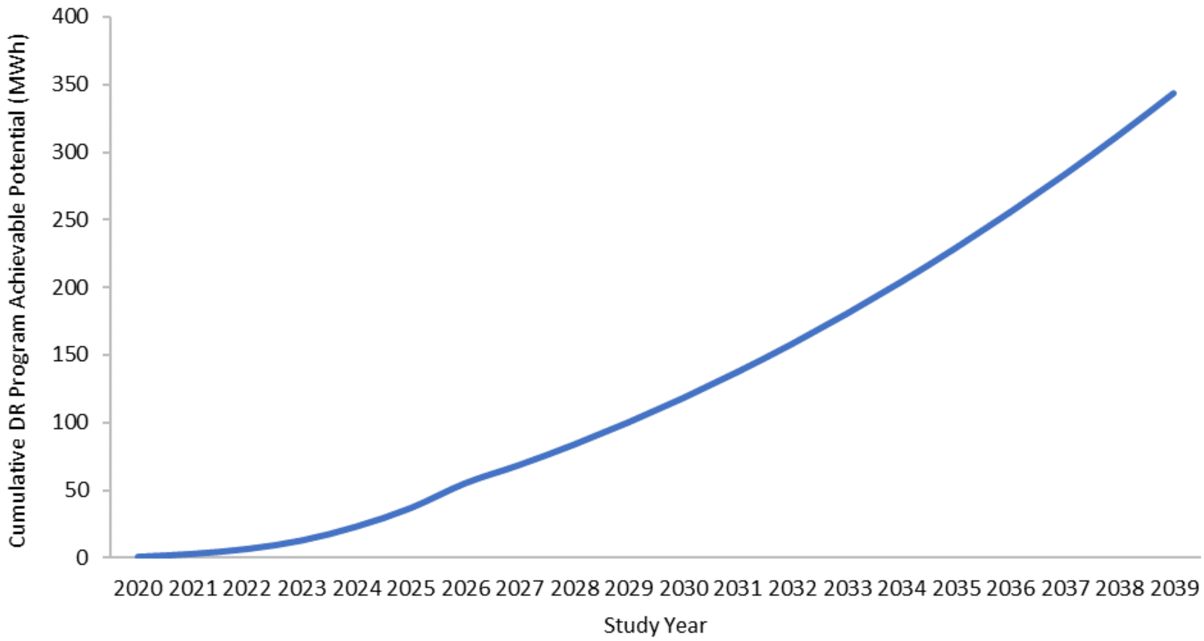


Figure 49 shows the cumulative, achievable, energy potential for all events in the DR program for each year of the study period.

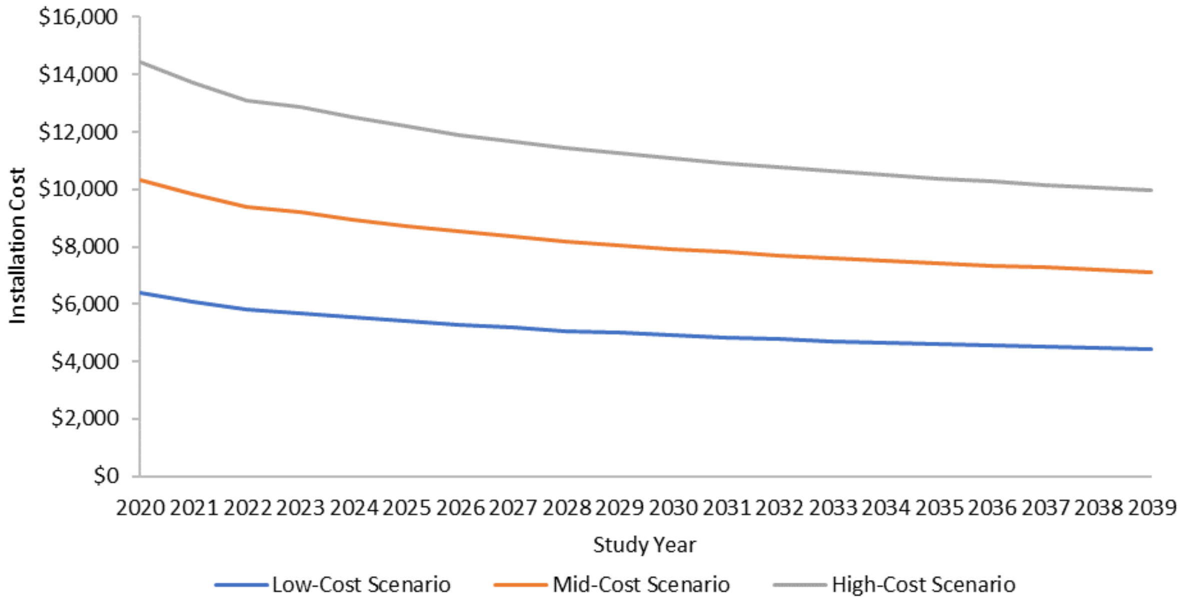
Figure 49. Cumulative Demand Response Program Achievable Potential (MWh)



