PREPARED FOR: **ARIZONA PUBLIC SERVICE**

Distributed Renewable Energy Operating Impacts and Valuation Study

January 2009

R·W·BECK

Mind Powered: Insight with Impact.

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In association with:
Energized Solutions, LLC
Phasor Energy Company, Inc.
Summit Blue Consulting, LLC

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ACKNOWLEDGMENTS

The Study team gratefully acknowledges the contributions made by members of the internal and external stakeholder groups, all of whom provided invaluable assistance in making this Report a success. A cornerstone of the Study has been the involvement of more than 60 individuals representing 35 solar vendors, academic institutions, solar advocates, local builders and land developers, and solar-related construction firms, as well as representatives of the regulatory community. Their input and critique was critically important in bridging between technical potential and practical reality. We thank them for their continued dedication to this Study and participation in the stakeholder process.

The Study team also acknowledges the enormous contributions from APS, who provided significant input to the Study as a critically important internal stakeholder. APS's expertise in Renewable Energy, Energy Delivery, Transmission, Resource Planning, Rates and Regulation, among others, was instrumental in the Study. The Study team greatly appreciates the effort and cooperation that produced results reflective of thoughtful scrutiny and a high degree of concurrence.

EXECUTIVE SUMMARY

Abundant sunshine and broad support for solar energy combine to create outstanding opportunities for solar technology deployment and value for all stakeholders.

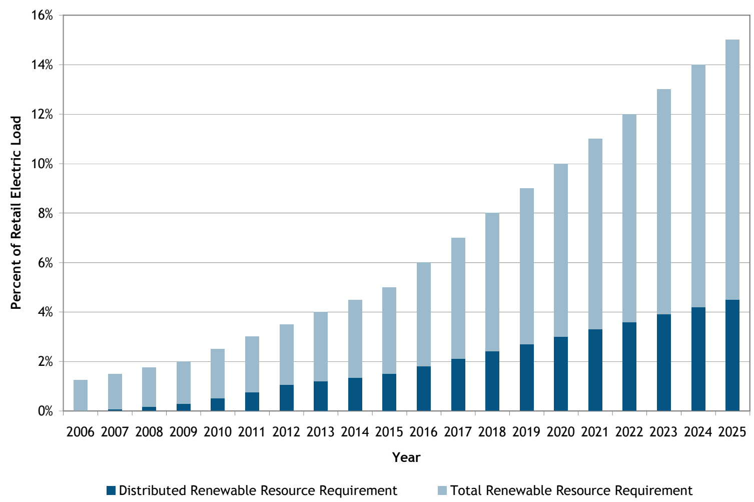
Background and Objectives

Arizona is richly endowed with solar resources. Arizona is also one of 28 states seeking to increase the amount of renewable resources in its state energy supply portfolio through Renewable Energy Standards (RES). This program, like those in other states, promulgates regulatory policies that require electric utilities to increase the production of electricity from renewable energy sources including wind, solar, biomass and geothermal energies. The abundant sunshine and broad interest and support for solar energy combine to create outstanding opportunity for solar technologies to be broadly utilized in the state.

Much attention is focused on development of large-scale solar installations. These utility scale projects capture media attention for their size and scale, and often for cutting edge technology. They are single-site projects that can add valuable renewable energy resources to the energy supply. Another technology category, distributed energy (DE), harvests value from broad scale deployments of much smaller installations. This is the domain of individual residential and business customers who install solar technologies on their rooftops to serve part or all of their own electrical energy during the day. Indeed, Arizona's RES calls for 15 percent of the retail electric load to be met with renewable energy resources and 30 percent of that amount to be met with distributed energy, as indicated in the graphic on the following page.

Large-scale deployment of DE is a relatively new concept and there are myriad complexities and implications associated with installing distributed solar generation (referred to herein as solar DE) broadly across a utility electrical system. The opportunity for broad solar deployment is matched by the complexity of the technical issues and the continuously changing solar technologies. The Study sought to create a factually based common understanding of the specific implications of solar DE on the Arizona Public Service (APS) system.

APS Renewable and Distributed Energy Requirements Through 2025



In February 2008, APS issued a Request for Proposal (RFP) for a Distributed Renewable Energy Operating Impacts and Valuation Study (the Study). APS initiated this Study to determine the potential value of solar DE technologies for its electrical system, and to understand the likely operating impacts. In recognizing that there are many uncertainties in the deployment of a new and evolving technology, the RFP made clear APS's expectation that this Study would encompass reasonably broad boundaries and establish a common basis of understanding.

Numerous studies have looked at the value of distributed energy, but none has specifically evaluated the costs and benefits to APS from solar DE technologies. APS sought to evaluate the realistic implications of solar DE deployment and production on their specific system conditions. The Study objectives were as follows:

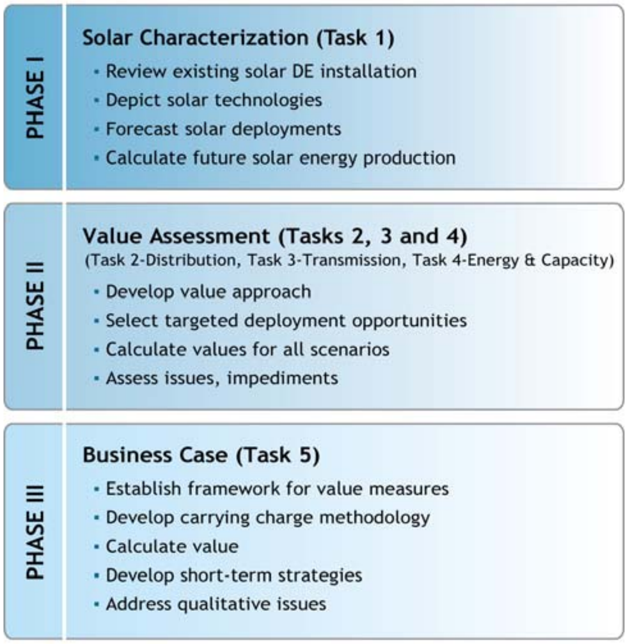
- Characterize the APS power system operations and planning specific to selected solar DE technologies.
- Define realistic solar DE deployment scenarios and projected production data to support subsequent analyses.
- Assess the value provided by solar DE technologies in terms of both capacity and energy.
- Evaluate impacts on system operation, reliability and value provided by solar DE generation on the APS system.
- Identify areas of potential improvement in value of solar DE for both owners of solar DE systems and for APS.
- Limit the Study assessment to three specific solar DE technologies:
  - residential and commercial photovoltaic systems
  - residential solar hot water systems
  - commercial daylighting systems
- Provide guidance to APS, its customers and renewable energy stakeholders for achieving the values identified in the Study.

The goal of the Study was to illuminate these issues and explore them in an open forum. Thus, this Study is intended to build a foundation of supportable fact and science, and wherever possible, to limit unsupportable assumptions and bias. The Study does not bend to any particular view but rather establishes a reasonable boundary of expected values – in essence creating "bookends" for evaluation. There is no single right answer or solution – there simply are too many uncertainties, expectations, and assumptions. Rather, from the outset, the Study established a rational, open and supportable foundation on which to calculate value assessments. The Study results should provide a common basis for understanding and serve as a starting point for further analyses on a variety of topics.

