[](http://www.nexant.com)[](http://www.gdsassociates.com)[C:\Users\kaytie.ruditys\AppData\Local\Microsoft\Windows\Temporary Internet Files\Content.Outlook\ISX68XGE\ria_logomark high.png](http://www.researchintoaction.com)[](http://www.apexanalyticsllc.com)

Prepared by:

**Statewide Evaluation Team**

Prepared for:

**Pennsylvania Public Utility Commission**

Final Report

**February 25, 2015**

**Demand Response Potential Pennsylvania**

**DR Potential Study Report for Pennsylvania**

Prepared for:

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**Glossary**

**– A –**

**Administration Costs:** As defined by 2013 TRC Order[[1]](#footnote-1).

**Avoided Cost**: The capacity, transmission, and distribution costs that are avoided by the implementation of a demand response program or practice. Such costs are used in benefit/cost analysis of demand response programs as defined by the Pennsylvania PUC in the TRC Test Order.[[2]](#footnote-2)

**– B –**

**Baseline**: Conditions that would have occurred without implementation of the subject measure or project. Baseline conditions are sometimes referred to as “business-as-usual” conditions and are used to calculate program related savings. Baselines can be defined as either project specific baselines or performance standard baselines (e.g., building codes). For the purposes of Act 129, baselines are defined in the Pennsylvania TRM, in approved custom protocols, and in TRM interim approved protocols.

**Baseline Data**: The information representing the systems being upgraded before program activity occurs.

**Benefit-Cost Ratio**: The mathematical relationship between the benefits and costs associated with the implementation of demand-side management measures, programs, or practices. The benefits and costs are typically expressed in dollars. This is the ratio of the discounted total benefits of the program to the discounted total costs over the program planning time horizon. The explicit formula for use in Pennsylvania is set forth in the Appendix to the TRC Order.[[3]](#footnote-3) Also see *Benefit-Cost Test*.

**Benefit-Cost Test**: Also called *Cost-Effectiveness Test,* defined as the methodology used to compare the benefits of an investment to the costs. For programs evaluated under Act 129, the TRC Test is the required benefit/cost test as issued in the TRC Order.[[4]](#footnote-4)

**Bias**: The extent to which a measurement, sample, or analytic method systematically underestimates or overestimates a value. Some examples of types of bias include engineering model bias; meter bias; sensor bias; an inadequate or inappropriate estimate of what would have happened absent a program or measure installation; a sample that is unrepresentative of a population.

**– C –**

**Coefficient of Variation**: The mean (average) of a sample divided by its standard error.

**Coincident Demand**: The demand of a device, circuit, or building that occurs at the same time as the peak demand of a utility’s system load or at the same time as some other peak of interest, such as a building or facility peak demand. The peak or interest should be specified (e.g., ‘demand coincident with the utility system peak’).

**Coincidence Factor**: The ratio, expressed as a numerical value or as a percentage of connected load, of the coincident demand of an electrical appliance or facility type with the utility system peak.

**Combined Heat and Power (CHP) Plant:**  A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by the Energy Information Administration in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the United States Public Utility Regulatory Policies Act (PURPA).

**Confidence**: An indication of the probability that an estimate is within a specified range of the true value of the quantity in question. Confidence is the likelihood that the evaluation has captured the true value of a variable within a certain estimated range. Also see *Precision*.

**Conservation Service Provider (CSP):** An entity that meets the Pennsylvania Public Utility Commission qualifications to provide consultation, design, administration, management, or advisory services to an electric distribution company regarding energy efficiency and conservation plans required under Act 129 of 2008, P.L. 1592.

**Correlation**: For a set of observations, such as for participants in demand response program, the extent to which values for one variable are associated with values of another variable for the same participant. For example, facility size and energy consumption usually have a high positive correlation.

**Cost-Benefit and Cost-Effectiveness Analysis**: See *Benefit-Cost Test*.

**Cost-Effectiveness**: An indicator of the relative performance or economic attractiveness of an investment or practice. The PV of the estimated benefits produced by efficiency demand response program is compared to the estimated total costs to determine if the proposed investment or measure is desirable from a variety of perspectives (e.g., whether the estimated benefits exceed the estimated costs from a societal perspective). See *Benefit-Cost Test*.

**Cost-Effectiveness Test**: See *Benefit-Cost Test*.

**Cumulative Capacity Savings**: The summation of capacity savings associated with multiple projects or programs over a specified period of time.

**Cumulative-to-Date**: Beginning June 1, 2009 through the end of the current quarterly reporting period (February 28/29, May 31, August 31, or November 30).

**Cumulative Portfolio/Program Inception-to-Date**: Beginning June 1, 2009 through the end of the current quarterly reporting period (February 28/29, May 31, August 31, or November 30).

**– D –**

**Defensibility**: The ability of evaluation results to stand up to scientific scrutiny. Defensibility is based on assessments by experts of the evaluation’s validity, reliability, and accuracy. Under Act 129, it is the role of the SWE Team to determine the defensibility of the verified savings estimates reported by each of the EDCs.

**Demand**: The rate of energy flow. Demand usually refers to the amount of electric energy used by a customer or piece of equipment over a defined time interval (e.g., 15 minutes), expressed in kW (equals kWh/h). Demand can also refer to natural gas usage over a defined time interval, usually as Btu/hr, kBtu/hr, therms/day, or ccf/day.

**Demand Reduction**: See *Demand Savings*.

**Demand Response (DR)**:A customer’s voluntary, short-term reduction in electricity use in response to control-room dispatch. DR resources are dispatched during high coincident system demand in an effort to enhance system reliability, to reflect market conditions and pricing, to support infrastructure optimization, or to defer the need to build system infrastructure. In exchange for customer compensation, DR programs may include contractually obligated or voluntary curtailment, direct load control, and pricing strategies.

**Demand-Side Management**: Strategies used to manage energy demand including DR, energy efficiency, load management, fuel substitution, and load building.

**Direct Expansion (DX) Cooling:** The predominant type of air conditioning in residential and small commercial businesses. It uses a refrigerant vapor expansion and compression cycle to directly cool the supply air to an occupied space.

**Distributed Generator (DG):**  A generator that is located close to the particular load that it is intended to serve. General, but non-exclusive characteristics of these generators include: an operating strategy that supports the served load; and interconnection to a distribution or sub-transmission system (138 kV or less).

**– E –**

**EE&C**: Energy Efficiency and Conservation

**EE&C Plan**: Energy Efficiency and Conservation Plan

**Effective Load Carrying Capacity (ELCC):** A measure of the relative importance of hours of availability for DR dispatch. Hours where load is highest have the highest contribution to ELCC.

**Effective Useful Life**: An estimate of the median number of years that efficiency measures installed under a program are still in place and operable. For DR programs implemented under Act 129, the 2013 order specified as a 10 year equipment life for DR infrastructure.

**Electric Distribution Company (EDC)**: In reference to Act 129, there are seven EDCs with at least 100,000 customers that are required to adopt a plan to reduce energy and demand consumption within their service territory in accordance with 66 Pa. C.S. § 2608. The seven EDCs include: West Penn Power, Duquesne Light, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, PECO Energy Company, and PPL Electric Utilities.

**Electric Distribution Company (EDC) Evaluation Costs**: Expenses incurred by the EDC pertaining to efficiency monitoring and verification activities. This includes expenses for contractors, metering equipment, evaluation software, etc.

**Electric Distribution Company (EDC) Implementation Costs**: Expenses incurred by the EDC pertaining to the implementation of Act 129 programs approved in their respective Energy Efficiency and Conservation Plans. This includes expenses for payments to conservation service providers, marketing expenses, rebates, etc.

**Electric Distribution Company (EDC) Incentive Costs**: Payments by the Electric Distribution Company to a customer participating in an Energy Efficiency and Conservation Program approved by the Commission. This may include cash payments for participation in programs.

**Energy Efficiency (EE):** Refers to programs that are aimed at reducing the energy used by specific end-use devices and systems, typically without affecting the services provided. These programs reduce overall electricity consumption (reported in megawatt-hours), often without explicit consideration for the timing of program-induced savings. Such savings are generally achieved by substituting technologically more advanced equipment to produce the same level of end-use services (e.g. lighting, heating, motor drive) with less electricity. Examples include high-efficiency appliances, efficient lighting programs, high-efficiency heating, ventilating and air conditioning (HVAC) systems or control modifications, efficient building design, advanced electric motor drives, and heat recovery systems.”

**Energy Efficiency Measure:** An installed piece of equipment or a system, modification of equipment systems, or modified operations in customer facilities that reduce the total amount of electrical or gas energy and the capacity that would otherwise have been needed to deliver an equivalent or improved level of comfort or energy service.

**Energy Savings**: A reduction in electricity use (kWh) or in fossil fuel use in thermal unit(s).

**Evaluation**: An assessment of a demand-side management program or portfolio that may include the following: a determination of the effects of a program; an assessment of program performance; market assessments; program-induced changes to electricity uses; estimates of demand or energy savings; and/or program cost-effectiveness.

**Ex ante Savings Estimate**: A quantitative forecast of savings used for program and portfolio planning purposes.

**Ex post Savings Estimate**: Savings estimate reported by an evaluator after the energy impact evaluation has been completed.

**– F –**

**Five Coincident Peak (5CP):** A mechanism used by some electric generation suppliers to allocate generation capacity costs to customers. The 5CP are the five hours of highest system demand for a given delivery year. The five hours must occur on five different days.

**– H, I –**

**Impact Evaluation**: An evaluation of the program-specific, directly induced quantitative changes (kWh, kW, and therms) attributable to efficiency DR program.

**Incremental Quarter:** The time period of one reporting quarter; typically used to reference the additional results accrued during the reporting quarter.

**– J, K –**

**Kilowatt (kW)**: A measure of the rate of power used during a pre-set time period (e.g., minutes, hours, days, months) equal to 1,000 Watts.

**Kilowatt-Hour (kWh)**: A common unit of electric energy; one kilowatt-hour is numerically equal to 1,000 Watts used for one hour.

**– L –**

**Lifetime Supply Costs**: The net-present value of avoided supply costs associated with demand and energy savings, net of changes in electricity use that would have happened in the absence of the program over the life of the program, factoring in persistence of savings. See *Avoided Cost*.[[5]](#footnote-5)

**Load Factor**: A percentage indicating the ratio of electricity or natural gas used during a given timeframe to the amount that would have been used if the usage had stayed at the highest demand the entire time. The term is also used to indicate the percentage of capacity of an energy facility, such as a power plant or gas pipeline that is utilized for a given period of time.

**Load Management**: Steps taken to reduce power demand at peak load times or to shift some of it to off-peak times. Load management may coincide with peak hours, peak days, or peak seasons. Load management may be pursued by persuading consumers to modify behavior or by using equipment that regulates some electric consumption. This may lead to complete elimination of electric use during the period of interest (load shedding) and/or to an increase in electric demand in the off-peak hours as a result of shifting electric usage to that period (load shifting). Control of central air condition systems is an example of a load management program.

**– M –**

**Measurement and Verification (M&V)**: A subset of program impact evaluations that document energy savings at individual sites or projects using measurements, engineering calculations, statistical analyses, and/or computer simulation modeling.

**Measurement Error**: A description of the likelihood and magnitude of an observation’s deviation from its true value. In the case of measured samples from a larger population, the error can be random or systematic (indicating bias).

**Megawatt (MW)**: A unit for measuring electricity equal to 1,000 kilowatts or one million Watts.

**Megawatt-Hour (MWh)**: A unit of electric energy numerically equal to 1,000,000 Watts used for one hour.

**Metered Data**: Data collected over time through a meter for a specific end use, energy-using system (e.g., lighting, HVAC), or location (e.g., floors of a building, a whole premise). Metered data may be collected over a variety of time intervals; usually refers to electricity or gas data.

**Metering**: The collection of energy consumption data over time through the use of meters. These meters may collect information about an end use, a circuit, a piece of equipment, or a whole building (or facility). Short-term metering generally refers to data collection for no more than a few weeks. End-use metering refers specifically to separate data collection for one or more end uses in a facility, such as lighting, air conditioning, or refrigeration. Spot metering is an instantaneous measurement (rather than over time) to determine equipment size or power draw.

**Monitoring**: The collection of data over time at a facility for the purpose of conducting a savings analysis, to evaluate equipment, or to evaluate system performance.

**– N –**

**Net Impact**: See *Net Savings*.

**Net-Present Value (NPV)**: The discounted value of the net benefits over a specified period of time (e.g., the expected useful life of the EE measure).[[6]](#footnote-6)

**Net Savings**: The total change in load that is attributable to a DR program. This change in load may include, implicitly or explicitly, the effects of free drivers, free-riders, EE standards, changes in the level of energy service, and other causes of changes in energy consumption or demand. Net savings are calculated by multiplying verified savings by a net-to-gross ratio.

**Net-to-Gross (NTG) Ratio**: A factor representing net program savings divided by gross program savings that is applied to gross program impacts to convert them into net program load impacts.

**Non-participant**: Any account that was eligible but did not participate in the subject DR program in a given program year.

**– O, P –**

**Off-peak Energy kWh Savings**: The kWh reduction that occurs during a specified period of off-peak hours for energy savings (see the PA TRM Table 1-1).

**On-peak Energy kWh Savings**: The kWh reduction that occurs during a specified period of on-peak hours for energy savings (see the PA TRM Table 1-1).

**Participant**: A utility customer enrolled in a DR program, defined as one transaction or one rebate payment in a program.

**Participant Costs**: Costs incurred by a customer participating in efficiency DR program. Typically, these costs are represented as incremental costs (i.e., the costs incurred for the purchase, installation, and maintenance of DR equipment or related third-party services).

**Peak Load**: The highest electrical demand within a particular period of time. Daily electric peaks on weekdays typically occur in the late afternoon and early evening. Annual peaks typically occur on hot summer days.

**Peak Load Contribution**: The amount of generation capacity an Electricity Distribution Company determines it must acquire on behalf of its customers.  PLC values may be expressed per account or in aggregate.  For example, PLC may be expressed for each account or totaled for a given economic activity.

**Portfolio**: Can be defined as: (1) a collection of programs addressing the same market (e.g., a portfolio of residential programs), technology (e.g., motor efficiency programs), or mechanisms (e.g., loan programs); or (2) the set of all programs conducted by one or more organizations, such as a utility or program administrator, which could include programs that cover multiple markets, technologies, etc.

**Precision**: An indication of the closeness of agreement among repeated measurements of the same physical quantity. It is also used to represent the degree to which an estimated result in social science (e.g., energy savings) would be replicated with repeated studies.

**Present Value Net Benefit (PVNB):** The sum of estimated program benefits for future years, expressed in present value dollar to account for time-related value preferences. Ergo, program benefits that accrue over a shorter time period are more highly valued.

**Process Evaluation**: A systematic assessment of an efficiency DR program for the purposes of documenting program operations at the time of the examination and identifying and recommending improvements to increase the program’s efficiency or effectiveness for acquiring energy resources, while maintaining high levels of participant satisfaction.

**Program Administrator**: Those entities that oversee the implementation of demand-side management programs. This generally includes regulated utilities, other organizations chosen to implement such programs, and state energy offices.

**Program Incentive**: An incentive, generally monetary, that is offered to a customer through efficiency DR programs to encourage their participation. The incentive is intended to compensate the customer for voluntary reducing their energy use during program events.

**Program Year (PY):** Defined as the period between June 1st and May 31st of the current reporting period.

**Program Year Target**: Demand response capacity savings target established for the given program year as approved in each EDC EE&C Plan.

**Program Year Sample Participant Target**: Estimated sample size for evaluation activities in the given program year.

**Project**: An activity or course of action involving one or multiple EE measures at a single facility or site.

**Projects in Progress**: Energy efficiency and DR projects currently being processed and tracked by the EDC, but that are not yet complete at the time of the report. A complete project is defined as a project in which the energy conservation measure has been installed and is commercially operable, and for which a rebate check has been issued.

**PY8-PY12:** Refers to Act 129 program years for the time period June 1, 2016, to May 31, 2021.

**– Q, R –**

**Rebound Effect**: The rebound effect, as applied to DR programs, describes customers’ shifting of electricity demands to the hours prior to or following a DR event.

**Regression Analysis**: A statistical analysis of the relationship between a dependent variable (response variable) to specified independent variables (explanatory variables). The mathematical model of their relationship is the regression equation.

**Regression Model**: A statistical analysis where the value of an observation is predicted using other data which are believed to determine its value. In so doing, the relationship between the variables is estimated statistically from the data used.

**Reliability:** The quality of a measurement process that would produce similar results on: (1) repeated observations of the same condition or event, or (2) multiple observations of the same condition or event by different observers.

**Renewable Energy**: Energy derived from resources that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action.

**Reporting Period**: The time following implementation of a DR program during which performance is to be determined.

**Representative Sample**: A sample that has approximately the same distribution of characteristics as the population from which it was drawn.

**– S –**

**Sample**: A portion of the population selected to represent the whole. Differing evaluation approaches rely on simple or stratified samples (based on some characteristic of the population).

**Sample Design**: The approach used to select the sample units.

**Sampling Error**: The degree of uncertainty that is inherent to statistical inferences about a population that are calculated from samples of that population. Sampling error results from an inability to observe all occurrences of a measureable quantity that exist in a population.

**Simple Random Sample**: A method for drawing a sample from a population such that all samples of a given size have an equal probability of being drawn.

**Snap Back**: See *Rebound Effect*.

**Statistically Adjusted Engineering Models**: A category of statistical analysis models that incorporate the engineering estimate of savings as a dependent variable. The regression coefficient in these models is the percentage of the engineering estimate of savings observed in changes in energy usage. For example, if the coefficient on the statistically adjusted engineering term is 0.8, the customers are, on average, realizing 80% of the savings from their engineering estimates.

**Stipulated Values**: See *Deemed Savings*.

**Stratified Random Sampling**: The population is divided into subpopulations, called strata, which are non-overlapping and together comprise the entire population. A simple random sample of each stratum is taken to create a sample based on stratified random sampling.

**Stratified Ratio Estimation**: A sampling method that combines a stratified sample design with a ratio estimator to reduce the coefficient of variation by using the correlation of a known measure for the unit (e.g., expected energy savings) to stratify the population and allocate a sample from the strata for optimal sampling.

**– T –**

**Takeback Effect**: See *Rebound Effect*.

**Total Resource Cost (TRC) Test**: A cost-effectiveness test that measures the net direct economic impact to the utility service territory, state, or region. The TRC Order[[7]](#footnote-7) details the method and assumptions to be used when calculating the TRC test for demand-side management programs implemented under Act 129. The results of the TRC test are to be expressed as both a NPV and a benefit/cost ratio.

**Total Resource Cost (TRC) Test Benefits**: Benefits calculated in the TRC test that include the avoided supply costs, such as the reduction in transmission, distribution, generation, and capacity costs, valued at a marginal cost for the periods when there is a consumption reduction. The Pennsylvania TRC benefits will consider avoided supply costs, such as the reduction in forecasted zonal wholesale electric generation prices, ancillary services, losses, generation capacity, transmission capacity, and distribution capacity. The avoided supply costs will be calculated using net program savings, defined as the savings net of changes in energy use that would have happened in the absence of the program. The persistence of savings over time will also be considered in the net savings.[[8]](#footnote-8)

**Total Resource Cost (TRC) Test Costs:** The costs calculated in the TRC test will include the costs of the various programs paid for by an EDC (or by a default service provider) and the participating customers, and costs that reflect any net change in supply costs for the periods in which consumption is increased in the event of load shifting. Note that the TRC test should use the incremental costs of services and equipment. Thus, for example, this would include costs for equipment, installation, operation and maintenance, removal (less salvage value), and administrative tasks, regardless of who pays for them.[[9]](#footnote-9)

**– U, V –**

**Uncertainty**: The range or interval of doubt surrounding a measured or calculated value within which the true value is expected to fall with some degree of confidence.

**Upstream Program**: A program that provides information and/or financial assistance to entities in the delivery chain of high-efficiency products at the retail, wholesale, or manufacturing level. Such a program is intended to yield lower retail prices for the products.

**Verification**: An independent assessment of the reliability (considering completeness and accuracy) of claimed energy savings or an emissions source inventory.

**– W, X, Y, Z –**

**Watt**: A unit of measure of electric power at a point in time as capacity or demand. One Watt of power maintained over time is equal to one Joule per second. The Watt is named after Scottish inventor James Watt, and is shortened to W and used with other abbreviations, as in kWh (kilowatt-hours).

**Watt-Hour**: One Watt of power expended for one hour. One-thousandth of a kilowatt-hour.

**Whole-building Calibrated Simulation Approach**: A savings measurement approach (defined in the International Performance Measurement and Verification Protocol (IPMVP), Option D and in the American Society of Heating, Refrigerating and Air-Conditioning Engineers (ASHRAE) Guideline 14) that involves the use of an approved computer simulation program to develop a physical model of the building in order to determine energy and demand savings. The simulation program is used to model the energy used by the facility before and after the retrofit. The pre- or post-retrofit models are developed by calibration with measured energy use, demand data, and weather data.

**Whole-building Metered Approach**: A savings measurement approach (defined in the IPMVP, Option C and in the ASHRAE Guideline 14) that determines energy and demand savings through the use of whole-facility energy (end-use) data, which may be measured by utility meters or data loggers. This approach may involve the use of monthly utility billing data or data gathered more frequently from a main meter.

**References**

Pennsylvania Public Utility Commission. *Implementation of Act 129 of 2009 – Total Resource Cost Test Order*. Docket No. M-2009-2108601. Issued June 18, 2009.

PAH Associations, prepared by Paul Horowitz. Facilitated by the Northeast Energy Efficiency Partnership. Glossary of Terms Version 1.0. A project of the Regional Evaluation, Measurement and Verification Forum. March 2009.

# Executive Summary

Demand Response (DR) is a demand-side management (DSM) tool for electric utilities, similar to energy efficiency (EE), which is intended to reduce the costs associated with maintaining power system reliability and meeting future capacity needs. In its February 2014 Demand Response Implementation Order, the Commission directed the Statewide Evaluator (SWE) to conduct a DR potential study during Phase II of Act 129.[[10]](#footnote-10) The SWE Team has conducted this study[[11]](#footnote-11) which:

* Estimates the amount of DR potential that exists in each of the seven investor-owned Pennsylvania electric distribution company (EDC) service territories[[12]](#footnote-12)
* Examines the costs and benefits of pursuing statewide policies that may encourage the development and deployment of DR resources during Phase III of Act 129.

The SWE Team communicated its analytical approach for this study to the Pennsylvania Public Utility Commission (PA PUC) Technical Utility Services (TUS) staff and the Act 129 Stakeholders and has sought continuous feedback and comment from those groups. As a result of this collaboration, the SWE Team has prepared a thorough analysis to estimate the DR potential for Phase III of Act 129 for the period June 1, 2016, through May 31, 2021.

We refer to our estimates as DR potential, but it does not fit neatly into the categories typically applied to EE potential. While EE can be thought of as “doing the same thing for less,” DR might be considered “doing less.” DR calls for a temporary reduction in customer demand for electricity and may be either active or passive. According to PJM Interconnection, LLC (PJM), DR typically occurs as a result of power grid needs, economic signals from a competitive wholesale market, or customers responding to special retail rates.

The study initially considered the standard four levels of EE potential – technical, economic, achievable and program – as they relate to DR. We determined that the concept of technical potential used for estimating EE potential does not have a counterpart for DR. For enough money, homes and businesses will forego virtually all electric demand temporarily. This report does not attempt to quantify technical potential for DR.

DR is based on consuming less electricity. If the total benefit the power grid enjoys from reduced demand by its customers is greater than the total amount of compensation desired by those customers, then the DR potential is economically efficient. This is the basis of economic potential for DR: determine the level of DR customer incentives that maximizes the present value (PV) of net benefits.

Achievable potential for DR is the most similar to its EE counterpart. Achievable potential seeks to account for additional market factors that can modify the economic potential of DR under a given cost-effective rate of compensation for demand reductions.

The final package of compensation that DR beneficiaries are able to offer DR providers can also limit potential. We refer to this package of compensation as the program potential for DR.

The SWE Team considered four hypothetical budget allocations of the 2% spending cap[[13]](#footnote-13) between EE and DR. The annual budget available for DR under each scenario is presented in Table 1‑1.

Table 1‑1: Annual DR Budget for Program Potential Scenarios

| EDC | 100% EE,  0% DR | 90% EE,  10% DR | 85% EE,  15% DR | 80% EE,  20% DR |
| --- | --- | --- | --- | --- |
| Duquesne | $0 | $1,954,595 | $2,931,893 | $3,909,190 |
| FE: Met-Ed | $0 | $2,486,689 | $3,730,034 | $4,973,378 |
| FE: Penelec | $0 | $2,297,474 | $3,446,212 | $4,594,949 |
| FE: Penn Power | $0 | $665,978 | $998,968 | $1,331,957 |
| FE: West Penn | $0 | $2,356,247 | $3,534,370 | $4,712,494 |
| PECO | $0 | $8,539,516 | $12,809,274 | $17,079,032 |
| PPL | $0 | $6,150,138 | $9,225,206 | $12,300,275 |
| Statewide | **$0** | **$24,450,637** | **$36,675,956** | **$48,901,275** |

## Peak Load Consumption

The primary objective of the Act 129 DR program modeled in this study is to lower the generation capacity that must be secured by PJM on behalf of the customers served by the EDCs. If successful, a statewide DR program would exert downward pressure on forecasts of summer peak demand and reduce the generation capacity required to meet PJM’s reliability requirements. This is somewhat different from the current PJM markets where DR falls on the supply-side and fills a requirement for generation capacity. The Commission’s Final Order on DR[[14]](#footnote-14) specified that EDCs will not be directed to bid their programs into PJM’s forward capacity market, so the SWE Team believes that actual reductions during peak conditions are the most viable mechanism for an Act 129 DR program to produce tangible avoided costs.

The SWE Team leveraged peak load contribution[[15]](#footnote-15) (PLC) information supplied by the EDCs for their customer bases in order to disaggregate the peak load forecasts to the sector level (residential, commercial, industrial). Peak load contribution refers to the share of that peak load forecast that an individual electric customer is responsible for and is a mechanism for EDCs and Electric Generation Suppliers (EGS) to recover the fixed costs of the electric system from their customers. The premise behind this analysis is that the sum of the PLCs from all customers will approximate the peak load forecast. A historic analysis of the distribution of PLCs by customer class was used to assign a proportion of the summer peak to each class and these proportions were then applied prospectively to the forecast. The SWE Team’s disaggregated peak load forecast for each EDC for the summer of 2016 is shown by customer sector in Table 1‑2.

Table 1‑2: Disaggregated 2016 Summer Peak Load Forecast (Megawatts [MW])

| EDC | Industrial | Commercial | Residential | Total |
| --- | --- | --- | --- | --- |
| Duquesne | 455 | 1,341 | 1,261 | 3,056 |
| FE: Met-Ed | 675 | 911 | 1,285 | 2,871 |
| FE: Penelec | 717 | 876 | 950 | 2,543 |
| FE: Penn Power | 212 | 297 | 465 | 974 |
| FE: West Penn | 1,045 | 1,151 | 1,676 | 3,873 |
| PECO | 981 | 3,986 | 3,848 | 8,815 |
| PPL | 1,595 | 2,795 | 3,179 | 7,568 |
| Statewide | **5,680** | **11,357** | **12,664** | **29,700** |

The economic argument for pursuing DR programs is that reducing peak demand may be cheaper than expanding generation capacity to meet growth in peak demand. The costs and benefits of producing and consuming electricity are related to the underlying supply of and demand for electric service.

## Economic Analysis

The TUS staff requested that the SWE Team develop scenarios to compare the relative benefits of Act 129 budget allocations between EE and DR programs. The TUS staff indicated a desire to compare alternative projects on the basis of the PV of net benefits as calculated by the Total Resource Cost[[16]](#footnote-16) (TRC) Test. This criterion is appropriate for comparing mutually exclusive program alternatives and selecting an alternative that provides the largest economic benefit. Comparing program alternatives solely on the basis of the TRC ratio obscures the relative magnitude of benefits provided by program alternatives.

We have also applied the concept of net benefit to our cost analysis of Phase III non-residential DR potential. In developing cost estimates, the SWE Team sought to identify the incentive levels that maximized the respective PV of net benefits from the large commercial and industrial (C&I) load curtailment programs. The incentive payment is an important component for estimating DR potential because the incentives paid to DR providers must be equal to or greater than the cost of providing DR capacity. Were these not the case, potential DR suppliers would elect not to participate in the program. The incentive level that maximizes the PV of net benefits to each of the DR programs we evaluated is the economically efficient level of DR. It is important to note that the level of incentives that maximizes net-present value (NPV) of benefits is not indicated by the TRC ratio.

## DR Program Design

In order to evaluate DR potential for Phase III of Act 129, the SWE Team had to make assumptions about the program design that would be implemented. The Top 100 hours construct implemented in Phase I of Act 129 proved problematic so the SWE Team elected to consider alternate designs that we felt were more likely to produce a cost-effective program. Key program design parameters that affect DR potential include:

* The expected number of events per year
* The duration of events
* The season and time of day the events occur
* The amount of advance notification participants are given
* Whether event participation is mandatory[[17]](#footnote-17) or voluntary.

The results of our analysis highlighted the existence of some tradeoffs in program design. A simulation we conducted demonstrates that a program design with a dispatch threshold of 96%, an event start time of 2:00 p.m., duration of 4 hours, and a maximum of 6 events per year is expected to provide the highest overall Effective Load Carrying Capacity[[18]](#footnote-18) (ELCC) for designs capped at 24 event hours.

## Avoided Cost of Transmission and Distribution Capacity

The SWE Team developed forecasts of transmission and distribution (T&D) avoided costs per kilowatt-year (kW/year) for each EDC subject to the DR program requirements of Act 129. For purposes of this study, T&D avoided costs were defined as the T&D infrastructure expenditures that could be avoided if an EDCs future load growth can be reduced with DR programs that reduce load at the time of utility system peak loads. To prepare the forecasts, the SWE Team:

* Reviewed eight major studies conducted in other states to determine best practices for developing forecasts of T&D avoided costs
* Developed a pragmatic methodology for forecasting T&D avoided costs based on the results of this literature search
* Collected the required EDC load growth and T&D expenditure forecasts necessary for developing the forecast of T&D avoided costs for each EDC.

The EDC T&D avoided costs per kW-year range from a low of $20.10 for PPL to a high of $49.27 for PECO. The T&D avoided costs for each EDC are provided in Table 1‑3.

Table 1‑3: Forecast of Average T&D Avoided Costs ($ per kW/year) by EDC

|  |  |  |
| --- | --- | --- |
| EDC | Average T&D Avoided Cost per kW/year for 2016 | Average Transmission Only Avoided Cost per kW/year for 2016 |
| Duquesne | $40.88 | $40.88 |
| FE: Met-Ed | $40.98 | $14.77 |
| FE: Penelec | $40.98 | $14.77 |
| FE: Penn Power | $40.98 | $14.77 |
| FE: West Penn | $40.98 | $14.77 |
| PECO | $49.27 | $3.88 |
| PPL | $20.10 | $0.00 |

## Residential DR Potential Methodology and Results

Direct Load Control (DLC) programs remotely manage residential customers’ end use demands by cycling off their electricity consuming equipment during control periods (typically at periods of peak electric demand). In exchange for an incentive payment, free equipment, or bill reduction, customers allow EDCs to remotely reduce equipment runtime during peak hours. The residential sector analysis examined the cost-effectiveness and potential peak demand reduction savings for load control of residential central A/C systems, window A/C’s, electric water heaters, and swimming pool pumps for Phase III of Act 129 programs. The Base Scenario of our potential analysis was limited to load control of only central A/C’s while the Second Scenario included load control of all four types of electrical equipment. Program participation and impacts (demand reductions) for residential customers were assumed to begin the summer of 2017. No program participants are assumed in 2016, due to the fact that Phase III begins on June 1, 2016, and it will take many months to arrange for the purchase and installation of load control equipment.

In order to maximize the benefits of a residential load reduction program, the installations of load control devices were assumed to have been completed only in 2016 and early in 2017 for the initiation of cycling the summer of 2017. For residential central A/C’s (base scenario), a maximum 12.5% penetration rate was assumed to determine potential peak load reduction savings. The 12.5% was derived from the actual participation rates for DLC programs of 20 utilities around the country. The SWE Team also conducted in-depth interviews with each of these utilities to understand details of program operations. Table 1‑4 contains the size of the eligible market for Phase III residential DLC programs by EDC. For load control of residential central A/C’s, the size of the eligible market in 2016 (the first year of Phase III) was determined by multiplying the forecast of each EDCs number of residential customers in 2016 by the saturation of the end use obtained from the 2014 SWE Residential Baseline Study[[19]](#footnote-19). To obtain the number of potential program participants by the summer of 2017 (the first year of control) for residential central A/C systems, the eligible market for each EDC was multiplied by 12.5%.

Table 1‑4: Eligible Markets for Phase III Residential DR Programs for EDCs – Central A/C

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Name of EDC | Projected Total No. of EDC Residential Customers in 2016 | Percent of Residential Customers with Central A/C Systems from 2014 Baseline Study (%) | Eligible Market for Participation in Load Control Program for Residential Central A/C (No. of Residential Customers) | Actual Program Participation Rate Achieved During Phase I of Act 129 for Central A/C Load Control (%) | Forecast Program Participation Rate for Phase III | Total Number of Program Participants Forecast for a Phase III Residential Central A/C Control Program |
| Duquesne | 528,973 | 77% | 407,309 | 0.45% | 12.50% | 50,914 |
| FE: Met-Ed | 492,237 | 61% | 300,265 | 5.3% | 12.50% | 37,533 |
| FE: Penelec | 505,353 | 38% | 192,034 | 6.5% | 12.50% | 24,004 |
| FE: Penn Power | 141,736 | 74% | 104,885 | 2.9% | 12.50% | 13,111 |
| FE: West Penn | 624,521 | 73% | 455,900 | 0.0% | 12.50% | 56,988 |
| PECO | 1,438,250 | 74% | 1,064,305 | 11.4% | 12.50% | 133,038 |
| PPL | 1,256,031 | 50% | 628,016 | 7.0% | 12.50% | 78,502 |
| Total | **4,987,101** | **63%** | **3,152,714** | **6.4%** | **12.50%** | **394,089** |

Potential impacts for programs that included window A/C’s, electric water heaters, and pool pumps were also analyzed. For these three end uses, the Study Team assumed that load control switches would only be installed for those homes where the central A/C system was also controlled.

Cost-effectiveness of residential load control was determined based on screening with the TRC Test. This TRC test was calculated according to the Commission’s latest TRC Order[[20]](#footnote-20), with two exceptions. First, the forecast of each EDCs T&D avoided costs are based upon estimates developed by the SWE Team, expressed on a $ per kW-year basis (as shown in Table 1‑3 above). Second, participant costs for load control programs were calculated as 75% of the customer incentive amount.