5.2.3. Tipping Point Analysis Results

Through conducting a tipping point analysis of the net present value of system costs and benefits, Cadmus determined the economic value of an installed, residential, solar-plus-storage system. This analysis focused on a system with 5 kW of battery storage capacity and an average of 4.39 kW of solar PV capacity. Due to the large variability in capital costs found in our literature review, Cadmus conducted the tipping point analysis for three separate cost scenarios: low-cost, medium-cost, and high-cost. Figure 50 shows cost forecasts for these scenarios.

Figure 50. Cost Forecast for Three 5 kW Powerwall Cost Scenarios



Cadmus found that a system installed in 2020 for any cost scenario would result in a net loss for a residential customer, even when including all relevant federal, state, and local incentives for the battery and PV components. Systems installed later in the program period benefit economically from lower battery and solar PV system costs and higher electricity purchase prices. Future systems also see revenue losses due to schedule expiration of the federal investment tax credit (ITC) in 2022. Loss of the ITC proves especially significant for residential solar-plus-storage systems, as the tax credit applies to both solar and storage components when combined during installation.

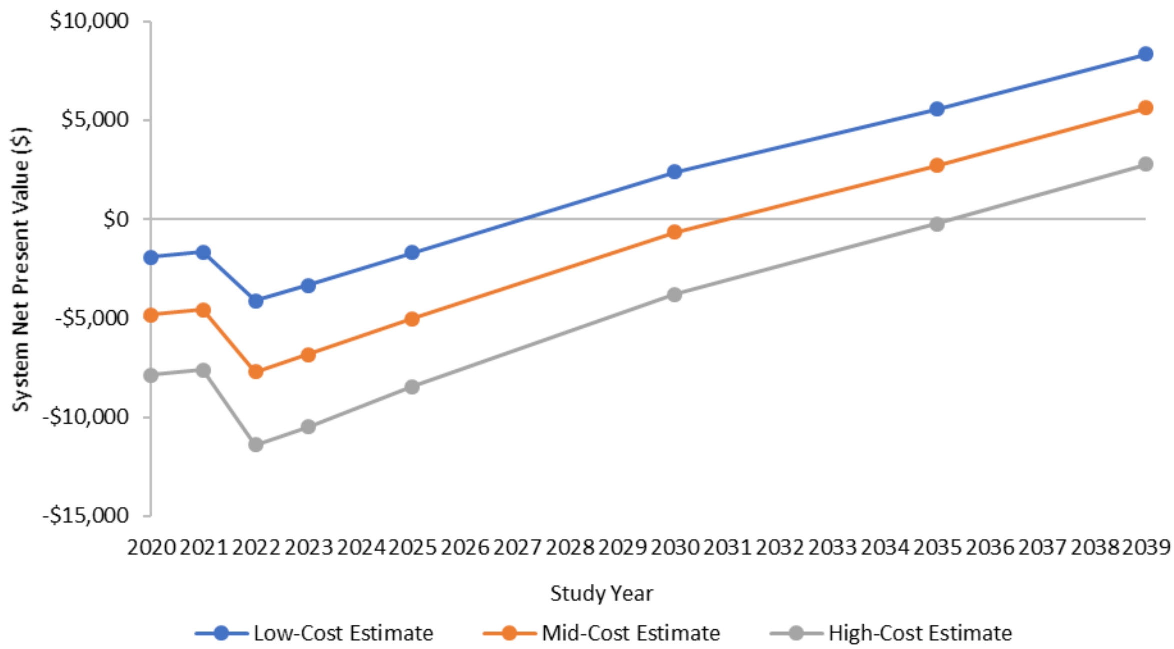
As these shifts in costs and benefits progress during the program period, systems of all three cost scenarios eventually show a net positive economic value for the customer. Table 54 shows this changing economic environment's results. The low-cost scenario reaches a net positive value to the customer between 2025 and 2030, while the medium-cost scenario reaches a positive value between 2030 and 2035, and the high-cost scenario reaches a positive value between 2035 and 2039.