To that end, a cornerstone of the project has been the involvement of a wide array of stakeholders, representing solar vendors, academics, solar advocates, local builders and land developers, solar related construction firms as well as representatives of the regulatory community. More than 60 individuals representing 35 companies, universities, trade associations and national laboratories actively participated in the Study process, which included an opening and closing forum and five extensive workshops in which each Task methodology and results were reviewed, discussed and evaluated. In addition to the external stakeholders, APS provided significant input to the Study as a critically important internal stakeholder. APS provided expertise and employee assistance from its Renewable Energy, Energy Delivery, Transmission, Resource Planning, Rates and Regulation divisions, as well as other organizational areas, all of whom were involved from the outset of the Study. APS and the Study team worked cooperatively to leverage the insight and specific knowledge of the APS employees, along with APS analytical capabilities, to produce results that reflect mutual scrutiny and a high degree of concurrence. The involvement and critique from APS, as well as from the external stakeholders, was essential to building support for the ultimate analysis conducted for the Study as well as bridging between technical potential and practical reality. This Study reflects the commitment and valuable input from all the stakeholders and the Study team is grateful for their continued contributions.

Study Approach

R. W. Beck, Inc. (R. W. Beck), in association with Energized Solutions, LLC, Phasor Energy Company, Inc, Summit Blue Consulting, LLC and Arizona State University (collectively the Study team) responded to the Request for Proposal and was award the engagement in March 2008. The overall Study approach consisted of three phases, encompassing five key tasks, as depicted in the graphic below. In the first, *Task 1 – Solar Characterization,* the Study team built a technical base for characterizing future solar production. Characterizing solar DE generation from the three targeted technologies was the cornerstone of the subsequent value assessment. Solar DE output, the pivotal determinant for assessing value, is dependent upon a variety of factors, including specific technology, customer type, demographics, customer energy usage, building orientation, season and weather. Each of these factors was methodically addressed in developing a solar characterization output model. The modeling also assessed alternative scenarios to understand how solar DE installations might be deployed and their associated production potential.



Once solar DE deployment was understood and modeled, the second phase of the Study built on that information and identified specific value to the APS system from the solar DE technologies. Each of the specific tasks, *Task 2 – Distribution, Task 3 – Transmission,* and *Task 4 – Energy and Capacity,* focused on developing models to assess discrete monetary value that could be derived in the electric system. Though the Study organized the investigation of three utility functions individually, in reality they are not totally separable. Thus, the three tasks were grouped into one phase to reflect the interdependencies when assessing value in the electrical system.

The last phase involved assembling the results and compiling an integrated value assessment. *Task 5 – The Business Case,* provided quantified methodologies to calculate the monetary value of the results from Tasks 2, 3 and 4. The Business Case also explored the non-quantifiable Study results which are enormously important in promoting a winning business case for Arizona. Importantly, Task 5 also provided an opportunity for the Study team and APS to explore strategies for meeting RES goals in the near term.

The foundation for the Study is based on an analytical construct that analyzes value in discrete scenarios. First, the Study focused on three of the 12 solar technologies identified in the RES; photovoltaic generation in residential and commercial applications, solar hot water in the residential sector and active solar daylighting in the commercial sector. These three technologies were selected in order to keep the project scope manageable and complete the Study in a reasonable timeframe. The selected technologies also are most likely to be deployed at a sufficient scale in the Study region, and thus support the value bookends. The Study framework can support expanding the analyses to encompass the other technologies if desired at a future time.

Using the selected technologies, the Study built a "Market Adoption" scenario for the solar characterization and resulting value assessment. In this scenario, the market dictates value by individual customer decisions as to deploying any of the three solar DE technologies. The adoption or penetration of solar DE in the market is primarily driven by the payback period, and thus the Study examined three different cases for payback periods, reflecting low, medium and high penetration of solar DE (referred to herein as the Low, Medium and High Penetration Cases). The Low Penetration Case used conservative economic input assumptions, resulting in longer payback periods and reflecting the lowest value APS might expect from solar DE. The High Penetration Case utilized more aggressive economic input assumptions, which resulted in shorter payback periods and relatively high values associated with solar DE to APS. The Medium Penetration Case varied a key economic input assumption and resulted in payback periods and ultimate value to APS within the range created by the previous cases.

In contrast to allowing the market to drive value, the Study also examined how APS might target discrete locations where to deploy – or encourage – solar DE placement. This Target scenario was based on the High Penetration Case, but assumed that APS could strategically deploy solar DE. Additionally, a sensitivity case was developed to the High Penetration Case which assumed all commercial photovoltaic (PV) deployments would utilize single-axis tracking PV technology in lieu of flat plate PV technology. This sensitivity was intended to reflect the theoretical upside or maximum value solar DE could deliver. As indicated above, the Study was developed to analyze value for discrete scenarios, which included three discrete target years – 2010, 2015 and 2025.

Study Results

Value Calculation

The Study assessed the following methods to derive economic value from solar DE deployment:

- Quantify the savings from avoided or reduced energy usage costs due to solar DE deployment, based primarily on reduced fuel and purchased costs.
- Quantify the savings from reduced capital investment costs resulting from solar DE deployment, including the deferral of capital expenditures for distribution, transmission and generation facilities
- Estimate the present value of these future energy and capital investment savings due to solar DE deployment.
- Consider the impacts of various qualitative factors that will impact solar DE deployment.

The Study approach to assessing value separated capacity and energy savings. Capacity savings represent value in terms of either deferral or avoided investment costs by the utility, while energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in the energy requirements of the utility.

The methodology utilized for the Study is consistent with the revenue requirement approach for capital investment economic evaluations developed by the Electric Power Research Institute (EPRI), which is widely accepted in the utility industry. The methodology recognizes all elements of a utility's cost to provide service, including energy components (fuel, purchased power, and operating and maintenance [O&M] expenses and taxes) and capacity components (capital investment depreciation, interest expense and net income or return requirements).

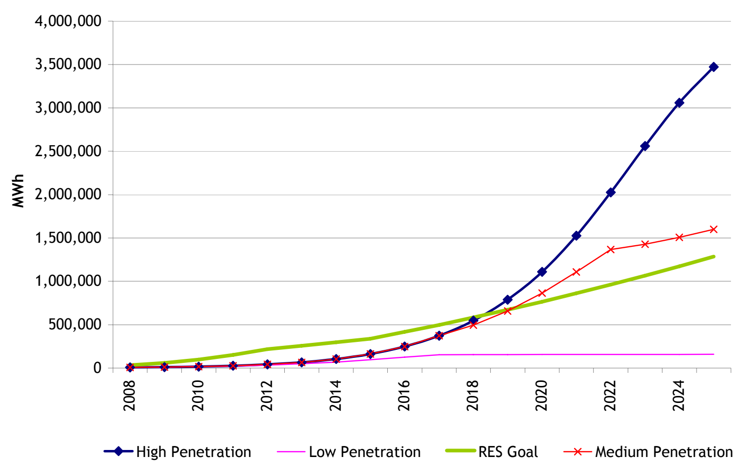
The value calculations measure the reduced energy and capacity costs that APS will not incur if solar DE is successfully deployed. The energy components and operational cost savings result from reduced fuel, purchased power, and reduced line related losses associated with reduced production requirements on the APS system due to solar DE deployment. Additional reductions in fixed O&M requirements for APS were quantified and included as annual cost savings. These values were used to estimate annual energy savings and cost reductions for the total entire APS system.