All program costs were escalated each year by the general rate of inflation assumed for this study.[[21]](#footnote-21) Benefits modeled included avoided electric generation capacity, energy shifted to off-peak hours, and avoided T&D costs.

A summary of the cost-effectiveness of a proposed Residential Direct Control Program limited to central A/C’s is shown below in Table 1‑5. Assuming a 12% market penetration, nearly 232 megawatts (MW) of peak load could be reduced statewide. However, this hypothetical program falls short of the cost- effectiveness hurdle benefit/cost ratio of 1.0 for all EDCs, except PECO. The relatively large number of central A/C’s already having load control switches from PECO’s Phase I program were assumed to carry over to a Phase III program and results in a slightly positive (1.05) benefit/cost ratio.[[22]](#footnote-22)

Table 1‑5: Residential DLC Benefits and Costs - Central A/C Control Only

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| EDC | Number of Program Participants | Average Annual Impact (MW at Generation Level) | PV of Program Benefits | PV of Program Costs | NPV[[23]](#footnote-23) of Benefits - NPV of Costs | Lifetime TRC Ratio |
| Duquesne | 40,268 | 36.75 | $26,890,047 | $35,098,670 | -$8,208,624 | 0.78 |
| FE: Met-Ed | 38,025 | 18.03 | $22,718,313 | $35,075,330 | -$12,357,017 | 0.65 |
| FE: Penelec | 20,846 | 10.13 | $12,386,117 | $18,968,416 | -$6,582,299 | 0.65 |
| FE: Penn Power | 12,154 | 5.24 | $4,465,010 | $9,882,516 | -$5,417,506 | 0.45 |
| FE: West Penn | 51,133 | 23.71 | $30,301,372 | $47,164,543 | -$16,863,170 | 0.64 |
| PECO | 108,049 | 82.20 | $68,684,924 | $65,334,434 | $3,350,490 | 1.05 |
| PPL | 80,072 | 55.46 | $48,813,983 | $64,151,543 | -$15,337,560 | 0.76 |
| Statewide | **350,546** | **231.51** | **$214,259,766** | **$275,675,452** | **-$61,415,686** | **0.83** |

Adding additional end uses worsened the cost-effectiveness of a potential residential DR program. Table 1‑6 below contains the cost-effectiveness of a Residential Direct Control Program for four end uses: central A/C’s, window A/C’s, electric water heaters, and swimming pool pumps. A program that includes control of all four of these residential end uses is not cost-effective for any of the EDCs for Phase III of Act 129.

Table 1‑6: Residential DLC Benefits and Costs- Control of Central A/C, Electric Water Heaters, Window A/C and Swimming Pool Pumps

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **EDC** | **Number of Program Participants** | **Average Annual Impact (MW at Generation Level)** | **PV of Program Benefits** | **PV of Program Costs** | **NPV of Benefits - NPV of Costs** | **Lifetime TRC Ratio** |
| Duquesne | 45,986 | 38.67 | 29,258,689 | 50,758,424 | -$21,499,735 | 0.58 |
| FE: Met-Ed | 52,475 | 22.62 | 29,582,690 | 47,927,900 | -$18,345,209 | 0.62 |
| FE: Penelec | 24,494 | 10.77 | 14,223,266 | 22,289,070 | -$1,483,504 | 0.64 |
| FE: Penn Power | 16,431 | 6.68 | 5,847,328 | 13,421,936 | -$2,157,102 | 0.44 |
| FE: West Penn | 70,307 | 31.82 | 40,701,592 | 64,247,612 | -$23,546,020 | 0.63 |
| PECO | 108,049 | 95.48 | 87,811,623 | 141,116,016 | -$53,304,393 | 0.62 |
| PPL | 105,046 | 63.93 | 59,379,084 | 105,805,641 | -$31,088,996 | 0.56 |
| **Statewide** | **459,788** | **269.98** | **266,804,271** | **445,566,598** | **-**$**178,762,327** | **0.60** |

## Small and Medium Commercial Direct Load Control

Small commercial businesses are similar in many respects to residential accounts. Many of these businesses rely on residential style direct expansion (DX) cooling equipment that can be controlled via DLC devices. The SWE Team’s approach for estimating DR potential for this customer base is determined by identifying the proportion of each customer’s summer peak load consumption that may be associated with the use of their heating, ventilating and air conditioning (HVAC) system for space cooling. We began by selecting customer accounts with a PLC greater than 5 kW, but less than or equal to 75 kW.

Accounts with less than 5 kW of PLC were assumed to be associated with non-premises accounts, or accounts with very low occupancy and space cooling during summer weekday afternoons. Those accounts with PLC greater than 75 kW were assigned to the hypothetical large C&I load curtailment program. The approach used to identify economically advantageous customers for DLC varied by EDC depending on data availability, but in each case the intent of the analysis was to identify accounts with enough A/C load during peak periods that the benefits from controlling the load would be likely to outweigh the cost of the equipment, installation, and incentive. This step is analogous to the TRC screening procedure used to estimate economic potential for EE.

Table 1‑7 shows the number of qualified accounts based on size and weather sensitivity, the cumulative number of sites that could be enrolled in Phase III assuming a 1% annual adoption rate, the corresponding number of load control devices, the estimated annual load impact of the program, and an expected lifetime benefit/cost ratio according to the TRC test. Like the residential DLC program, PECO is the only EDC where a Phase III small commercial DLC program for control of central air condition equipment passes cost-effectiveness testing.

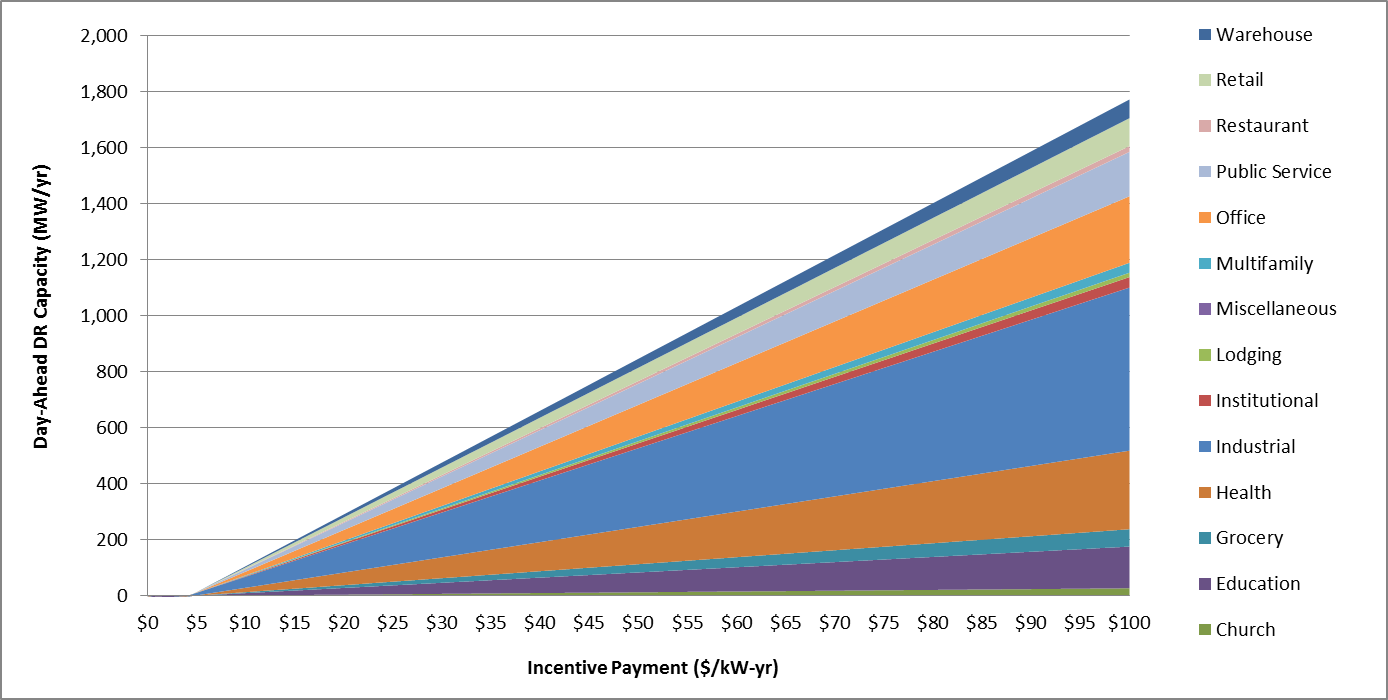
Table 1‑7: Small Commercial DLC Potential by EDC

| EDC | Total Qualified Accounts | Cumulative Sites | Cumulative Devices | Average Annual Impact (MW) | Lifetime TRC Ratio |
| --- | --- | --- | --- | --- | --- |
| Duquesne | 10,529 | 471 | 829 | 0.56 | 0.76 |
| FE: Met-Ed | 7,128 | 325 | 754 | 0.52 | 0.83 |
| FE: Penelec | 7,120 | 321 | 680 | 0.47 | 0.77 |
| FE: Penn Power | 2,446 | 113 | 258 | 0.17 | 0.45 |
| FE: West Penn | 9,492 | 438 | 921 | 0.64 | 0.85 |
| PECO | 35,880 | 3,262 | 6,099 | 5.73 | 1.41 |
| PPL | 39,735 | 1,833 | 3,088 | 2.14 | 0.72 |
| Statewide | **112,330** | **6,763** | **12,629** | **10.23** | **0.97** |

## Large Commercial and Industrial

Customer accounts with a PLC greater than 75 kW were assigned to a hypothetical C&I program. In addition to accounting for a large share of EDC peak loads, program data from Phase I of Act 129 and DR program across North America indicate that these customers represent a large share of DR potential which can be aggregated for incentive payments alone. Unlike DLC programs, EDCs do not need to incur any capital or labor costs from the installation of equipment to capture load reductions from these customers. Our estimates of DR potential for C&I load curtailment in Phase III are based on the sensitivity of DR participants (EDC customers) to changes in price. We have developed estimates of DR price elasticity and applied them to C&I peak loads to determine the change in quantity of DR supplied in response to a range of incentive values. Figure 1‑1 illustrates the relationship between DR potential and incentive payments graphically for a hypothetical PECO program with day-ahead notification of event calls.

Figure 1‑1: PECO Day-Ahead DR Potential by Customer Segment as a Function of Incentive Payment



The SWE Team modeled three notification types, or “products”: day-ahead, day-of, and fast response. DR potential increases with the amount of notification and preparation time participants are afforded. The average annual DR potential estimates, by EDC, for each product are presented in Table 1‑8.

Table 1‑8: Achievable Potential Estimates by EDC and DR Product Type (MW/year)

| EDC | Day-Ahead | Day-Of | Fast Response |
| --- | --- | --- | --- |
| Duquesne | 426 | 201 | 67 |
| FE: Met-Ed | 265 | 126 | 40 |
| FE: Penelec | 261 | 123 | 41 |
| FE: Penn Power | 122 | 58 | 20 |
| FE: West Penn | 498 | 231 | 80 |
| PECO | 912 | 428 | 168 |
| PPL | 732 | 386 | 115 |
| Statewide | **3,216** | **1,552** | **532** |

The Commission’s Final Order on DR directed the SWE Team to “*disallow dual participation when it performs its LC* [load curtailment] *analysis as part of its DR Potential Study*.”[[24]](#footnote-24) This need for mutual exclusivity is contentious as the mechanisms of producing benefits to ratepayers of the Commonwealth differ somewhat between the programs. PJM uses DR to meet the reliability requirement for a given year. The prospective Act 129 program relies on actual load reductions in a given year lowering resource requirements in future years. Policy implications aside, this directive adds a layer of complexity to the estimation of Act 129 DR potential for the following reasons:

* PJM’s Base Residual Auction (BRA) has been held for the delivery years coinciding with the first two program years of a potential Phase III of Act 129.
* The current volume (MW) of DR commitments by EDC are known for these two delivery years, but the participating accounts supplying the load reductions will not be known by the EDCs until the delivery year in question.
* Although small, relative to the BRA, PJM holds incremental capacity auctions prior to the delivery during which additional demand resources may commit load reductions, or committed resources can sell their positions. Historically, incremental auctions have lowered the committed MW from DR in Pennsylvania.
* The BRA for the PJM delivery year corresponding to Act 129 PY10-PY12[[25]](#footnote-25) had not occurred at the time of this study. Consequently, there are not currently any DR commitments in the PJM Emergency program and all load reductions are potentially available for Act 129 DR. However, historic analysis shows that if PJM markets continue to operate in a “business-as-usual” fashion a large number of MW will be committed by Pennsylvania businesses.
* There is considerable uncertainty regarding what DR in wholesale markets will look like during Phase III of Act 129. The vacation of **Federal Energy Regulatory Commission** (FERC) Order 745 and subsequent extrapolation of this ruling to forward capacity markets has led to speculation about continuing to allow DR participants to act as supply-side resources. PJM’s recent white paper[[26]](#footnote-26) on the topic speculated “*PJM’s markets would not separately compensate demand as a supply-side resource. The economics and incentives in having demand participate would result from avoided costs and obligations. State programs, of course, could offer added incentives to both wholesale and retail market participants.*”

Considering these challenges, the SWE Team evaluated two approaches to net out potential from customers enrolled in PJM programs. The first scenario assumes that PJM markets will exist as they have in previous years and Pennsylvania businesses will continue to participate in a similar fashion. To present this “business-as-usual” scenario, the SWE Team estimated PJM commitments for all of Phase III using the average DR participation from the 2012/2013, 2013/2014, and 2014/2015 delivery years[[27]](#footnote-27). The “Business as Usual” potential for an Act 129 load curtailment program with day-ahead notification net of projected PJM commitments are shown in Table 1‑9 along with projected TRC ratios. Load curtailment potential in this scenario exists for all EDCs other than Penelec.

Table 1‑9: Day-Ahead MW Potential Net of Projected PJM Commitments

| EDC | 2016  (PY8) | 2017  (PY9) | 2018  (PY10) | 2019  (PY11) | 2020  (PY12) | TRC  Ratio |
| --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 319 | 324 | 323 | 321 | 318 | 1.94 |
| FE: Met-Ed | 50 | 52 | 51 | 49 | 48 | 1.90 |
| FE: Penelec | -33 | -31 | -36 | -41 | -46 | 0.0 |
| FE: Penn Power | 67 | 68 | 66 | 64 | 62 | 1.93 |
| FE: West Penn | 153 | 157 | 154 | 155 | 155 | 1.94 |
| PECO | 494 | 499 | 488 | 474 | 460 | 1.69 |
| PPL | 93 | 99 | 94 | 95 | 95 | 1.88 |
| Statewide | **1,142** | **1,168** | **1,139** | **1,117** | **1,091** | **1.78** |

The second scenario is referred to as “wholesale changes” and only subtracts the volume of MW currently committed to PJM for the 2016/2017 and 2017/2018 delivery years from our estimates of Act 129 DR potential. Table 1‑10 shows the SWE Team’s estimates of DR potential, by year, once the DR MW from PJM’s BRAs have been subtracted. Instances where PJM commitments exceed the SWE Team’s estimate of “Day-Ahead” notification potential are presented in red. Estimated TRC ratios for the five-year phase are also presented.

Table 1‑10: Day-Ahead MW Potential Net of Current PJM Commitments

| EDC | 2016  (PY8) | 2017  (PY9) | 2018  (PY10) | 2019  (PY11) | 2020  (PY12) | TRC  Ratio |
| --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 281 | 268 | 427 | 426 | 423 | 1.94 |
| FE: Met-Ed | -48 | -32 | 266 | 264 | 263 | 1.90 |
| FE: Penelec | -166 | -90 | 262 | 257 | 252 | 1.92 |
| FE: Penn Power | -3 | 53 | 123 | 121 | 119 | 1.93 |
| FE: West Penn | 120 | -10 | 498 | 499 | 499 | 1.94 |
| PECO | 392 | 448 | 917 | 903 | 889 | 1.69 |
| PPL | -269 | 50 | 731 | 732 | 731 | 1.88 |
| Statewide Potential | **306** | **687** | **3,224** | **3,202** | **3,175** | **1.82** |

If “business-as-usual” DR practices do not continue at PJM because of court rulings or revisions to market architecture and DR is no longer able to participate as a supply-side resource in PJM’s forward capacity market, the findings in the 2018-2020 columns in Table 1‑10 tell a compelling story. Should DR no longer be included as a PJM capacity resource, the SWE Team believes it would be incumbent upon the Commission to enact a load curtailment program to harness the tremendous pool of DR potential available in the Commonwealth. Our analysis shows that the benefits of such a program would nearly double the costs. Pennsylvania businesses who supply DR to the wholesale markets will be eager for a way to replace PJM revenues and an Act 129 program would help insulate ratepayers from the price spikes that would result in PJM filling resource requirements without DR[[28]](#footnote-28). If this outcome were to materialize, an Act 129 load curtailment program would be an important way to engage large C&I accounts who may otherwise be interested in opting out of Act 129 programs.

## Program Potential

The TUS staff directed the SWE Team to consider four distinct program potential scenarios as part of its EE and DR potential studies. Each scenario considers a different funding split between EE and DR:

1. 100% spending on EE, 0% on DR
2. 90% spending on EE, 10% on DR
3. 85% spending on EE, 15% on DR
4. 80% spending on EE, 20% on DR.

The SWE Team analyzed program potential using only cost-effective DR potential options net of projected PJM commitments. We assumed that PECO would only install new DLC equipment for control of central A/C equipment in addition to leveraging existing infrastructure for controlling central A/C systems.[[29]](#footnote-29) For the other six EDCs, all program potential comes from large C&I load curtailment.

The Commission will face a key question when authoring an Implementation Order for Phase III of Act 129 and setting conservation targets for the EDCs. How should the 2% funding cap be allocated between EE and DR programs? With the exception of PECO, DLC does not appear to be a viable option for Pennsylvania EDCs. We have also established that if “business-as-usual” DR operations continue in PJM’s forward capacity market, a large share of the DR potential in the state will commit load reductions to the wholesale market. However, if court rulings or revisions to market architecture remove DR as a potential supply-side resource, an Act 129 load curtailment program could insulate Pennsylvania ratepayers from adverse effects to electric prices[[30]](#footnote-30). The program potential estimates shown in Table 1‑11 and Table 1‑12 are based on the “Wholesale Changes” scenario where PJM demand response commitments disappear after PY9. The SWE Team feels this scenario provides the more comprehensive side-by-side comparison of EE and DR. If EE is more attractive in this comparison, it will certainly be more attractive in a scenario where the majority of the DR potential in the state is captured by PJM.

Table 1‑11 shows the TRC costs, TRC benefits, TRC ratio, and PV of net benefits for each of the four EE/DR funding splits at the statewide level. Section 7.3 of the reports presents this information at the EDC level. Our analysis shows that EE and DR provide a fairly similar return on investment. Energy efficiency is marginally more attractive so as DR funding increases, the net benefits and TRC of a Phase III Act 129 Energy Efficiency & Conservation (EE&C) program decrease. Given the uncertainty associated with DR participation in PJM’s wholesale markets and whether enough DR potential will even be available for Act 129 DR to utilize a 10%, 15% or 20% funding allocation, we believe that EE is a safer investment of the 2% Demand-Side Management (DSM) funding cap set forth in the legislation.

Table 1‑11: TRC Costs and Benefits for EE and DR Funding Allocation Scenarios

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Scenario (EE/DR) | NPV Costs ($Million) | NPV Benefits ($Million | PV of Net Benefits ($Million) | Scenario TRC |
| 100/0 | $1,692 | $3,184 | $1,492 | 1.882 |
| 90/10 | $1,612 | $3,028 | $1,416 | 1.879 |
| 85/15 | $1,572 | $2,950 | $1,378 | 1.877 |
| 80/20 | $1,531 | $2,871 | $1,340 | 1.875 |

The potential energy and peak demand savings associated with each of the four funding allocations over a five-year Phase III are presented in Table 1‑12. EDC-specific results are shown in Table 7‑7. Peak demand savings are presented separately for EE and demand savings because of subtle differences in definition. For EE, only the first-year peak demand reductions resulting from installations in that program year are counted, but demand savings typically last for many years. For DR, the impacts are net of “business as usual” PJM projections and expected reductions in each of the five program years are averaged.

Table 1‑12: Statewide Energy and Demand Impacts for EE and DR Funding Allocation Scenarios

| Scenario (EE/DR) | Sum of Incremental Annual Megawatt-Hour (MWh) Savings from EE | Sum of Incremental Annual MW Savings from EE | Average Annual MW Savings from DR |
| --- | --- | --- | --- |
| 100/0 | 6,629,460 | 916 | 0 |
| 90/10 | 5,966,514 | 824 | 375 |
| 85/15 | 5,635,041 | 779 | 492 |
| 80/20 | 5,303,568 | 733 | 607 |

## Organization of the Report

The remainder of this report is organized in the following sections:

***Section 2: Analysis Approach*** details the methodology used to develop the estimates of technical, economic, achievable and program potential for electric EE savings.

***Section 3: Characterization of Pennsylvania Service Areas*** ***and Phase I/II Demand Response Offerings*** provides an overview of the Pennsylvania EDC service areas and a brief discussion of the historical and forecasted electric energy sales by sector as well as peak demand.

***Section 4: Residential DR Potential*** presents the methodology and results of the SWE Team’s analysis of DLC potential in the residential sector.

***Section 5: Small and Medium Commercial Direct Load Control*** summarizes A/C DLC potential from small commercial accounts within each EDC service territory.

***Section 6: Large Commercial and Industrial*** provides an overview of the analytical techniques used to estimate DR potential from large accounts in the Commonwealth and the associated results. Implications of potential overlap with PJM’s wholesale DR markets are also discussed.

***Section 7: Program Potential Estimates*** imposes funding caps on estimates of DR potential under various funding splits between EE and DR. The impacts, costs, and benefits of four funding allocations are presented and discussed.

# Analysis Approach

Demand response resources are intended to reduce the costs associated with maintaining power system reliability and meeting future capacity needs. Demand response is a demand-side management tool for electric utilities, similar to EE. This study estimates the amount of DR potential that exists in each of the EDC service territories. It also examines the costs and benefits of pursuing statewide policies that may encourage the development and deployment of DR resources.

## Summary

The SWE Team prepared a straightforward analysis to estimate the magnitude of DR potential for Phase III of Act 129. Our review of the policy and stakeholder landscape of a potential state-led DR market in Pennsylvania indicated a level of market complexity and uncertainty that required deliberate review and consideration of multiple modeling frameworks. Our approach is defensible and provides a workable framework for planning-level estimates of DR potential. Our approach and analysis takes into consideration EDC experience with DR programs conducted during Phase I of Act 129, as well as experience in other states. We anticipate our DR potential estimates will inform the Commission’s deliberations on potential targets for DR in Phase III of Act 129. After determining current and projected summer peak load consumption for the various EDCs and their customer segments, we executed the following analyses:

* Performed a computer simulation using summer peak loads in the PJM region for the 2006-2013 time periods subject to constraints imposed by various program design characteristics and selected a program dispatch design that we believe will be effective in reducing future resource requirements.
* Assigned customers to one of three categories of DR program offerings: large C&I load curtailment, small and medium commercial DLC, and Residential DLC.
* Estimated the likely participation in residential DLC programs based on (1) EDC experience with participation in Phase I residential DR programs and participation results at other electric utilities and (2) estimates of the size of the total eligible market for such programs.
* Estimated the quantity of DR capacity that may be offered by large C&I customers for a range of incentive values.
* Used computer simulations to identify the incentive level that is expected to maximize the PV of net benefits from a large C&I load curtailment program.
* Estimated the magnitude of small and medium commercial demand that might be available for DLC.
* Estimated the magnitude of residential electric central A/C, room A/C, electric water heating and swimming pool pump load that could be curtailed via DLC.
* Collected cost and performance data from Phase I DR programs to inform program cost estimates, peak load reductions and cost-effectiveness.

## DR Overview

This study seeks to quantify statewide DR potential for the period June 1, 2016 through May 31, 2021. We compared the costs and benefits of DR to those of EE, where appropriate, to provide broader, policy-relevant analysis to Pennsylvania state officials. In this section we discuss the logic and methods used to produce our DR potential estimates and summarize the results. The SWE Team has communicated their approach to the TUS staff and the Act 129 Stakeholders over the course of this study and has sought continuous feedback and comment from those groups.

We present DR potential estimates for the state and for each of the EDCs. The estimates were generated by constructing DR potential models for each EDC and associated market sectors. The study results may inform performance objectives for Phase III of the Pennsylvania Act 129 programs. Our analysis of DR potential is based on the most recent electricity consumption data and demand forecasts provided by the EDCs. The time period of electric demand forecast data used in our analysis is 2016 – 2030[[31]](#footnote-31), while the electric consumption data we relied upon is from January 1, 2012, through May 31, 2013. We estimated DR potential in each year from 2016 - 2021.

The term “DR potential,” is similar to language used to describe the potential reductions in electricity consumption that may be achieved through EE. While the concept of DR potential is essentially the same as for EE potential, we wish to note that the approach for estimating DR potential differs from the prescriptive framework often used to estimate EE potential. The EE framework describes EE potential in terms of technical, economic, achievable, and program potential. We borrow this terminology for convenience, but we will distinguish points of departure between the approaches for estimating EE potential and DR potential throughout our analysis.

## Differences between Demand Response Potential and Energy Efficiency Potential

DR potential does not fit neatly into the categories typically applied to EE potential. Energy efficiency can be thought of as “doing the same thing for less.” Energy efficiency is a technology-driven concept that seeks to satisfy the same economic demands for electricity consumption without altering customer behavior. In contrast, DR might be thought of as “doing less.” Demand response calls for a temporary reduction in customer demand for electricity and may be either active or passive. According to PJM, DR typically occurs as a result of power grid needs, economic signals from a competitive wholesale market, or special retail rates.

### Technical Potential

Adopting technologies that allow customers to consume less electricity without altering their behavior may be costly. These technologies result from significant investments of time and effort to scientific and engineering research. Consequently, many EE technologies exist, but only subsets of technologies are economically attractive to customers. In contrast, DR requires customers to simply use less electricity (upon request). The concept of technical potential used for estimating EE potential does not have a direct analogue for DR. For enough money, homes and businesses will forego virtually all electric demand temporarily. This report does not attempt to quantify technical potential for DR.

### Economic Potential

There is no theoretical difference in economic potential between EE and DR. Nevertheless, the practical application of this concept is slightly different for these two DSM tools. The technologic nature of EE means satisfying the same customer demands (or amenity) while reducing the energy needed to do so. Customers adopting EE technologies, by definition, will enjoy the savings associated with their reduced consumption. As previously mentioned, this savings is nearly always achieved at a cost. Customers can objectively compare the NPV of the benefits and costs they accrue by consuming electricity with and without the efficient technology; and, they can make a decision about whether to adopt the technology on the basis of cost-effectiveness.

Demand response is based on consuming less electricity. Customers benefit from consuming electricity; thus, asking customers to use less electricity may reduce their economic welfare. In the case of residential households, this loss of welfare is related to the discomfort resulting from reduced A/C use on hot summer days or reduced amenity when other end uses are controlled. Reducing consumption in the C&I sectors could also mean discomfort, but is more commonly related to lost opportunity or disruption because companies need electricity to produce widgets. The question then arises: who benefits from reducing electricity demand, and can they compensate customers for potential loss of welfare? If the beneficiary of customer demand reductions— the power grid —compensates customers by giving them something else they value, then there may be no net loss in welfare. If electric customers behave in ways that can be described by standard economic models of utility, then they should be willing to exchange their consumption of electricity for substitute goods or services of equal value. If the total benefit the power grid enjoys from reduced demand by its customers is greater than the total amount of compensation desired by those customers, then the DR potential is economically efficient. This is the basis of economic potential for DR: determine the level of DR customer incentives that maximizes the PV of net benefits.

### Achievable Potential

Achievable potential for DR is most like the corresponding measure of EE potential. The 2007 National Action Plan for Energy Efficiency[[32]](#footnote-32) defines achievable potential as, “…the result of how much market barriers and program uptake limits will reduce the economic potential.” Factors other than the value of electricity consumption can determine how much demand customers are willing to reduce in exchange for compensation. Typical market failures could occur in a DR market—customers may not be aware that utilities are willing to compensate them for reduced energy use. Transaction costs may also create market inefficiencies that increase the cost of participating in the DR market to the point where doing so is no longer cost-effective. Lastly, as in any market, not all participants will hold the same preferences for the good or service in question (e.g. not everyone is willing to buy or sell at the same price). Achievable potential seeks to account for these additional market factors that can modify the economic potential of DR for a given, cost-effective rate of compensation for demand reductions.

### Program Potential

The final package of compensation that DR beneficiaries are able to offer DR providers can also limit potential. We refer to this package of compensation as the program potential for DR. It may be that EDCs are not willing or able to provide compensation to all willing market participants for a given level of compensation. Program budgets are likely to limit the amount of total compensation that can be paid. Likewise, the specifics of the final program offered to potential DR providers may not meet the level of compensation they are willing to accept for demand reductions. The SWE Team considered four hypothetical budget allocations of the 2% spending cap between EE and DR. The annual budget available for DR under each scenario is presented in Table 2‑1.

Table 2‑1: Annual DR Budget for Program Potential Scenarios

| EDC | 100% EE, 0% DR | 90% EE, 10% DR | 85% EE, 15% DR | 80% EE, 20% DR |
| --- | --- | --- | --- | --- |
| Duquesne | $0 | $1,954,595 | $2,931,893 | $3,909,190 |
| FE: Met-Ed | $0 | $2,486,689 | $3,730,034 | $4,973,378 |
| FE: Penelec | $0 | $2,297,474 | $3,446,212 | $4,594,949 |
| FE: Penn Power | $0 | $665,978 | $998,968 | $1,331,957 |
| FE: West Penn | $0 | $2,356,247 | $3,534,370 | $4,712,494 |
| PECO | $0 | $8,539,516 | $12,809,274 | $17,079,032 |
| PPL | $0 | $6,150,138 | $9,225,206 | $12,300,275 |
| Statewide | **$0** | **$24,450,637** | **$36,675,956** | **$48,901,275** |

## Peak Load Consumption

The primary objective of the Act 129 DR program modeled in this study is to lower the generation capacity that must be secured by PJM on behalf of the EDCs. If successful, a statewide DR program would exert downward pressure on forecasts of summer peak demand and reduce the generation capacity required to meet PJM’s reliability requirements.[[33]](#footnote-33) This is somewhat different from the current PJM markets where DR falls on the supply-side and fills a requirement for generation capacity. The Commission’s Final Order on DR[[34]](#footnote-34) specified that EDCs will not be directed to bid their programs into PJM’s forward capacity market so the SWE Team believes that actual reductions during peak conditions are the most viable mechanism for an Act 129 DR program to produce tangible avoided costs.

The SWE Team was provided a summer and winter peak load forecast for each of the EDC service territories as part of a data request issued during the early stages of the study. Unlike the energy sales forecasts, which are completed by the EDCs, the peak load forecasts were completed by PJM[[35]](#footnote-35). The PJM load forecasts are available publicly[[36]](#footnote-36) and are also explored in more detail in Section 3.2. One important characteristic of these forecasts is that they are at the EDC-level and do not distinguish load from the residential class from commercial or industrial loads. Disaggregation of these summer peak load forecasts was an important precursor to the DR potential assessment.

PJM’s forecast for peak demand is the driver of the amount of generation capacity that must be secured to ensure reliable delivery of electricity to the region. Peak load contribution refers to the share of peak load forecast that an individual electric customer is responsible for and is a mechanism for EDCs and EGS’s to recover the fixed costs of the electric system from their customers. The timing and calculation details vary by EDC, rate class, and the availability of interval metering but the underlying concept is similar. A customer’s average load during periods of high system demand is used to determine the share of the electric generation capacity costs that are borne by that account. If a grocery store has an average load of 250 kW on the peak summer weekday afternoons, that grocery store will be assessed the costs associated with 250 kW of generation, T&D capacity. These demand charges may thereby represent up to 30% of customer billings—a fact which indicates the magnitude of potential savings from lowering peak demand and avoiding capital intensive expansion of infrastructure.

The SWE Team leveraged PLC information supplied by the EDCs for their customer bases in order to disaggregate the peak load forecasts to the sector level. The premise behind this analysis is that the sum of the PLCs from all customers will approximate the peak load forecast. A historic analysis of the distribution of PLCs by customer class was used to assign a proportion of the summer peak to each class and these proportions were then applied prospectively to the forecast. The SWE Team’s disaggregated forecast for each EDC is shown by customer sector in Table 2‑2.

Table 2‑2: Disaggregated 2016 Summer Peak Load Forecast (MW)

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| EDC | Industrial | Commercial | Residential | Total |
| Duquesne | 455 | 1,341 | 1,261 | 3,056 |
| FE: Met-Ed | 675 | 911 | 1,285 | 2,871 |
| FE: Penelec | 717 | 876 | 950 | 2,543 |
| FE: Penn Power | 212 | 297 | 465 | 974 |
| FE: West Penn | 1,045 | 1,151 | 1,676 | 3,873 |
| PECO | 981 | 3,986 | 3,848 | 8,815 |
| PPL | 1,595 | 2,795 | 3,179 | 7,568 |
| Statewide | **5,678** | **11,354** | **12,660** | **29,700** |

### Peak Load Consumption by Sector

The non-residential sector consists of many account segments, each comprised of different types of business, non-profit, or institutional users. Each segment may exhibit distinct patterns of electricity use, economic growth, or opportunity for DR. Accordingly, our analysis of non-residential DR potential was performed at the segment level to avoid imposing “one-size-fits-all” assumptions. Using data provided by each EDC, the SWE Team determined peak load consumption for each commercial segment. The industrial sector is treated uniformly as a whole, without segmentation. This section summarizes the results of the segmentation analysis. Our analysis of DR potential is based on premise accounts; the findings presented in this section do not include transmission, substation, irrigation or street lighting rate classes.

Figure 2‑1 shows the statewide distribution of load across the residential, commercial, and industrial sectors. The residential sector represents 43% of summer peak demand, the commercial sector totals 38% of summer peak load consumption in the state, while the industrial sector represents 19%. Summer peak load consumption is highest for the office, miscellaneous, education, retail, and health segments of the commercial sector.

Figure 2‑1: Statewide Distribution of Summer Peak Load

### Peak Load Consumption by Commercial Segment

The SWE Team used 13 building types to classify commercial accounts. Figure 2‑2 shows the percent contribution of each commercial segment to the summer peak load forecast. Offices, Miscellaneous, and Retail are the largest segments accounting for almost 50% of the summer peak load in the Commercial sector.