Table 54. Tipping Point Analysis Results by Program Year and Cost Scenario

Project Start Year	Net Present Value			PCT Ratio		
	Low-Cost	Mid-Cost	High-Cost	Low-Cost	Mid-Cost	High-Cost
2020	-$3,832	-$4,836	-$7,869	0.75	0.70	0.59
2021	-$3,567	-$4,574	-$7,615	0.76	0.71	0.59
2022	-$6,471	-$7,701	-$11,416	0.64	0.60	0.50
2023	-$5,649	-$6,856	-$10,505	0.68	0.63	0.53
2025	-$3,871	-$5,015	-$8,472	0.76	0.71	0.60
2030	$388	-$652	-$3,796	1.03	0.96	0.79
2039	$7,134	$6,199	$3,373	1.60	1.48	1.21

Figure 51 shows trends in the solar-plus-storage system net present value. The negative impact of expiration of the federal ITC, leading to a three-year dip in net present value, is visible in the years between 2020 and 2022.

Figure 51. Net Present Value of a Solar-Plus-Storage System by Cost Scenario



6. Electric Vehicles

6.1. *Electric Vehicle Market Share*

Figure 52 depicts the EV market share of light-duty vehicle sales for all three adoption scenarios in El Paso County from 2019 through 2039. Note that these projections are not forecasts. Rather, sales are expected to be driven substantially by price parity timing, future policy and incentives, and diversity and desirability of new vehicle models (e.g., enough options with long range; enough CUV, SUV, and pickup options).

Figure 52. EV Sales Share by Scenario

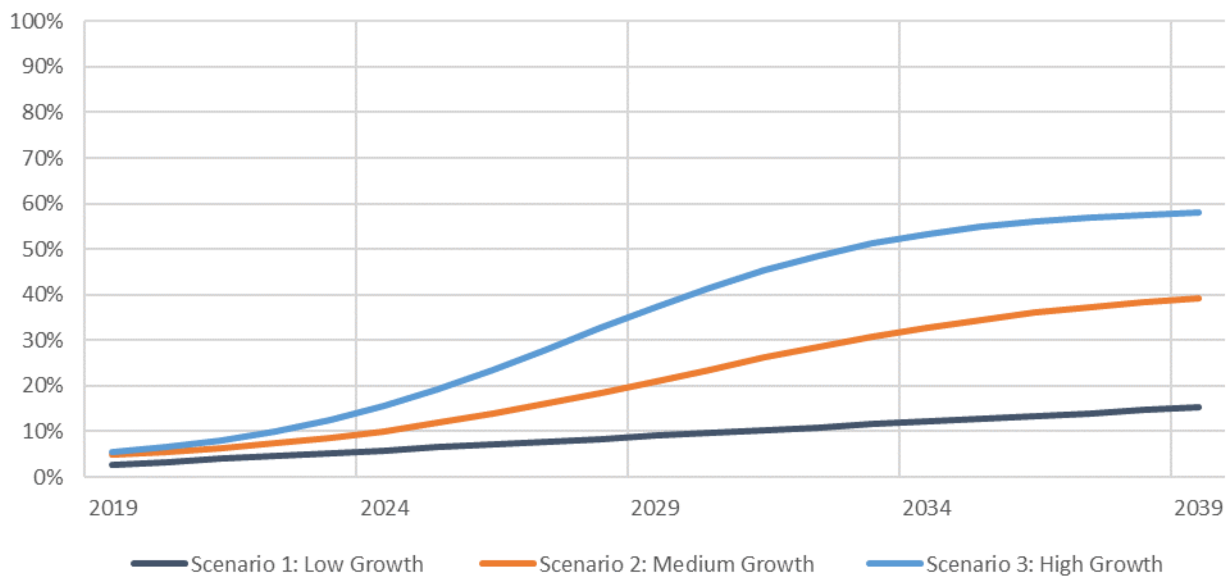


Table 55 details the major milestones for each scenario.

Table 55. EV Sales Shares Milestones

Scenario	2024	2029	2034	2039
Scenario 1: Low Growth	5.9%	9.0%	12.2%	15.3%
Scenario 2: Medium Growth	10.1%	21.0%	32.8%	39.2%
Scenario 3: High Growth	15.5%	37.3%	53.2%	58.1%

6.2. *Electric Vehicle Adoption in the In-Use Fleet*

EVs as a percentage of the registered, in-use fleet would lag EV market share increases due to slow turnover in the vehicle fleet (the average age of a vehicle before scrapping is assumed at 13 to 17 years old, based on NHTSA scrappage rates). Figure 53 shows the percentage of electric vehicles in the total, in-use, light-duty fleet.