The capacity savings associated with solar DE deployment required a more complicated evaluation framework to calculate estimated savings for target years of the Study. The Study identified reduction or deferral in total capacity investments in distribution, transmission, and power supply. The corresponding annual reduction in APS's revenue requirements resulting from these capacity investment savings were estimated using carrying charges calculated separately for each sector. As these carrying charges generally decline over time as depreciation accumulates, the Study utilized a levelized carrying charge for each utility sector to address inherent uncertainty.

Value Summary

The Study shows that solar DE brings value to APS in both the near term and, increasingly, over the time. One of the key aspects of the Study reflects the fact that solar adoption will likely follow the economic attractiveness. Alternative funding mechanisms, such as third party leasing, may alter the economic drivers for individual adoption decisions. In the absence of such alternatives, payback period is the primary driver for most technology adoption, which applies to solar DE adoption as well. As electric rates increase and technology costs decease, the payback period will shorten and deployment will accelerate. The resulting traditional technology "S" shaped curve for adoption has significant impact on near term value calculations, particularly in the 2010 and 2015 timeframes. The following chart shows how the solar DE adoption is anticipated to accelerate in the future.

Solar DE (Commercial and Residential Combined)



Using the adoption cases and characterizing the solar DE production, the Study developed the capacity impacts on APS. For the distribution system, the Market Adoption scenarios (Low, Medium, and High Penetration Cases) created no real value. This is because the need to meet peak customer load when solar DE is unavailable eliminates most of the potential benefits. However, value for the distribution system can be derived when sufficient solar DE is deployed on a specific feeder. Such deployment can potentially defer distribution upgrade investments, but these solar installations must be located on a specific feeder to reduce a specific overloaded condition. The associated annual savings, which include the impact from carrying costs, are represented in the table below. The distribution value assessment is more fully discussed in Section 3.

Capital Reductions at Distribution Level (2008 $000)

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Target Scenario			
2010	$345	12.06%	$42
2015	$3,335	12.06%	$402
2025	$64,860	12.06%	$7,822
Single-Axis Sensitivity			
2010	$345	12.06%	$42
2015	$3,450	12.06%	$416
2025	$67,045	12.06%	$8,086

Unlike the distribution system, the specific location of the solar DE was not an impediment to obtaining value for the transmission system. However, there are several other issues that did affect value. First, the long term planning requirements for transmission facilities made opportunities in 2010 and 2015 unlikely. Initially, the load pocket in Yuma was targeted for transmission relief through solar DE, but the near term need for additional transmission capacity in that area eliminated this targeted value opportunity. Second, transmission improvements are "lumpy" in nature. A significant number of solar DE installations would be required to aggregate sufficient capacity demand reduction to avoid or defer transmission system investment. Therefore, the calculated transmission capacity savings occur only in the last target year (2025) and for the High Penetration Case. The carrying costs are represented in the annual savings shown below. The transmission system value assessment is more fully discussed in Section 4.

Capital Reductions at Transmission Level (2008 $000)

	Transmission System	Carrying Charge (%)	Associated Annual Savings
High Penetration Case			
2010	$0	11.84%	$0
2015	$0	11.84%	$0
2025	$110,000	11.84%	$13,024

Solar DE value for the generation system was similar to the transmission system in that the specific location of solar DE was not an impediment to determining capacity savings. Also similar to the transmission system, capacity cost reductions for the generation system require a significant aggregation of solar DE installations, and benefits occur only in the later years of the Study period. Unlike the transmission system however, generation capital cost reductions were determined to exist for both the Medium and High Penetration Cases, as shown in the table below (which incorporates the impacts from the associated carrying costs). The generation system value assessment is more fully discussed in Section 5.

Capital Cost Reductions at Generation Level (2008 $000)

	Generation System	Carrying Charge (%)	Associated Annual Savings
Medium Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$184,581	11.79%	$21,762
High Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$299,002	11.79%	$35,252

Much of the potential annual saving from solar DE production results from APS avoiding the need to produce that same energy from conventional sources. This reduced energy requirement decreases fuel and purchased power requirements and brings associated reductions in line losses and annual fixed O&M costs. Generally, these energy savings were found to exist for all deployment cases, with the exception of reduction in fixed O&M costs for the Low Penetration Case. Additionally, unlike certain capital deferrals, the specific location of the deployment of solar DE was not a determinant for these value characteristics.

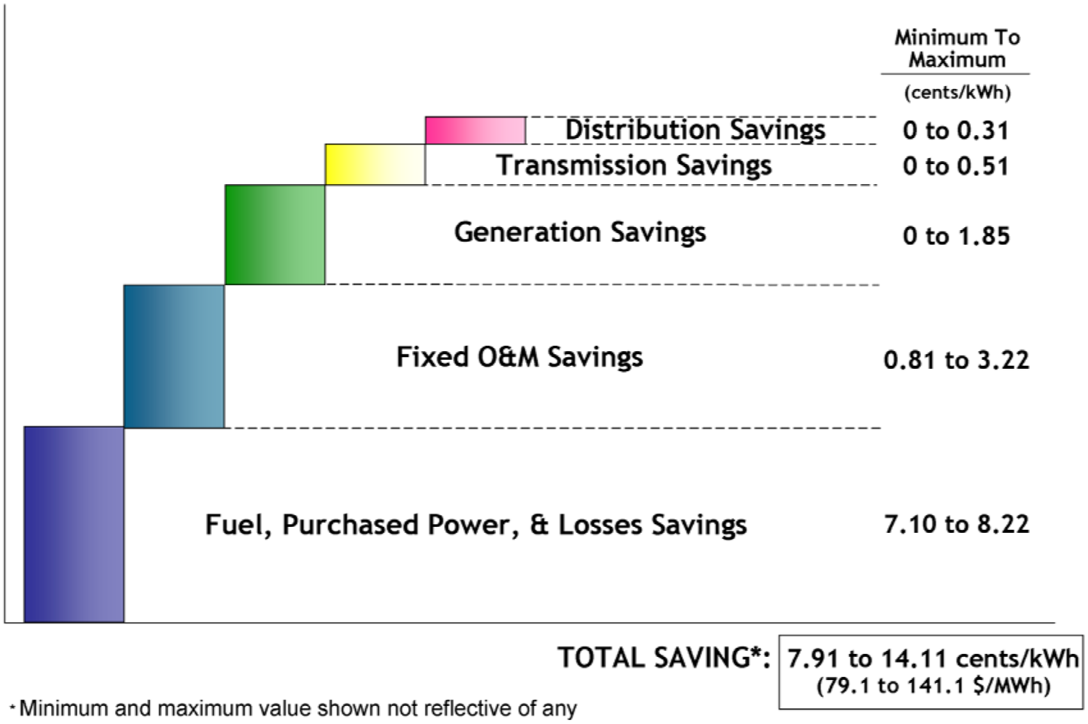
The values determined for the annual energy savings (including the reduction in losses discussed in Section 4 and the reduction in fuel and purchased power costs discussed in Section 5) are shown in the table below and are a direct result of the output from the solar DE installations. As more solar DE technology is installed, these savings values will directly increase. Reductions in fixed O&M costs related to the reduction in demand for the dependable generating capacity. The Target scenario results are identical to the High Penetration Case (as the Target scenario is focused on specific locations of solar DE on the distribution system, which impacts the capacity savings, but not the energy savings). The single-axis sensitivity shows a slightly higher energy savings resulting from increased production from these units. The energy value assessment is more fully discussed in Section 5.