Figure 2‑2: Distribution of Summer Peak Load – Commercial

## Eligible Commercial and Industrial Accounts and Resource Categorization

The SWE Team used customer billing data provided by the EDCs for June 1, 2012, to May 31, 2013, to assign non-residential customers into one of two potential DR programs. These programs are a large C&I load curtailment program and a small and medium commercial DLC program. We assigned all customers with a PLC greater than 75 kW to the eligible pool for the C&I program and customers with a PLC less than 75 kW to the DLC program based on two factors:

1. Many load curtailment aggregation programs, including PJM’s, require a minimum load reduction commitment of 50 kW. Customers with a PLC under 75 kW are unlikely to be able to produce a 50 kW load shed.
2. Sites with a PLC above 75 kW are likely to have a central cooling plant that would not be suitable for DLC equipment that is designed for package DX cooling units.

Non-residential accounts with a PLC less than 5 kW were excluded from the analysis based on an assumption that they are either non-premise accounts, do not have cooling equipment, or have a negligible cooling load at the time of the system peak. These characteristics mean it would not be worthwhile to recruit the customer or install equipment at his or her location. We refer to these accounts as not “qualified”. Accounts which showed a lack of sensitivity to outdoor air temperature were also excluded from the pool of qualified DLC sites. Table 2‑3 shows the number of sites, and the associated summer peak load, for the two non-residential DR programs analyzed in this study. The PECO qualified DLC customers and MW are inclusive of those accounts which already have DLC equipment installed.

Table 2‑3: Assignment of Customers and Load to Non-Residential DR Programs

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| EDC | Eligible C&I Customers | Eligible C&I Load (MW) | Qualified DLC Customers | Qualified DLC Load (MW) |
| Duquesne | 2,934 | 1,316 | 10,529 | 71 |
| FE: Met-Ed | 2,836 | 1,116 | 7,128 | 55 |
| FE: Penelec | 2,888 | 1,175 | 7,120 | 50 |
| FE: Penn Power | 988 | 364 | 2,446 | 19 |
| FE: West Penn | 3,304 | 1,674 | 9,492 | 63 |
| PECO | 5,676 | 3,442 | 35,880 | 255 |
| PPL | 10,412 | 3,580 | 39,735 | 232 |
| Statewide | **29,038** | **12,667** | **112,330** | **745** |

## Economic Analysis

The economic argument for pursuing DR programs is that reducing peak demand may be cheaper than expanding generation and T&D capacity to meet growth in peak demand. The costs and benefits of producing and consuming electricity are related to the underlying supply of and demand for electric service. If the costs of supply expansion outweigh the benefits associated with increased demand, then society may wish to consider whether the supply expansion can be avoided. Meeting current and future peak demand without expanding supply capacity requires changes to demand. There are at least two policy approaches for influencing demand: price and non-price interventions.

Demand for electricity is based on the price of electricity and customer preferences for its consumption. Given a set of preferences and prices, customers select the quantity of consumption that is most valuable to them. Since price is influenced by the cost of producing electricity, the forces of demand and supply in a competitive market interact to reach an equilibrium price and quantity for electricity consumption. Increases in the quantity of electricity demanded, without a change in price, indicates a shift in demand. The price is the same, but the quantity demanded has increased. In this situation, society would benefit from the increase consumption (both consumers and producers).

The benefits of increased consumption of a product with increasing demand are strictly increasing if the marginal costs and benefits of consumption are constant. This is not the case in the electric industry in the short run as evidenced by the PJM forward capacity market. In its annual BRA, PJM procures electric generation capacity on behalf of its stakeholders. Generators bid capacity into the market and PJM commits to purchasing units and paying the marginal cost increase per unit, until the projected capacity requirement is met. Neither marginal benefit nor marginal cost is constant in this market, thus outward shifts of demand would be satisfied at an increasing marginal cost of electricity production. These characteristics of supply and demand give rise to the potential for DR to satisfy increasing demands at a lower cost than supply expansion.

Since consuming electricity benefits electric customers, reducing demand also reduces those benefits. If the Commonwealth asks consumers to voluntarily reduce their peak demand, then doing so brings a cost to those customers, and any rational customer will wish to be compensated. If the total cost of compensating these customers for reduced demand is less than the total cost of expanding supply capacity, then DR programs may generate positive net benefits to society. In accordance with the Commission’s Final Order on DR[[37]](#footnote-37) this study assumes that customers will not enter a ‘break-even’ arrangement so the financial benefits of DR participation must outweigh the costs. Accordingly, we have used 75% of the incentive amount as a proxy for the participant cost when examining the cost-effectiveness of DR.

One potential demand response benefit stream that was not included in this analysis is wholesale price suppression. Wholesale price suppression refers to a reduction in the market clearing price for a product resulting from lower quantity demanded leading to a lower position on the supply curve. The Commission found stakeholder comments about the uncertainty associated with price suppression estimates persuasive[[38]](#footnote-38) and directed the SWE not to perform a price suppression study or include estimates of price suppression benefits in the DR potential study.

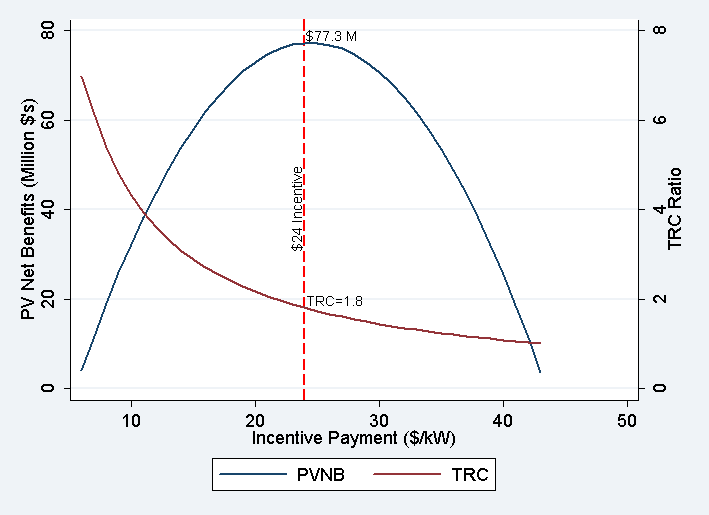
### Net Benefits as a Decision Criterion

The TUS staff requested that the SWE Team develop scenarios to compare the relative benefits of Act 129 budget allocations between EE and DR programs. The TUS staff indicated a desire to compare alternative projects on the basis of the PV of net benefits. This criterion is appropriate for comparing mutually exclusive program alternatives and selecting an alternative that provides the largest economic benefit. Comparing program alternatives solely on the basis of the TRC ratio obscures the relative magnitude of benefits provided by program alternatives.

We have also applied the concept of net benefit to our cost analysis of Phase III non-residential DR Potential. In developing cost estimates, the SWE Team sought to identify the incentive levels that maximized the respective PV of net benefits from the large C&I load curtailment programs. The incentive payment is an important component for estimating DR potential because the incentives paid to DR providers must be equal to or greater than the cost of providing DR capacity. Where this is not the case, potential DR suppliers would elect not to participate in the program.

The incentive level that maximizes the PV of net benefits to each of the DR programs we evaluated is the economically efficient level of DR. It is important to note that the level of incentives that maximizes NPV of benefits is not indicated by the TRC ratio. While the TRC ratio indicates the relative costs and benefits of a program, it does not allow one to compare two programs and determine which one provides the greatest economic benefit. A program that costs $1 and generates $2 in benefits has a higher TRC ratio than a program that costs $1,000,000 and generates $1,500,000 in benefits. We illustrate this concept below in Figure 2‑3, using representative data to calculate the net benefits and TRC ratio. In this representative example higher TRC ratios have lower net benefits.

Figure 2‑3: Relationship between Incentive Amount, TRC, and PVNB[[39]](#footnote-39)



The incentive level that maximizes the present value of expected total net benefits (PVNB) is likely to be lower than the avoided cost of capacity. If the DR incentive cost per unit were higher than the cost of capacity per unit, potential would be extremely high because the lucrative payments would be attractive to participants, but the costs would exceed the benefits and the better choice is to increase capacity through traditional generation. If the DR incentive costs plus administrative costs were equal to the avoided costs of capacity, program potential would be high, but the TRC would equal 1.0 and there would be no net benefit from running the program.

It is critical to remember that the truth of this comparison is based on accurate cost information and a competitive market. The realities of market failure, such as natural monopolies, externalities, imperfect information, and transaction costs can lead to the wrong conclusion if these are not accounted for in the price. Our estimate of DR potential accounts for the opportunity costs DR suppliers face when choosing between the *status quo* and reduced peak consumption. This topic is discussed further in Section 6.1, where we present the price elasticity values that were used to estimate DR potential.

### Avoided Generation Capacity Costs

The most recent PJM BRA provides information on avoided costs of generation capacity. The Commission’s February 20, 2014 Order[[40]](#footnote-40) stated that EDCs would not be directed to bid Act 129 DR programs into PJM’s forward capacity market. Since Act 129 DR would not be a recognized wholesale resource and receive payment as such, the primary benefit of a Phase III DR program would be reducing the amount of future generation capacity that would be purchased on behalf of the EDCs at the market-clearing prices established in the annual BRA. Table 2‑4 shows the avoided cost of generation capacity values that were used in the study. The 2016/2017 and 2017/2018 delivery year values are based on actual auction results and the subsequent years are based on a 1.87% annual escalation factor[[41]](#footnote-41) from the clearing prices in the 2017/2018 delivery year.

Table 2‑4: Phase III Avoided Cost of Generation Capacity Values ($/kW/year)

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| **EDC** | **Act 129 PY8/  PJM Delivery Year 2016/2017** | **Act 129 PY9/ PJM Delivery Year 2017/2018** | **Act 129 PY10/ PJM Delivery Year 2018/2019** | **Act 129 PY11/ PJM Delivery Year 2019/2020** | **Act 129 PY12/**  **PJM Delivery Year 2020/2021** |
| Duquesne | $21.67 | $43.80 | $44.62 | $45.45 | $46.30 |
| FE: Met-Ed | $43.48 | $43.80 | $44.62 | $45.45 | $46.30 |
| FE: Penelec | $43.48 | $43.80 | $44.62 | $45.45 | $46.30 |
| FE: Penn Power | $41.69 | $43.80 | $44.62 | $45.45 | $46.30 |
| FE: West Penn | $21.67 | $43.80 | $44.62 | $45.45 | $46.30 |
| PECO | $43.48 | $43.80 | $44.62 | $45.45 | $46.30 |
| PPL | $43.48 | $43.80 | $44.62 | $45.45 | $46.30 |

When modeling the benefits of DR, the SWE Team multiplied the average expected kW reduction in each program year by the avoided cost of generation capacity values in Table 2‑4. The mechanics of the calculations highlights a critical assumption of the study. We are assuming that each kW of observed load reduction from an Act 129 DR program will lower PJM’s summer peak load forecast and subsequent reliability requirement by 1 kW in a future delivery year. The SWE Team discussed this assumption with PJM staff during a July 2, 2014 teleconference and confirmed that Act 129 DR events would place downward pressure on PJM’s peak load forecast, although PJM staff declined to comment on the appropriateness of the 1:1 approach utilized in this study. The PJM peak load forecast is a complex econometric model, so in practice a 1 kW reduction in 2016 could lower the forecast by less than 1 kW in a given year, but reductions in a single summer could also affect the forecast for multiple delivery years.

The capital costs of supply expansion may also include costs associated with expanding T&D infrastructure. In Phase I and Phase II of Act 129, avoided T&D benefits were expressed on a $/kWh basis. One implication of this approach is that DR programs, which save peak kW, but typically not any net kWh, will receive no monetary benefits in a TRC calculation. The SWE Team and TUS staff believe that valuing expansion of T&D infrastructure on a $/kW basis is more appropriate and consistent with most other jurisdictions. The SWE Team’s estimates of Phase III potential rely on avoided T&D costs calculated from capital budgets and project-by-project determinations of the reason for the expenditure provided by the EDCs. Additional detail on the SWE Team’s calculations of avoided T&D capacity costs are presented in Section 2.8.

All else equal, as long as the cost per unit of acquiring DR capacity is lower than these capacity costs, the economy would benefit from reducing demand rather than increasing supply. Avoiding the costs associated with supply expansion would liberate capital that could be put to more valuable uses.

### Program Costs

#### Residential programs

For the residential DR programs, the costs of load control switches and switch installation costs are based on the SWE Team’s review of data supplied by the EDCs and by equipment suppliers. The costs for program administration, marketing and incentives (for program participants) are based on actual costs experienced from the Phase I residential DR programs. Non-incentive program costs are based on observation, experience, and professional judgment. Additional information on the data sources used to develop program costs for residential DR programs is provided in Section 4 of this report.

#### Commercial and Industrial programs

For the hypothetical large C&I we used cost information reported by the EDCs from Phase I. We employ a top-down approach that examines the proportion of program administration costs to total program cost for each EDC. The range of administrative costs as a share of total costs varied slightly by EDC in Phase I. We elected to employ the average value of 15% for each EDC in this study. For example, if a modeled EDC load curtailment program has $850,000 in incentive costs, an additional $150,000 in non-incentive costs is included to account for costs related to program marketing, administration, Conservation Service Provider (CSP) fees, and evaluation.

Small commercial DLC program costs were developed using a more bottom-up approach.

## DR Program Design

In order to evaluate DR potential for Phase III of Act 129, the SWE Team had to make assumptions about the program design that would be implemented. The Top 100 hours construct implemented in Phase I of Act 129 proved problematic, therefore the SWE Team elected to consider alternate designs that we felt were more likely to produce a cost-effective program. Key program design parameters that affect DR potential include:

* The expected number of events per year
* The duration of events
* The season and time of day the events occur
* The amount of advance notification participants are given
* Whether event participation is mandatory[[42]](#footnote-42) or voluntary.

This report section describes the SWE Team’s approach for quantitatively evaluating the implications of different program design assumptions. It provides a brief introduction of key concepts and then reviews the methods and results of the program effectiveness simulation designed for this study. The results were shared with TUS staff in October 2014, and the SWE Team was directed to utilize the recommended program design for the potential assessment. We used publicly available historical metered load data from PJM to examine the implications of program design on program effectiveness.

### Key Concepts

Practical considerations for DR program design may place natural limits on its effectiveness. Program budgets can be exhausted by a large number of DR events, and the timing of system peaks cannot be predicted with perfect accuracy. Even though these limitations are known to exist and are inevitable, it is challenging to estimate their impact quantitatively. We investigate the impacts of various program design considerations using a simulation approach to generate estimates of program effectiveness. We refer to these estimates as ELCC.

The simulation takes advantage of historical system load data to compare the ELCC for 1,600 hypothetical program designs[[43]](#footnote-43). We explicitly define ELCC as the percentage of a target load that is captured during a simulated event. In this analysis, the target load is all energy above 90% of the forecasted system peak for the year.[[44]](#footnote-44) For example, if hour 17[[45]](#footnote-45) (4:00 p.m. to 5:00 p.m.) on July 12, 2010 had an observed load of 148,000 MW and the forecasted summer peak for the 2010/2011 delivery year was 160,000 MW, the target load for the simulation would be equal to:

The Commission’s February 20, 2014 Order[[46]](#footnote-46) stated that EDCs will not be directed to bid their DR programs into PJM’s BRA; therefore, avoided capacity benefits from Act 129 DR will need to come from curtailments placing downward pressure on PJM’s forecasted summer peaks and the corresponding resource requirements in EDC zones. The SWE Team believes that the hours when the system load is greater than 90% of the forecasted peaks for the year are a primary driver of PJM’s peak load forecasts. Having a set metric for effectiveness allows us to compare possible program designs side-by-side and quantitatively assess the relative performance of alternative program designs.

In addition to the ELCC, the simulation can also provide information on the performance of program design relative to capturing the 5CP, which some EDCs use to calculate PLC and allocate capacity obligations to their customers. As DR program participants reduce demand during system peak hours, the SWE Team anticipates a commensurate reduction in their PLC[[47]](#footnote-47), which will therefore reduce the amount of generation capacity that the EDC must secure to serve those customers over time. Demand response participants will benefit economically from the program by reducing the capacity requirement charge portion of their electric bill, as well as collecting the participation incentive offered through the EDC DR program and reducing their billed energy consumption. The benefits realized from PLC reduction will be directly proportional to the ability of the program design to capture the 5CP hours in a given year. In addition to the ELCC performance metric, we compare various programs based on their historic ability to capture 5CP hours for 2006 to 2013.

### Methodology

The SWE Team identified the projected peak load for each year using historical PJM load forecasts.[[48]](#footnote-48) We set the target load for DR at 90% of the forecasted summer peak and the simulation results record the percentage of the target load that is captured by the program design parameters (defined as the ELCC). For example, the forecasted peak load in 2009 was 134,428 MW.[[49]](#footnote-49) The simulation results give us the percentage of the target load (loads greater than 120,985 MW) captured by the DR program design. The term ‘captured’ means that the program design would call for a DR event during that hour and has no bearing of the amount of load which could be curtailed.

The program design parameters of the simulation include a dispatch criterion, dispatch hour, event duration, and a maximum number of events that can be called in a year. Each iteration of the simulation cycles through these parameters and calculates the percentage of target load captured (ELCC). The output of the simulation is a series of DR scenarios that vary by program design parameters and ELCC. Table 2‑5 defines each simulation parameter and its range. Each parameter is incremented by units of 1 through the range.

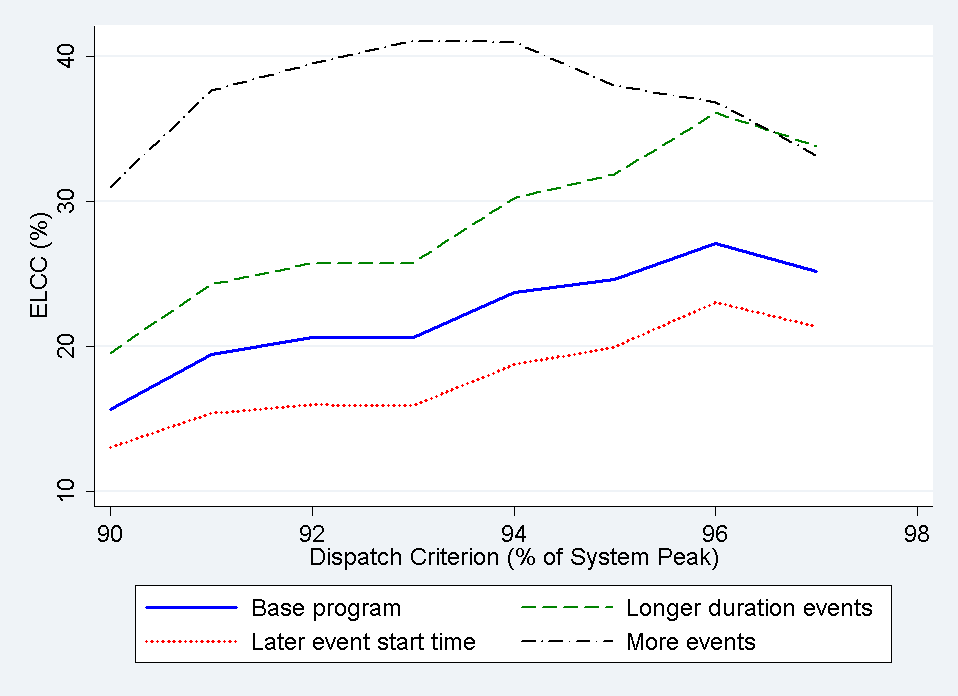
Table 2‑5: Simulation Parameters and Ranges

|  |  |  |
| --- | --- | --- |
| Simulation Parameter | Definition | Range |
| Dispatch Criterion | Load threshold which determines the days when events occur | Loads > 90% - 97% of forecasted annual system peak |
| Dispatch Hour | Start time of events | Hours 13 - 17 |
| Event Duration | Duration of event | 2 to 6 hours |
| Maximum Events | Maximum number of events that can be called in a program year | 5 to 12 |

### Results

Figure 2‑4 provides an example of how different program designs perform under a range of dispatch criteria. Each line in the graph illustrates the effect of changing one program element, while holding all others fixed at the base level. The lines can be used to compare whether specific program elements produce higher or lower overall target load capture. For example, the “more events” line is higher than the “base” case line, indicating that all else equal, increasing the maximum number of events is likely to capture more of the target load (higher ELCC). This particular result is obvious; an unconstrained increase in the number of events will clearly capture more of the target load. Yet in practice, an unconstrained increase in the number of DR events is likely to quickly exhaust program budgets, negatively impact cost-effectiveness, and reduce the appeal of the program among potential participants. This is an example of the tradeoffs that should be considered when selecting a final DR program design. The SWE Team has conducted this simulation to provide the Commission and Stakeholders with a quantitative basis for comparing how alternative program designs may affect program effectiveness.

Figure 2‑4: Comparison of Program Design Variables



Further examination of the inflection points in Figure 2‑4 provides more information. For example, the marginal benefit of calling an event, in terms of expected target load capture, is greatest with dispatch criteria between 93% and 96% of system peak load. Target load capture becomes limited by simple occurrence of required conditions for dispatch criteria greater than 96% of the system peak. Table 2‑6 provides a summary of the scenarios plotted in Figure 2‑4.

Table 2‑6: Summary of Simulated Program Design Elements Illustrated In Figure 2‑4

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Scenario | Dispatch | Event Duration | Max No. Events | Event Start  (Hour)[[50]](#footnote-50) |
| Base | 90%-97% | 4 | 6 | 15 |
| Longer Events | 90%-97% | 6 | 6 | 15 |
| Later Start | 90%-97% | 4 | 6 | 17 |
| More Frequent Events | 90%-97% | 4 | 12 | 15 |

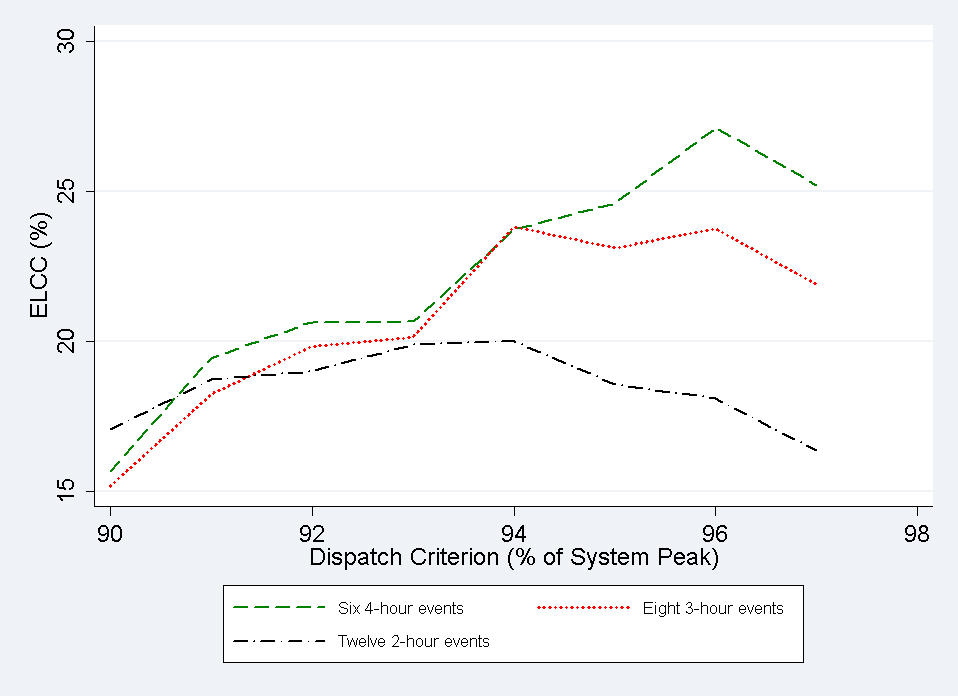
A number of hypothetical examples can be used to compare potential DR program designs. For example, all else equal, the simulation indicates a later start time can be expected to decrease ELCC relative to the base program design at each dispatch threshold. In we present a program design with a maximum of 7 events annually, each lasting 3 hours, and with a dispatch criterion of days when load reaches 96% of system peak. These simulation results demonstrate that events called from 3:00 p.m. to 6:00 p.m. are expected to outperform events called from 2:00 p.m. to 5:00 p.m. or from 4:00 p.m. to 7:00 p.m., holding all other factors constant.

Figure 2‑5, we present a program design with a maximum of 7 events annually, each lasting 3 hours, and with a dispatch criterion of days when load reaches 96% of system peak[[51]](#footnote-51). These simulation results demonstrate that events called from 3:00 p.m. to 6:00 p.m. are expected to outperform events called from 2:00 p.m. to 5:00 p.m. or from 4:00 p.m. to 7:00 p.m., holding all other factors constant.

Figure 2‑5: Expected ELCC for a Range of Event Start Times

Changing more than one program design variable can have interactive effects. It can be difficult to compare programs with different combinations of duration and event frequency. We illustrate these types of interactive effects below in Figure 2‑6, which compares three different programs with a maximum of 24 event hours per year: one program consisting of 4-hour events with a maximum of 6 events, one consisting of 3-hour events with a maximum of 8 events, and one consisting of 2-hour events with a maximum of 12 events. All three of these designs assume dispatch at 2:00 p.m. The simulation results indicate that the program with a maximum of 6 events lasting 4 hours is expected to perform best; further, it is likely to capture the highest percentage of target load if it is dispatched on days when load is expected to reach 96% of system peak.

Figure 2‑6: Comparison of Three Potential Program Designs, Each with No More Than 24 Total Event Hours



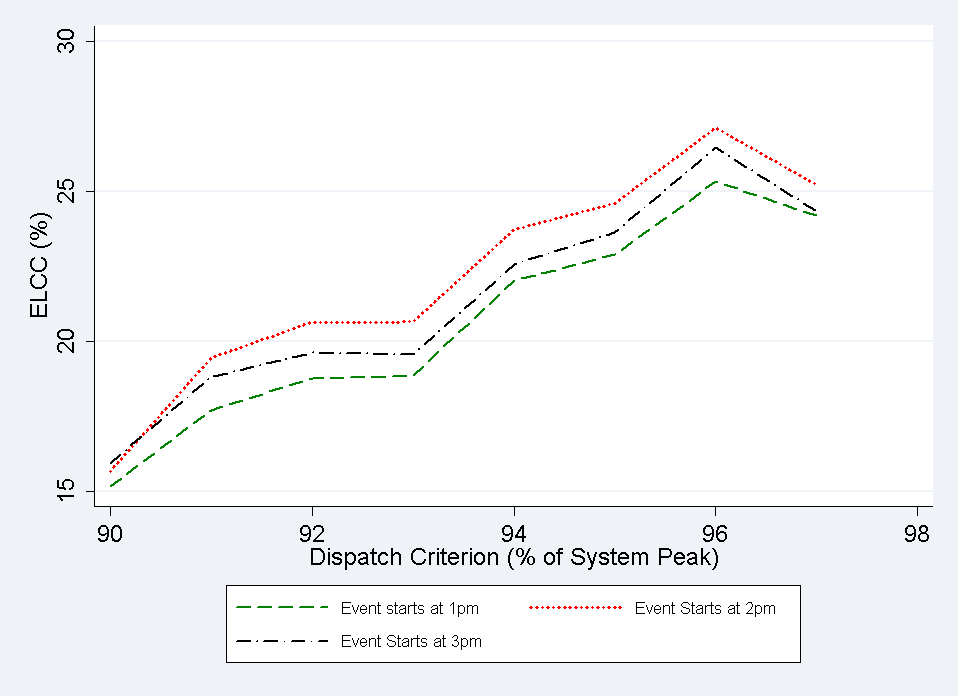
Even though a higher dispatch criterion improves the simulated ELCC, a higher dispatch criterion can also result in fewer events, or even no events in a cool summer. Table 2‑7 illustrates this concept by showing the number of events that would have been called in each year, based on the preceding hypothetical program design.

Table 2‑7: Historic Event Calls by Dispatch Criterion (Assuming Max Events = 6)

| Year | Load Threshold | | | | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 90% | 91% | 92% | 93% | 94% | 95% | 96% | 97% |
| 2006 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 2007 | 6 | 6 | 6 | 6 | 6 | 6 | 4 | 4 |
| 2008 | 6 | 6 | 5 | 4 | 1 | 0 | 0 | 0 |
| 2009 | 3 | 2 | 1 | 1 | 1 | 0 | 0 | 0 |
| 2010 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 4 |
| 2011 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 |
| 2012 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 3 |
| 2013 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 4 |
| Average | **5.6** | **5.5** | **5.3** | **5** | **4.6** | **4.4** | **4.1** | **3.4** |

Figure 2‑7 shows the effect of changing the start time for a program that consists of a maximum of 6 events lasting 4 hours each. Each line demonstrates the simulated results using a different event start time. The figure indicates that a start time of 2:00 p.m. can be expected to perform best for a program of no more than 6 events lasting 4 hours, to be dispatched on days when system load reaches 96% of the projected annual peak.

Figure 2‑7: Comparison of Event Start Times (4 hour Events, Max Events = 6)



### Conclusions

We expect the program design criteria to impose limits on the amount of DR potential in Phase III. These limits are primarily the result of finite program budgets that make it necessary to limit the number of potential DR events. Further, the inherent uncertainty of the regional transmission organization’s (RTO) system peak forecasts and weather predictions casts uncertainty over when events should be called. This simulation is an attempt to quantitatively explore the relative effectiveness of DR for Phase III under a range of potential program designs.

Our simulations do not consider seasonal effects because the Commission’s 2/20/2014 Order[[52]](#footnote-52) directed the SWE Team to only consider Summer DR. The amount of advance notification customers receive is only a driving factor of non-residential DR, as residential customers are typically DLC customers and are not notified at all prior to an event.[[53]](#footnote-53) Section 6 presents separate estimates of potential for three notification protocols:

1. **Day-Ahead**. Customers are informed in the afternoon that the following day will be a DR event. (Highest Potential)
2. **Day-Of**. Customers are informed in the late-morning that that afternoon will be a DR event.
3. **Fast Response**. Customers are notified 30 minutes prior to the beginning of an event. (Lowest Potential)

We expect that the Commission will weigh the relative merits of these notification systems when considering the potential estimates generated by the SWE Team. Table 2‑8 presents the long-run simulated results for potential program designs with no more than 24 event hours. We list the top-scoring simulation results for programs with a maximum of 24 event hours, and have truncated these results for the sake of brevity. The results of the simulation indicate that a program design of no more than 6 events lasting 4 hours, beginning at 2:00 p.m. (hour 15) and dispatched on days when load is expected to reach 96% of system peak, may capture roughly 27% of the target load and approximately 58% of 5CP hours.

Table 2‑8: Truncated Simulation Results

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| **ELCC (%)** | **5CP Captured (%)** | **Dispatch Criterion (%)** | **Event Start (hour)** | **Event End (hour)** | **Event Duration (hrs.)** | **Max No. Events** | **Average No. Events** |
|
|
| 27.1 | 57.5 | 96 | 15 | 18 | 4 | 6 | 4.1 |
| 26.4 | 55 | 96 | 16 | 19 | 4 | 6 | 4.1 |
| 25.3 | 55 | 96 | 14 | 17 | 4 | 6 | 4.1 |
| 25.2 | 55 | 97 | 15 | 18 | 4 | 6 | 3.4 |
| 24.6 | 52.5 | 95 | 15 | 18 | 4 | 6 | 4.4 |
| 24.3 | 50 | 97 | 16 | 19 | 4 | 6 | 3.4 |
| 24.2 | 62.5 | 96 | 16 | 18 | 3 | 8 | 4.6 |
| 24.2 | 55 | 97 | 14 | 17 | 4 | 6 | 3.4 |
| 24.2 | 60 | 94 | 16 | 18 | 3 | 8 | 5.8 |
| 23.8 | 62.5 | 94 | 15 | 17 | 3 | 8 | 5.8 |
| 23.7 | 65 | 96 | 15 | 17 | 3 | 8 | 4.6 |
| 23.7 | 50 | 94 | 15 | 18 | 4 | 6 | 4.6 |
| 23.6 | 50 | 95 | 16 | 19 | 4 | 6 | 4.4 |
| 23.4 | 60 | 95 | 16 | 18 | 3 | 8 | 5.3 |
| 23.1 | 62.5 | 95 | 15 | 17 | 3 | 8 | 5.3 |
| 23 | 52.5 | 96 | 17 | 20 | 4 | 6 | 4.1 |
| 22.9 | 50 | 95 | 14 | 17 | 4 | 6 | 4.4 |
| 22.6 | 57.5 | 96 | 17 | 19 | 3 | 8 | 4.6 |
| 22.6 | 47.5 | 94 | 16 | 19 | 4 | 6 | 4.6 |
| 22.1 | 55 | 97 | 16 | 18 | 3 | 8 | 3.6 |
| 22 | 47.5 | 94 | 14 | 17 | 4 | 6 | 4.6 |
| 21.9 | 52.5 | 94 | 17 | 19 | 3 | 8 | 5.8 |
| 21.9 | 60 | 97 | 15 | 17 | 3 | 8 | 3.6 |
| 21.6 | 10 | 96 | 14 | 16 | 3 | 8 | 4.6 |
| 21.6 | 70 | 93 | 16 | 17 | 2 | 12 | 8.6 |

The results in Table 2‑8 indicate the existence of some tradeoffs in program design. The simulation demonstrates that a program design with a dispatch threshold of 96%, an event start time of 2:00 p.m., duration of 4 hours, and a maximum of 6 events per year is expected to provide the highest overall ELCC for designs capped at 24 event hours. Even so, the simulation shows that the last program design listed in Table 2‑8 is expected to capture 70% of past 5CP events. The former program design achieves the highest simulated ELCC while the latter captures the highest percentage of 5CP events, but with a lower overall ELCC of 21.6%.

Potential Phase III participants are likely to hold preferences about program design that may or may not align with the preferences of the Commission. Based purely on the criteria of maximizing the ELCC, the first program design in Table 2‑8 is the clear winner[[54]](#footnote-54). Alternatively, if participants wish to maximize the potential bill savings, they may prefer the last program listed in Table 2‑8, which is more likely to reduce their demand during system peaks (5CP hours) and thus lower their capacity charges (assuming they have information on expected reductions in capacity charges). They may be just as likely to prefer fewer events and therefore oppose this program design, which could include up to 12 events in some years.

The SWE Team raises this issue of tradeoffs because we wish to be clear about how the results of the simulation can be used. The simulation we have presented provides an estimate of the natural limits that program design parameters place on Phase III DR potential. This simulation does not contain information that can be used to infer how actual program participants would react to any given program design. The goal of the SWE Team in conducting the simulation was to establish a quantitative basis for recommending a Phase III program design for which to estimate potential. All of the potential estimates in this study assume the program design listed in the first row of Table 2‑8.