Figure 53. Percent Electric Vehicles of Total Light Duty Vehicle Fleet in El Paso County by Scenario

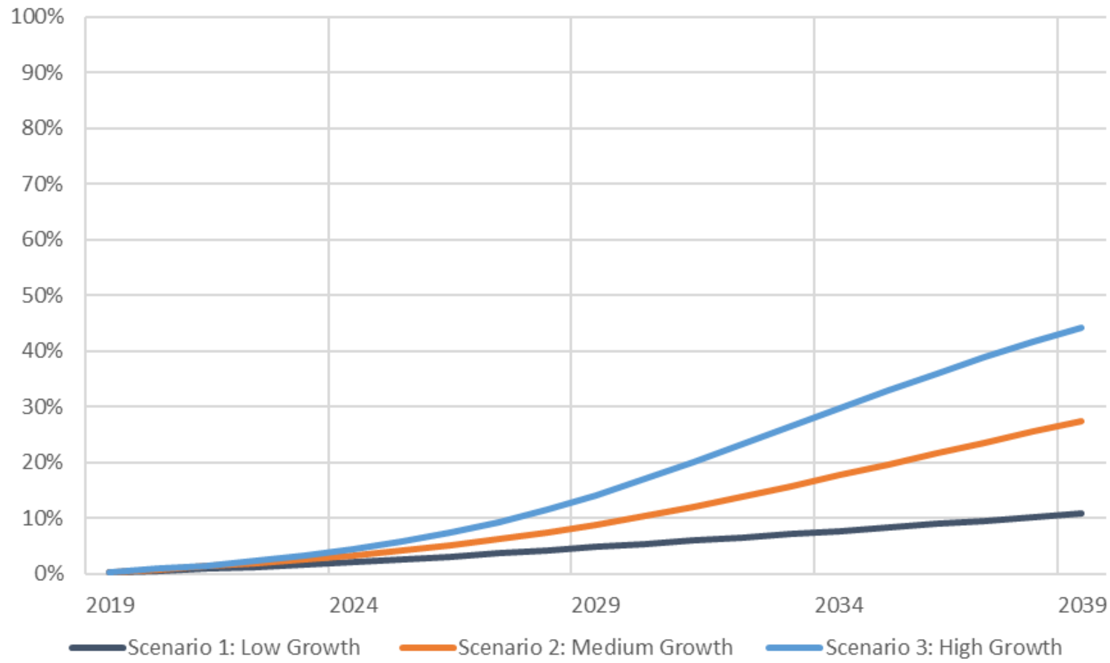


Table 56 lists scenario milestones in five-year intervals.

Table 56. Percent Electric Vehicles of Total Light Duty Vehicle Fleet Milestones

Scenario	2024	2029	2034	2039
Scenario 1: Low Growth	2.1%	4.8%	7.7%	10.8%
Scenario 2: Medium Growth	3.3%	8.9%	17.6%	27.3%
Scenario 3: High Growth	4.3%	14.1%	29.7%	44.2%

6.3. Estimated Electric Vehicle Charging Infrastructure

Estimated charging infrastructure needs, based on NREL's EVI-Pro Lite tool, can provide an indication for types of charging profiles CSU may see as EV adoption increases. While most charging has occurred at home for early adopter EV drivers, who primarily have been higher-income, single-family homeowners, charging patterns may shift as adoption spreads to different household types, such as those living in multifamily buildings or rentals.

Based on the share of multifamily and renter households in the CSU service area, Cadmus estimates approximately 25% of the population may lack the ability to charge at home, shifting more charging to public and workplace charging, likely to occur during daytime hours rather than at night. Seventy-five percent of households are estimated to charge at home, though not all are expected to install a Level 2 charger (the number of Level 2 chargers installed for home charging is estimated below). Based on inputs described previously, Cadmus expects an equal number of households will utilize Level 1 charging (a typical wall outlet) to charge their vehicles. Table 57 outlines the estimated number of different types of EV chargers in each scenario.