Annual Energy and Fixed O&M Savings (2008 $000)

	Reduction in Losses	Reduction in Fuel/ Purchased Power	Reduction in Fixed O&M Costs	Total Energy Related and Fixed O&M Savings
Low Penetration Case				
2010	$102	$834	$0	$936
2015	$501	$5,105	$659	$6,266
2025	$701	$7,847	$3,728	$12,276
Medium Penetration Case				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$8,659	$87,936	$18,946	$115,542
High Penetration Case / Target Scenario				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$14,529	$167,480	$20,965	$202,974
Single-Axis Sensitivity				
2010	$114	$918	$0	$1,031
2015	$1,074	$9,504	$1,546	$12,124
2025	$14,925	$173,921	$21,444	$210,290

The summary of the value calculations is shown below. This chart presents the results from the Study for 2025 in terms of a range of potential unit savings (in $ per kWh) by each of the value categories. The relative contribution from each of these value categories is represented by the relative size in the following graph; the distribution savings are the smallest and the energy related savings are the largest. These values reflect the maximum and minimum for each category and while they are not reflective of any specific scenario analyzed for this Study, they present insight into where value can be achieved.

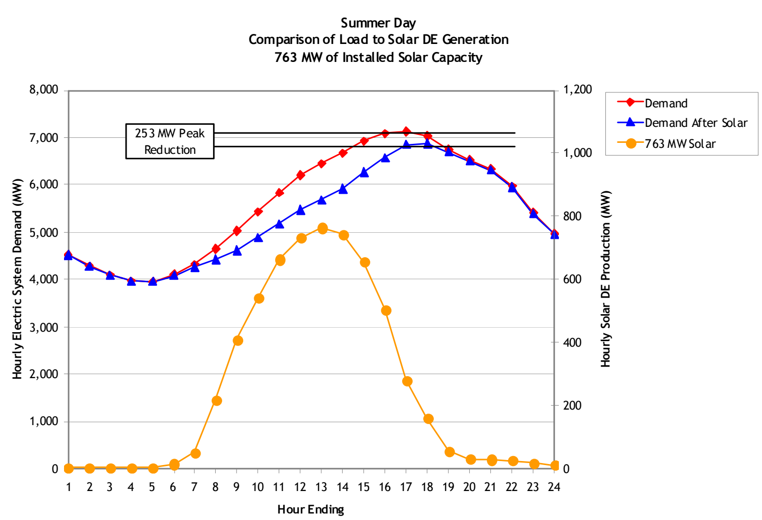
Solar DE Value Buildup



* Minimum and maximum value shown not reflective of any specific scenario as evaluated in this Study

The value outcomes shown in the chart above are the result of many complex factors that weigh on how value is derived from solar DE. The chart shows that most solar DE savings are realized in terms of energy. Perhaps one of the most significant findings in the Study found that peak solar production is not coincident with the APS customer demand curve which peaks late in the day, when the sun is setting or is lower in the horizon (see graph at right). Thus, the capacity savings are limited by the time of day of APS's system peak demand. Notably, solar hot water stores thermal energy into the peak demand period, and helps reduce the rate of diminishing returns. Even with solar hot water, adding additional solar production results in diminishing returns in capacity value. At some point the additional solar production simply pushes the APS peak later into the day. This may seem counterintuitive especially from the customer cost perspective, where both residential and

Solar Production Versus Demand Peak



commercial customers (without demand changes) will see the energy portion of their bill reduced as a direct offset for both energy and demand reduction in delivered energy from APS.

Another critical aspect of the value assessment focused on understanding the dependable capacity from solar DE. Power supply planning is concerned with the ability of a given resource portfolio to reliably serve the total system load – not just at the time of the peak but across all hours of the year. The capability of solar DE resources to displace power supply resources must, therefore, be evaluated to determine the amount of solar DE capacity relative to the quantity of traditional capacity needed to provide the same level of reliability. When compared to traditional gas turbine resources, the type of resources most likely to be offset, solar DE requires a higher production level to achieve similar reliability. The dependable capacity for 100 MW of solar DE is shown below.

Percent Dependable Solar DE Capacity
100 MW Installation

	Base Case Resource Plan					
Solar DE Technology	**2007**	**2006**	**2005**	**2004**	**2003**	**Average**
Solar Hot Water	47.8%	41.8%	43.9%	46.3%	43.1%	44.6%
Daylighting:						
Low Penetration Case	72.7%	64.1%	N/A	58.7%	62.0%	64.4%
High Penetration Case	73.3%	66.2%	N/A	59.0%	63.6%	65.5%
Residential PV:						
18.4° Tilt, S-Facing	41.5%	52.5%	48.4%	41.1%	42.3%	45.2%
18.4° Tilt, SE-Facing	28.4%	40.8%	36.5%	28.7%	32.5%	33.4%
18.4° Tilt, SW-Facing	54.2%	63.4%	58.8%	53.1%	50.7%	56.0%
Commercial PV:						
10° Tilt, S-Facing	43.7%	55.2%	50.8%	42.9%	44.3%	47.4%
0° Tilt, N/S Single-Axis Tracking	73.1%	75.3%	74.0%	68.3%	60.4%	70.2%

The value assessment reflects these and many other complex factors that were identified and researched for the Study. Despite initial belief to the contrary, there is relatively little value from solar DE on the distribution or transmission systems on a unit basis. This is because there is insufficient solar DE to offset much of the necessary capacity needed to meet peak customer load for these systems. In addition, transmission projects require substantial lead time and thus most opportunities for value, even under the High Penetration Case, reside well into the future.