### Supplemental Findings

The SWE Team anticipates that the ultimate effectiveness of Phase III may depend on whether participants recognize the potential for reductions in demand charges. There is ample evidence that large C&I customers are quite savvy in this regard and many are already actively managing their PLCs. However, we believe that small C&I customers are less likely to understand this market function and actively monitor their consumption on likely 5CP days. This section provides additional tables and figures on the topic.

Table 2‑9 provides the number of 5CP events captured in each year for a program design consisting of no more than 6 events lasting 4 hours, beginning at 2:00 p.m. on days when load is expected to reach 96% of the projected annual peak.

Table 2‑9: Simulated Number of 5CP Events Each Year for a Hypothetical Program Design

| Year | Number of 5CP Hours Captured | Number of Events Called |
| --- | --- | --- |
| 2006 | 4 | 6 |
| 2007 | 4 | 4 |
| 2008 | 0 | 0 |
| 2009 | 0 | 0 |
| 2010 | 5 | 6 |
| 2011 | 1 | 6 |
| 2012 | 4 | 6 |
| 2013 | 5 | 5 |

Figure 2‑8 shows the historical occurrences of the potential dispatch criteria for 5CP days. The x-axis indicates the maximum daily demand as a percentage of the projected annual peak for each year.

Figure 2‑8: Histogram of Dispatch Criteria Frequency During 5CP Events

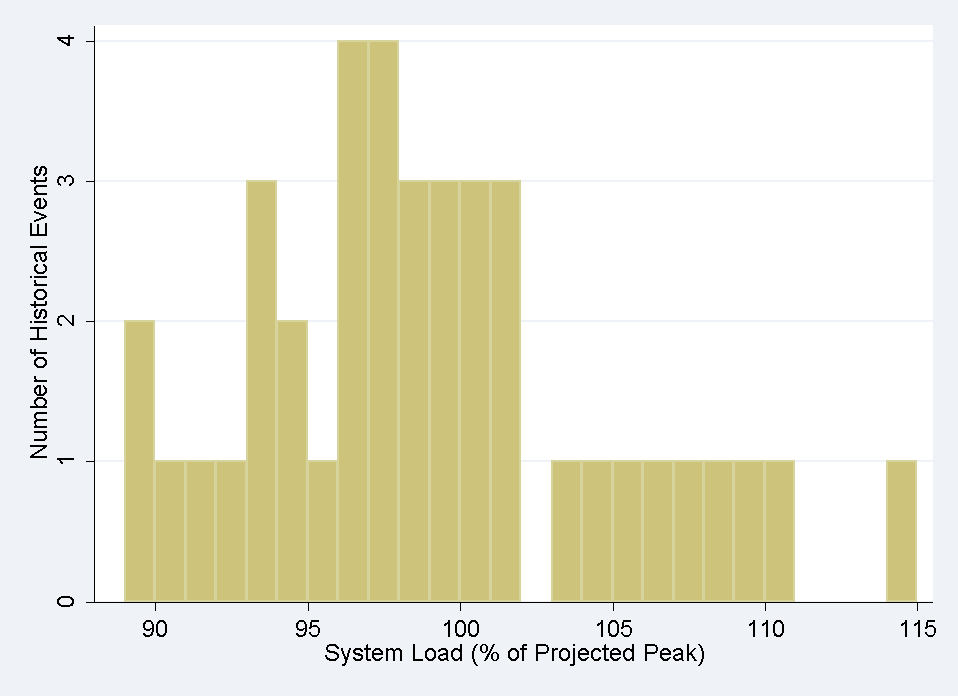


Table 2‑10 shows the number of 5CP hours that have occurred in each hour. Times are expressed in hours on a 1 to 24 basis so hour 15 is the hour from 2:00 p.m. to 3:00 p.m.

Table 2‑10: Historical Count of 5CP Events, by Hour-Ending

| Hour | Occurrences | Percentage (%) |
| --- | --- | --- |
| 15 | 3 | 7.5 |
| 16 | 4 | 10 |
| 17 | 32 | 80 |
| 18 | 1 | 2.5 |

Lastly, Table 2‑11 reports the number of days in each year that exceeded the corresponding dispatch criterion. Notice the stark contrast between 2008-2009 and 2011 in terms of the number of days above a given load threshold. This illustrates the inherent challenges the Commission faces in designing a forward-looking DR program.

Table 2‑11: Number of Days Exceeding Dispatch Criteria Each Year

| Year | Dispatch Criterion (% of Projected Annual Peak) | | | | | | | |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| 90% | 91% | 92% | 93% | 94% | 95% | 96% | 97% |
| 2006 | 16 | 13 | 12 | 12 | 10 | 9 | 7 | 6 |
| 2007 | 13 | 13 | 11 | 11 | 7 | 6 | 4 | 4 |
| 2008 | 9 | 6 | 5 | 4 | 1 | 0 | 0 | 0 |
| 2009 | 3 | 2 | 1 | 1 | 1 | 0 | 0 | 0 |
| 2010 | 26 | 22 | 19 | 17 | 14 | 9 | 6 | 4 |
| 2011 | 38 | 33 | 31 | 27 | 24 | 22 | 19 | 16 |
| 2012 | 16 | 14 | 14 | 12 | 9 | 7 | 7 | 3 |
| 2013 | 7 | 6 | 6 | 5 | 5 | 5 | 5 | 4 |

## Avoided Cost of Transmission and Distribution Capacity

The SWE Team developed forecasts of T&D avoided costs per kW/year for each EDC subject to the DR program requirements of Act 129. For purposes of this study, T&D avoided costs are defined as the T&D infrastructure expenditures that can be avoided if an EDCs future load growth can be reduced with DR programs that reduce load at the time of utility peak loads. The SWE Team reviewed numerous studies conducted in other jurisdictions to determine best practices for developing forecasts of T&D avoided costs. Furthermore, the SWE Team then developed a pragmatic methodology for forecasting T&D avoided costs based on the results of this literature search. Lastly, the SWE Team collected the required EDC load growth and T&D expenditure forecasts necessary for developing the forecast of T&D avoided costs for each EDC.

### Summary of Recent Transmission and Distribution Avoided Cost Studies in Other Jurisdictions

The SWE Team reviewed and prepared a summary of the methodologies used in several different T&D avoided cost studies, including the methodology used by Navigant to develop customized T&D avoided costs for PECO in the fall of 2014. The names, dates, and authors of each T&D avoided cost study reviewed by the SWE Team are listed in Table 2‑12.

Table 2‑12: T&D Avoided Cost Studies Reviewed by the SWE Team

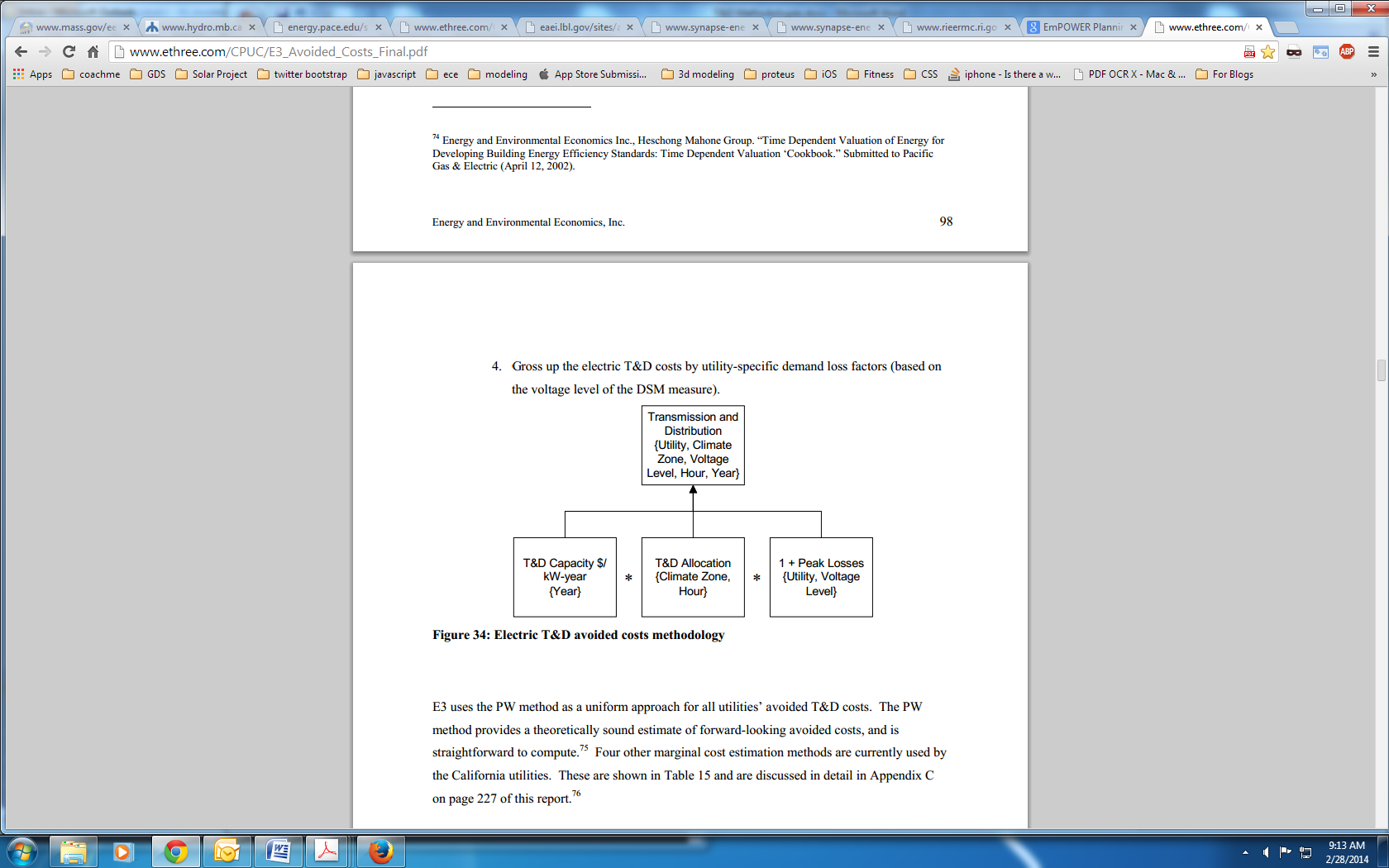
| Title of Study | Date | Firm |
| --- | --- | --- |
| Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs[[55]](#footnote-55) | October, 2004 | Energy and Environmental Economics |
| Marginal Transmission & Distribution Cost Estimates[[56]](#footnote-56) | April, 2005 | Manitoba Hydro |
| Avoided Energy Supply Costs in New England[[57]](#footnote-57) | December, 2005 | ICF Consulting |
| Deployment of Distributed Generation for Grid Support and Distribution System Infrastructure[[58]](#footnote-58) | February, 2011 | Synapse Energy Economics |
| Avoided Energy Supply Costs in New England[[59]](#footnote-59) | July, 2011 | Synapse Energy Economics |
| Avoided Energy Supply Costs in New England [[60]](#footnote-60) | July, 2013 | Synapse Energy Economics |
| Maryland Energy - EmPOWER Maryland 2015-2017 Cost-Effectiveness Framework[[61]](#footnote-61) | December 2013 | Maryland Energy Administration |
| PECO T&D Avoided Cost Study[[62]](#footnote-62) | November 2014 | Navigant |

**Energy and Environmental Economics Study (October, 2004)**

Energy and Environmental Economics’ (E3) approach to calculating electric T&D avoided costs is illustrated in Figure 2‑9. Overall, E3 used a four-step method to develop the T&D avoided costs:

1. Estimate the annual electric marginal T&D costs by planning area for Pacific Gas and Electric (PG&E), Southern California Edison (SCE), and San Diego Gas and Electric (SDG&E) in $/kW/year using the present worth method.
2. Develop 20-year forecasts of annual avoided T&D costs by planning area and climate zone for each utility. Costs past the utility T&D planning horizons are escalated at the rate of inflation.
3. Allocate electric T&D costs to peak hours of the year by climate zone and utility using the time dependent valuation methodology.
4. Gross up the electric T&D costs by utility-specific demand loss factors (based on the voltage level of the DSM measure).

Figure 2‑9: E3’s Electric T&D Avoided Costs Methodology



**Manitoba Hydro Study (April, 2005)**

The Manitoba Hydro study explored the concept of calculating the T&D avoided costs achieved due to a one year deferral of T&D investment. Below is an excerpt detailing this approach.

*“The method to be presented below may be viewed as a probability-based one. In this method, the deferral time is restricted to one year, while the size of load reduction can be anywhere between 0 and one year’s worth of load growth. The restriction on the deferral time is consistent with the planning practice that T&D capital investments are planned to meet the forecasted annual peak load.*

*Let us start with an example. Suppose the capacity of a substation is 40 MWA[[63]](#footnote-63), the power factor is 1.0, and the expected peak loads of the station are 38.5 MW and 41.2 MW for 2010/11 and 2011/12, respectively. The expected load growth in 2011/12 at this station is 2.7 MW. The existing station capacity can meet the 2010/11 peak load but cannot meet the 2011/12 one. The shortage or scarcity of capacity for 2011/12 is 1.2 MW, as shown in Fig. 1. Based on the above information, a new transformer has been planned for service in 2011/12. Now, a reduction of 1.5 MW in the peak load, for instance, is expected for 2011/12. Considering that the load reduction of 1.5 MW exceeds the capacity shortage of 1.2 MW for 2011/12, we can defer the installation of the new transformer from 2011/12 to 2012/13. This suggests that the load reduction needs not to reach at least one year’s worth of load growth of 2.7 MW in order to cause a capital deferral!”[[64]](#footnote-64)*

**ICF Study (December, 2005)**

The methodology employed in the study by ICF Consulting (ICF) closely resembles that of the Synapse study discussed below (it was, in fact, emulated by the 2011 and 2013 Synapse studies). To calculate T&D avoided costs, ICF employed a spreadsheet model with four distinct sheets:

1. A sheet cataloging investments in T&D systems over a period of years.
2. A sheet calculating the annual carrying charge of those investments based on 118 assumptions on taxes, financing costs, operational expenses, and other recurring costs.
3. A sheet cataloging peak demand growth over the same period of years.
4. A summary sheet detailing the T&D avoided capacity costs resulting from the analysis.

**Synapse Study (February, 2011)**

The 2011 Synapse study discussed a common method for estimating T&D avoided costs known as projected embedded analysis, in which utilities use long-term historical trends (more than 10 years) and sometimes planned T&D costs to estimate future avoided T&D costs. This approach often looks at load-related investments (as opposed to customer related) and estimates system-wide (e.g., utility service territory) average avoided T&D costs. It has been mainly applied to the evaluation of the benefits of EE programs. This approach does require historical and forecast peak load information as well as historical and forecast information on T&D expenditures. This approach is relatively inexpensive and less time consuming than the system planning approach as it does not require an engineering study of the electric system nor does it require obtaining site specific load and investment data. As a weak point however, it does not provide an accurate picture of avoided costs for specific T&D projects. It fails to capture the highest value projects that might be deferred by the installation of distributed generation/combined heat and power systems (DG/CHP). Still, an average value estimated using the projected embedded analysis does provide an indicator of T&D avoided costs sufficient for evaluating DG/CHP for an energy-future scenario that assumes a significant amount of DG/CHP deployment statewide. The value would provide a rough estimate of long-term T&D avoided cost values for DG/CHP projects that could reliably operate to support the grid system.

**Synapse Study (July, 2011)**

The July 2011 Synapse study provided a critique of the methodology employed in a Black and Veatch (B&V) T&D avoided cost study:

*“The basic method in the ICF model, the ICF report for CL&P* [Connecticut Light and Power Company]*, and most other avoided T&D estimates is to divide actual or expected investment by actual or expected load growth. The B&V report for UI* [United Illuminating] *uses a different approach, dividing the cost of each investment by the full capacity it could accommodate. Since T&D investments may be required by even small increases in load above the capacity of existing equipment, the B&V approach may not accurately reflect the savings from reducing load growth. Since avoidable T&D costs are estimated as the ratio of actual or expected investment to actual or expected load growth, the costs used in the analysis are those not actually avoided. Analysts do not generally have estimates of costs that have actually been (or are expected to be) avoided by energy-efficiency; such analysis would usually be prohibitively expensive.*

*Any single investment is unlikely to increase delivery capability all the way from the generators to the customer meter. Adding line transformers allows customers to draw more power from the primary distribution system; reconfiguring existing primary feeders maximizes the amount of regional available substation capacity that can be delivered to the line transformers, and so on. Depending on the amount of excess capacity on the various levels of T&D equipment in a particular area, reducing load by any particular customer may avoid addition of a line transformer the next year, and contribute to delaying or avoiding the reconfiguration of feeders, the upgrading of a substation, and the construction of transmission lines in following years. At another location, load reductions may have little effect on T&D investment for many years. The basic approach to avoided cost estimates this complex relationship by computing the average ratio of all load-related investments to all load growth, rather than just the load growth that has the greatest effect on investment.”[[65]](#footnote-65)*

**Synapse (July, 2013)**

The 2013 Synapse study reviewed a different approach employed by Black & Veatch to estimate T&D avoided costs for United Illuminating (UI), an investor-owned utility in Connecticut. A summary of the B&V methodology is presented below:

1. Identification of historical and future T&D capacity additions which could have been fully or partially avoided with additional EE programs.
2. Collection of historical costs plus the allowance for funds used during construction (AFUDC) associated with projects identified in the first step. Calculated project costs are then divided by each project’s incremental MW load carrying capacity to derive a marginal capital cost for T&D capacity per MW.
3. Calculation of marginal operation and maintenance expenses.
4. Converting marginal capital costs to annual costs ($ per kW/year) adjusting for revenue requirements based on accounting inputs.
5. Calculation of EE savings based on historical and projected load growth.
6. Calculations of annual avoided cost based on annual costs and identified EE savings.

However, Synapse argues that “most demand-response and load-management programs will not avoid T&D costs, since they are as likely to shift local loads to new hours as to reduce local peak load.” [[66]](#footnote-66)

**Maryland (April 2014)**

The 2014 EmPower Maryland Cost-Effectiveness Framework employs a methodology comparable to the aforementioned studies – avoidable T&D costs are estimated by evaluating the incremental T&D investment that occurs over a period of time in the future that can be attributed to load growth, divided by the peak load growth in the forecast period.

### SWE Team Recommendation for Calculation Methodology for Transmission and Distribution Avoided Costs

Based on their review of recent T&D avoided cost studies, the SWE Team developed a pragmatic, common method for estimating future avoided T&D costs for each EDC. This approach is based upon the methodologies in the studies discussed above. The approach for this study used the following steps to develop the forecast of annual T&D avoided costs for the 2014 to 2018 time period:

1. First, the SWE Team gathered information on the electric peak load forecast for each EDC.
2. Second, the SWE Team requested from each EDC a forecast of annual load-related capital expenditures for new T&D investment for the next five years (2014 to 2018) and ten years (2014 to 2023). For purposes of this DR study, only load-growth related T&D investment (as opposed to customer related) is considered for the development of the forecast of avoidable T&D costs.[[67]](#footnote-67)
3. Then, for each year from 2014 to 2018, the annual forecast of T&D expenditures for each EDC was divided by the change in the system peak load forecast to arrive at the T&D avoided costs per kW.
4. Then, the SWE Team calculated the average T&D avoided costs per kW for the five year period (2014 to 2018).
5. Then, the SWE Team used a capital cost recovery factor to convert the average avoided T&D investment cost for 2014 to 2018 to be on a $ per kW/year basis by applying a capital cost recovery factor. The average value for the 2014 to 2018 time period represents the value used for the starting year of our DR analysis, 2016.
6. The starting value for the T&D avoided cost per kW/year in 2016 was then escalated at the general rate of inflation for all years after 2016.

This approach is relatively inexpensive and less time consuming than other approaches as it does not require an engineering study of the electric system nor does it require obtaining site specific load and investment data. The SWE Team recommends that this approach be used as the basis for developing forecasts of T&D avoided costs for use in TRC test calculations for Act 129 cost-effectiveness screening.

As a weak point, it does not provide an accurate picture of avoided costs for specific T&D projects. It fails to capture the highest value projects that DR programs might defer. Still, an average value estimated using the projected embedded analysis does provide an indicator of T&D avoided costs sufficient for evaluating DR resources for an energy future scenario that assumes a significant amount of DR deployment statewide.

### SWE Team T&D Avoided Costs for Each Pennsylvania EDC

The SWE Team developed T&D avoided costs per kW/year for each EDC using the methodology described in Section 2.7.2. Table 2‑13below provides the forecast of the average T&D avoided costs for the 2014 to 2018 time period for each EDC included in this DR study.

Table 2‑13: Forecast of Average T&D Avoided Costs ($per kW/Year) by EDC

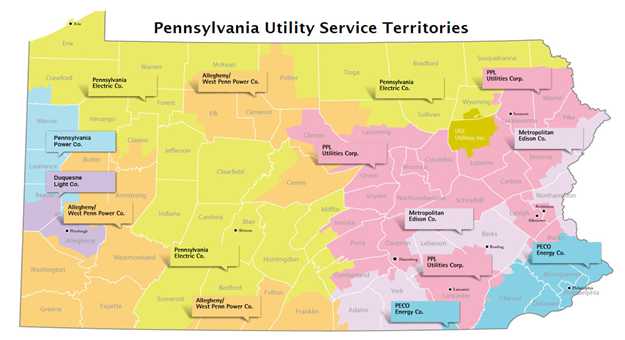
|  |  |  |
| --- | --- | --- |
| EDC | Average T&D Avoided Cost per kW/year for 2016 | Average Transmission Only Avoided Cost per kW/year for 2016 |
| Duquesne | $40.88 | $40.88 |
| FE: Met-Ed | $40.98 | $14.77 |
| FE: Penelec | $40.98 | $14.77 |
| FE: Penn Power | $40.98 | $14.77 |
| FE: West Penn | $40.98 | $14.77 |
| PECO | $49.27 | $3.88 |
| PPL | $20.10 | $0.00 |

The average T&D avoided costs per kW-Year for the 2014 to 2016 time period range from a low of $20.10 for PPL to a high of $49.27 for PECO.

# Characterization of Pennsylvania Service Areas & Phase I/II Program Offerings

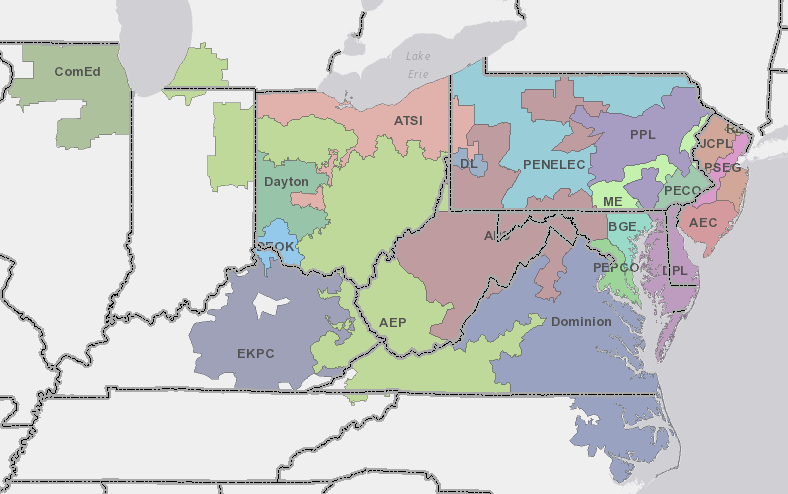
## EDC Areas

Figure 3‑1 provides a map of the service territories for each of the EDCs in Pennsylvania. There is significant diversity with regards to size and population density across the EDCs that must be accounted for in an assessment of potential.

Figure 3‑1: Pennsylvania EDC Service Territories

The costs and benefits of DR programs are heavily intertwined with RTO operations as PJM’s forward capacity markets set the cost of the products being avoided. Figure 3‑2 is a map of the zones within the PJM footprint. One or more zones in PJM make up a Locational Delivery Area (LDA). The PJM LDAs covered in this study include Eastern Mid-Atlantic Area Council Region (EMAAC), Mid-Atlantic Area Council Region (MAAC), American Transmission Systems, Incorporated (ATSI), and Allegheny Power Transmission System (APS). The portion of the EMAAC residing in the state consists of PECO zones. The MAAC area includes Met-Ed, PPL, and Penelec zones. The ATSI LDA is located primarily in Ohio, but also includes the Penn Power service territory. The RTO LDA includes Duquesne and APS zones. The APS zone is comprised of West Penn, as well as portions of West Virginia, Maryland, and Virginia, while the Duquesne zone is solely the Duquesne service territory.

Figure 3‑2: Map of PJM Zones



## Historical Load & Statewide Load Forecast

### 2012 Historical Load

At the beginning of the study, the SWE Team requested energy sales and forecast data from each EDC. We classified the customer account information, where provided, into commercial segments for further analysis. Table 3‑1 provides the 2012 sector-specific breakdown of summer peak load for each EDC.

Table 3‑1: Sector-level Contribution to Summer Peak Load (MW) for each EDC in 2012

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| EDC | Residential | Commercial | Industrial | Total |
| Duquesne | 1,206 | 1,281 | 435 | 2,922 |
| FE: Met-Ed | 1,257 | 890 | 660 | 2,807 |
| FE: Penelec | 944 | 871 | 712 | 2,527 |
| FE: Penn Power | 452 | 289 | 205 | 946 |
| FE: West Penn | 1,626 | 1,117 | 1,014 | 3,757 |
| PECO | 3,793 | 4,333 | 562 | 8,688 |
| PPL | 3,005 | 2,060 | 1,175 | 6,240 |
| Statewide | **12,283** | **10,841** | **4,763** | **27,887** |

### Statewide Load Forecast

Forecasts of total summer peak load consumption in Pennsylvania show a slow growth between the years 2015 and 2025. This indicates projected annual growth rate in summer peak load is 0.54% per year. The peak load forecasts produced by PJM are at the EDC level and do not distinguish between customer classes. The SWE Team performed an historical analysis of peak load shares by customer class and held these shares constant over time to estimate the contribution of each sector and segment to the summer peak load forecast over the study horizon. Figure 3‑3 shows the statewide summer peak load forecast by sector from 2016 to 2025.

Figure 3‑3: Pennsylvania Summer Peak Load Forecast by Sector

## Phase I Program Data Review

In Phase I of Act 129, the Commission directed the EDCs to implement demand reduction programs during the summer of 2012. The legislated peak demand reduction target was a 4.5% reduction, with the peak period defined as the 100 hours with greatest demand during the summer of 2012. [[68]](#footnote-68) The 4.5% demand reduction target included both coincident demand reductions from EE measures and reductions from DR programs.

### DR Program Savings

The peak demand reduction totals achieved by each EDC during the Top 100 hour Phase I performance period are presented in Table 3‑2. Forty six percent of the Phase I demand reductions were attributable to DR programs active during the summer of 2012.

Table 3‑2: Phase I Demand Reductions by EDC

| **EDC** | **DR Program Savings (MW)** | **EE Program Savings (MW)** | **Total Demand Savings (MW)** | **% Demand Reduction from DR** |
| --- | --- | --- | --- | --- |
| Duquesne | 74.43 | 64.13 | 138.56 | 54% |
| FE: Met-Ed | 59.89 | 65.13 | 125.02 | 48% |
| FE: Penelec | 60.31 | 53.63 | 113.94 | 53% |
| FE: Penn Power | 28.16 | 18.04 | 46.20 | 61% |
| FE: West Penn | 98.76 | 87.31 | 186.07 | 53% |
| PECO | 161.80 | 240.30 | 402.10 | 40% |
| PPL | 136.43 | 204.50 | 340.93 | 40% |
| **Total** | **619.78** | **733.04** | **1,352.82** | **46%** |

Using the performance of Phase I C&I load curtailment programs to inform potential for Phase III was challenging for several reasons. Demand response participants had the ability to enroll in both Act 129 programs, as well as PJM programs and this dual enrollment option created questions of attribution. The Phase I SWE Team developed and implemented an approach for discounting Act 129 impacts from customers enrolled in both markets. Phase I DR programs also allowed customers to use backup generators to reduce the amount of load supplied by the EDC. Commission staff requested that the SWE Team exclude this environmentally questionable source of DR as potential for Phase III. Lastly, the number of hours Act 129 programs dispatched participants during Phase I was far greater than the program design being evaluated for Phase III.

### Program Cost-Effectiveness

Phase I program costs included equipment and installation costs, program administrative costs, marketing costs, evaluation costs, and incentives paid to participants. Two broad categories of programs were offered by EDCs in Phase I: passive DLC programs and active load curtailment programs. The DLC programs install thermostats or A/C switches that can be operated remotely by the utility, thus giving the utility direct control over the HVAC systems of passive participants. The load curtailment programs were based on active participants that managed load reductions at their facilities during DR events. A breakdown of Phase I TRC ratios is presented below in Table 3‑3.

Table 3‑3: Act 129 DR Program TRC Ratios – Phase I

|  |  |  |
| --- | --- | --- |
| **Phase I TRC Ratio / Program Type** | | |
| **EDC** | **DLC** | **Load Curtailment** |
| Duquesne | 0.1 | 0.24 |
| FE: Met-Ed | 0.58 | 0.78 |
| FE: Penelec | 0.36 | 0.81 |
| FE: Penn Power | 0.82 | 0.79 |
| FE: West Penn | N/A | 0.99 |
| PECO | 0.17 | 0.31 |
| PPL | 0.08 | 0.49 |

The values in Table 3‑3 are based on Act 129 annual reports filed by the EDCs. The Phase I SWE Team noted in the DR study[[69]](#footnote-69) that avoided capacity costs exhibited geographic variation. Capacity prices for the western zones were much lower than in the eastern zones. Low capacity prices impacted the TRC ratios of Duquesne’s DR programs in particular. As shown in Table 2‑4, the geographic variation in generation capacity prices observed in Phase I have largely disappeared for Phase III. The Top 100 hours performance definition in Phase I also played a large role in the low TRC ratios observed in Phase I load curtailment programs because EDCs had to compensate participants generously to curtail load for such a large number of events. For DLC programs, the one-year effective useful life of load control equipment was a key driver of the low TRC ratios shown in Table 3‑3.

### Residential Load Control Performance

This section of the report provides detailed information on the costs and performance for the EDC DLC programs implemented during Phase I of Act 129. The SWE Team used the results of the Phase I residential DR programs where appropriate in the development of the projections of program costs and peak load reductions for potential Phase III residential DR programs.

**Duquesne Phase I Residential DR Program**

During Phase I of Act 129, Duquesne implemented a residential load control program for central A/C systems called Watt Choices. During 2012, the SWE Team estimates that 320,168 (61%) of Duquesne’s residential customers with central A/C systems were eligible for this DR program, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study for the Duquesne service area and the total number of Duquesne residential customers in 2012. The 1,474 Duquesne residential customers with central A/C systems, who participated in this program, represented a 0.46% participation rate.[[70]](#footnote-70) The Duquesne Phase I Watt Choices program used A/C cycling strategies of 50%[[71]](#footnote-71), which means central A/C units were cycled off 50% of each hour (during DR events).

In Phase I of the program, the central A/C units of Duquesne’s participating residential customers were controlled by a company-owned cycling switch[[72]](#footnote-72). Duquesne marketed this program via a company website[[73]](#footnote-73) and two service line inserts (bill inserts offering an average bill credit of $36.60 during the summer of 2012 for participating residential customers). A total of $1.1 million was spent on this program during Phase I.[[74]](#footnote-74) The overall program had a TRC benefit/cost ratio of 0.1 according to the Duquesne Final Phase I Annual Report and a total kW reduction of 465 kW[[75]](#footnote-75), with an average reduction of 0.845 kW[[76]](#footnote-76) per A/C unit. Duquesne’s benefit/cost analysis for the Phase I program assumed average T&D line losses of 6.9%.[[77]](#footnote-77) Key program data are provided in Table 3‑4.

Table 3‑4: Key Characteristics of Duquesne’s Phase I Residential A/C Cycling Program

| Description of Characteristic | Duquesne Data | Data Source |
| --- | --- | --- |
| 2012 number of residential customers | 524,865 | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 21 |
| Percent of residential customers with central A/C systems (2012 End Use and Saturation Study) | 61% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 7 |
| Homes with central A/C in 2012 (Eligible Market) | 320,168 | 61% of 524,865 residential customers |
| Phase I participants in A/C cycling program | 1,474 | Duquesne response to 6/12/2014 SWE DR Study Data Request, Request #2 |
| Program participation rate (participation as a percent of the eligible market) | 0.45% | 1,474 participants /320,168 residential customers with central A/C |
| Cycling strategies Used (50%, 75%, 100%, etc.) | 50% | Duquesne response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | 12 events | <https://www.duquesnelight.com/WattChoices/files/EECPlan_20100915.pdf> page 56 |
| Maximum duration (in hours) for each cycling event – summer 2012 | 4 hours | <https://www.duquesnelight.com/WattChoices/files/EECPlan_20100915.pdf> page 56 |
| Type of central computer | To be provided | <https://www.duquesnelight.com/WattChoices/default.cfm> |
| Type of load control switch utilized | Digital Control Unit | Duquesne Light Act 129 Phase I report to the Pennsylvania PUC, page 75. |
| Average kW load reduction per unit in Phase I | 0.845 kW | Duquesne response to 6/12/2014 SWE DR Study Data Request, Request #18 |
| Incentive amount per participant | $36.60 | Duquesne Final Phase I Annual Report, page 75 |
| Total program expenditures – Program Year 4 | $1.1 million | Duquesne Final Phase I Annual Report, page 77 |
| EDC reported kW savings for all participants – summer 2012 | 465 kW | Duquesne Final Phase I Annual Report, page 75 |
| T&D line losses percentage used in TRC test for PY4 | 6.9% | Duquesne Final Phase I Annual Report, page 26 |
| EDC Reported TRC Test Ratio for PY 4 | 0.1 | Duquesne Final Phase I Annual Report, page 26 |
| EDC reported kW savings as a percent of 2012 summer total peak load for EDC | .02% | Duquesne response to SWE 6/12/2014 DR Study Data Request, Request #10 (465 kW divided by 3,051,000 kW) |
| Marketing methods used by Duquesne for residential DR program | Two bill inserts | Duquesne response to SWE Supplemental DR Study Data Request to Pennsylvania EDCs, Request #7a |
| T&D avoided costs used in the Duquesne Phase I benefit/cost analysis | $0 per kW-year | Duquesne Phase I Final Report, supporting work papers |

**Metropolitan Edison Phase I Residential DR Program**

Met-Ed implemented a residential DLC program for central A/C systems during Phase I of Act 129. The SWE Team estimates that 301,517 (62%) of Med-Ed’s residential customers had central A/C systems, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study and the total number of residential customers in 2012. A total of 16,032 of its 301,517 residential customers with central A/C systems participated in this program, resulting in a 5.3% participation rate.[[78]](#footnote-78) The program used a variety of A/C cycling strategies depending on participants’ choices and the system needs at the time of the events.[[79]](#footnote-79)

In Phase I of the program, the central A/C units of Met-Ed’s participating residential customers were controlled by a load control switch. To market this program, the company employed door-to-door marketing.[[80]](#footnote-80) Met-Ed offered an average of $39.70 in bill credits during the summer of 2012 for residential customers that participated in the program.[[81]](#footnote-81) The company spent a total of $1,544,000 on this program during Phase I[[82]](#footnote-82), which had a TRC benefit/cost ratio of 0.58 according to the Met-Ed Final Phase I Annual Report. Met-Ed reported a total kW reduction of 8,690 kW and an average per unit savings of 0.44 kW per unit.[[83]](#footnote-83) Average T&D line losses during peak load hours of 16.6%[[84]](#footnote-84) were assumed.