Table 57. Estimated EV Charging Infrastructure by Scenario and Charger Type

ESTIMATED WORKPLACE LEVEL 2 PLUGS	2024	2029	2034	2039
Scenario 1: Historic Trend	270	584	941	1314
Scenario 2: Moderate Projection	423	1087	2143	3319
Scenario 3: High Scenario (Statewide target)	547	1730	3612	5368
ESTIMATED PUBLIC LEVEL 2 PLUGS	**2024**	**2029**	**2034**	**2039**
Scenario 1: Historic Trend	434	866	1528	2282
Scenario 2: Moderate Projection	680	1612	3480	5765
Scenario 3: High Scenario (Statewide target)	879	2565	5864	9325
ESTIMATED DCFC PLUGS	**2024**	**2029**	**2034**	**2039**
Scenario 1: Historic Trend	119	240	285	425
Scenario 2: Moderate Projection	186	446	649	1074
Scenario 3: High Scenario (Statewide target)	240	710	1093	1738
ESTIMATED LEVEL 2 HOME PLUGS	**2024**	**2029**	**2034**	**2039**
Scenario 1: Historic Trend	4,702	11,710	20,863	31,174
Scenario 2: Moderate Projection	7,373	21,798	47,528	78,745
Scenario 3: High Scenario (Statewide target)	9,523	34,688	80,094	127,357

6.4. Potential EV Load Growth

Based on the fleet model results described above, Cadmus estimated energy consumption increases associated with EV driving in El Paso County through 2039 for each of the three scenarios. Figure 54 shows the results for four horizon years. To put this figure's numbers in context, the total load on the CSU distribution system was 4,656 GWh in 2014, per the 2016 Electric Integrated Resources Plan.[29] In 2024, therefore, scenarios range from adding 1% to 2% to total electric loads from that year. In 2039, EV load grows to 6% of the total 2014 load in the low scenario, 15% in the moderate scenario, and 24% in the high scenario.

Note that estimated energy consumption from added charging of electric vehicles is sensitive to two additional factors that remain uncertain: the mix of PHEVs and BEVs; and the relative amount that BEVs, PHEVs, and conventional vehicles will be driven, per vehicle. This model assumes BEVs continue to gain popularity relative to PHEVs, in alignment with recent trends toward more BEVs versus PHEVs in El Paso County and in alignment with EIA's projections of BEVs' and PHEVs' future shares. As for average annual mileage driven by each vehicle type, historical data cannot provide conclusive evidence to inform this assumption, particularly in more distant years of the scenarios.

Reasons exist, however, to expect that future BEVs could be driven more than conventional vehicles (e.g., lower costs per mile, quieter operations, and many other factors); on the other hand, reasons exist to expect future BEVs could be driven less than conventional vehicles (e.g., range anxiety, cargo capacity, charging convenience—factors that, in future years, may decrease in importance). For all

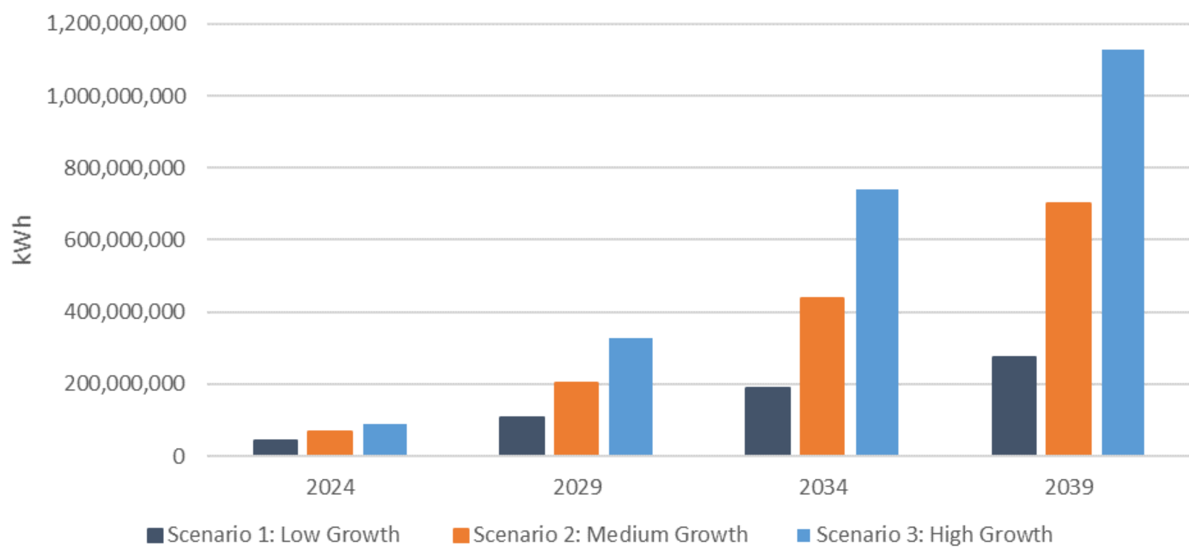
29 Available online: https://www.csu.org/CSUDocuments/2016eirp.pdf

scenarios, Cadmus therefore assumed that BEVs and PHEVs would be driven about as much as their conventional vehicle counterparts.