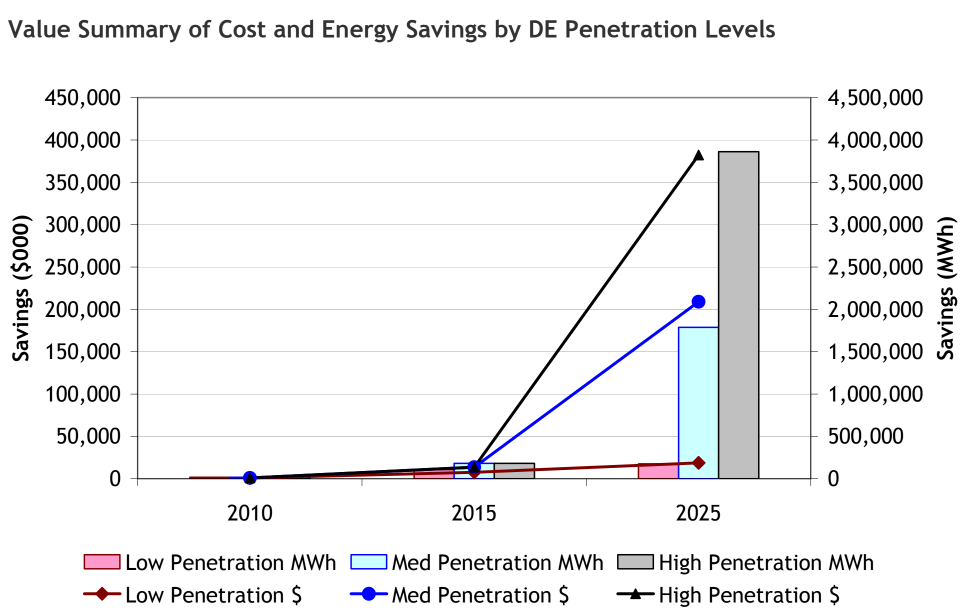
Generating savings results from deferred capital investment and show greater opportunities for value. Clearly, savings result from increased solar DE deployment. However, the issue of dependable capacity has a significant impact on the relative value opportunities, and the Study found that dependable solar DE capacity diminishes as solar DE installation increases. This results because as more solar DE resources are added to the electric system, the APS system peak demand will be pushed to a later hour in the day. Because the output of the solar DE resources becomes significantly less as the available sunlight diminishes at dusk, the delay of the peak hour to a later hour could diminish the ability of the solar DE resources to meet the electric system peak demand and satisfy reliability planning criteria.

Moving Forward

Solar DE deployment represents the opportunity to accrue real value to APS and a broad range of stakeholders in Arizona. The winning business case for solar DE in Arizona is a combination of hard, quantitative economic facts, such as the reduction of line losses, energy savings for customers, and reduced or deferred capital expenditures. But it also includes softer, qualitative benefits such as increased job opportunities for installers, a more sustainable environment, and as yet unquantifiable benefits that will likely become economic in the future, such as the value of carbon. Even broader economic benefits would include improved worker productivity and a more robust solar DE manufacturing industry.

To capture the benefits of a winning business case it will be important to regularly monitor and report on the progress being made, and to look for opportunities to remove barriers to the successful expansion of solar in the state. It is the removal of those barriers and the movement toward the tipping point – where solar is the norm – that will prove that solar programs have become mainstream and are part of a new energy future. The value potential is shown below and it is the range of value potential that is noteworthy. The state of Arizona can influence the value potential and has great opportunity to play an important role in the future of solar energy.

The Study has focused primarily on the monetary values involved in solar DE deployment. This economic view is a cornerstone for any forward-looking opportunity to promote major gains in solar DE deployment in Arizona. However, customer conditions or perceptions may affect the tipping point that can be achieved either through market push (subsidies), market pull or a combination of both.



Creation of a successful business case will require both long-term fundamental changes in the market and the proper stimulation of conditions to encourage solar DE development. Most of these market transformation efforts are beyond sole control of APS, but can be encouraged with the right combination of economic, policy, political and business strategies. APS is clearly not the creator of these barriers; some are technological, others practical, and still others typical of nascent markets. Some of these factors, such as energy storage, are broad issues which require massive amounts of investment. The adoption of new building requirements has been shown to have significant implications, such as in requiring greater energy efficiency in new construction. Solar-ready construction and special consideration for communities that opt for a certain percentage of SHW and daylighting could spur adoption and have a substantial impact on solar deployment. Similarly, current land use requirements might be altered, facilitating the ability to harvest greater benefit from greenfield areas. Indeed, dramatic future growth projections for new planned urban developments offer Arizona a unique opportunity to promote and integrate solar DE in emerging communities.

Institutional support from banks and appraisers needs to recognize that homes with superior energy efficiency may warrant lower mortgage rates, reflecting lower financial exposure to utility bills. Appraisals will need to reflect how solar DE systems offer positive value to a home and tie to the banking community's understanding and willingness to support larger, and/or lower cost, loans that finance solar technologies.

Many market changes are underway in business models and approaches. Third party equipment leasing and ownership is becoming more common and may become the norm, changing the buyer behavior and driving accelerated adoption. APS may want to consider a new business model itself in which it directly provides services that help promote solar DE market development.

Other opportunities may emerge in the near term as well. Community systems, especially in greenfield areas, require a single "sale" and offer greater solar energy production output, accelerating deployment. Accelerated adoption may result from initially concentrating on community solar DE development over individual premises. Developers and homebuilders may be interested in opportunities to promote community solar DE projects on common parcels or on less desirable sites. And rather than fixed installations, single-axis tracking could extend PV production and utilize less desirable locations.

Much opportunity exists to transform the marketplace. The greenfield potential for the developing areas in and around the APS service territory provides a unique opportunity to accelerate solar DE deployment above and beyond normal adoption rates through the promotion of solar, partially solar and "green" communities. The scale of these developments and the opportunity to drive adoption by "building in" some, or many, solar DE technologies holds tremendous opportunities for accelerating residential production goals.

As described in the Study, the "Law of Diminishing Returns" shows that the first unit of energy (MWh) of solar production is more valuable to APS than the last. There may be opportunity to incentivize early adoption. Another variation may be to consider rewarding larger systems, which would decrease the administrative cost per MWh while boosting net incremental production.

Lastly, APS may wish to be more involved in the promoting the solar marketplace by being more active as a market entrant. APS could stimulate the market in several ways, such as by easing consumer adoption. Easy, streamlined, one-stop shopping will help move customers to early adoption as has been shown in automobile leasing. A similar approach that streamlines financing, contacting, installation and operation/maintenance could attract customers and build market momentum. APS may wish to evaluate partnering with developers and homebuilders to encourage SHW heating and optional-sized PV systems. APS could make technology procurement easy and transparent to the end customer by offering financing options. Such alternatives reflect creative business models that create opportunities for APS to work with the local installation, supply and manufacturing communities in achieving a mutual goal for a successful Solar Future Arizona.

APS's study to evaluate Distributed Renewable Energy Operating Impacts and System Valuation examined three solar DE technologies at three discrete future points in time.

SECTION 1 — STUDY BACKGROUND AND DESCRIPTION

1.1 Introduction

1.1.1 Background

In February 2008, Arizona Public Service (APS) issued a Request for Proposal (RFP) for the APS Distributed Renewable Energy Operating Impacts and Valuation Study (the Study). APS initiated this Study to determine the potential value of solar distributed energy (referred to herein as "solar DE") technologies for its electrical system, as well the likely operating impacts. Though numerous studies had previously looked at the value of distributed energy, none had specifically evaluated the costs and benefits to APS from solar DE technologies. APS sought to evaluate the realistic implications of solar DE deployment and production on their specific system conditions.

R. W. Beck, Inc. (R. W. Beck) responded to the RFP with a proposal to address the requested work scope, and was awarded the assignment in March 2008. This Report provides a summary of the methodology and results of this Study.