Table 3‑5 below highlights key aspects of the program.

Table 3‑5: Key Characteristics of Met Ed’s Phase I Residential A/C Cycling Program - 2012

| Description of Characteristic | Met Ed Data | Data Source |
| --- | --- | --- |
| Number of residential customers | 486,318 | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study (Page 21) |
| Percent of residential customers with central A/C systems (2012 End Use and Saturation Study) | 62% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study (Page 7) |
| Homes with central A/C in 2012 (Eligible Market) | 301,517 | 62% of 486,318 residential customers |
| Phase I participants in A/C cycling program | 16,032 | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Program participation rate (participation as a percent of the eligible market) | 5.3% | 16,032/301,517 |
| Cycling strategies Used | Adjusted depending on the need of the event | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | No Maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum duration (in hours) for each cycling event – summer 2012 | No Maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Type of central computer | To be provided | <https://www.fes.com/content/fes/home/residential/offers.html> |
| Type of load control switch utilized | DLC | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Average kW load reduction per unit | 0.44 kW | FE PA EDC Response to SWE Supplemental Data Request, request #6 |
| Incentive amount per participant | $39.70 | Met Ed Final Phase I Annual Report, page 38 |
| Total program expenditures – Program Year 4 | $1,544,000 | Met Ed Final Phase I Annual Report, page 38 |
| EDC reported kW savings for all participants – summer 2012 (generation level) | 8,690 kW | Met Ed Final Phase I Annual Report, page 36 |
| T&D line losses percentage used in TRC test for PY4 | 16.6% | Met Ed Final Phase I Annual Report, page 11 |
| EDC Reported TRC Test Ratio for Program Year 4 | 0.58 | Met Ed Final Phase I Annual Report, page 40 |
| Marketing methods used by FE | Door to door sales | FE PA EDC Response to SWE Supplemental Data Request, request #7 |
| T&D avoided costs used in the Phase I benefit/cost analysis | $0 per kW-year | Met Ed Phase I Final Report, supporting work papers |

**Pennsylvania Electric Company Phase I Residential DR Program**

In compliance with Phase I of Act 129, Penelec implemented a residential DLC program for central A/C systems. During 2012, the SWE Team estimates that Penelec had 166,469 (33%) residential customers with central A/C systems, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study and Penelec’s 2012 reported residential customer count. Nearly 11,000 (10,844) of Penelec’s 166,469 residential customers with central A/C systems participated in this program, resulting in a 6.5% participation rate.[[85]](#footnote-85) The program used a variety of A/C cycling strategies depending on the control duration choices made by the program participants and the system needs during the event.[[86]](#footnote-86)

Table 3‑6 below highlights key aspects of the Penelec Phase I residential DR program.

Table 3‑6: Key Characteristics of Penelec’s Phase I Residential A/C Cycling Program - 2012

| Description of Characteristic | Penn Electric Data | Data Source |
| --- | --- | --- |
| Number of residential customers | 504,450 | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study (Page 21) |
| Percent of residential customers with central A/C systems (2012 End Use and Saturation Study) | 33% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study (Page 7) |
| Homes with central A/C in 2012 (Eligible Market) | 166,469 | 33% of 504,450 residential customers |
| Phase I participants | 10,844 | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Program participation rate (participation as a percent of the eligible market) | 6.5% | 10,844/166,469 |
| Cycling strategies Used (50%, 75%, 100%, etc.) | Varied depending on participant choice and system need during event | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | No Maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum duration (in hours) for each cycling event – summer 2012 | No Maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Type of central computer | To be provided | <https://www.fes.com/content/fes/home/residential/offers.html> |
| Type of load control switch utilized | DLC | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Average kW load reduction per unit in Phase I | 0.44 kW | FE PA EDC Response to SWE Supplemental Data Request, request #6 |
| Incentive amount per participant | $19.50 | Penn Electric Final Phase I Annual Report, page 37 |
| Total program expenditures – Program Year 4 | $1,239,000 | Penn Electric Final Phase I Annual Report, page 37 |
| EDC reported kW savings for all participants – summer 2012 | 5,350 kW | Penn Electric Final Phase I Annual Report, page 36 |
| T&D line losses percentage used in TRC test for PY4 | 21.2% | Penn Electric Final Phase I Annual Report, page 11 |
| EDC Reported TRC Test Ratio for PY 4 | 0.36 | Penn Electric Final Phase I Annual Report, page 37 |
| Marketing methods used by FE | Bill inserts, on bill messages, direct mail, telemarketing | FE PA EDC Response to SWE Supplemental Data Request, request #7 |
| T&D avoided costs used in the Phase I benefit/cost analysis | $0 per kW-year | Penelec Phase I Final Report, supporting work papers |

**Pennsylvania Power Company Phase I Residential DR Program**

During Phase I of Act 129, Penn Power implemented a residential DLC program for central A/C systems. For 2012, the SWE Team estimates that 96,738 (69%) of Penn Power’s residential customers had central A/C systems, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study for the Penn Power service area and the total number of residential customers in 2012. Of Penn Power’s residential customers with central A/C systems, 2,806 participated in this program, resulting in a 2.9% participation rate.[[87]](#footnote-87) The program used a variety of A/C cycling strategies depending on the levels of load control selected by participants and the system needs at the time of the events.[[88]](#footnote-88)

In Phase I of the program, the central A/C units of Penn Power’s participating residential customers were controlled by a switch. To market this program, Penn Power provided information to customers using bill inserts, messages printed on bills, direct mail, and telemarketing.[[89]](#footnote-89) Penn Power offered an average of $19.15 in bill credits during the summer of 2012 for participating customers.[[90]](#footnote-90) The company spent a total of $97,000 on this program during Phase I[[91]](#footnote-91) and had a TRC benefit/cost ratio of 0.82 (FE Final Phase I Annual Report). Penn Power reported a total kW reduction of 930 kW and average per unit savings of 0.39 kW per unit.[[92]](#footnote-92) Penn Power’s benefit/cost analysis assumed average T&D line losses of 14.2%.[[93]](#footnote-93) Table 3‑7 below highlights key aspects of the program.

Table 3‑7: Key Characteristics of Penn Power Phase I Residential A/C Cycling Program - 2012

| Description of Characteristic | PP Data | Data Source |
| --- | --- | --- |
| Number of residential customers | 140,200 | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 21 |
| Percent of residential customers with central A/C systems (2012 End Use and Saturation Study) | 69% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 7 |
| Homes with central A/C in 2012 (Eligible Market) | 96,738 | 69% of 140,200 residential customers |
| Phase I participants in A/C cycling program | 2,806 | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Program participation rate (participation as a percent of the eligible market) | 2.9% | 2,806/96,738 |
| Cycling strategies Used | Varied depending on the need at the time of the events | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | No maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum duration (in hours) for each cycling event – summer 2012 | No maximum | FE response to 6/12/2014 DR Study Data Request, Request #9 |
| Type of central computer | To be provided | <https://www.fes.com/content/fes/home/residential/offers.html> |
| Type of load control switch utilized | DLC | FE response to 6/12/2014 DR Study Data Request, Request #2 |
| Average kW load reduction per unit in Phase I | 0.39 kW | FE PA EDC Response to SWE Supplemental Data Request, request #6 |
| Incentive amount per participant | $19.15 | Penn Power Final Phase I Annual Report, page 35 |
| Total program expenditures – Program Year 4 | $97,000 | Penn Power Final Phase I Annual Report, page 35 |
| EDC reported kW savings for all participants – summer 2012 | 930 kW | Penn Power Final Phase I Annual Report, page 34 |
| T&D line losses percentage used in TRC test for Program Year 4 | 14.2% | Penn Power Final Phase I Annual Report, page 11 |
| EDC Reported TRC Test Ratio for PY 4 | .82 | Penn Power Final Phase I Annual Report, page 35 |
| Marketing methods used by FE | Bill inserts, on bill messages, direct mail, telemarketing | FE PA EDC Response to SWE Supplemental Data Request, request #7 |
| T&D avoided costs used in the Phase I benefit/cost analysis | $0 per kW-year | Penn Power Phase I Final Report, supporting work papers |

**West Penn Power Company Phase I Residential DR Program**

West Penn did not implement any residential DLC program during Phase I of Act 129.

**PECO Energy Company Phase I Residential DR Program**

PECO implemented a residential load control program for central A/C systems, the “Smart AC Saver” program, during Phase I of Act 129. During 2012, SWE Team estimates that 847,924 (60%) of PECO’s residential customers had central A/C systems, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study for the PECO service area. A reported 97,000 of PECO’s 847,924 residential customers with central A/C systems participated in this program, an 11.44% participation rate.[[94]](#footnote-94) The PECO Phase I Smart AC Saver program used an A/C cycling strategy of 50%.[[95]](#footnote-95) This means that central A/C units were cycled off 50% of each hour during DR events.

During the Phase I program, the central A/C units of PECO’s participating residential customers were controlled by a company-owned cycling switch. To market this program to residential customers, PECO provided information through direct mail campaigns, television and online ads, and referral programs.[[96]](#footnote-96) PECO offered a $30 bill credit each month for the four summer months of 2012 for residential customers that participated in the program[[97]](#footnote-97) and spent a total of $15.3 million on this program during Phase I.[[98]](#footnote-98) The Phase I program had a TRC benefit/cost ratio of 0.17 according to the PECO Final Annual Report for Phase I (PY 4). PECO reported a total kW reduction of 51,300 kW and average per unit savings of 0.7 kW per unit.[[99]](#footnote-99) PECO’s benefit/cost analysis for the Phase I program assumed average T&D line losses of 19.16%.[[100]](#footnote-100) Key program statistics for PECO’s Phase I DR program are provided in Table 3‑8 below.

Table 3‑8: Key Characteristics of PECO’s Phase I Residential A/C Cycling Program

| Description of Characteristic | PECO Data | Data Source |
| --- | --- | --- |
| PECO’s 2012 number of residential customers | 1,413,206 | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 21 |
| Percent of PECO residential customers with central A/C systems (2012 End Use and Saturation Study) | 60% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 7 |
| Homes in the PECO service area with central A/C in 2012 (Eligible Market) | 847,924 | 60% of 1,413,206 residential customers |
| Phase I participants in A/C cycling program | 97,000 | PECO response to 6/12/2014 DR Study Data Request, Request #2 |
| Program participation rate (participation as a percent of the eligible market) | 11.44% | 97,000 program participants divided by the eligible market of 847,924 residential customers with central A/C. |
| Cycling strategies Used (50%, 75%, 100%, etc.) | 50% | PECO response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | 10 | <https://www.peco.com/Savings/ProgramsandRebates/Residential/Pages/PECOSmartACSaver.aspx> |
| Maximum duration (in hours) for each cycling event – summer 2012 | 4 hours | <https://www.peco.com/Savings/ProgramsandRebates/Residential/Pages/PECOSmartACSaver.aspx> |
| Type of central computer | To be provided | <https://www.peco.com/Savings/ProgramsandRebates/Residential/Pages/PECOSmartACSaver.aspx> |
| Type of load control switch utilized | Digital control unit | PECO response to 6/12/2014 DR Study Data Request, Request #3 |
| Average kW load reduction per unit in Phase I | 0.7 kW | PECO response to 6/12/2014 DR Study Data Request, Request #9 |
| Incentive amount per participant | $30 per month for 4 months. $120 per year | PECO Final Annual Report PY4[[101]](#footnote-101), page 155 |
| Total program expenditures – Program Year 4 | $15,294,000 | PECO Final Annual Report PY4, page 158 |
| EDC reported kW savings for all participants – summer 2012 | 51,300 kW | PECO Final Annual Report PY4, page 151 |
| T&D line losses percentage used in TRC test for PY4 | 19.16% | PECO Final Annual Report PY4, page 149 |
| EDC Reported TRC Test Ratio for PY 4 | 0.17 | PECO Final Annual Report PY4, page 158 |
| EDC Reported kW savings as a percent of PECO 2012 summer total system peak load | 0.6 % | Summer 2012 weather normalized PECO peak load of 8,650 MW obtained from PJM web site. |
| Marketing methods used by PECO | Direct Mail Campaigns, TV and online ads, referral programs | PECO response to SWE Supplemental Data Response Data Request, Request #7a |
| T&D avoided costs used in the Phase I benefit/cost analysis | $0 per kW-year | PECO Final Annual Report PY4, supporting work papers |

**PPL Electric Utilities Corporation Phase I Residential DR Program**

PPL implemented a residential load control program for central A/C systems, the “Power Peak Saver” program, under Phase I of Act 129. During 2012, the SWE Team estimates that PPL had 625,171 residential customers with central A/C systems, based on the SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study for the PPL service area and the total number of PPL residential customers in 2012. In the summer of 2012, 51% of homes in the PPL service area had central A/C systems. Of PPL’s 625,175 residential customers with central A/C systems, 43,637 participated in this program, resulting in a 6.98% participation rate.[[102]](#footnote-102) The PPL Phase I Power Peak Saver program used A/C cycling strategies of 50%, 60%, 65%, 70%, and 100% as selected by the household[[103]](#footnote-103). This means that central A/C units were cycled off 50%, 60%, 65%, 70%, and 100% of each hour (during DR events), as chosen by the customer.

The A/C units in the homes of participating customers were controlled by a cycling switch installed and operated by ComVerge, Inc., and leased to PPL. To market this program to residential customers, PPL provided program information via a PPL website[[104]](#footnote-104) and also used direct mail. PPL offered a one-time $32 bill credit during the summer of 2012 for residential customers who participated and spent a total of $8.3 million on this program.[[105]](#footnote-105) The Phase I program had a TRC benefit/cost ratio of 0.08 according to the PPL Final Phase I Annual Report. PPL reported a total kW reduction of 16,430 kW and average per unit savings of 0.632 kW.[[106]](#footnote-106) PPL’s benefit/cost analysis for the Phase I program assumed average T&D line losses of 8.3%[[107]](#footnote-107). The residential customers most likely to participate in this Phase I program had a household income of more than $80,000 per year and were over the age of 55.[[108]](#footnote-108) Table 3‑9 below highlights key aspects of the program.

Table 3‑9: Key Characteristics of PPL’s Phase I Residential A/C Cycling Program

| Description of Characteristic | PPL Data | Data Source |
| --- | --- | --- |
| PPL’s 2012 number of residential customers | 1,225,825 | SWE 2012 Pennsylvania Statewide Residential Baseline Study Page 21 |
| Percent of PPL residential customers with central A/C systems (2012 End Use and Saturation Study) | 51% | SWE 2012 Pennsylvania Statewide Residential End Use and Saturation Study Page 7 |
| Homes with central A/C in 2012 (Eligible Market) | 625,171 | 51% of 1,225,825 residential customers |
| Phase I participants in A/C cycling program | 43,637 | PPL Phase I Report to the Pennsylvania PUC, page 126 |
| Program participation rate (participation as a percent of the eligible market) | 6.98% | 43,637/625,171 |
| Cycling strategies Used (50%, 75%, 100%, etc.) | 50%,60%,65%, 70%, and 100% | PPL response to 6/12/2014 DR Study Data Request, Request #9 |
| Maximum number of cycling events allowable per summer of 2012 | No maximum (21 were called in 2012) | <http://www.pennsylvaniapeaksaver.com/> |
| Maximum duration (in hours) for each cycling event – summer 2012 | 1 hour | <http://www.pennsylvaniapeaksaver.com/> |
| Type of central computer | To be provided | PPL response to 6/12/2014 DR Study Data Request, Request #3 |
| Type of load control switch utilized | Digital control unit | <http://www.pennsylvaniapeaksaver.com/> |
| Average kW load reduction per unit in Phase I | 0.632 kW | PPL response to 6/12/2014 DR Study Data Request, Request #18 |
| Incentive amount per participant | $32 during Phase I | <http://lancasteronline.com/business/ppl-will-pay-to-control-your-air-conditioner/article_89b9adbf-efd7-583d-bb31-df7e52aeed20.html> |
| Total program expenditures – Program Year 4 | $8.83 million | PPL Final Phase I Annual Report, page 133 |
| EDC reported kW savings for all residential customer participants – summer 2012 | 16,430 kW | PPL Final Phase I Annual Report, page 19 |
| T&D line losses percentage used in TRC test for PY4 | 8.3% | PPL Final Phase I Annual Report, page 3 |
| EDC Reported TRC Test Ratio for PY 4 | 0.08 | PPL Final Phase I Annual Report, page 133 |
| EDC reported residential DLC kW savings as a percent of 2012 summer total peak load for EDC | .2% | 16.43 MW for residential DLC program divided by summer 2012 peak load of 7,181 MW. See PPL Final Phase I Annual Report, page 132 and PJM data for PPL’s 2012 metered peak load (7,181 MW). |
| Marketing methods used by PPL | <http://www.pennsylvaniapeaksaver.com/>  also, direct mail adverts | <http://www.pennsylvaniapeaksaver.com/> |
| T&D avoided costs used in the Phase I benefit/cost analysis | $0 per kW-year | PPL Phase I Final Report, supporting work papers |

# Residential DR Potential

## Summary

Direct Load Control programs remotely manage residential customers’ end use demands by cycling off their electricity consuming equipment during control periods (typically at periods of electric peak demand). In exchange for an incentive payment, free equipment, or bill reduction customers allow EDCs to remotely reduce equipment runtime during peak hours. This analysis examined the cost-effectiveness and potential peak demand reduction savings for load control of residential central A/C systems, window A/C’s, electric water heaters, and swimming pool pumps for Phase III of Act 129 programs. The Base Scenario of our potential analysis was limited to load control of only central A/Cs while the Second Scenario included load control of all four types of electrical equipment. This study of the potential took into account the experience of the EDCs with DLC of central A/C systems during Phase I of Act 129, as well as actual program participation experience for similar load control programs conducted by electric utilities in the region and across the US. The SWE Team conducted an extensive literature search for costs, program participation, and peak load reduction information for residential DLC programs and also conducted phone interviews with many utilities to get up-to-date information on the performance of such programs.

## Methodology

### Participation Rates

Program participation and impacts (demand reductions) for residential customers were assumed to begin the summer of 2017. No program participants are assumed in 2016, due to the fact that Phase III begins on June 1, 2016. The time needed to specify and procure load control equipment or select a vendor for an outsourced program, market the program, recruit participants, and install and test the load control equipment is not sufficient to achieve program load reductions in the summer of 2016.

In order to maximize the benefits of residential load reduction, the installations of load control devices were assumed to have been completed only in 2016 and early in 2017 for the initiation of cycling the summer of 2017. For residential central A/C’s (base scenario), a maximum 12.5% penetration rate was assumed to determine potential peak load reduction savings. In other words, a participation rate of 12.5% of residential customers with central A/C’s was assumed, with all participants having had switches installed in 2016 through May 2017. The participation rate of 12.5% is assumed to be the maximum penetration rate and no further installations of new load control devices occur after that time. Under the second scenario, a 12.5% penetration rate was also assumed for all other load control equipment on electric water heaters, room A/C’s, and swimming pool pumps.

The 12.5% was derived from the actual participation rates for DLC programs of 20 utilities around the country. The average, long-term participation rate of these 20 utilities was 25%, so that number was halved to provide a conservative participation rate estimate and to reflect the short time period available for installation of equipment during Phase III of Act 129. It is important to note that PECO attained an 11.4% participation rate in their Phase I program for load control of residential central A/C systems. Some of the utility programs in the region included in this calculation of the average participation rate include Baltimore Gas and Electric (BG&E), Northern Virginia Electric Cooperative (NOVEC), Southern Maryland Electric Cooperative (SMECO), Met-Ed, Potomac Electric Power Company (PEPCO), PECO, Penelec, Penn Power and PPL. Listed below in Table 4‑1 is the data collected by the SWE Team on program participation rates for residential central A/C control programs by various electric utilities in the US. The SWE Team also asked the EDCs and their Evaluation Teams for any studies, reports, or other data they had on participation rates in residential DLC programs for other utilities outside of Pennsylvania, but the EDCs responded that they did not have any such studies, reports or other data.

Table 4‑1: Actual Participation Rates Achieved by Electric Utility Residential Central A/C Load Control Programs in the US

**(Sorted from Highest to Lowest)**

|  |  |  |
| --- | --- | --- |
| Utility | % of Eligible Residential Customers Participating Based on Data Obtained Directly from Utility | Year |
| SMECO | 60.2% | 2013 |
| Dakota Electric Association | 59.2% | 2013 |
| PEPCO | 53% | 2013 |
| SMECO | 50% | 2013 |
| BG&E | 38% | 2013 |
| DPL | 37% | 2013 |
| BG&E | 36.5% | 2013 |
| NOVEC | 36.2% | 2013 |
| Public Service Company of New Mexico | 25.4% | 2013 |
| Sacramento Municipal Utility District | 25.4% | 2013 |
| Connexus Energy | 21.5% | 2013 |
| DTE Electric Co. | 19.3% | 2013 |
| PECO | 10.80% | 2012 |
| Dairyland Power Cooperative | 7.1% | 2013 |
| PPL | 6% | 2012 |
| FE: Met-Ed | 5.20% | 2012 |
| Georgia Power | 4.2% | 2013 |
| FE: Penelec | 3.40% | 2012 |
| FE: Penn Power | 3.20% | 2012 |
| Duquesne | 0.45% | 2012 |
| Average Participation Rate | 25.1% |  |

Table 4‑2 through Table 4‑5 provide information on the size of eligible markets for Phase III residential DLC programs by EDC. For load control of residential central A/C, the size of the eligible market in 2016 (the first year of Phase III) was determined by multiplying the forecast of each EDCs number of 2016 residential customers by the saturation of the end use obtained from the 2014 SWE Residential Baseline Study. To obtain the number of potential program participants by the summer of 2017 for control of residential central A/C systems, the eligible market for each EDC was multiplied by 12.5%.

Table 4‑2: Eligible Markets for Phase III Residential DR Programs for EDCs – Central A/C

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| Name of EDC | Projected Total No. of EDC Residential Customers in 2016 | Percent of Residential Customers with Central A/C Systems from 2014 Baseline Study (%) | Eligible Market for Participation in Load Control Program for Residential Central A/C (No. of Residential Customers) | Actual Program Participation Rate Achieved During Phase I of Act 129 for Residential, Central A/C Control (%) | Forecast Program Participation Rate for Phase III | Total Number of Program Participants Forecast for a Phase III Residential Central A/C Control Program |
| Duquesne | 528,973 | 77% | 407,309 | 0.45% | 12.50% | 50,914 |
| FE: Met Ed | 492,237 | 61% | 300,265 | 5.3% | 12.50% | 37,533 |
| FE: Penelec | 505,353 | 38% | 192,034 | 6.5% | 12.50% | 24,004 |
| FE: Penn Power | 141,736 | 74% | 104,885 | 2.9% | 12.50% | 13,111 |
| FE: West Penn | 624,521 | 73% | 455,900 | 0.0% | 12.50% | 56,988 |
| PECO | 1,438,250 | 74% | 1,064,305 | 11.4% | 12.50% | 133,038 |
| PPL | 1,256,031 | 50% | 628,016 | 7.0% | 12.50% | 78,502 |
| Total | **4,987,101** | **63%** | **3,152,713** | **5.45%** | **12.50%** | **394,089** |

For the other end uses, the SWE Team assumed that load control switches would only be installed for those homes where the central A/C system was also controlled. This assumption was made because control of the central A/C unit provides the most peak load reduction and is the most cost-effective end use to control. The SWE Team determined that load control of residential end uses other than central A/C units was clearly not cost-effective. The size of the eligible market for control of electric water heaters, room A/C’s, and swimming pool pumps was determined by multiplying each EDCs 2016 number of residential customers by the saturation of central A/C and then multiplied by the percentage of that market (the number of customers with central A/C units) that had the end use to be controlled.

Table 4‑3: Eligible Markets for Phase III Residential DR Demand Response Programs for EDCs – Electric Water Heaters

| Name of EDC | Projected Total No. of EDC Residential Customers in 2016 | Percent of Residential Customers with Central A/C Systems from 2014 Baseline Study (%) | Percent of Customers with Central A/C having Electric Water Heaters (%) | Eligible Market for Participation in Load Control Program for Res. Central A/C & EWH (No. of Residential Customers) | Actual Program Participation Rate Achieved during Phase I of Act 129 for Residential Central A/C Control (%) | Forecast Program Participation Rate for Phase III | Total Number of Program Participants Forecast for a Phase III Residential EWH Control Program |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 528,973 | 77% | 8% | 30,996 | 0.45% | 12.50% | 3,875 |
| FE: Met Ed | 492,237 | 61% | 28% | 85,455 | 5.3% | 12.50% | 10,682 |
| FE: Penelec | 505,353 | 38% | 10% | 20,010 | 6.5% | 12.50% | 2,501 |
| FE: Penn Power | 141,736 | 74% | 36% | 37,821 | 2.9% | 12.50% | 4,728 |
| FE: West Penn | 624,521 | 73% | 35% | 160,978 | 0.0% | 12.50% | 20,122 |
| PECO | 1,438,250 | 74% | 20% | 209,136 | 11.4% | 12.50% | 26,142 |
| PPL | 1,256,031 | 50% | 30% | 185,453 | 7.0% | 12.50% | 23,182 |
| Total | **4,987,101** | **63%** | **-** | **729,849** | **5.45%** | **12.50%** | **91,231** |

Table 4‑4: Eligible Markets for Phase III Residential DR Programs for EDCs – Room A/C

| Name of EDC | Projected Total No. of EDC Residential Customers in 2016 | Percent of Residential Customers with Central A/C Systems from 2014 Baseline Study (%) | Percent of Customers with Central A/C having Room A/C’s (%) | Eligible Market for Participation in Load Control Program for Res. Central A/C & Room A/C (No. of Residential Customers) | Actual Program Participation Rate Achieved During Phase I of Act 129 for Central A/C Control | Forecast Program Participation Rate for Phase III | Total Number of Program Participants Forecast for a Phase III Residential Room A/C Control Program |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 528,973 | 77% | 4% | 16,292 | 0.45% | 12.50% | 2,037 |
| FE: Met Ed | 492,237 | 61% | 8% | 24,021 | 5.3% | 12.50% | 3,003 |
| FE: Penelec | 505,353 | 38% | 0% | - | 6.5% | 12.50% | - |
| FE: Penn Power | 141,736 | 74% | 8% | 8,391 | 2.9% | 12.50% | 1,049 |
| FE: West Penn | 624,521 | 73% | 9% | 41,031 | 0.0% | 12.50% | 5,129 |
| PECO | 1,438,250 | 74% | 1% | 10,643 | 11.4% | 12.50% | 1,330 |
| PPL | 1,256,031 | 50% | 5% | 31,401 | 7.0% | 12.50% | 3,925 |
| Total | **4,987,101** | **-** | **-** | **131,779** | **5.45%** | **12.50%** | **16,472** |

Table 4‑5: Eligible Markets for Phase III Residential DR Programs for EDCs – Swimming Pool Pumps

| Name of EDC | Projected Total No. of EDC Residential Customers in 2016 | Percent of Residential Customers with Central A/C Systems from 2014 Baseline Study (%) | Percent of Customers with Central A/C having Swimming Pool Pumps (%) | Eligible Market for Participation in Load Control Program for Res. Central A/C & Swimming Pool Pumps (No. of Residential Customers) | | Actual Program Participation Rate Achieved During Phase I of Act 129 for Central A/C Control | Forecast Program Participation Rate for Phase III | Total Number of Program Participants Forecast for a Phase III Residential Room A/C Control Program |
| --- | --- | --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 528,973 | 77% | 0% | | - | 0.45% | 12.50% | - |
| FE: Met Ed | 492,237 | 61% | 1% | | 3,003 | 5.3% | 12.50% | 375 |
| FE: Penelec | 505,353 | 38% | 0% | | - | 6.5% | 12.50% | - |
| FE: Penn Power | 141,736 | 74% | 2% | | 2,098 | 2.9% | 12.50% | 262 |
| FE: West Penn | 624,521 | 73% | 0% | | - | n/a | 12.50% | - |
| PECO | 1,438,250 | 74% | 0% | | - | 11.4% | 12.50% | - |
| PPL | 1,256,031 | 50% | 2% | | 12,560 | 7.0% | 12.50% | 1,570 |
| Total | **4,987,101** | **-** | **-** | | **17,661** | **5.45%** | **12.50%** | **2,208** |

### Useful Lives and Failure Rates of Load Control Devices

Load control device, or switch failure rates were assumed at 3% per year. This failure rate was obtained from PECO’s benefit/cost analysis for the Company’s A/C Smart Saver program that was included in PECO’s Phase II EE&C Plan filing. Following the methodology described above, this 3% replacement rate was applied for the years 2017 to 2020. The useful life of load control devices was assumed to be 10 years, in compliance with the PUC’s latest Demand Response Order.

### Load Control Events and Durations

A maximum of six load control events were assumed to occur each cycling season, June through September. The duration of each event was assumed to be four hours, yielding a maximum total cycling time of 24 hours per year. The limit of 24 hours of cycling time per year is in compliance with the PUC’s latest Demand Response Order and was developed by the SWE Team based upon the ELCC analysis discussed in Section 2.7.

### Peak Load Reductions per Unit Controlled

The peak load reduction per central A/C unit installed for each EDC was based on the impact evaluation results from each EDCs Phase I DLC program. The per unit peak load reduction for electric water heaters, room A/C’s, and swimming pool pumps were obtained from a literature search of such programs conducted by the SWE Team.

### Program Costs and Other Key Input Assumptions

For our analysis, expenditures on load control computer equipment and load control switches were expensed, not capitalized, as the cost-effectiveness analysis for Phase III assumes that all costs of Phase III DR programs need to be incurred and recovered during Phase III. The load control equipment (central computer, load control switches) purchased for the program were expensed in the year in which they were purchased and installed.

Incentives paid to consumers were assumed to be $40 per cycling season, which were paid out for the four summers during which cycling occurred (2017 to 2020). This incentive amount is based on a SWE Team review of typical incentive amounts paid by utilities to participants in residential central A/C cycling programs. Table 4‑6 below summarizes the key input assumptions for each EDC for the benefit/cost analysis of residential load control programs for Phase III.

Table 4‑6: Key Input Assumptions for Cost-Effectiveness and Potential Analysis for Phase III Residential DLC Programs

|  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- | --- |
|  | **Per Unit Peak kW Reduction**  **(at customer meter):** | | | |  |  |  |  |  |  |  |  |  |  |  |  |  |  |
|  | **Central A/C System** | **Electric Water Heater** | **Room A/C** | **Pool Pump** | **Forecast Program Participation Rate for Phase IIII** | **Cost of Load Control Switch (Equipment)** | **Installation Cost per Load Control Switch** | **Cost of Central Computer for Load Control** | **Useful Life of Load Control Equipment (years)** | **Maximum Annual Hours of Load Control** | **Annual $ Paid to Each Program Participant ($2016)** | **Annual Participant Cost  (per unit, $2016)** | **Annual Costs - Administration, Marketing, etc.** | **Annual Rate of Switch Failure** | **Avoided Cost of Generation Capacity ($2016)** | **Avoided Cost of Energy - on Peak ($2016 per MWH)** | **Avoided Cost of Energy - off Peak ($2016 per MWH)** | **Avoided Cost of T&D per kW-Year ($2016)** |
| Duquesne | 0.85 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $667,304 | 3% | $43.38 | $46.65 | $32.85 | $13.90 |
| FE: Met-Ed | 0.44 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $935,623 | 3% | $43.38 | $51.09 | $39.83 | $40.98 |
| FE: Penelec | 0.44 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $512,917 | 3% | $43.38 | $49.84 | $33.23 | $40.98 |
| FE: Penn Power | 0.39 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $299,029 | 3% | $41.69 | $51.25 | $31.81 | $40.98 |
| FE: West Penn | 0.42 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $1,258,133 | 3% | $24.67 | $48.99 | $38.44 | $40.98 |
| PECO | 0.70 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $2,017,632 | 3% | $43.38 | $51.56 | $37.10 | $49.27 |
| PPL | 0.63 | 0.25 | 0.45 | 1.36 | 12.50% | $109 | $91 | $25,000 | 10 | 24 | $40 | $30 | $1,018,816 | 3% | $43.38 | $51.01 | $30.49 | $20.10 |

### Budget Scenarios

For the next step, the SWE Team examined scenarios for the Phase III implementation of EE and DR programs at different budget levels. The SWE Team considered four hypothetical budget allocations of the 2% spending cap.[[109]](#footnote-109) (The cap is a percent of EDC annual electric revenues between EE and DR.) The annual budget available for DR under each scenario is presented in Table 4‑7.

Table 4‑7: Annual DR Budget for Program Potential Scenarios

| EDC | 100% EE, 0% DR | 90% EE, 10% DR | 85% EE, 15% DR | 80% EE, 20% DR |
| --- | --- | --- | --- | --- |
| Duquesne | $0 | $1,954,595 | $2,931,893 | $3,909,190 |
| FE: Met-Ed | $0 | $2,486,689 | $3,730,034 | $4,973,378 |
| FE: Penelec | $0 | $2,297,474 | $3,446,212 | $4,594,949 |
| FE: Penn Power | $0 | $665,978 | $998,968 | $1,331,957 |
| FE: West Penn | $0 | $2,356,247 | $3,534,370 | $4,712,494 |
| PECO | $0 | $8,539,516 | $12,809,274 | $17,079,032 |
| PPL | $0 | $6,150,138 | $9,225,206 | $12,300,275 |
| Statewide | **$0** | **$24,450,637** | **$36,675,956** | **$48,901,275** |

### Cost-Effectiveness

Cost-effectiveness of residential load control was determined based on screening with the TRC test. This TRC test was calculated according to the Commission’s latest TRC Test Order. All program costs were escalated each year by the general rate of inflation assumed for this study.[[110]](#footnote-110) Benefits modeled included avoided electric generation capacity, energy shifted to off-peak hours, and avoided T&D costs. A summary of the cost-effectiveness of a proposed residential DLC program limited to central A/Cs is shown in Table 4‑8.