If PHEVs remain as a higher percentage of the in-use fleet than BEVs, or if BEVs and PHEVs are driven at less mileage per vehicle than conventional vehicles, these additional load estimates could be overstated. Conversely, if the price spread between driving electric miles and gasoline miles results in more drivers putting more mileage on BEVs (and more mileage in the charge-depleting mode of their PHEVs), the additional load modeled could increase.

These effects, while possibly significant, are expected to have somewhat less impact on EV energy consumption than on the impact of overall EV uptake rates in the fleet, which itself remains relatively uncertain. Nonetheless, energy calculations presented in Figure 54 provide useful bracketing of the likely magnitude of the consumption increase.

Figure 54. Estimated kWh from Light-Duty EVs in El Paso County by Scenario, Horizon Year

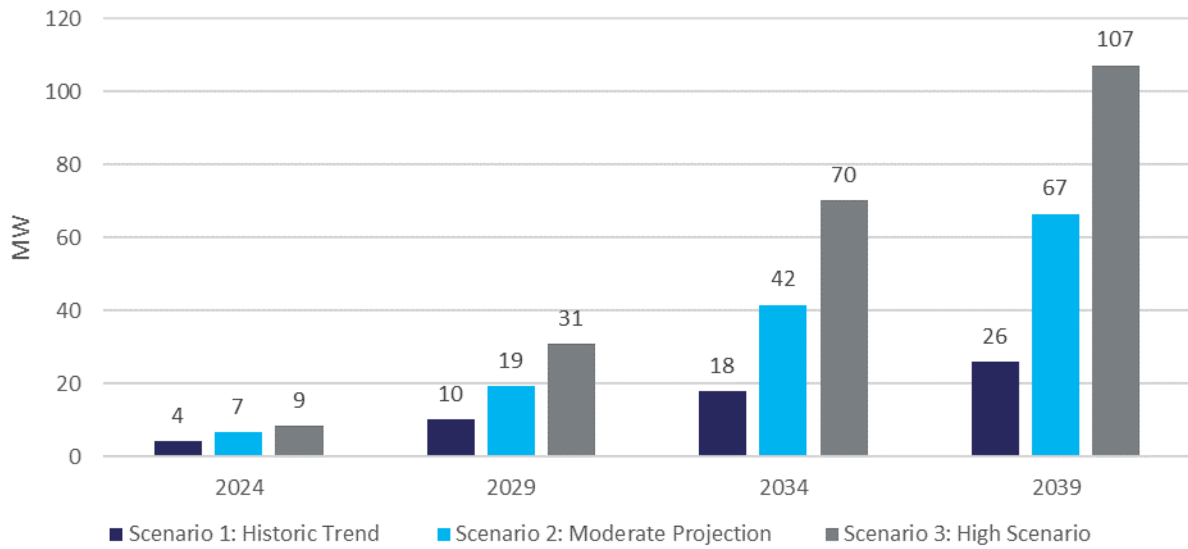


6.5. Potential EV Demand Impacts

Figure 55 depicts the potential EV load growth's contribution to Springs Utilities' peak demand. Cadmus estimated potential EV demand impacts (kW) by applying a peak coincidence factor to estimated annual energy consumption (kWh) from light-duty EVs (shown in Figure 58). Cadmus calculated the peak coincidence factor using an 8760 hourly EV load profile from the U.S. Department of Energy,[30] and calculated the potential EV load's coincidence with Springs Utilities' system peak—modeled as the average load of the top 10 four-hour peak events in summer (June through August, from 5:00 pm to 9:00 pm), based on the 2020 system load forecast.

30 U.S. Department of Energy. "EV Project Electric Vehicle Charging Infrastructure Summary Report." 2013. Available online: https://www.energy.gov/sites/prod/files/2014/02/f8/evproj_infrastructure_q22013_0.pdf

Figure 55. Estimated Peak Demand from Light-Duty EVs in El Paso County by Scenario, Horizon Year



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