1.1.2 Objectives

APS had many specific objectives they wanted to accomplish through this Study effort. These included:

- Characterize the APS power system operations and planning specific to selected solar DE technologies.
- Define realistic solar DE deployment scenarios and projected production data to support subsequent analyses.
- Assess the value provided by solar DE technologies in terms of both capacity and energy.

- Evaluate impacts on system operation, reliability and value provided by solar DE generation on the APS system.
- Identify areas of potential improvement in value of solar DE for both owners of DE systems and for APS.
- Specifically limit the Study assessment to the following solar DE technologies:
  - residential and commercial photovoltaic systems
  - residential solar hot water systems
  - commercial daylighting systems
- Provide guidance to APS, its customers and renewable energy stakeholders for achieving the values identified in the Study.

1.1.3 Study Need and Philosophy

The need for an objective study of this type was driven by the enthusiasm for renewable energy in a region as richly endowed with solar resources as Arizona, the strong and diverse viewpoints among stakeholders in the region, and the technical complexity of a technology involving rapid change. Not surprisingly, strong advocacy is manifest across many stakeholders who represent the solar industry, builders and developers, consumer advocates, green and conservation advocates and others. They all share a particular appeal for solar technologies in a resource rich region such as the Southwest United States.

Though strongly supported, there are myriad complexities and implications associated with installing distributed solar generation broadly across a utility electrical system. The objectives of the Study called for illuminating these issues and exploring them in an open forum. Because the entire issue of solar energy reflects the interests of such a diverse range of stakeholders, this Study was intended to provide an independent and transparent means to establish a foundation for agreement moving forward. Clearly, there are strongly held beliefs and assumptions about solar benefits and impediments. This Study is intended to build a foundation of supportable fact and science, and wherever possible, limit unsupportable assumptions and bias. With any new and rapidly evolving technology, much is unknown and will only be resolved in the future. Solar energy technologies patently reflect this uncertainly as evidenced by prominent individuals at industry symposia who vary greatly in their forecasts of future capabilities, costs, and market response of solar technologies.

The Study does not bend to any particular view but rather sets out to establish a reasonable boundary of expected values – in essence creating "bookends" for evaluation. There is no single right answer or solution – there simply are too many uncertainties, expectations, and assumptions. Rather, from the outset the Study intent has been to establish a rational, open and supportable foundation on which to calculate value assessments. The Study results should provide a common basis for understanding and serve as a starting point for further analyses in a variety of applications. Appendix A to this Report provides a glossary of the terms and abbreviations utilized herein.

1.2 APS Solar Program

1.2.1 Arizona Renewable Energy Standards Program

Arizona is one of 28 states seeking to increase renewable resources in its state energy supply portfolio through the mechanism of Renewable Portfolio Standards. The Arizona program, termed "Renewable Energy Standards" (RES), promulgates regulatory policies that require electric utilities to increase the production of electricity from renewable energy sources including wind, solar, biomass and geothermal energies.

Since being enacted in 2006, the Arizona Corporation Commission (ACC) has expanded the state's RES goal. The most recent change, effective in August 2007, increased the goal to 15 percent of total energy sales by 2025. This standard applies to investor-owned utilities (IOUs), such as APS, serving retail customers in Arizona, with the exception of distribution companies who have more than half of their customer base outside Arizona.

Utilities must not only obtain sufficient renewable energy credits (RECs) from eligible renewable resources to meet their 15 percent target for 2025, they must ensure that at least 30 percent of the target is derived from distributed renewable resources by 2012. The schedule for compliance, which increases annually, is shown in Figure 1-1. Many renewable energy technologies apply towards meeting the standards set forth and these are shown in Table 1-1. Utilities may recover RES costs through a monthly surcharge approved by the ACC.

Figure 1-1: RES Compliance Schedule

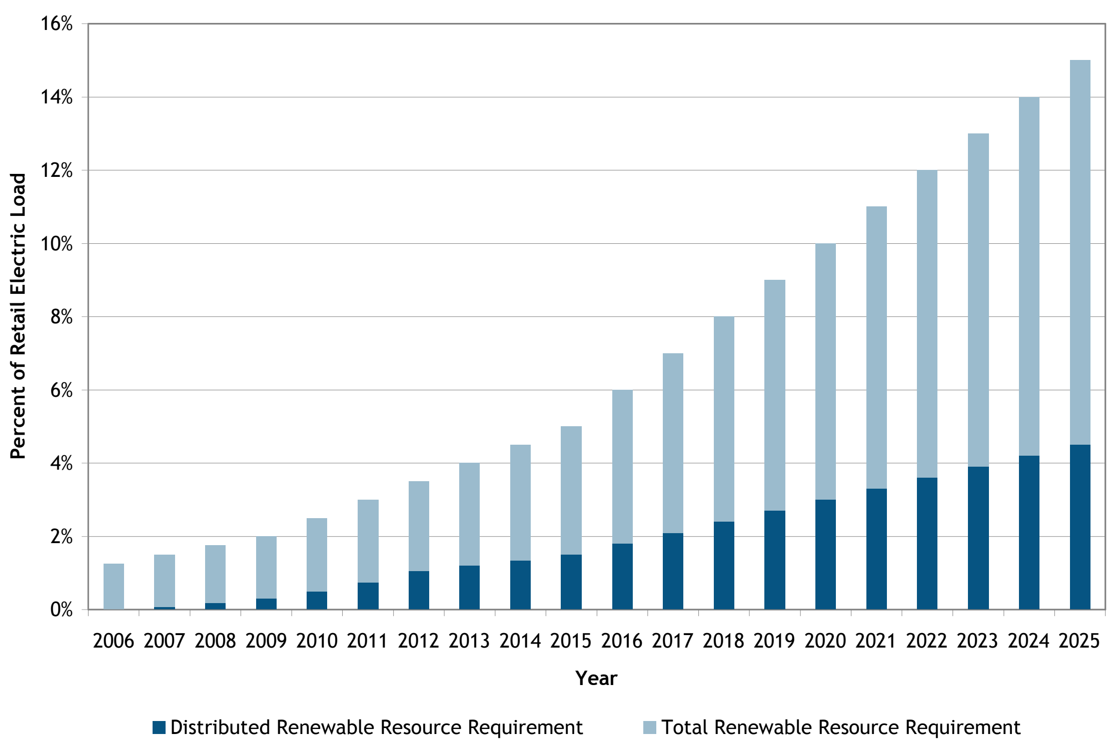


Table 1-1
RES Eligible Technologies

Eligible Renewable Energy Resources	Eligible Distributed Renewable Energy Resources
Biogas Electricity Generator	YES (and Biomass Thermal Systems)
Biomass Electricity Generator	YES (and Biogas Thermal Systems)
Eligible Hydropower Facilities	
Fuel Cells that Use Only Renewable Fuels	YES
Geothermal Generator	YES
Hybrid Wind and Solar Electric Generator	
Landfill Gas Generator	
New Hydropower Generator of 10 MW or Less	YES
Solar Electricity Resources	YES
Wind Generator	YES (1 MW or Less)
Distributed Renewable Energy Resources	▪ Renewable Combined Heat and Power System ▪ Commercial Solar Pool Heaters ▪ Solar Daylighting (non-residential) ▪ Solar Heating, Ventilation, and Air Conditioning ▪ Solar Industrial Process Heating and Cooling ▪ Solar Space Cooling ▪ Solar Space Heating ▪ Solar Water Heater ▪ Geothermal Space Heating and Process Heating Systems

Utilities are required to submit annual compliance reports to the ACC annually, on April 1, as well as implementation plans on July 1. They are also required to provide an electronic copy of these reports suitable for posting on ACC's web site. If a utility fails to meet the annual requirements, noncompliance must be indicated in its annual compliance report along with a plan describing how the utility intends to meet the shortfall and the associated costs. If the utility fails to comply with its implementation plan as approved by the ACC, the ACC may disallow plan cost recovery and/or impose penalties.