Assuming a 12.5% market penetration, nearly 232 MW of peak load could be reduced statewide. However, this hypothetical program falls short of the cost-effectiveness hurdle for all EDCs, except PECO. The relatively large number of central A/C’s already having load control switches from PECO’s Phase I program were assumed to carry over to a Phase III program. Because these load control switches were purchased during Phase I of Act 129, there is no additional cost for these switches in Phase III. As a result, a DLC program for PECO for those program participants that already have load control switches on central A/C units increased the cost-effectiveness results to slightly positive (1.05) for Phase III.

Table 4‑8: Residential DLC Benefits and Costs – Central A/C Control Only

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| **EDC** | **Number of Program Participants** | **Average Annual Impact**  **(MW at Generation Level)** | **PV of Program Benefits** | **PV of Program Costs** | **NPV of Benefits - NPV of Costs** | **Lifetime TRC Ratio** |
| Duquesne | 40,268 | 36.75 | $26,890,047 | $35,098,670 | -$8,208,624 | 0.78 |
| FE: Met Ed | 38,025 | 18.03 | $22,718,313 | $35,075,330 | -$12,357,017 | 0.65 |
| FE: Penelec | 20,846 | 10.13 | $12,386,117 | $18,968,416 | -$6,582,299 | 0.65 |
| FE: Penn Power | 12,154 | 5.24 | $4,465,010 | $9,882,516 | -$5,417,506 | 0.45 |
| FE: West Penn | 51,133 | 23.71 | $30,301,372 | $47,164,543 | -$16,863,170 | 0.64 |
| PECO | 108,049 | 82.20 | $68,684,924 | $65,334,434 | $3,350,490 | 1.05 |
| PPL | 80,072 | 55.46 | $48,813,983 | $64,151,543 | -$15,337,560 | 0.76 |
| **Statewide** | **350,546** | **231.51** | **$214,259,766** | **$275,675,452** | **-$61,415,686** | **0.83** |

Adding additional end uses decreased, rather than improved, the cost-effectiveness of a potential residential DR program. Table 4‑9 below contains the cost-effectiveness of a residential direct control program for four end uses: central A/C’s, window A/C’s, electric water heaters, and swimming pool pumps. If residences had central A/C’s, the saturations of the other three end uses were applied to project the demand reduction impacts from a proposed load control program. As in the central A/C only scenario above, a 12.5% penetration rate was assumed for these three additional end uses. The results of the benefit/cost analysis for a Phase III load control program for all four end uses shows that this program would not be cost-effective according to screening with the TRC test. The overall statewide TRC ratio for such a program for Phase III is 0.64.

Table 4‑9: Residential DLC Benefits and Costs – Control of Central A/C, Electric Water Heaters, Room A/C, and Swimming Pool Pumps

| **EDC** | | **Number of Program Participants** | **Average Annual Impact**  **(MW at Generation Level)** | **PV of Program Benefits** | **PV of Program Costs** | **NPV of Benefits - NPV of Costs** | **Lifetime TRC Ratio** |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 45,986 | | 38.67 | $29,258,689 | $50,758,424 | -$21,499,735 | 0.58 |
| FE: Met Ed | 52,475 | | 22.62 | $29,582,690 | $47,927,900 | -$18,345,209 | 0.62 |
| FE: Penelec | 24,494 | | 10.77 | $14,223,266 | $22,289,070 | -$1,483,504 | 0.64 |
| FE: Penn Power | 16,431 | | 6.68 | $5,847,328 | $13,421,936 | -$2,157,102 | 0.44 |
| FE: West Penn | 70,307 | | 31.82 | $40,701,592 | $64,247,612 | -$23,546,020 | 0.63 |
| PECO | 108,049 | | 95.48 | $87,811,623 | $141,116,016 | -$53,304,393 | 0.62 |
| PPL | 105,046 | | 63.93 | $59,379,084 | $105,805,641 | -$31,088,996 | 0.56 |
| **Statewide** | **422,478** | | **269.98** | **$266,804,271** | **$445,566,598** | **-$151,424,959** | **0.60** |

The kW reductions per participant for the three non-central A/C end uses are much smaller than for the central A/C load control program participants. The costs of adding load control for window A/C’s, electric water heaters, and swimming pool pumps to a proposed central A/C program outweighed the benefits, further driving the benefit/cost ratios for each EDC into negative territory.

# Small and Medium Commercial Direct Load Control

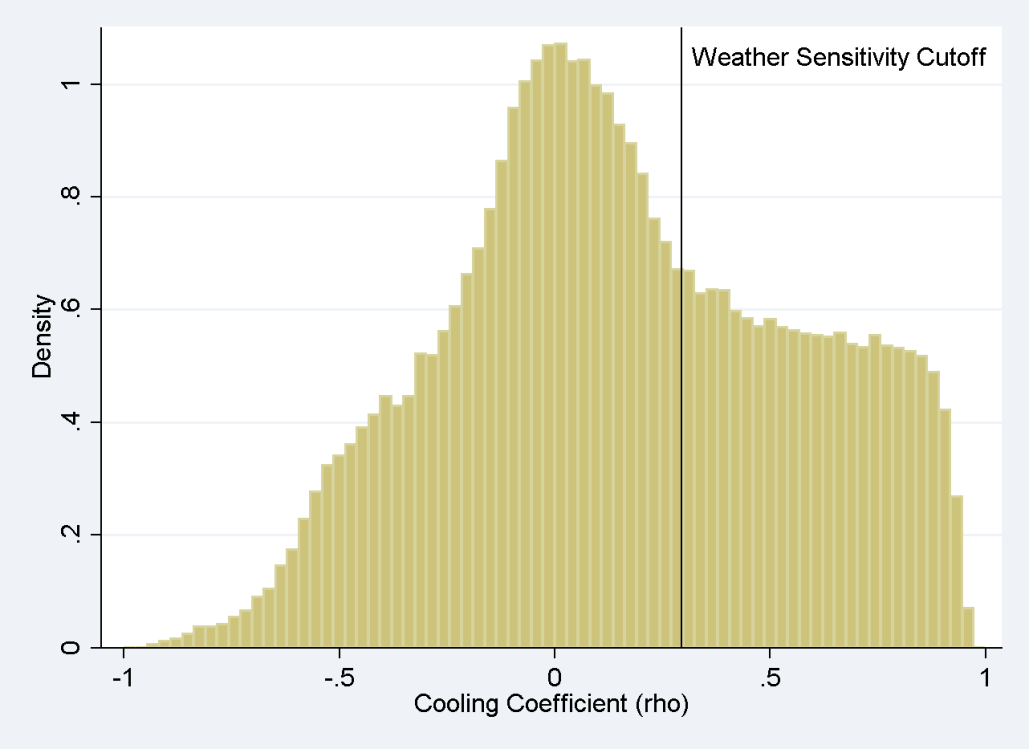
## Methodology

DLC programs remotely manage customers’ HVAC demands by directly controlling their HVAC systems. In exchange for an incentive payment or bill reduction, customers allow EDCs to remotely limit HVAC runtime during peak hours. Our approach for estimating potential for this program rests with identifying the proportion of each customer’s summer peak load consumption that may be associated with the use of their HVAC system for space cooling. We began by selecting customer accounts with a PLC greater than 5 kW, but less than or equal to 75 kW. We assumed accounts with less than 5 kW of PLC are associated with non-premises accounts, accounts with very low occupancy and space cooling during summer weekday afternoons. Those accounts with PLC greater than 75 kW were assigned to the C&I program described in Section 6. The approach used to identify economically advantageous customers for DLC varied by EDC depending on data availability. The following sections detail the various approaches used. In each case the intent of the analysis was to identify accounts with enough A/C load during peak periods that the benefits from controlling the load would be likely to outweigh the cost of the equipment, installation, and incentive. This step is analogous to the TRC screening procedure used to estimate economic potential for EE.

### PPL

PPL is the only EDC that provided interval meter data to the SWE Team for analysis. Hourly outdoor air temperature records from the Allentown weather station were merged with hourly load records for calendar year 2013. Next, a correlation coefficient ρ (rho) was calculated for each account between daily electric consumption and cooling degree days. This statistic falls between -1.0 and 1.0 and represents the extent to which electric loads increase or decrease during hot weather. Those customers with a strong positive correlation are ideal candidates for a DLC program because we assume the increased electric consumption on hot days is attributable to A/C that could be curtailed if the site were to enroll in an EDC program. Customers with a correlation coefficient less than 0.3 were excluded from the eligible pool of participants. The SWE Team then modeled DLC potential for accounts with a correlation coefficient greater than 0.3. The distribution of customer accounts above and below the threshold is shown in Figure 5‑1.

Figure 5‑1: Segmentation of PPL Accounts Based on Weather Sensitivity



Once the weather sensitive accounts were identified, a series of regression models were developed to estimate weekday afternoon loads as a function of outdoor air temperature and humidity. A separate model was developed for each customer segment for each weekday. The model coefficients were then used to compare predicted loads at peak conditions (as observed July 15-19, 2013) to predicted loads at 60 degrees (F) and 40% relative humidity. The premise behind this comparison is that the difference in the two predictions is A/C load. Table 5‑1 shows the filters and calculations discussed in this section for each weekday aggregated across customer segments. Although these filters reduce the number of eligible accounts significantly, the ‘AC Load per Account’ column shows that the eligible customers that pass the screening have a considerable average cooling load that could be curtailed by an Act 129 DLC program.

Table 5‑1: Estimation of DX Cooling Load During Peak Conditions

|  |  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- | --- |
| Day of Week | Accounts with PLC < 75 kW | Accounts with 5 kW < PLC < 75 kW | Weather Sensitive Accounts | Predicted kW  (July 15-19, 2013) | Predicted kW at 60 Degrees (F) | AC Load (kW) | AC Load per Account (kW) |
| Monday | 160,994 | 87,082 | 38,843 | 631,567 | 420,626 | 210,941 | 5.43 |
| Tuesday | 160,994 | 87,082 | 38,840 | 653,325 | 437,247 | 216,078 | 5.56 |
| Wednesday | 160,994 | 87,082 | 38,830 | 656,499 | 442,954 | 213,545 | 5.50 |
| Thursday | 160,994 | 87,082 | 38,823 | 678,485 | 441,639 | 236,847 | 6.10 |
| Friday | 160,994 | 87,082 | 38,821 | 672,774 | 429,338 | 243,436 | 6.27 |

### PECO and FirstEnergy

PECO and FE provided monthly billing data for our analysis. A PLC for each account was also provided for the 2013/2014 delivery year. Our approach for selecting candidates for the DLC program is based on customers’ ratio of peak demand to base demand. A peak demand ratio was calculated for each account using consumption in billing period 7 (July) as the peak period and the average of consumption during billing periods 4 and 10 (April and October) as the base period. Accounts with a peak to base ratio less than 1.3 were excluded under the assumption that these customers do not use a significant amount of A/C. Each account’s PLC was divided by its peak-to-base ratio to develop a proxy of base load demand and this base load estimate was then subtracted from the PLC to estimate the share of the PLC attributable to A/C. The calculation is shown for a hypothetical customer in Table 5‑2. FirstEnergy provided the SWE Team with the number of days in each billing period which allowed us to use an average daily kWh figure for April, July, and October in the calculations.

Table 5‑2: Sample Calculation of AC Load Available for DLC

|  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- |
| PLC (kW) | July Billed kWh | Average  (April, July, October) Billed kWh | Peak-to-Base Ratio | Base Load (kW) | AC Load (kW) |
| 8.0 | 6,000 | 4,000 | 1.5 | 5.33 | 2.67 |

### Duquesne Light

Duquesne provided basic customer account data that contained maximum observed demand from each account during the calendar year 2012. While these data allowed segmentation of customer accounts, the SWE Team developed alternative approaches to estimate DR potential. The forecast data provided by Duquesne for 2015 to 2025 was “back-cast” to 2012 using the average annual growth rate of the forecast. The result is a non-residential summer peak load estimate of 1,716 MW. This figure is confirmed by non-residential peak load allocation estimates provided to the SWE Team by Duquesne. The sum of the maximum demand for all non-residential customer accounts provided by Duquesne is 2,650 MW. The ratio of customer account maximum demand to peak load share is 1.577. We apply this factor to the small and medium commercial DLC load cutoff points of 5 kW and 75 kW, which returns values of 7.88 kW and 118.28 kW, respectively. We use these scaled cutoff values to assign Duquesne accounts to the DLC program. In the absence of account-level PLC estimates from Duquesne, we assigned the average calculated A/C load, by customer segment, from all other EDCs to the Duquesne accounts classified as eligible for the DLC program.

### Size and Efficiency Assumptions

Once an estimate of A/C load during peaking conditions was developed for each account, the SWE Team used average size and efficiency values collected as part of the Non-Residential End Use Saturation Study[[111]](#footnote-111) to estimate the number of condensing units present at each location. This step is important because equipment costs for a DLC program are incurred on a per-condensing unit basis rather than a per-site basis.

Table 5‑3 shows the capacity and efficiency assumptions for each customer segment. An average duty cycle of 70% was assumed for all accounts[[112]](#footnote-112).

Table 5‑3: Average Size and Efficiency of DX Cooling Equipment by Segment

|  |  |  |
| --- | --- | --- |
| Customer Segment | Average Cooling Capacity (Tons) | Average Seasonal EE Ratio (SEER) |
| Church | 5.9 | 12.4 |
| Education | 2.5 | 11.6 |
| Grocery | 6.2 | 12.6 |
| Health | 7.1 | 14.5 |
| Industrial | 5.3 | 12.4 |
| Institutional | 5.9 | 12.4 |
| Lodging | 3.6 | 9.6 |
| Miscellaneous | 3.6 | 9.6 |
| Multifamily | 5.5 | 11.9 |
| Office | 5.6 | 10.5 |
| Public Service | 4.9 | 10.5 |
| Restaurant | 4.0 | 11.9 |
| Retail | 6.2 | 12.6 |
| Warehouse | 2.5 | 14.4 |

## DLC Benefits and Costs

The cost and benefit components of the DLC program are more numerous than for the C&I program, yet the calculations are more straightforward. Our potential estimates for DLC are based on screening accounts for those expected to be cost-effective on the basis of weather sensitivity. The inputs to the cost-benefit analysis of the DLC are presented below in Table 5‑4.

Table 5‑4: Modeling Assumptions for Commercial DLC

| Item | Value | Note |
| --- | --- | --- |
| Average Duty Cycle During Peak | 70% | Assumed loading of DX equipment |
| Participation Rate | 1% | Annual program enrollment |
| Percentage Load Reduction | 30% | Load response per enrollee |
| General Inflation Rate | 1.74% | US Energy Information Administration 2014 Annual Energy Outlook General Rate of Inflation |
| Peak Demand Line Loss Factor | 5-9% | Varies by EDC |
| Attrition Rate | 3% | Annual program drop-outs |
| Service Rate | 1% | Annual onsite service calls |
| Scheduling Rate | 10% | Percentage of sites requiring call center scheduling. Balance assumed to be self-scheduled online. |
| Walk-Away Rate | 2% | Non-eligible units\safety concerns |
| Participant Cost | 75% of incentive value | Commission Order based on California’s 2010 DR Cost-Effectiveness Protocols[[113]](#footnote-113) |
| Discount Rate | 7-9% | Varies by EDC |
| Measure Life | 10 years | Assumed equipment life |
| Program Start Year | 2016 | Commission Order[[114]](#footnote-114) |
| Program Length | 5 years | Staff Directive |
| Planning Horizon | 15 years  (Phase Length + Measure Life) | Staff Directive and Commission Order[[115]](#footnote-115) |

We assume that a commercial DLC program will not be created in the absence of a companion residential program. Many of the overhead costs for initiating the program are born by the residential program, so the commercial DLC program enjoys some economies of scale in setup cost savings. However, the unit-based costs and some additional fixed costs remain and are summarized in Table 5‑5.

Table 5‑5: Commercial DLC Cost Inputs

|  |  |  |
| --- | --- | --- |
| Item | Value | Basis |
| Annual Customer Incentive | $40 | Per A/C Unit |
| Device Cost | $85 | Per A/C Unit |
| Fixed Cost per Site (Mobilization and Install) | $115 | Per Site |
| Program Management Fee | $25,000[[116]](#footnote-116) | Annual |
| EM&V | 5% of Program Costs | Annual |
| Marketing and Outreach | $5 per qualified account | Annual |
| Incentive Processing Cost | $3 | Per Site |
| Enrollment Fee (Marketing Production) | $5 | Per Site |
| Service Fee | $100 | Per Site |
| Scheduling Fee | $15 | Per Site |
| Walk-Away Fee | $40 | Per Site |

## DLC Potential by EDC

Table 5‑6 shows the results of the SWE Team’s analysis of A/C DLC for the small commercial sector. The cumulative number of sites and devices are net of customer attrition and the MW impact figures are an average value over the five summers in the phase presented at the generator level. Lifetime TRC ratios assume that funding is available to pay customer incentives after the end of Phase III so that the full effective useful life of the equipment can be realized.

Table 5‑6: Small and Medium Commercial DLC Potential by EDC

| EDC | Total Qualified Accounts | Cumulative Sites | Cumulative Devices | Average Annual Impact (MW) | Lifetime TRC Ratio |
| --- | --- | --- | --- | --- | --- |
| Duquesne | 10,529 | 471 | 829 | 0.56 | 0.76 |
| FE: Met-Ed | 7,128 | 325 | 754 | 0.52 | 0.83 |
| FE: Penelec | 7,120 | 321 | 680 | 0.47 | 0.77 |
| FE: Penn Power | 2,446 | 113 | 258 | 0.17 | 0.45 |
| FE: West Penn | 9,492 | 438 | 921 | 0.64 | 0.85 |
| PECO | 35,880 | 3,262 | 6,099 | 5.73 | 1.41 |
| PPL | 39,735 | 1,833 | 3,088 | 2.14 | 0.72 |
| Statewide | **112,330** | **6,763** | **12,629** | **10.23** | **0.97** |

PECO is the only EDC whose small commercial DLC program shows a TRC ratio greater than 1.0 in Table 5‑6. This finding is driven by several key factors.

1. Based on discussions with PECO program staff, the SWE Team estimates that PECO will have 3,443 load control devices installed at 1,981 sites at the outset of Phase III. There are no Phase III labor or equipment costs associated with these customers. Without these “sunk assets” the TRC ratio of a Phase III program in PECO territory would be 1.18. If no new switches are installed in Phase III, we estimate the TRC ratio for existing PECO switches will be 1.91 for Phase III.
2. PECO has the largest pool of qualified accounts[[117]](#footnote-117). As a result, the same penetration rate will result in a greater number of installs and this can overcome some of the fixed program costs.
3. PECO has the highest avoided T&D capacity costs so a 1 kW load impact is most valuable in PECO territory.

It is worth noting that the modeling parameters defined by the Commission’s Final Order on DR[[118]](#footnote-118) require the SWE Team to examine hypothetical DLC programs over a five year time horizon. We have assigned DR investments on an annual basis through the year 2020. The DR potential builds each year of the phase as additional customers are recruited and enrolled into the program. After the program is complete, recruitment of new participants ceases, and natural attrition of DLC participants leads to a gradual decrease in MW controlled. We illustrate this effect below in Figure 5‑2, using the Penelec results as an example.

Figure 5‑2: MW Controlled by Year - Penelec

## DLC Potential by Market Segment

Statewide DLC potential by segment is presented below in Figure 5‑3. The largest segment is offices, comprising one third of statewide DLC potential. The education segment has the lowest statewide DLC potential, which is not surprising given that summer peak hours coincide with summer vacation for most K-12 schools. The office segment has the greatest number of premises. Estimated potential tracks with the most common premises types for the top three segments, where the number of sites dominates potential estimates. This trend begins to diverge after the top three premises types, whereby estimated A/C load and average condensing units per site begins to exert more influence on segment-level potential.

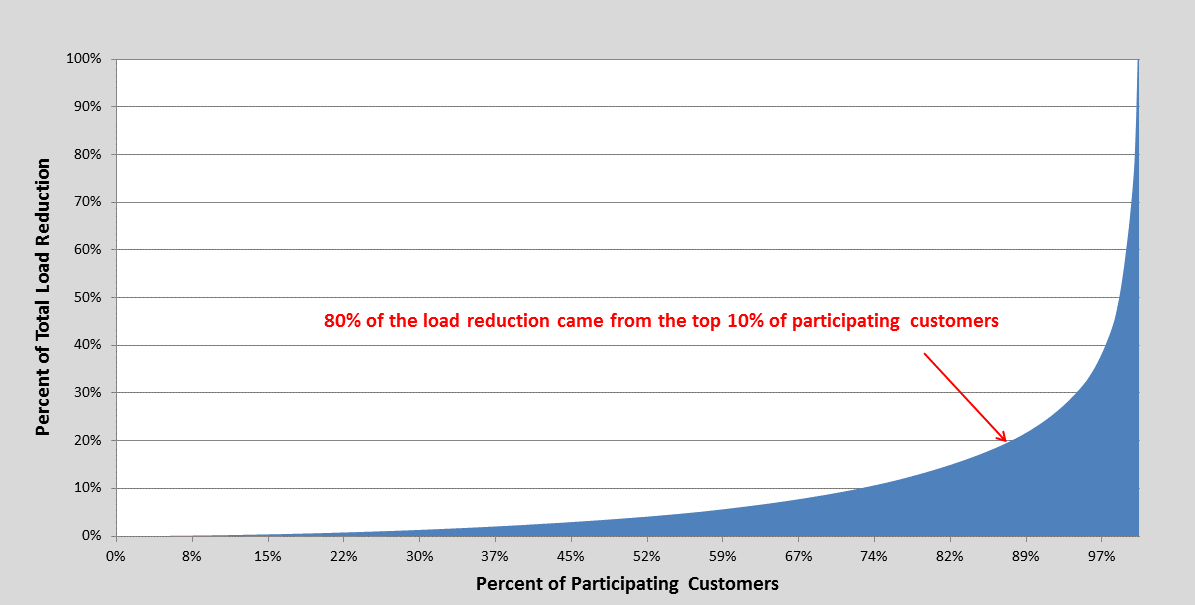
Figure 5‑3: Statewide DLC Potential by Segment

# Large Commercial and Industrial

## Methodology

Customer accounts with a PLC greater than 75 kW were assigned to a hypothetical C&I program. In addition to accounting for a large share of EDC peak loads, program data from Phase I of Act 129 and DR programs across North America indicate that these large customers represent a large share of DR potential which can be aggregated for incentive payments alone. Unlike DLC programs, EDCs do not need to incur any capital or labor costs from the installation of equipment to capture load reductions from these customers. Figure 6‑1 presents the quantity of DR capacity in Phase I relative to the number of participants. This graph indicates that a small number of Phase I participants provided a large share of the statewide load reductions from DR. Even amongst the large accounts, a large share of the DR tends to come from the largest and most savvy customers.

Figure 6‑1: Cumulative Percentage of Phase I Total Reductions vs. Percentage of Customers



Our estimates of DR potential for C&I load curtailment in Phase III are based on the sensitivity of DR participants (EDC customers) to changes in price. We have developed estimates of DR price elasticity and applied them to C&I peak loads to determine the change in quantity of DR supplied in response to a range of incentive values. Price elasticity is defined as the percentage change in quantity for a given percentage change in price as shown in Equation 6‑1.

Equation 6‑1: Price Elasticity Formula

In this equation refers to the elasticity of supply for DR. and signify the original quantity and price of electricity, and and are the new quantity and price (DR incentive payment). The elasticity estimates used in this study are based on data from observed variation in DR incentives and associated program performance from investor-owned utilities across California with a variety of notification times (day-ahead, day-of, and fast response).

The elasticity estimates are based on actual load reduction, incentive level and dispatch data for non-residential DR programs in the state of California. The underlying assumption is that demand reductions were based on overall annual payments and how often the programs have been historically dispatched. That is, all else being equal customers are more likely to commit to large demand reductions if a program is dispatched infrequently than if it is dispatched more frequently. There are other program design and implementation characteristics that can influence enrollment and demand reduction decisions but the SWE Team believes that payment amount and dispatch frequency are by far the two most important components in customer decision making.

To calculate these elasticity values, load data was taken from annual evaluation results for DR programs in California, which are available publicly.[[119]](#footnote-119) These estimates are broken down by customer segment. In addition, incentive levels for these programs are published on the utility websites, which were also needed to derive elasticity estimates. For this analysis, the following programs were studied: the aggregator managed portfolio program (AMP, but known as the DRC program in SCE service territory)[[120]](#footnote-120), the capacity bidding program (CBP)[[121]](#footnote-121),[[122]](#footnote-122), the base interruptible program (BIP)[[123]](#footnote-123),[[124]](#footnote-124), the demand bidding program (DBP)[[125]](#footnote-125),[[126]](#footnote-126) and the Peak Day Pricing program (also known as critical peak pricing, or CPP)[[127]](#footnote-127),[[128]](#footnote-128). This collection of programs includes each of the three types of DR products, and data is available at the industry level. Details about the programs investigated are included in Table 6‑1. It is important to note that the California programs investigated do not allow on-site generation as a form of DR. As a result, the SWE Team’s potential estimates presented in Section 6.3 do not take into account load reductions which could be achieved through back-up generation.

Table 6‑1: California Non-Residential DR Programs

|  |  |  |  |  |
| --- | --- | --- | --- | --- |
| Program | Program Type | Expected Incentive ($/kW/year) | 5-Year Average Number of Dispatch Hours | DR Capacity (MW) |
| SCE BIP | Fast Response | $108.88 | 1.2 | 573 |
| PG&E BIP | Fast Response | $102.00 | 2.1 | 221 |
| PG&E DBP | Day-Ahead | $4.50 | 9.0 | 38 |
| SCE DBP | Day-Ahead | $40.80 | 81.6 | 83 |
| SDG&E CPP | Day-Ahead | $29.32 | 28.0 | 17 |
| PG&E CPP | Day-Ahead | $63.84 | 60.8 | 30 |
| SDG&E CBP DA | Day-Ahead | $55.85 | 23.2 | 6 |
| SCE CPP | Day-Ahead | $79.17 | 57.6 | 34 |
| SCE CBP DA | Day-Ahead | $54.03 | 58.2 | 0 |
| SCE DRC DA | Day-Ahead | $13.37 | 14.4 | 22 |
| PG&E CBP DA | Day-Ahead | $59.39 | 13.4 | 20 |
| PG&E AMP DA | Day-Ahead | $26.59 | 6.0 | 50 |
| SDG&E CBP DO | Day-Of | $67.01 | 29.0 | 10 |
| SCE CBP DO | Day-Of | $62.11 | 17.2 | 16 |
| SCE DRC DO | Day-Of | $20.22 | 5.6 | 160 |
| PG&E CBP DO | Day-Of | $68.32 | 13.0 | 23 |
| PG&E AMP DO | Day-Of | $33.63 | 6.4 | 130 |

Each of these programs was placed into one of three response time categories depending on the level of advanced notification participants received at the beginning of a DR event. This terminology is used frequently in the results section of the report so the products are defined explicitly below.

* **Day-Ahead.** Participants are notified in the afternoon or evening that the following afternoon will be a DR event. This is typically tied to the release of a day ahead forecast.
* **Day-Of.** Participants are notified in the morning or mid-day that a DR event will be called that afternoon.
* **Fast Response.** Participants are given 1 hour or less notification prior to the beginning of a DR event.

Elasticity values were calculated separately for each product and customer type. The natural sign of each value is negative (a reduction in electric consumption), but we have chosen to express them as positive, or the amount of DR that can be expected. The customer taxonomy used in California is not identical to the customer sectors and segments used by the SWE Team in the baseline and market potential studies so some mapping was required. Notice that the elasticity values get smaller as the amount of notification time decreases.

Table 6‑2: Elasticity of Supply Values by Customer Segment and DR Product

|  |  |  |  |
| --- | --- | --- | --- |
| Segment | Day-Ahead | Day-Of | Fast Response |
| Church | 0.021 | 0.007 | 0.002 |
| Education | 0.009 | 0.003 | 0.001 |
| Grocery | 0.010 | 0.009 | 0.001 |
| Health | 0.021 | 0.007 | 0.002 |
| Industrial | 0.013 | 0.007 | 0.003 |
| Institutional | 0.021 | 0.007 | 0.002 |
| Lodging | 0.010 | 0.005 | 0.002 |
| Miscellaneous | 0.011 | 0.006 | 0.006 |
| Multifamily | 0.011 | 0.006 | 0.006 |
| Office | 0.010 | 0.005 | 0.002 |
| Public Service | 0.021 | 0.007 | 0.002 |
| Restaurant | 0.010 | 0.005 | 0.002 |
| Retail | 0.010 | 0.009 | 0.001 |
| Warehouse | 0.036 | 0.045 | 0.003 |

In order to test the external validity of the California elasticity values and determine if it is reasonable to use them in an assessment of DR potential in Pennsylvania, the SWE Team performed a similar elasticity calculation on publicly available data for the PJM BRA Report[[129]](#footnote-129) for the 2016/2017 delivery year. PJM does not distinguish between customer types in its reporting and the notification time is somewhere between “Fast Response” and “Day-Of”, so this exercise was only meant to serve as a high-level assumption check. Key data inputs and assumptions to the calculation are listed below:

1. A total of 12,412 MW of demand resources cleared in the BRA.
2. The total payment to these resources is $406 billion and the weighted average clearing price[[130]](#footnote-130) of these resources was $32,686 per MW/year.
3. Eight hours of assumed dispatch per year. This is an estimate of what customer/CSP assumptions are based on historic dispatch frequency.
4. Based on the figures in #1-3, the expected incentive payment on a $/MWh basis is $4,086.
5. Fifty five percent of PJM’s 160 gigawatt footprint are non-residential accounts (88,000 MW).
6. The average customer facing price of electricity will be $0.10 per kWh in 2016.

These values are then inserted into the elasticity formula as shown below:

After converting the sign to positive, we see that the resulting elasticity value falls roughly in between the “Day-Of” and “Fast Response” values from Table 6‑2, which is exactly the type of DR product being procured by PJM. This exercise gave the SWE Team confidence that the elasticity estimates from California were reasonable to use in Pennsylvania. Even though electric rates are higher in California, we believe that commercial customers face similar tradeoffs with regard to accepting incentives to reduce electric consumptions and negatively impact their primary business model.

### Sample Calculation

Elasticity values are used to estimate the DR potential for a given incentive level. Rearranging the elasticity equation, we have the pieces necessary to estimate a change in quantity of DR supplied:

The initial price, , for each segment is given by each EDCs retail electricity rate ($/kWh). Most EDCs have a separate rate for industrial and commercial accounts. The new price,, is determined by the incentive level and the number of hours the site will be expected to perform. The elasticity values used in this study were presented in Table 6‑2. A sample calculation is provided below for illustration.

Consider the fast response DR potential for an EDC whose eligible accounts classified as Warehouse represent 5 MW of the summer peak load forecast, have a retail rate of $0.09 per kWh, a total of 24 DR program hours, and an elasticity value of -0.003 (bottom right cell of Table 6‑2). For this calculation we assume that the DR incentive amount is $25 per kW. First we express the incentive on a $/kWh basis to align with the retail rate:

Next insert this value and the retail electric into the equation.

We see this is a 1062% change in the value of a kWh reduced[[131]](#footnote-131) for these customers, then multiply by the elasticity value.

Our elasticity assumption tells us this change in price will produce a 3.186% reduction in consumption.

Our initial reference load (Q0) was 5 MW or 5,000 kWh in a given hour. Applying the calculated percent change to the reference load shows a reduction of:

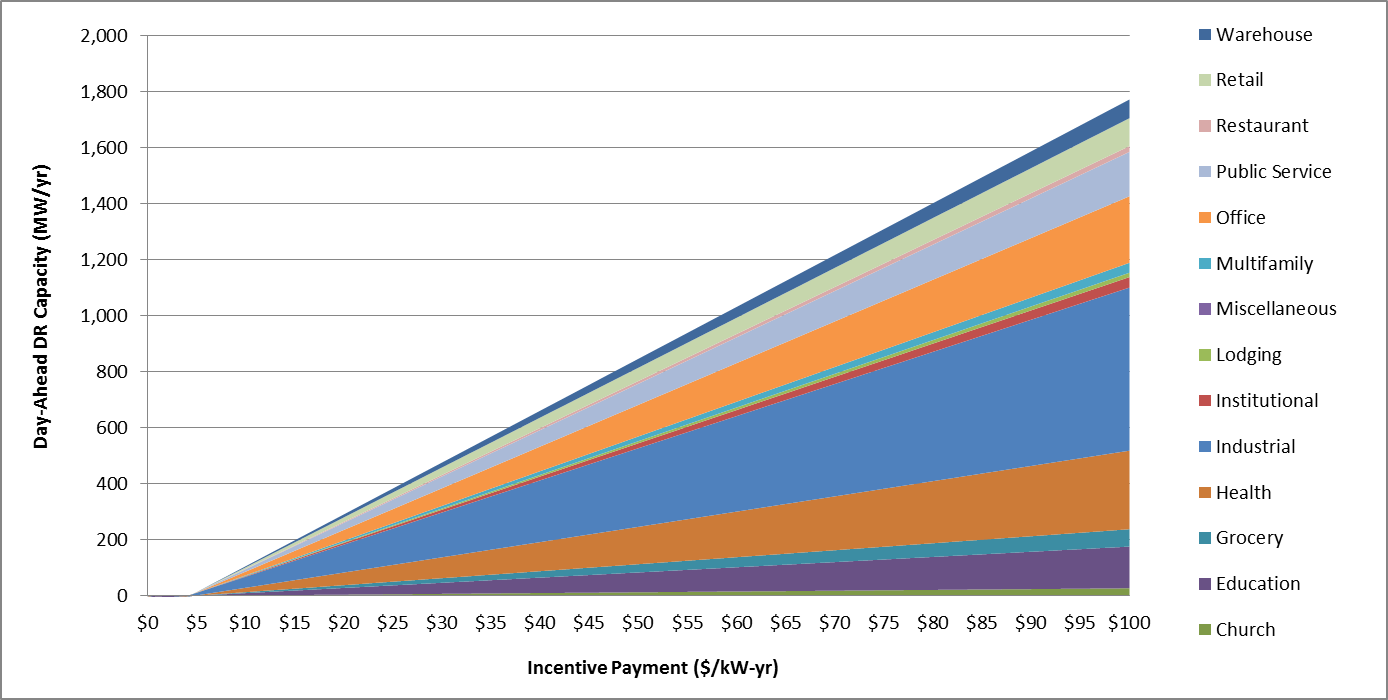
This is expressed as 0.159 MW of DR. Similarly we could insert our calculated values of and Q0 into the equation for Q1 and arrive at the same result.

Once the algebra is complete, we are left with a result of:

Which is (5 – 4.841) = 0.159 MW less than the reference load, or 0.159 MW of DR.

The application of these calculations and the subsequent effect of incentive amounts on DR potential are illustrated graphically in Figure 6‑2.

Figure 6‑2: PECO Day-Ahead DR Potential by Customer Segment and Incentive Amount



## C&I Benefits and Costs

Customer incentives are the primary cost of a C&I load curtailment program. There are inherent tradeoffs associated with setting incentives between potential and TRC that must be considered. EDCs could offer generous incentives that would cause customers to flock to the program and produce large estimates of DR potential, but the TRC ratio of such a program would be poor. Conversely, an EDC could elect to offer minimal incentives to customers in order to produce a program with a high TRC ratio, but very few customers would participate and DR potential would be low. While it may be true that setting incentives at a level that produces a TRC ratio of 1.0 would produce the largest DR potential that would pass the TRC test, this does not mean that we have maximized the value of the program. The TRC ratio only measures the relationship between costs and benefits—it does not provide information that allows us to select the most valuable project from a set of alternatives. The SWE Team’s analysis identifies the incentive amount that maximizes the PVNB. This amount is calculated separately for each EDC and is based on the avoided costs of generation, transmission, and distribution capacity, line loss factors, participant cost assumptions, the distribution of peak load amongst customer segments, and the price elasticity of each segment. The incentive amount that maximizes the PVNB varies by EDC. Figure 6‑3 shows the relationship between incentive amounts, PVNB, TRC graphically. The SWE Team’s approach is to select the incentive payment which corresponds to the apex of the PVNB curve.

Figure 6‑3: Relationship between PVNB and Incentive Payment

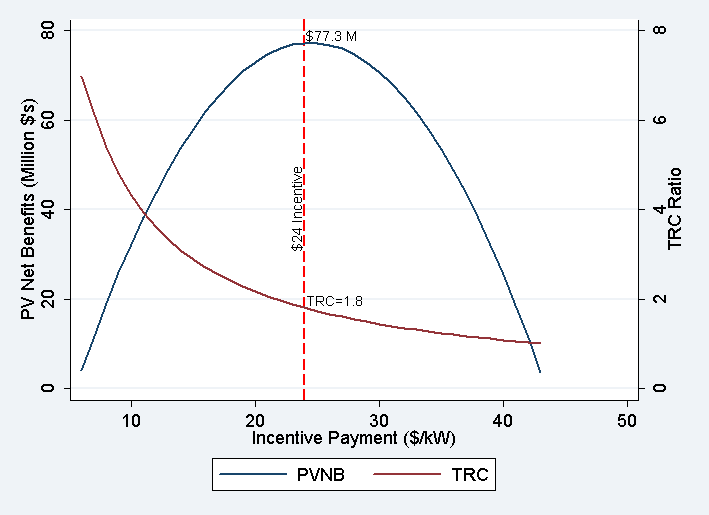


Table 6‑3 presents the DR incentive payment amounts that maximize PVNB for each EDC in PY8. Incentive payments are escalated annually using the 5-year rolling average of the US Bureau of Labor and Statistics’ (BLS) factor[[132]](#footnote-132). It is also critical to note that the incentive structure modeled by the SWE Team in this study is a reservation payment. This is fundamentally different from the energy payment model the EDCs implemented in Phase I of Act 129 where customers were paid based on performance on an hourly basis. A reservation payment model incents customers to produce the committed load reduction when dispatched and the payment amount does not depend on the number of event hours called. The number of annual hours is still subject to the program design characteristics discussed in Section 2.7.

Table 6‑3: Program Year 8 Incentive Payments by EDC

| EDC | Incentive Payment ($/kW/year) |
| --- | --- |
| Duquesne | $48 |
| FE: Met-Ed | $42 |
| FE: Penelec | $42 |
| FE: Penn Power | $41 |
| FE: West Penn | $38 |
| PECO | $49 |
| PPL | $24 |

Table 6‑4 summarizes the other assumptions used to produce estimates of C&I load curtailment potential. Key parameters are discussed in additional detail following the table.

Table 6‑4: Benefit Cost Assumptions in C&I Load Curtailment Models

|  |  |  |
| --- | --- | --- |
| Program Variable | Value | Source |
| Annual Cost Escalation | 1.87% | US Bureau of Labor Statistics Producer Price Index (2010-2014) |
| Discount Rate | 7-9% (varies by EDC) | EDC Data Request Responses |
| Program Start Year | 2016 | Commission Order[[133]](#footnote-133) |
| Program Length | 5 years | Staff Directive |
| End Year | 2020 | Staff Directive |
| Program Management Budget (Non-Incentive Costs) | 15% | Phase I EDC Benefit Cost Reporting |
| Avoided Cost of Generation Capacity | EDC-specific | PJM BRA Results |
| Avoided Cost of T&D Capacity | EDC-specific | SWE Team Analysis of EDC Capital Investment Plans and Load Growth |
| Avoided Cost of Electricity | EDC-specific | Difference between Summer On-Peak and Summer Off-Peak |
| Retail Electricity Cost ($/MWh) | Varies by Sector | EDC Data Request Responses (FirstEnergy and Duquesne). EIA[[134]](#footnote-134) data (PECO and PPL) |
| Incentive Payment ($/kW) | $24-$49 | Cost-Benefit Simulations |
| Participant Cost | 75% of incentive | Commission Order based on California’s 2010 DR Cost-Effectiveness Protocols |
| Line Losses | 4-8% (varies by EDC and sector) | EDC Data Request Responses |

The SWE Team assumed that all energy saved during event dispatch will be recovered by participants during off-peak hours so an avoided cost of energy value equal to the difference between summer on-peak and summer off-peak prices was applied to each kWh reduced. This assumption is likely an oversimplification of a complex issue because whether or not DR events produce a net energy savings or is not dependent on the type of process curtailed in the facility. However, as avoided energy benefits currently account for less than 0.5% of total benefits[[135]](#footnote-135) this was deemed a conservative assumption that would not materially affect the outcome of the study.

The retail rate of electricity is an important component of potential estimates (P0 in Equation 6‑1). Since Pennsylvania allows customers to choose the company who generates the electricity supplied to their home or business, the ultimate rate paid for electricity is somewhat dependent on the EGS each customer selects. The SWE Team used average rates as supplied by EDCs or gathered from EIA data. Separate retail rates were used for C&I accounts.

The SWE Team analysis of avoided T&D capacity costs presented in Section 2.8 distinguishes between T&D investments where EDC-supplied data was sufficiently granular. Both the avoided T&D costs were applied to load reduction from the commercial customer segments. Industrial customers only received the avoided cost of transmission capacity under the assumption that many industrial accounts receive high voltage service, often very close to transmission lines. The SWE Team felt that because these large industrials are mostly removed from the distribution system it would be inappropriate to assume any distribution projects could be avoided or deferred because of DR impacts from large industrial accounts. Separate line loss values were also applied to the C&I segments where available for similar reasons.

## C&I Potential by EDC

Table 6‑5 presents the average annual DR potential for each of the three DR products by EDC. For each company, DR potential is greatest when participants are notified the day before an event call. The MW potential estimates presented in Table 6‑5 are average annual figures. Because EDC peak load forecasts escalate at a slower rate than avoided costs, there are subtle differences in the annual estimates, with later years showing slightly less potential than the early years of Phase III. These are estimates of full potential, prior to consideration of available funding or overlap with PJM DR enrollment, and adjusted for line losses for presentation at the generator level.

Table 6‑5: Phase III Achievable Potential Estimates by EDC and DR Product Type (MW/year)

|  |  |  |  |
| --- | --- | --- | --- |
| EDC | Day-Ahead | Day-Of | Fast Response |
| Duquesne | 426 | 201 | 67 |
| FE: Met-Ed | 265 | 126 | 40 |
| FE: Penelec | 261 | 123 | 41 |
| FE: Penn Power | 122 | 58 | 20 |
| FE: West Penn | 498 | 231 | 80 |
| PECO | 912 | 428 | 168 |
| PPL | 732 | 386 | 115 |
| Statewide | **3,216** | **1,552** | **532** |

Figure 6‑4 shows the DR potential estimates expressed as a percent reduction. The numerator of each percentage is the value shown in Table 6‑5 and the denominator is the share of the summer peak load forecast attributable to accounts with a PLC greater than 75 kW as shown in Table 2‑3. The combination of low retail electric rates and high incentive payments driven by T&D avoided costs give western EDCs the highest DR potential estimates on a percentage basis. Recall that industrial customers were only allocated avoided generation and transmission capacity benefits. Duquesne’s avoided T&D benefits were all from transmission and this led to increased incentive amounts and DR potential for its industrial customer base.

Figure 6‑4: Percent Reduction by DR Product and EDC

One implication of the decision to model an incentive payment that maximizes the PVNB is that TRC ratios are homogenous across EDCs and DR product types. Table 6‑6 shows the modeled TRC ratios for each DR product type by EDC.

Table 6‑6: Phase III TRC Ratios by EDC and DR Product Type

|  |  |  |  |
| --- | --- | --- | --- |
| EDC | Day-Ahead | Day-Of | Fast Response |
| Duquesne | 1.94 | 1.94 | 1.94 |
| FE: Met-Ed | 1.90 | 2.01 | 1.95 |
| FE: Penelec | 1.92 | 1.98 | 1.93 |
| FE: Penn Power | 1.93 | 2.03 | 2.00 |
| FE: West Penn | 1.94 | 2.02 | 1.98 |
| PECO | 1.92 | 1.98 | 1.99 |
| PPL | 1.88 | 1.97 | 1.91 |

While the TRC ratios of various DR notification approaches were very similar, the total EDC expenditures to harvest the available load are quite different because of the variance in potential. Table 6‑7 shows the 5-year Phase III EDC expenditures, TRC costs, and the PVNB for each DR product type by EDC. The parameters shown in Table 6‑7 are defined below for reference.

* **Scenario Spend** – the cost incurred by the EDC over the five-year phase to capture the available potential. This is the sum of annual budgets, without discounting.
* **PV Costs** – the present value of TRC costs. This is different from the scenario spend because of discounting and the Commission’s directive to only include 75% of the incentive amount as participant cost in the TRC test.
* **PV Benefits** – the present value of TRC benefits.
* **Phase III PVNB –** the present value of benefits, net costs. PV Benefits – PV Costs.

Table 6‑7: DR Financials by EDC and Product

| EDC | Parameter | Day-Ahead | Day-Of | Fast Response |
| --- | --- | --- | --- | --- |
| Duquesne | Scenario Spend | $123,129,469 | $58,101,105 | $19,501,745 |
| Duquesne | PV Benefits | $163,446,783 | $77,125,852 | $25,887,437 |
| Duquesne | PV Costs | $84,213,258 | $39,738,079 | $13,338,161 |
| Duquesne | Phase III PVNB | $79,233,525 | $37,387,773 | $12,549,276 |
| FE: Met-Ed | Scenario Spend | $67,089,778 | $31,796,669 | $10,193,520 |
| FE: Met-Ed | PV Benefits | $87,014,563 | $43,731,788 | $13,620,089 |
| FE: Met-Ed | PV Costs | $45,897,658 | $21,753,731 | $6,973,910 |
| FE: Met-Ed | Phase III PVNB | $41,116,905 | $21,978,057 | $6,646,179 |
| FE: Penelec | Scenario Spend | $65,433,538 | $30,959,262 | $10,337,269 |
| FE: Penelec | PV Benefits | $85,998,896 | $41,962,479 | $13,674,061 |
| FE: Penelec | PV Costs | $44,869,943 | $21,230,662 | $7,088,898 |
| FE: Penelec | Phase III PVNB | $41,128,953 | $20,731,817 | $6,585,163 |
| FE: Penn Power | Scenario Spend | $30,037,504 | $14,134,757 | $4,975,185 |
| FE: Penn Power | PV Benefits | $37,463,490 | $18,509,860 | $6,434,142 |
| FE: Penn Power | PV Costs | $19,380,826 | $9,120,479 | $3,210,248 |
| FE: Penn Power | Phase III PVNB | $18,082,664 | $9,389,381 | $3,223,895 |
| FE: West Penn | Scenario Spend | $114,245,420 | $52,899,197 | $18,279,548 |
| FE: West Penn | PV Benefits | $150,300,985 | $72,409,614 | $24,565,696 |
| FE: West Penn | PV Costs | $77,565,587 | $35,916,078 | $12,410,957 |
| FE: West Penn | Phase III PVNB | $72,735,398 | $36,493,536 | $12,154,739 |
| PECO | Scenario Spend | $267,806,019 | $125,723,868 | $49,311,442 |
| PECO | PV Benefits | $352,140,276 | $170,366,398 | $67,244,140 |
| PECO | PV Costs | $183,240,405 | $86,025,197 | $33,740,820 |
| PECO | Phase III PVNB | $168,899,871 | $84,341,202 | $33,503,320 |
| PPL | Scenario Spend | $150,057,450 | $79,086,130 | $23,518,897 |
| PPL | PV Benefits | $190,794,338 | $105,580,984 | $30,405,615 |
| PPL | PV Costs | $101,498,879 | $53,495,327 | $15,908,618 |
| PPL | Phase III PVNB | $89,295,459 | $52,085,658 | $14,496,997 |

Although clearly profitable, the level of expenditure required to capture all of the load curtailment potential in the Commonwealth is quite high. For the “Day-Ahead” product, the statewide spending total would equal $818 million over the five years of Phase III. This is over two thirds of the available DSM funding under Act 129. For Duquesne, spending for the “Day-Ahead” scenario would exceed the entire 2% funding cap allocated by Act 129.

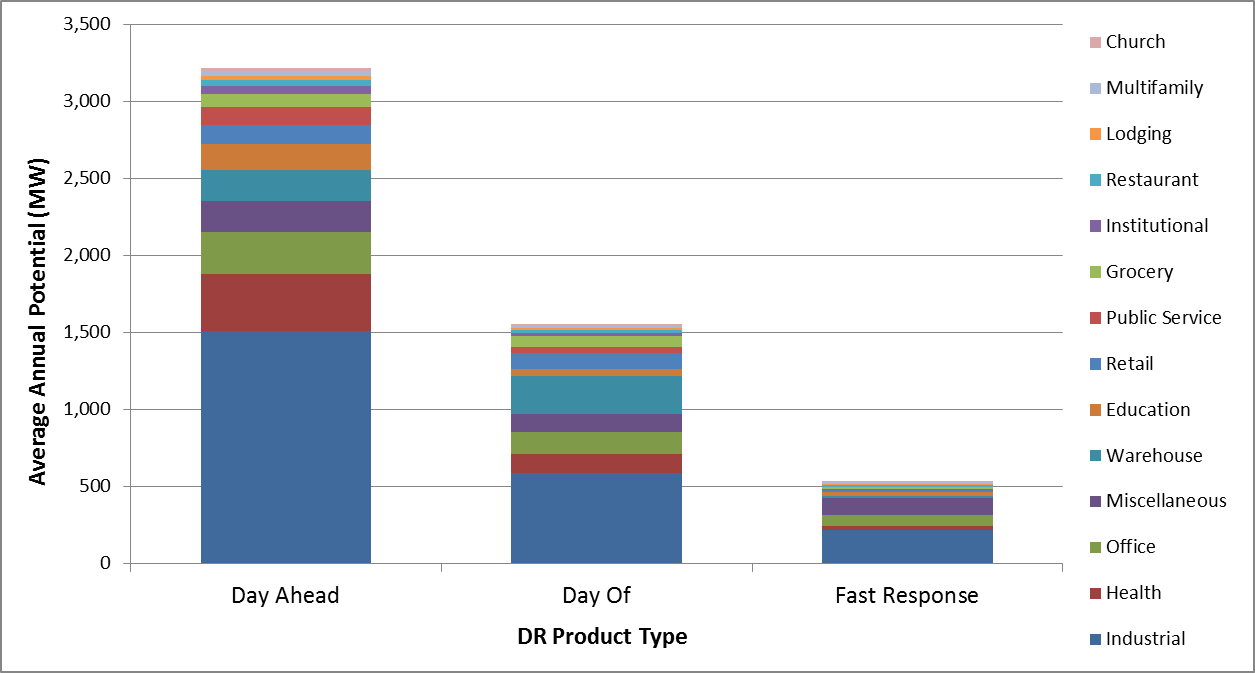
While the full estimates of potential presented in this section are informative and a necessary step in the analysis, they do not take into account the fact that much of the DR potential in the Commonwealth is aggregated under PJM’s DR offerings. Section 6.5 addresses the volume of DR currently enrolled in PJM’s Emergency Load Response program and how this affects load curtailment potential estimates. Section 7 then incorporates additional program budget constraints.

One caveat to note when reviewing these estimates of DR potential is the fact that Pennsylvania electric rates are structured in a way that promotes a transparent form of DR that may cannibalize Act 129 potential. As discussed in Section 2.4, some EDCs and EGSs use observed loads during the 5CP hours to allocate capacity obligations to its customers. These charges can represent up to 30% of the annual electric charge for a facility so savvy businesses actively manage loads on peak summer days to intentionally lower their obligation and associated charges. The extent to which these practices occur is difficult to quantify as there are no enrollment or incentive records.

## C&I Potential by Market Segment

Figure 6‑5 shows the average annual statewide load curtailment potential broken up by customer segment. The industrial customer base is a leading contributor for each of the three notification types considered. The distribution of potential within each DR type was similar across EDCs.

Figure 6‑5: Annual Statewide Load Curtailment Potential by Customer Type



## PJM Commitments

The estimates of DR presented in Section 6.3 represent the total achievable DR potential for customers with a PLC greater than 75 kW. These are the MW reductions the SWE Team estimates the EDCs could achieve with an unconstrained budget, with economically efficient incentive payments, and absent any restrictions on customer enrollment. As we consider program potential for a potential Phase III C&I load curtailment program, an enormous restriction on customer enrollment must be factored in.

The Commission’s Final Order on DR directed the SWE Team to “*disallow dual participation when it performs its LC analysis as part of its DR Potential Study*.”[[136]](#footnote-136) This need for mutual exclusivity is contentious as the mechanisms of producing benefits to ratepayers of the Commonwealth differ somewhat between the programs. PJM uses DR to meet the reliability requirement for a given year. The prospective Act 129 program relies on actual load reductions in a given year lowering resource requirement in future years. Policy implications aside, this directive adds a layer of complexity to the estimation of Act 129 DR potential for the following reasons:

* PJM’s Base Residual Auction (BRA) has been held for the delivery years coinciding with the first two program years of a potential Phase III of Act 129.
* The current volume (MW) of DR commitments by EDC are known for these two delivery years, but the participating accounts supplying the load reductions will not be known by the EDCs until the delivery year in question.
* Although small, relative to the BRA, PJM holds incremental capacity auctions prior to the delivery during which additional demand resources may commit load reductions, or committed resources can sell their positions. Historically, incremental auctions have lowered the committed MW from DR in Pennsylvania.
* The BRA for the PJM delivery year corresponding to Act 129 PY10-PY12[[137]](#footnote-137) had not occurred at the time of this study. Consequently, there are not currently any DR commitments in the PJM Emergency program and all load reductions are potentially available for Act 129 DR. However, historic analysis shows that if PJM markets continue to operate in a “business-as-usual” fashion a large number of MW will be committed by Pennsylvania businesses.
* There is considerable uncertainty regarding what DR in wholesale markets will look like during Phase III of Act 129. The vacation of **Federal Energy Regulatory Commission** (FERC) Order 745 and subsequent extrapolation of this ruling to forward capacity markets has led to speculation about continuing to allow DR participants to act as supply-side resources. PJM’s recent white paper[[138]](#footnote-138) on the topic speculated “*PJM’s markets would not separately compensate demand as a supply-side resource. The economics and incentives in having demand participate would result from avoided costs and obligations. State programs, of course, could offer added incentives to both wholesale and retail market participants.*”

With these challenges in mind, the SWE Team elected to implement a simple approach to net out potential from customers enrolled in PJM programs. Two scenarios were considered: a “business as usual” case which assumes historical DR commitments will enroll in the PJM forward capacity market and a “wholesale changes” scenario where the PJM DR market essentially vanishes after the 2017/2018 delivery year.

Table 6‑8 shows the MW commitments by EDC for the first two years of Phase III based on cleared offers in the PJM’s BRAs. In the “wholesale changes” scenario, these are the amounts subtracted from the total potential for each DR product on annual basis. This approach does not account for the differences in dispatch frequency, duration, and notification between the PJM emergency program and a potential Act 129 program. That is, the same customer may commit more load reduction to the PJM emergency program because of the historically infrequent dispatch compared to an Act 129 program where dispatch is expected to be more frequent. Conversely, the additional notification time of an Act 129 day-ahead or day-of program could attract larger commitments from customers because of the ability to schedule processes around event dispatch.

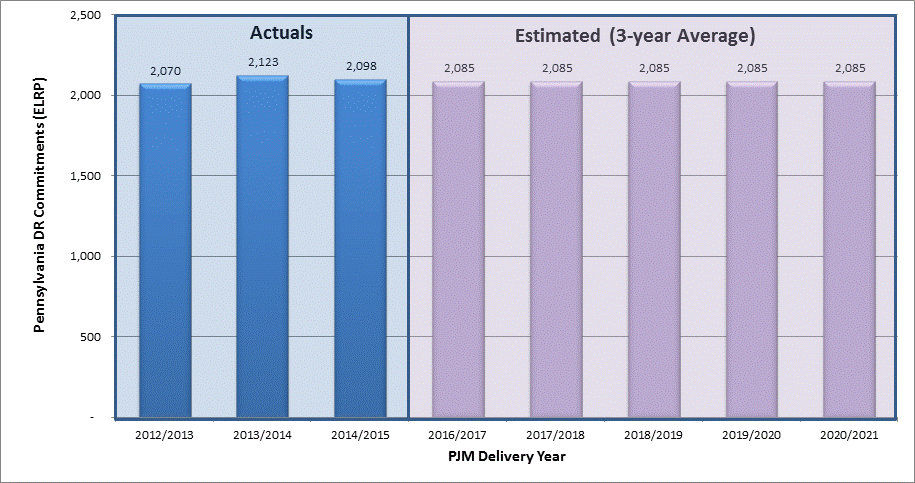
Table 6‑8: Demand Resources Committed in PJM’s BRA by Delivery Year

| EDC | 2016/2017 (PY8) | 2017/2018 (PY9) | PY10, PY11, PY12 |
| --- | --- | --- | --- |
| Duquesne | 143.1 | 161.4 | N/A |
| FE: Met-Ed | 313.6 | 298.9 | N/A |
| FE: Penelec | 431.5 | 356.8 | N/A |
| FE: Penn Power[[139]](#footnote-139) | 126.8 | 71.4 | N/A |
| FE: West Penn Power[[140]](#footnote-140) | 376.5 | 510.9 | N/A |
| PECO | 531.1 | 480.0 | N/A |
| PPL | 998.2 | 686.2 | N/A |
| Statewide Total | **2,920.9** | **2,565.6** | **N/A** |

The values shown in Table 6‑8 are actual commitments. Since the BRAs for the PJM delivery year’s corresponding to Act 129 program years 10, 11, and 12 have not yet occurred, the current DR commitments in PJM for those years is 0 MW for each EDC. The PY8 and PY9 commitments can go up or down at incremental auctions prior to the delivery. However, historical results indicate that commitments are reduced at incremental auctions. The values shown in Table 6‑8 were used in the SWE’s “wholesale changes” scenario which assumes that the PJM DR markets will no longer be in place beginning in the 2018/2019 delivery year.

The SWE also considered a “business-as-usual” scenario which assumes that the historic DR participation levels in PJM’s forward capacity market will continue for Phase III of Act 129. The SWE Team averaged the DR commitments for the last three PJM delivery years (2012/2013, 2013/2014, and 2014/2015), by EDC, to estimate the magnitude of these commitments in Phase III. The statewide result is presented in Figure 6‑6.

Figure 6‑6: Statewide Historical and Projected DR Commitments in PJM BRA



The SWE Team believes a day-ahead notification program is the most logical option for an Act 129 load curtailment program. In addition to having the largest load reduction potential, it is most different from the PJM Emergency DR product, which is very much a Fast Response program. Offering a different DR product could appeal to customers with different DR preferences and make the two programs more complimentary than competitive.

d Duquesne service territories. Instances where PJM commitments exceed the SWE Team’s estimate of day-ahead notification potential are presented in red.

Table 6‑9 shows the SWE Team’s estimates of the Act 129 DR potential and TRC ratios for a day-ahead notification program assuming the projected DR commitments shown in Figure 6‑6 and the associated TRC ratios. This “business as usual” scenario shows that there is C&I load curtailment potential beyond the PJM programs for all EDCs other than Penelec, but is most concentrated in PECO and Duquesne service territories. Instances where PJM commitments exceed the SWE Team’s estimate of day-ahead notification potential are presented in red.

Table 6‑9: Day-Ahead MW Potential Net of Projected PJM Commitments

| EDC | 2016  (PY8) | 2017  (PY9) | 2018  (PY10) | 2019  (PY11) | 2020  (PY12) | TRC  Ratio |
| --- | --- | --- | --- | --- | --- | --- |
| Duquesne | 319 | 324 | 323 | 321 | 318 | 1.94 |
| FE: Met-Ed | 50 | 52 | 51 | 49 | 48 | 1.90 |
| FE: Penelec | -33 | -31 | -36 | -41 | -46 | 0.0 |
| FE: Penn Power | 67 | 68 | 66 | 64 | 62 | 1.93 |
| FE: West Penn | 153 | 157 | 154 | 155 | 155 | 1.94 |
| PECO | 494 | 499 | 488 | 474 | 460 | 1.69 |
| PPL | 93 | 99 | 94 | 95 | 95 | 1.88 |
| Statewide | **1,142** | **1,168** | **1,139** | **1,117** | **1,091** | **1.78** |

Table 6‑10 shows the SWE Team’s estimate of DR potential, by year, for the “wholesale changes” scenario. This analysis relies on the PJM commitment values shown in Table 6‑8. Potential estimates for PY8 and PY9 are lower in Table 6‑10 because the reduction in DR commitments which has historically happened at incremental auctions is not reflected. Estimated TRC ratios for the five-year phase are also presented.

Table 6‑10: Day-Ahead MW Potential Net of Current PJM Commitments

|  |  |  |  |  |  |  |
| --- | --- | --- | --- | --- | --- | --- |
| EDC | 2016  (PY8) | 2017  (PY9) | 2018  (PY10) | 2019  (PY11) | 2020  (PY12) | TRC  Ratio |
| Duquesne | 281 | 268 | 427 | 426 | 423 | 1.94 |
| FE: Met-Ed | -48 | -32 | 266 | 264 | 263 | 1.90 |
| FE: Penelec | -166 | -90 | 262 | 257 | 252 | 1.92 |
| FE: Penn Power | -3 | 53 | 123 | 121 | 119 | 1.93 |
| FE: West Penn | 120 | -10 | 498 | 499 | 499 | 1.94 |
| PECO | 392 | 448 | 917 | 903 | 889 | 1.69 |
| PPL | -269 | 50 | 731 | 732 | 731 | 1.88 |
| Statewide | **306** | **687** | **3,224** | **3,202** | **3,175** | **1.82** |

Table 6‑10 tells a much different story than Table 6‑9 in program years 10, 11, and 12 because PJM’s BRA has not yet taken place so there are no MW commitments from DR to net out of Act 129 potential.

If “business-as-usual” DR practices do not continue at PJM because of court rulings or revisions to market architecture and DR is no longer able to participate as a supply-side resource in PJM’s forward capacity market, the findings in Table 6‑10 could become an accurate representation of the DR potential available to Act 129 in PY10-PY12. If this outcome materializes, the SWE Team believes it would be incumbent upon the Commission to enact an Act 129 load curtailment program to harness the tremendous pool of DR potential available in Commonwealth. Our analysis shows that the benefits of such a program would nearly double the costs. Pennsylvania businesses who supply DR to the wholesale markets will be eager for a way to replace PJM revenues and an Act 129 program would help insulate ratepayers from the price spikes that would result in PJM filling resource requirements without DR[[141]](#footnote-141). If this outcome were to materialize, an Act 129 load curtailment program would be an important way to engage large C&I accounts who may otherwise be interested in opting out of Act 129 programs.

# Program Potential Estimates

## DR Program Potential

The TUS staff directed the SWE Team to consider four distinct program potential scenarios as part of its EE and DR potential studies. Each scenario considers a different funding split between EE and DR.

1. 100% spending on EE, 0% on DR
2. 90% spending on EE, 10% on DR
3. 85% spending on EE, 15% on DR
4. 80% spending on EE, 20% on DR.

The exact dollar amounts available to fund DR under each scenario were presented in Table 2‑1. For a specific annual level of DR funding, The SWE Team calculated the potential that could be captured by dividing the annual funding level by the DR acquisition cost ($/MW/year). For example, consider an EDC program that could achieve 200 MW of load reduction each year of Phase III and to do so would cost $8 million each year. Over a potential five year phase the total load impact would be 1,000 MW/year and the expenditures would be $40 million and the cost per MW reduction achieved would be $40,000. If this EDC only had a $15 million Phase III budget for DR, the program potential estimate would be:

The SWE Team analysis in Section 6 found cost-effective load curtailment potential for each of the seven EDCs[[142]](#footnote-142) beyond what is currently committed in PJM’s forward capacity market. This Act 129 DR potential is mostly concentrated in the last three years of Phase III because the BRA for these delivery years has not yet occurred. Section 6.5 explored the uncertainty associated with the volume of DR that will commit in PJM for these years and what will remain available for an Act 129 load curtailment program and also presented a “business-as-usual” scenario which assumes historic PJM participations will continue. This section presents DR program potential for both scenarios.

Using the Act 129 “Day-Ahead” load curtailment potential estimates from Table 6‑10 and the modeled acquisition cost for each program year, by EDC, the SWE Team calculated the weighted average Phase III load curtailment acquisition costs shown in Table 7‑1 For each of the EDCs other than PECO, the C&I load curtailment values from Table 7‑1 and the associated costs and benefits are the sole driver of the program potential estimates in Table 7‑4 and the benefit cost information in Table 7‑5.

Table 7‑1: Average Annual Phase III Load Curtailment Acquisition Costs

| EDC | Acquisition Cost ($/MW/year) |
| --- | --- |
| Duquesne | $57,976 |
| FE: Met-Ed | $51,210 |
| FE: Penelec | $50,782 |
| FE: Penn Power | $49,349 |
| FE: West Penn | $46,203 |
| PECO | $58,893 |
| PPL | $41,622 |
| Statewide Average | **$52,310** |

The acquisition cost of residential DLC, small commercial DLC, and C&I load curtailment programs vary. For PECO, which has cost-effective DR potential in multiple DR program types, the SWE Team calculated a weighted average acquisition cost across program types to estimate the average annual savings potential which could be achieved at the various DR spending levels. Results of the “business as usual” PJM scenario were used for this calculation and the input figures and result are shown in Table 7‑2.

Table 7‑2: PECO Acquisition Cost Calculation

| PECO Program | 5-Year MW Potential | 5-Year Costs | Acquisition Cost ($/MW/year) |
| --- | --- | --- | --- |
| Load Curtailment | 2,414 | $142,167,801 | $58,893 |
| Small Business DLC | 29 | $3,013,153 | $105,222 |
| Residential DLC | 392 | $36,960,776 | $94,300 |
| Total | **2,835** | **182,141,730** | **$64,257** |

Table 7‑3 shows the Phase III DR potential for the “business as usual” scenario. Penelec, PPL, and Met-Ed potential estimates are presented in red for certain scenarios where the EDC would run out of load curtailment potential before exhausting the allocated funding. Duquesne, PECO, West Penn, and Penn Power could each spend the entirety of a 10%, 15%, or 20% funding allocation on cost-effective DR potential net of “business as usual” estimates of PJM commitments. For PECO, a portion of this potential could be achieved by the residential sector, or from a small and medium commercial DLC program.

Table 7‑3: Phase III DR Program Potential – Net of Projected PJM Commitments

| EDC | 5-Year DR Spending Ceiling | Program Acquisition Costs ($/MW/year) | Average Annual Potential Savings (MW) | % Reduction Relative to 2007-2008 Peak Demand |
| --- | --- | --- | --- | --- |
| 2016-2020 – 10% DR Spending | | | | |
| Duquesne | $9,772,976 | $57,976 | 34 | 1.3% |
| FE: Met-Ed | $12,433,446 | $51,210 | 49 | 1.8% |
| FE: Penelec | $11,487,372 | $50,782 | **0** | 0.0% |
| FE: Penn Power | $3,329,892 | $49,349 | 13 | 1.4% |
| FE: West Penn | $11,781,234 | $46,203 | 51 | 1.5% |
| PECO | $42,697,579 | $64,257 | 133 | 1.7% |
| PPL | $30,750,688 | $41,622 | **95** | 1.4% |
| Statewide | **$122,253,187** | **$52,310** | **375** | **1.4%** |
| 2016-2020 – 15% DR Spending | | | | |
| Duquesne | $14,659,464 | $57,976 | 51 | 2.0% |
| FE: Met-Ed | $18,650,169 | $51,210 | **50** | 1.9% |
| FE: Penelec | $17,231,058 | $50,782 | **0** | 0.0% |
| FE: Penn Power | $4,994,838 | $49,349 | 20 | 2.1% |
| FE: West Penn | $17,671,851 | $46,203 | 76 | 2.2% |
| PECO | $64,046,369 | $64,257 | 199 | 2.5% |
| PPL | $46,126,032 | $41,622 | **95** | 1.4% |
| Statewide | **$183,379,781** | **$52,310** | **492** | **1.9%** |
| 2016-2020 – 20% DR Spending | | | | |
| Duquesne | $19,545,952 | $57,976 | 67 | 2.7% |
| FE: Met-Ed | $24,866,892 | $51,210 | **50** | 1.9% |
| FE: Penelec | $22,974,744 | $50,782 | **0** | 0.0% |
| FE: Penn Power | $6,659,784 | $49,349 | 27 | 2.8% |
| FE: West Penn | $23,562,468 | $46,203 | 102 | 2.9% |
| PECO | $85,395,159 | $64,257 | 266 | 3.4% |
| PPL | $61,501,376 | $41,622 | **95** | 1.4% |
| Statewide | **$244,506,374** | **$52,310** | **607** | **2.3%** |

Table 7‑4 shows the average annual DR potential, by EDC, for each level of DR spending. Table 7‑4 assumes the “wholesale changes” scenario where there is no PJM DR in PY10, PY11, and PY12. The funding split with 100% spending on EE has been omitted from the table as the DR potential for that scenario is 0 MW for all EDCs. Program potential estimates assume “Day-Ahead” event notification for C&I load curtailment programs. The estimates of DR potential presented in Table 7‑4 reflect a scenario where the PJM DR markets disappear after the 2017/2018 delivery year and all of the load curtailment potential in the Commonwealth is available for an Act 129 DR program. This scenario may become a reality depending on the outcome of certain legal battles and market reforms.