1.2.2 APS Renewable Programs

APS offers incentive programs to encourage customers to take advantage of distributed renewable technologies to meet its requirements for the RES goals, including the three solar DE technologies that formed the basis of this Study. As a foundation for the overall analysis, R. W. Beck evaluated the current programs in place, and the existing state of installation, of each of the three solar DE technologies listed in the Study objectives. This analysis helped identify the characteristics of typical systems, current system deployment patterns, and service territory preference for system deployment. Though the RES goals are stated in terms of total energy production as a percent of total customer load, APS drives, maintains, and tracks separate internal goals for commercial and residential customer classes. All analyses in this Study have maintained this important distinction between residential and commercial goals consistent with APS. The results helped validate the baseline system assumptions for each solar DE technology utilized for this Study. The results of this analysis are shown in the tables below.

Photovoltaic Systems

APS offers rebate incentives for both residential and commercial photovoltaic (PV) systems. Rebates for both customer classes are based on a dollar per installed watt capacity and decrease over time. The declining incentive assumes that market adoption gains momentum as costs drop and market forces take hold. The current rebate schedules are presented in Table 1-2.

Table 1-2
Photovoltaic (PV) Rebates

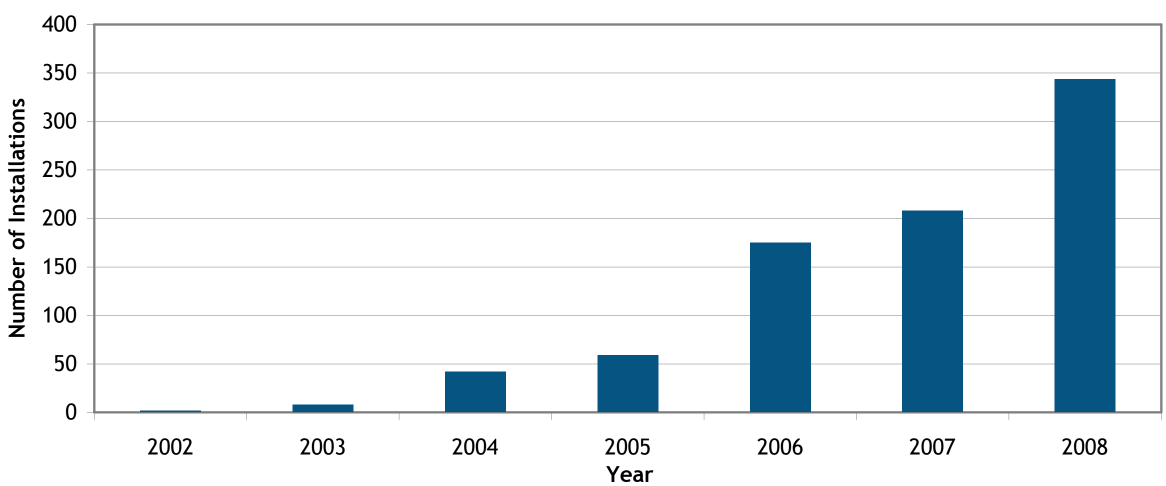
APS Rebates $/Watt	2008	2009	2010	2011	2012	2013
Commercial PV	$2.50	$2.50	$2.25	$2.25	$1.91	$1.91
Residential PV	$3.00	$3.00	$2.70	$2.70	$2.30	$2.30

Source: APS

Residential PV:

The number of residential PV systems installed has been increasing. As shown in Figure 1-2, there has been a steady increase in installations per year since 2002 (and as far back as 1995). Although the rate of growth has been rapid, the cumulative number of installations since 2002 is only 581, an insufficient number on which to base any trends. However, demand is clearly growing, as evidenced by the 2008 forecast of 344 residential PV installations (annualized based on 11½ months of data). This represents a 70 percent increase over 2007.

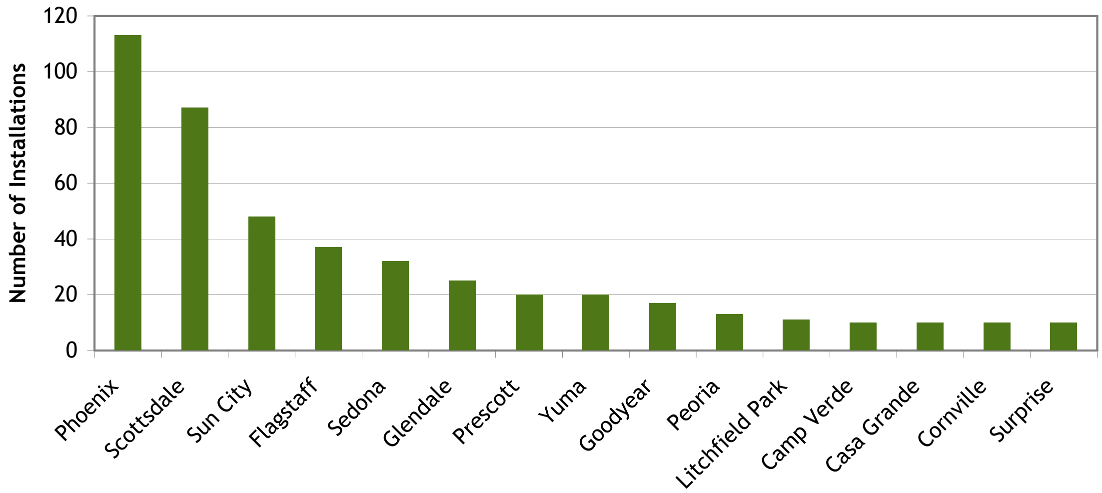
Figure 1-2: Number of Residential PV Installations by Year



Source: APS Data
Note: 2008 value is annualized based on 11½ months of data.

The number of installations by city/community is shown in Figure 1-3. Although the geographic dispersion of residential PV installations is broad, it remains geographically centered in North Phoenix, Scottsdale, and Sun City, reflecting a clear bias toward higher income customers.