Table 7‑4: Phase III DR Program Potential – Net of Only Current PJM Commitments

| EDC | 5-Year DR Spending Ceiling | Program Acquisition Costs ($/MW/year) | Average Annual Potential Savings (MW) | % Reduction Relative to 2007-2008 Peak Demand |
| --- | --- | --- | --- | --- |
| 2016-2020 – 10% DR Spending | | | | |
| Duquesne | $9,772,976 | $57,976 | 34 | 1.3% |
| FE: Met-Ed | $12,433,446 | $51,210 | 49 | 1.8% |
| FE: Penelec | $11,487,372 | $50,782 | 45 | 1.9% |
| FE: Penn Power | $3,329,892 | $49,349 | 13 | 1.4% |
| FE: West Penn | $11,781,234 | $46,203 | 51 | 1.5% |
| PECO | $42,697,579 | $64,257 | 133 | 1.7% |
| PPL | $30,750,688 | $41,622 | 148 | 2.2% |
| Statewide | **$122,253,187** | **$52,310** | **473** | **1.8%** |
| 2016-2020 – 15% DR Spending | | | | |
| Duquesne | $14,659,464 | $57,976 | 51 | 2.0% |
| FE: Met-Ed | $18,650,169 | $51,210 | 73 | 2.8% |
| FE: Penelec | $17,231,058 | $50,782 | 68 | 2.8% |
| FE: Penn Power | $4,994,838 | $49,349 | 20 | 2.1% |
| FE: West Penn | $17,671,851 | $46,203 | 76 | 2.2% |
| PECO | $64,046,369 | $64,257 | 199 | 2.5% |
| PPL | $46,126,032 | $41,622 | 222 | 3.4% |
| Statewide | **$183,379,781** | **$52,310** | **709** | **2.7%** |
| 2016-2020 – 20% DR Spending | | | | |
| Duquesne | $19,545,952 | $57,976 | 67 | 2.7% |
| FE: Met-Ed | $24,866,892 | $51,210 | 97 | 3.7% |
| FE: Penelec | $22,974,744 | $50,782 | 90 | 3.8% |
| FE: Penn Power | $6,659,784 | $49,349 | 27 | 2.8% |
| FE: West Penn | $23,562,468 | $46,203 | 102 | 2.9% |
| PECO | $85,395,159 | $64,257 | 266 | 3.4% |
| PPL | $61,501,376 | $41,622 | 296 | 4.5% |
| Statewide | **$244,506,374** | **$52,310** | **945** | **3.6%** |

## DR Program Potential Benefits and Costs

The financials associated with each program potential scenario shown in Table 7‑4 are presented in Table 7‑5. TRC ratios hold constant as DR funding increases, while the TRC costs, benefits and net benefits (benefits minus costs) increase linearly. The results of each EE/DR funding scenario are combined with similar results from the EE market potential study in Section 7.3. Only the scenario where PJM DR goes away after the 2017/2018 delivery year is presented in Table 7‑5. For the “business-as-usual” scenario, the TRC ratios for West Penn, Penn Power, Met-Ed, PPL, Duquesne, and PECO are the same and the TRC ratio for Penelec is zero because there is no cost-effective DR potential net of projected PJM participation.

Table 7‑5: TRC Costs and Benefits for DR Program Potential Scenarios

| EDC | NPV Costs | | NPV Benefits | PV Net Benefits | TRC BC Ratio |
| --- | --- | --- | --- | --- | --- |
| 2016-2020 – 10% DR Spending | | | | | |
| Duquesne | | $6,684,136 | $12,973,023 | $6,288,887 | 1.94 |
| FE: Met-Ed | | $8,506,006 | $16,126,017 | $7,620,011 | 1.90 |
| FE: Penelec | | $7,877,271 | $15,097,782 | $7,220,511 | 1.92 |
| FE: Penn Power | | $2,148,516 | $4,153,121 | $2,004,605 | 1.93 |
| FE: West Penn | | $7,998,731 | $15,499,362 | $7,500,631 | 1.94 |
| PECO | | $34,907,800 | $58,978,910 | $24,071,110 | 1.69 |
| PPL | | $20,799,769 | $39,098,740 | $18,298,970 | 1.88 |
| Statewide | | **$88,922,229** | **$161,926,954** | **$73,004,725** | **1.82** |
| 2016-2020 – 15% DR Spending | | | | | |
| Duquesne | | $10,026,204 | $19,459,535 | $9,433,331 | 1.94 |
| FE: Met-Ed | | $12,759,009 | $24,189,025 | $11,430,016 | 1.90 |
| FE: Penelec | | $11,815,907 | $22,646,673 | $10,830,767 | 1.92 |
| FE: Penn Power | | $3,222,774 | $6,229,681 | $3,006,907 | 1.93 |
| FE: West Penn | | $11,998,096 | $23,249,042 | $11,250,947 | 1.94 |
| PECO | | $52,361,700 | $88,468,366 | $36,106,666 | 1.69 |
| PPL | | $31,199,654 | $58,648,109 | $27,448,455 | 1.88 |
| Statewide | | **$133,383,344** | **$242,890,431** | **$109,507,087** | **1.82** |
| 2016-2020 – 20% DR Spending | | | | | |
| Duquesne | | $13,368,272 | $25,946,046 | $12,577,774 | 1.94 |
| FE: Met-Ed | | $17,012,012 | $32,252,033 | $15,240,021 | 1.90 |
| FE: Penelec | | $15,754,543 | $30,195,565 | $14,441,022 | 1.92 |
| FE: Penn Power | | $4,297,032 | $8,306,241 | $4,009,209 | 1.93 |
| FE: West Penn | | $15,997,461 | $30,998,723 | $15,001,262 | 1.94 |
| PECO | | $69,815,600 | $117,957,821 | $48,142,221 | 1.69 |
| PPL | | $41,599,539 | $78,197,479 | $36,597,940 | 1.88 |
| Statewide | | **$177,844,459** | **$323,853,909** | **$146,009,450** | **1.82** |

## Energy Efficiency and Demand Response Funding Scenarios

The Commission will face a key question when authoring an Implementation Order for Phase III of Act 129 and setting conservation targets for the EDCs. How should the 2% funding cap be allocated between EE and DR programs? With the exception of PECO, DLC does not appear to be a viable option for Pennsylvania EDCs. We have also established that if “business-as-usual” DR operations continue in PJM’s forward capacity market, a large share of the DR potential in the state will commit load reductions to the wholesale market. However, if court rulings or revisions to market architecture remove DR as a potential supply-side resource and Act 129 load curtailment program could insulate Pennsylvania ratepayers from adverse effects to electric prices.

Table 7‑6 shows the TRC costs, TRC benefits, TRC ratio, and PVNB for each of the four EE/DR funding splits by EDC and at the statewide level. To provide the most comprehensive comparison of DR and EE, we have used the “wholesale changes” DR scenario which assumes there is no PJM DR in PY10, PY11, and PY12. Our analysis shows that EE provides a slightly better return on investment for Pennsylvania ratepayers than DR. Given the uncertainty associated with DR participation in PJM’s wholesale markets and whether enough DR potential will even be available for Act 129 DR to utilize these funds, we believe that EE is a safer investment of the 2% DSM funding cap set forth in the legislation.

Table 7‑6: TRC Costs and Benefits for Energy Efficiency and DR Funding Allocation Scenarios

| Scenario (EE/DR) % | EDC | NPV Costs ($Million) | NPV Benefits ($Million) | PV of Net Benefits ($Million) | Scenario TRC |
| --- | --- | --- | --- | --- | --- |
| 100/0 | Duquesne | $143.71 | $300.93 | $157.22 | 2.09 |
| FE: Met-Ed | $168.93 | $325.03 | $156.10 | 1.92 |
| FE: Penelec | $159.66 | $277.79 | $118.13 | 1.74 |
| FE: Penn Power | $43.05 | $72.48 | $29.44 | 1.68 |
| FE: West Penn | $153.53 | $275.02 | $121.50 | 1.79 |
| PECO | $600.11 | $1,162.94 | $562.83 | 1.94 |
| PPL | $423.00 | $770.05 | $347.05 | 1.82 |
| **Statewide** | **$1,692** | **$3,184** | **$1,492** | **1.88** |
| 90/10 | Duquesne | $136.03 | $283.81 | $147.79 | 2.09 |
| FE: Met-Ed | $160.55 | $308.65 | $148.11 | 1.92 |
| FE: Penelec | $151.57 | $265.11 | $113.54 | 1.75 |
| FE: Penn Power | $40.89 | $69.39 | $28.50 | 1.70 |
| FE: West Penn | $146.17 | $263.02 | $116.85 | 1.80 |
| PECO | $575.00 | $1,105.62 | $530.62 | 1.92 |
| PPL | $401.50 | $732.14 | $330.65 | 1.82 |
| **Statewide** | **$1,612** | **$3,028** | **$1,416** | **1.88** |
| 85/15 | Duquesne | $132.18 | $275.25 | $143.07 | 2.08 |
| FE: Met-Ed | $156.35 | $300.46 | $144.11 | 1.92 |
| FE: Penelec | $147.53 | $258.77 | $111.24 | 1.75 |
| FE: Penn Power | $39.81 | $67.84 | $28.03 | 1.70 |
| FE: West Penn | $142.50 | $257.02 | $114.52 | 1.80 |
| PECO | $562.45 | $1,076.97 | $514.51 | 1.91 |
| PPL | $390.75 | $713.19 | $322.44 | 1.83 |
| **Statewide** | $1,572 | $2,950 | $1,378 | 1.88 |
| 80/20 | Duquesne | $128.34 | $266.69 | $138.35 | 2.08 |
| FE: Met-Ed | $152.16 | $292.28 | $140.12 | 1.92 |
| FE: Penelec | $143.48 | $252.43 | $108.94 | 1.76 |
| FE: Penn Power | $38.73 | $66.29 | $27.56 | 1.71 |
| FE: West Penn | $138.82 | $251.02 | $112.20 | 1.81 |
| PECO | $549.90 | $1,048.31 | $498.41 | 1.91 |
| PPL | $380.00 | $694.24 | $314.24 | 1.83 |
| **Statewide** | **$1,531** | **$2,871** | **$1,340** | **1.87** |

The potential energy and peak demand savings associated with each of the four funding allocations over a five-year Phase III are presented in Table 7‑7. Peak demand savings are presented separately for EE and demand savings because of subtle differences in definition. For EE, only the first-year peak demand reductions resulting from installations in that program year are counted, but demand savings typically last for many years. For DR, the expected reductions in each of the five program years are averaged. The DR potential column in Table 7‑7 is net of “business as usual” projections of PJM commitments. PECO could achieve the MW savings from DR from one of three DR program types. While the SWE Team used a weighted average acquisition cost from the three program types to estimate potential, how the load reductions would be achieved would be a program design decision for PECO. DR savings amount shown in red in Table 7‑7 indicate that DR potential, rather than DR funding, is the constraining factor.

Table 7‑7: Energy and Demand Impacts for Energy Efficiency and DR Funding Allocation Scenarios

| Scenario (EE/DR) | EDC | Sum of Incremental Annual MWh Savings from EE | Sum of Incremental Annual MW Savings from EE | Average Annual MW Savings from DR[[143]](#footnote-143) |
| --- | --- | --- | --- | --- |
| 100/0 | Duquesne | 522,837 | 77 | 0 |
| FE: Met-Ed | 682,474 | 91 | 0 |
| FE: Penelec | 598,704 | 80 | 0 |
| FE: Penn Power | 189,107 | 25 | 0 |
| FE: WPP | 650,760 | 81 | 0 |
| PECO | 2,311,387 | 330 | 0 |
| PPL | 1,674,191 | 232 | 0 |
| **Statewide** | **6,629,460** | **916** | **0** |
| 90/10 | Duquesne | 470,553 | 70 | 34 |
| FE: Met-Ed | 614,226 | 82 | 49 |
| FE: Penelec | 538,834 | 72 | **0** |
| FE: Penn Power | 170,196 | 23 | 13 |
| FE: WPP | 585,684 | 73 | 51 |
| PECO | 2,080,248 | 297 | 133 |
| PPL | 1,506,772 | 209 | **95** |
| **Statewide** | **5,966,514** | **824** | **375** |
| 85/15 | Duquesne | 444,411 | 66 | 51 |
| FE: Met-Ed | 580,103 | 78 | **50** |
| FE: Penelec | 508,898 | 68 | **0** |
| FE: Penn Power | 160,741 | 21 | 20 |
| FE: WPP | 553,146 | 69 | 76 |
| PECO | 1,964,679 | 280 | 199 |
| PPL | 1,423,062 | 197 | **95** |
| **Statewide** | **5,635,041** | **779** | **492** |
| 80/20 | Duquesne | 418,269 | 62 | 67 |
| FE: Met-Ed | 545,979 | 73 | **50** |
| FE: Penelec | 478,963 | 64 | **0** |
| FE: Penn Power | 151,286 | 20 | 27 |
| FE: WPP | 520,608 | 65 | 102 |
| PECO | 1,849,110 | 264 | 266 |
| PPL | 1,339,353 | 185 | **95** |
| **Statewide** | **5,303,568** | **733** | **607** |

1. Pennsylvania Public Utility Commission Total Resource Cost Test Order August 31, 2012. [↑](#footnote-ref-1)
2. Ibid. [↑](#footnote-ref-2)
3. Ibid. [↑](#footnote-ref-3)
4. Ibid. [↑](#footnote-ref-4)
5. Ibid*.* [↑](#footnote-ref-5)
6. Ibid. [↑](#footnote-ref-6)
7. Ibid. [↑](#footnote-ref-7)
8. Ibid. [↑](#footnote-ref-8)
9. Ibid. [↑](#footnote-ref-9)
10. See the Pennsylvania Public Utility Commission Demand Response Order dated February 20, 2014, at 20 (Docket Nos.  M‑2012‑2289411 and M-2008-2069887). [↑](#footnote-ref-10)
11. DR Final Order entered February 20, 2014 at page 17, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-11)
12. The seven EDCs with Act 129 Energy Efficiency and Conservation obligations are Duquesne Light Company (Duquesne); Metropolitan Edison Company (Met-Ed), Pennsylvania Electric Company (Penelec), Pennsylvania Power Company (Penn Power), West Penn Power Company (West Penn) (collectively, these are FirstEnergy (FE) companies); PECO Energy Company (PECO); and PPL Electric Utilities Corporation (PPL). [↑](#footnote-ref-12)
13. Pennsylvania Act 129, enacted in 2008, states that “The total cost of any plan required under this section shall not exceed 2% of the electric distribution company’s total annual revenue as of December 31, 2006”. See 66 Pa. C.S. § 2806.1(g) [↑](#footnote-ref-13)
14. <http://www.puc.pa.gov/pcdocs/1269801.doc> [↑](#footnote-ref-14)
15. The amount of generation capacity an Electricity Distribution Company determines it must acquire on behalf of its customers.  PLC values may be expressed per account or in aggregate.  For example, PLC may be expressed for each account or totaled for a given economic activity.  [↑](#footnote-ref-15)
16. The Total Resource Cost (TRC) test is a cost effectiveness test that measures the net direct economic impact to the utility service territory, state, or region. The Commission’s August 2012 TRC Order details the method and assumptions to be used when calculating the TRC test for EE&C portfolios implemented under Act 129. The results of the TRC test are to be expressed as both a net-present value and a benefit/cost ratio. [↑](#footnote-ref-16)
17. In a mandatory design EDCs would penalize customers financially for non-performance during DR events. [↑](#footnote-ref-17)
18. A measure of the relative importance of hours of availability for DR dispatch. Hours where load is highest have the highest contribution to ELCC [↑](#footnote-ref-18)
19. [www.puc.state.pa.us/Electric/pdf/Act129/SWE-2014\_PA\_Statewide\_Act129\_Residential\_Baseline\_Study.pdf](http://www.puc.state.pa.us/Electric/pdf/Act129/SWE-2014_PA_Statewide_Act129_Residential_Baseline_Study.pdf) [↑](#footnote-ref-19)
20. 2012 PA Total Resource Cost Test Order, August 31, 2012, Docket No. M-2012-2300653. [↑](#footnote-ref-20)
21. The data source for the long-term (2014 to 2034) general rate of US inflation was the US Energy Information Administration 2014 Annual Energy Outlook data table titled “ Macroeconomic Indicators”, from the Reference Case provided in Excel row 21. The price index used was the US Gross Domestic Product Price Index. The 1.74% annual rate of inflation was calculated by the Study Team from the forecast provided in this Table. [↑](#footnote-ref-21)
22. The SWE Team notes that the reason there was a relatively large number of load control switches remaining in the PECO territory is because PECO purchased them while the other EDCs rented or leased this equipment. [↑](#footnote-ref-22)
23. Net-Present Value [↑](#footnote-ref-23)
24. DR Final Order entered February 20, 2014 at page 57, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-24)
25. Program Year (PY): Defined as the period between June 1st and May 31st of the current reporting period, (see glossary). [↑](#footnote-ref-25)
26. <http://www.pjm.com/~/media/documents/reports/20141007-pjm-whitepaper-on-the-evolution-of-demand-response-in-the-pjm-wholesale-market.ashx> [↑](#footnote-ref-26)
27. This approach takes into account the reduction in commitment which has historically occurred at incremental auctions [↑](#footnote-ref-27)
28. DR has been the single largest asset in PJM’s forward capacity market, accounting for over 10,000 MW of supply. [↑](#footnote-ref-28)
29. The SWE Team recommends that PECO only be allowed to conduct a load control program during Phase III for control of central A/C equipment in the residential and small commercial sectors. [↑](#footnote-ref-29)
30. Wholesale price suppression effects were not included in the benefits stream for DR in this study per the Commission’s February 20, 2014 Order. [↑](#footnote-ref-30)
31. In some cases the demand forecasts provided by the EDCs did not extend until 2030 so a growth rate was applied to estimate forecast values for years at the end of the study horizon. The Commission’s Order directed the SWE Team to look at a 10 year measure life for DLC equipment. If a switch was installed in 2020 the equipment would not reach its useful life until 2030. [↑](#footnote-ref-31)
32. <http://www.epa.gov/cleanenergy/documents/suca/vision.pdf> [↑](#footnote-ref-32)
33. The SWE Team also notes that DR programs can help to reduce future costs of T&D facilities. [↑](#footnote-ref-33)
34. DR Final Order entered February 20, 2014 at page 50, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-34)
35. PECO provided its own peak load forecast which it believed to be more accurate than the PJM forecast. The SWE Team elected to use the PECO forecast instead of the PJM forecast because the PECO forecast is based on more in-depth knowledge of business expansions, closures, and upcoming cogeneration within the service territory. [↑](#footnote-ref-35)
36. The 2014 report utilized in this study is available at <http://www.pjm.com/~/media/documents/reports/2014-load-forecast-report.ashx> [↑](#footnote-ref-36)
37. <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-37)
38. DR Final Order entered February 20, 2014 at page 32, <http://www.puc.pa.gov/pcdocs/1269801.doc> [↑](#footnote-ref-38)
39. Present value of expected total net benefits. [↑](#footnote-ref-39)
40. DR Final Order entered February 20, 2014, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-40)
41. Per the 2013 TRC Order, this escalation factor was calculated as the 5-year average of the BLS Electric Power Generation Transmission Distribution (GTD) sector price index (BLS factor: NAICS 221110) [↑](#footnote-ref-41)
42. In a mandatory design EDCs would penalize customers financially for non-performance during DR events. [↑](#footnote-ref-42)
43. In this context “program design” refers to a unique combination of dispatch threshold, event start hour, event duration, and maximum number of events per year [↑](#footnote-ref-43)
44. The term “target load,” is used solely to define the output of our simulation, and should not be interpreted as a quantified demand reduction target for Phase III. We use the term “target load,” only because of its ease of use when examining the simulation output. [↑](#footnote-ref-44)
45. This report refers to hours on a 1 to 24 basis. Hour 17 is the hour from 4:00 p.m. to 5:00 p.m. [↑](#footnote-ref-45)
46. DR Final Order entered February 20, 2014 at page 50, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-46)
47. These benefits are likely to be more direct for customers with interval meters. EDCs without interval meters use a stock load shape by rate class to assign PLC rather than the actual metered load for the site. [↑](#footnote-ref-47)
48. PJM. 1999-2014. “Previous Load Forecast Reports.” PJM Website accessed 09/24/2014. <http://www.pjm.com/planning/resource-adequacy-planning/load-forecast-dev-process/prev-load-reports.aspx> [↑](#footnote-ref-48)
49. PJM. 2009. “Executive Summary.” 2009 PJM Load Forecast Report. File accessed via PJM website 09/24/2014. http://www.pjm.com/~/media/documents/reports/2009-pjm-load-report.ashx [↑](#footnote-ref-49)
50. Hours are presented on a 1 to 24 basis so Hour 15 is the hour from 2:00 p.m. to 3:00 p.m. and Hour 17 is the hour from 4:00 p.m. to 5:00 p.m. [↑](#footnote-ref-50)
51. Section 2.7.5 includes a table indicating the number of days in each year that exceeded the dispatch criteria, which range from 90% to 97% of projected annual system peak. [↑](#footnote-ref-51)
52. DR Final Order entered February 20, 2014, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-52)
53. There are residential DR programs, such as Critical Peak Pricing, that require customer notification of events. However, the SWE Team has been instructed to only evaluate direct control residential programs, which do not require customer notification. [↑](#footnote-ref-53)
54. The simulation results shown in Table 2‑8 are a subset of the total 1,600 potential programs included in the simulation. The SWE Team has assumed that program budgets would limit the total number of potential event hours to 24. [↑](#footnote-ref-54)
55. Source: <http://www.ethree.com/CPUC/E3_Avoided_Costs_Final.pdf> [↑](#footnote-ref-55)
56. Source: <http://www.hydro.mb.ca/regulatory_affairs/electric/gra_2012_2013/Appendix_35.pdf> [↑](#footnote-ref-56)
57. Source: <http://www.mass.gov/eea/docs/dpu/energy-efficiency/avoided-energy-supply-costs-in-new-england/2005-avoided-energy-supply-costs-report.pdf> [↑](#footnote-ref-57)
58. Source: <http://energy.pace.edu/sites/default/files/publications/11-23-Deployment-of-Distributed-Generation-for-Grid-Support-Final.pdf> [↑](#footnote-ref-58)
59. Source: <http://www.synapse-energy.com/Downloads/SynapseReport.2011-07.AESC.AESC-Study-2011.11-014.pdf> [↑](#footnote-ref-59)
60. Source: <http://www.rieermc.ri.gov/documents/2013%20Evaluation%20Studies/AESC%20Report%20-%20With%20Appendices%20Attached.pdf> [↑](#footnote-ref-60)
61. EmPower Maryland 2015-2017 Cost-Effectiveness Framework, released by the Maryland Energy Administration, August 18, 2014. [↑](#footnote-ref-61)
62. PECO T&D Avoided Cost Study, prepared by Navigant Consulting, November 10, 2014. [↑](#footnote-ref-62)
63. MWA is an abbreviation for Megawatt Amperes. [↑](#footnote-ref-63)
64. Manitoba Hydro Study at page 10. [↑](#footnote-ref-64)
65. July 2011 Synapse Study at page 6-71. [↑](#footnote-ref-65)
66. 2013 Synapse Study at page A-10. [↑](#footnote-ref-66)
67. During early June 2014, the SWE Team worked closely with TUS staff to phrase our data request to ask EDCs for information on where new transmission or distribution lines or transformers are being constructed, or where existing lines are being upgraded. The SWE Team also conducted a teleconference with EDC staff to better understand the amount of the planned new T&D infrastructure that is needed to address load growth as opposed to reliability. The SWE Team also issued supplemental data requests as needed to collect the information needed to develop the forecast of avoided T&D costs. [↑](#footnote-ref-67)
68. See 66 Pa. C.S. § 2806.1(d). [↑](#footnote-ref-68)
69. <http://www.puc.pa.gov/pcdocs/1256728.docx> [↑](#footnote-ref-69)
70. Duquesne response to 6/12/2014 Demand Response Study Data Request, Request #2 [↑](#footnote-ref-70)
71. Duquesne response to 6/12/2014 SWE Demand Response Study Data Request, Request #9 [↑](#footnote-ref-71)
72. Duquesne’s response to the SWE Supplemental DR Study data request states that “As a result of the DR residential program run in Phase I EE&C, Duquesne Light owns the installed control switches for residential air conditioning units”. [↑](#footnote-ref-72)
73. See <https://www.duquesnelight.com/WattChoices/default.cfm> [↑](#footnote-ref-73)
74. 3 Duquesne Final Phase I Annual Report, page 77 [↑](#footnote-ref-74)
75. Duquesne Final Phase I Annual Report, page 75 [↑](#footnote-ref-75)
76. Duquesne response to 6/12/2014 DR Study Data Request, Request #18 [↑](#footnote-ref-76)
77. Duquesne Final Phase I Annual Report, page 9 [↑](#footnote-ref-77)
78. FE response to 6/12/2014 Demand Response Study Data Request, Request #2 [↑](#footnote-ref-78)
79. FE response to 6/12/2014 SWE Demand Response Study Data Request, Request #9 [↑](#footnote-ref-79)
80. FE PA EDC Response to SWE Supplemental Data Request, request #7 [↑](#footnote-ref-80)
81. Met Ed Final Phase I Annual Report, page 38 [↑](#footnote-ref-81)
82. Met Ed Final Phase I Annual Report, page 38 [↑](#footnote-ref-82)
83. FE PA EDC Response to SWE Supplemental Data Request, request #6 [↑](#footnote-ref-83)
84. Met Ed Final Phase I Annual Report, page 11 [↑](#footnote-ref-84)
85. FE response to 6/12/2014 Demand Response Study Data Request, Request #2 [↑](#footnote-ref-85)
86. FE response to 6/12/2014 SWE Demand Response Study Data Request, Request #9 [↑](#footnote-ref-86)
87. FE response to 6/12/2014 DR Study Data Request, Request #2 [↑](#footnote-ref-87)
88. FE response to 6/12/2014 SWE DR Study Data Request, Request #9 [↑](#footnote-ref-88)
89. FE PA EDC Response to SWE Supplemental Data Request, request #7 [↑](#footnote-ref-89)
90. PP Final Phase I Annual Report, page 35 [↑](#footnote-ref-90)
91. PP Final Phase I Annual Report, page 35 [↑](#footnote-ref-91)
92. FE PA EDC Response to SWE Supplemental Data Request, request #6 [↑](#footnote-ref-92)
93. PP Final Phase I Annual Report, page 11 [↑](#footnote-ref-93)
94. PECO response to 6/12/2014 DR Study Data Request, Request #2 [↑](#footnote-ref-94)
95. PECO response to 6/12/2014 SWE DR Study Data Request, Request #9 [↑](#footnote-ref-95)
96. PECO response to SWE Supplemental Data Response Data Request, Request #7a [↑](#footnote-ref-96)
97. PECO Final Annual Report PY4, page 155 [↑](#footnote-ref-97)
98. PECO Final Annual Report PY4, page 158 [↑](#footnote-ref-98)
99. PECO response to 6/12/2014 DR Study Data Request, Request #9 [↑](#footnote-ref-99)
100. PECO Final Annual Report PY4, page 149 [↑](#footnote-ref-100)
101. <https://www.peco.com/CustomerService/RatesandPricing/RateInformation/Documents/PDF/New%20Filings/PECO%20Act%20129%20PY4%20Annual%20Report%20Fin%2011%2015%202013.pdf> [↑](#footnote-ref-101)
102. PPL response to 6/12/2014 DR Study Data Request, Request #2 [↑](#footnote-ref-102)
103. PPL response to 6/12/2014 SWE DR Study Data Request, Request #9 [↑](#footnote-ref-103)
104. <https://www.epowerpeaksaver.com/> [↑](#footnote-ref-104)
105. 39 PPL Final Phase I Annual Report, page 133 [↑](#footnote-ref-105)
106. 40 PPL response to 6/12/2014 DR Study Data Request, Request #18 [↑](#footnote-ref-106)
107. PPL Final Phase I Annual Report, page 3 [↑](#footnote-ref-107)
108. 42 PPL response to SWE 6/12/2014 DR Study Data Request, request #4. [↑](#footnote-ref-108)
109. Pennsylvania Act 129, enacted in 2008, states that “The total cost of any plan required under this section shall not exceed 2% of the electric distribution company’s total annual revenue as of December 31, 2006”. See 66 Pa. C.S. § 2806.1(g) [↑](#footnote-ref-109)
110. The data source for the long-term (2014 to 2034) general rate of US inflation was the US Energy Information Administration 2014 Annual Energy Outlook data table titled “ Macroeconomic Indicators”, from the Reference Case provided in Excel row 21. The price index used was the US Gross Domestic Product Price Index. The 1.74% annual rate of inflation was calculated by the Study Team from the forecast provided in this Table. [↑](#footnote-ref-110)
111. <http://www.puc.state.pa.us/Electric/pdf/Act129/SWE-2014_PA_Statewide_Act129_Non-Residential_EndUse_Saturation_Study.pdf> Table 4-16 DX Cooling Parameters. Page 58. [↑](#footnote-ref-111)
112. This assumed duty cycle is higher than the coincidence factor (CF) values in the 2015 Pennsylvania TRM for most building types. The weather sensitivity filters applied to EDC customer databases should ensure that the eligible customers for the small commercial DLC program have above average cooling tendencies. [↑](#footnote-ref-112)
113. http://www.cpuc.ca.gov/PUC/energy/Demand+Response/Cost-Effectiveness.htm [↑](#footnote-ref-113)
114. DR Final Order entered February 20, 2014, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-114)
115. DR Final Order entered February 20, 2014, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-115)
116. This value represents additional cost/fees for a commercial component. The residential DLC program is assumed to carry most of the fixed program costs. [↑](#footnote-ref-116)
117. A qualified account is defined as a site with a summer PLC between 5 kW and 75 kW that is weather sensitive (electric consumption increases during hot weather). [↑](#footnote-ref-117)
118. <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-118)
119. California utilities are required to estimate the reductions attained for each event given the conditions during the event and share of resources dispatched. [↑](#footnote-ref-119)
120. Braithwait, Hansen, and Armstrong, *2012 Statewide Load Impact Evaluation of California's Aggregator DR Programs Volume 1: Ex Post and Ex Ante Results* [↑](#footnote-ref-120)
121. Ibid [↑](#footnote-ref-121)
122. PG&E CBP Program: <http://www.pge.com/tariffs/tm2/pdf/ELEC_SCHEDS_E-CBP.pdf>; SCE CBP Program: <https://www.sce.com/NR/sc3/tm2/pdf/ce293.pdf>; SDG&E CBP Program: <https://www.sdge.com/sites/default/files/documents/1557147468/Capacity%20Bidding%20Program%20Tariff.pdf> [↑](#footnote-ref-122)
123. George, Schellenberg, Savage, *2012 Load Impact Evaluation of California's Statewide Base Interruptible Program* [↑](#footnote-ref-123)
124. PG&E BIP Program: <http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/baseinterruptible/>; SCE BIP Program: <https://www.sce.com/NR/sc3/tm2/pdf/CE195-12.pdf> [↑](#footnote-ref-124)
125. Hansen , Braithwait, and Armstrong, *2012 Load Impact Evaluation of California Statewide Demand Bidding Programs (DBP) for Non-Residential Customers: Ex Post and Ex Ante Report* [↑](#footnote-ref-125)
126. PG&E DBP Program: <http://www.pge.com/mybusiness/energysavingsrebates/demandresponse/dbp/>; SCE DBP Program: <https://www.sce.com/NR/sc3/tm2/pdf/ce185.pdf> [↑](#footnote-ref-126)
127. Bode, Churchwell and George, *2012 California Statewide Non-residential Critical Peak Pricing Evaluation* [↑](#footnote-ref-127)
128. PG&E CPP Program: <http://www.pge.com/mybusiness/energysavingsrebates/timevaryingpricing/peakdaypricing/charges/>; SCE CPP Program: <https://www.sce.com/NR/sc3/tm2/pdf/ce300.pdf>; SDG&E CPP Program: <http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-SCHEDS_EECC-CPP-D.pdf> [↑](#footnote-ref-128)
129. <http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx> [↑](#footnote-ref-129)
130. Individual DR offer prices would be the more precise input to use in these calculations. Since this analysis was only intended to be a high-level assumption check and not the primary driver of potential estimates, clearing price was a reasonable proxy. [↑](#footnote-ref-130)
131. Absent DR, the customer would save the retail rate ($0.09) for not consuming a 1 kWh [↑](#footnote-ref-131)
132. Bureau of Labor Statistics’ Electric Power Generation Transmission Distribution (GTD) sector price index (BLS factor: NAICS 221110). 2013 TRC Order, page 34. [↑](#footnote-ref-132)
133. DR Final Order entered February 20, 2014, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-133)
134. US Energy Information Administration (EIA) Average Retail Price of Electricity to Ultimate Customers by End-Use Sector. <http://www.eia.gov/electricity/monthly/epm_table_grapher.cfm?t=epmt_5_6_a> [↑](#footnote-ref-134)
135. Avoided energy costs would represent approximately 1% of total benefits if the SWE Team assumed that no energy was recovered. [↑](#footnote-ref-135)
136. DR Final Order entered February 20, 2014 at page 57, <http://www.puc.pa.gov/pcdocs/1269801.doc>. [↑](#footnote-ref-136)
137. Program Year (PY): Defined as the period between June 1st and May 31st of the current reporting period, (see glossary). [↑](#footnote-ref-137)
138. <http://www.pjm.com/~/media/documents/reports/20141007-pjm-whitepaper-on-the-evolution-of-demand-response-in-the-pjm-wholesale-market.ashx> [↑](#footnote-ref-138)
139. Assumes Penn Power represents 7% of the DR commitments in the ATSI zone based on PJM Load Response Activity Reports for the 2013/2014 and 2014/2015 delivery years. [↑](#footnote-ref-139)
140. Assumes West Penn Power represents 55% of the DR commitments in the APS zone based on PJM Load Response Activity Reports for the 2013/2014 and 2014/2015 delivery years. [↑](#footnote-ref-140)
141. DR has been the single largest asset in PJM’s forward capacity market, accounting for over 10,000 MW of supply. [↑](#footnote-ref-141)
142. When projections of PJM DR in PY10, PY11, and PY12 were added, only four EDCs showed incremental load curtailment potential. [↑](#footnote-ref-142)
143. Assumes a five-year performance definition [↑](#footnote-ref-143)