Figure 1-3: Number of Residential PV Installations by Community

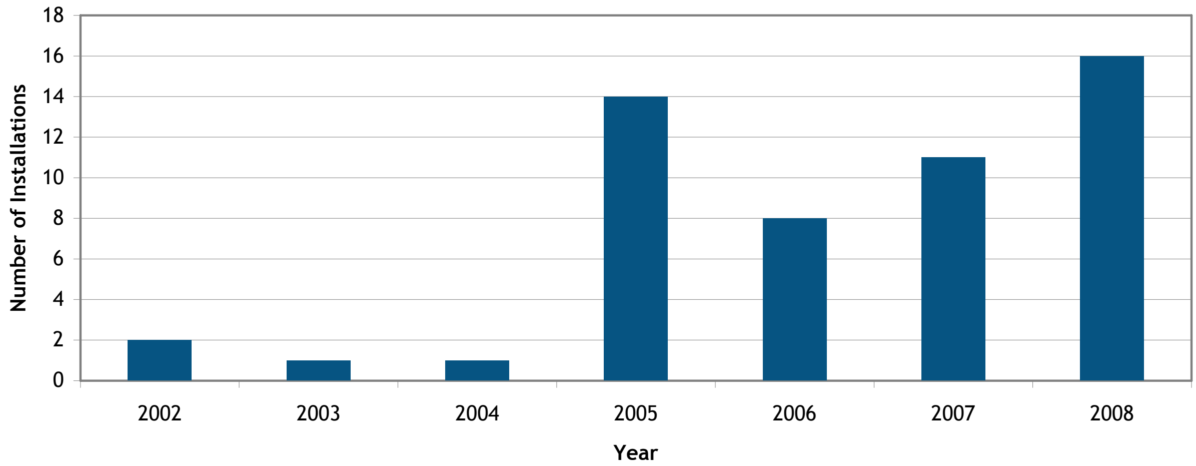


Source: APS Data

Commercial PV:

The annual installation of commercial PV systems is shown in Figure 1-4. Similar to the trend shown for residential PV installation, 2008 shows significant increase over preceding years, based on an annualized forecast. Nevertheless, for the purposes of this Study, R. W. Beck found that a cumulative total of only 53 systems have been installed in the APS service territory (based on an expected value for 2008), which is insufficient to characterize the typical commercial PV system installation for the APS service territory. Accordingly, to properly characterize commercial PV applications for this Study, R. W. Beck drew upon additional data and results from other sources, particularly jurisdictions in California and New Jersey (see Appendices B and C).

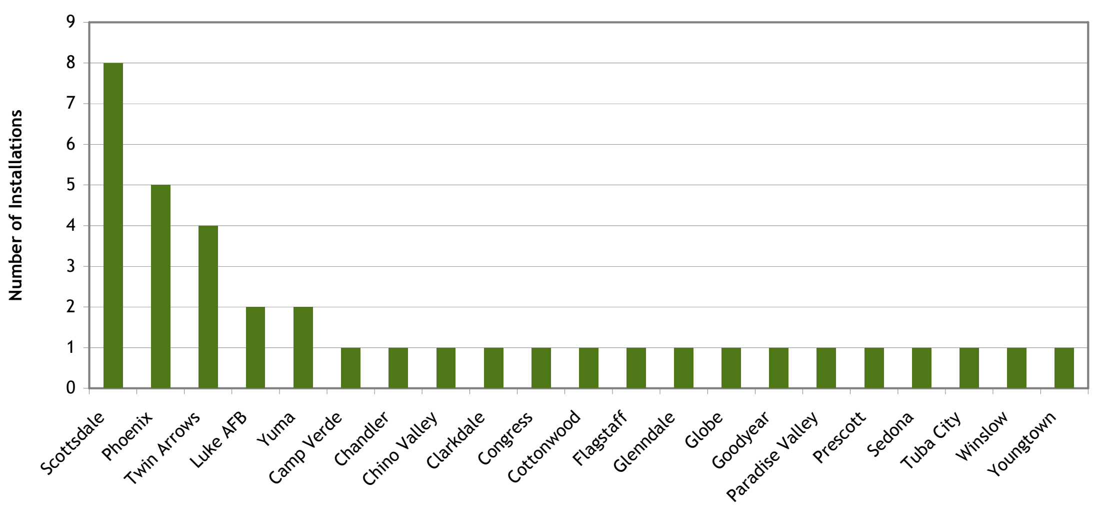
Figure 1-4: Number of Commercial PV Installations by Year



Source: APS Data
Note: 2008 value is annualized based on 11½ months of data.

Showing trends similar to residential PV, most commercial installations are located in Scottsdale, Phoenix, and Twin Arrows. Figure 1-5 shows the number of installations by city/community.

Figure 1-5: Number of Commercial PV Installations by Community



Source: APS Data

Solar Hot Water Heating Systems

Solar hot water (SHW) heating is a distributed solar application designed to reduce load from residential domestic hot water heating. It is applicable to residential customers only and incentives are offered to customers on a first year dollar per kilowatt hour ($/kWh) basis (the incentives are designed to be a one-time "up-front" payment). Table 1-3 shows the current schedule of rebate offerings.

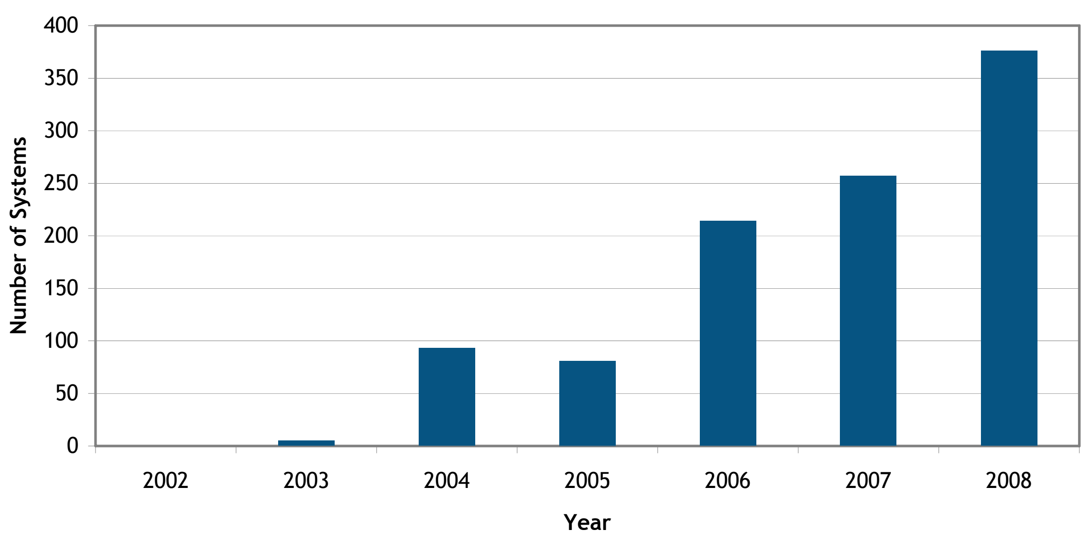
Table 1-3
Residential Solar Hot Water Rebates

APS Rebates $/kWh	2008	2009	2010	2011	2012	2013
Residential SHW	$0.750	$0.750	$0.675	$0.675	$0.574	$0.574

Source: APS
Note: The incentives are for first year energy savings only and are a one-time, "up-front" payment.

As of the end of 2008, there were 1,076 SHW systems installed in the APS service territory. Of this total, more than one-third (376) were installed in 2008 (annualized basis), suggesting a rapid increase in adoption of these systems. Figure 1-6 presents the number of SHW installations by year.

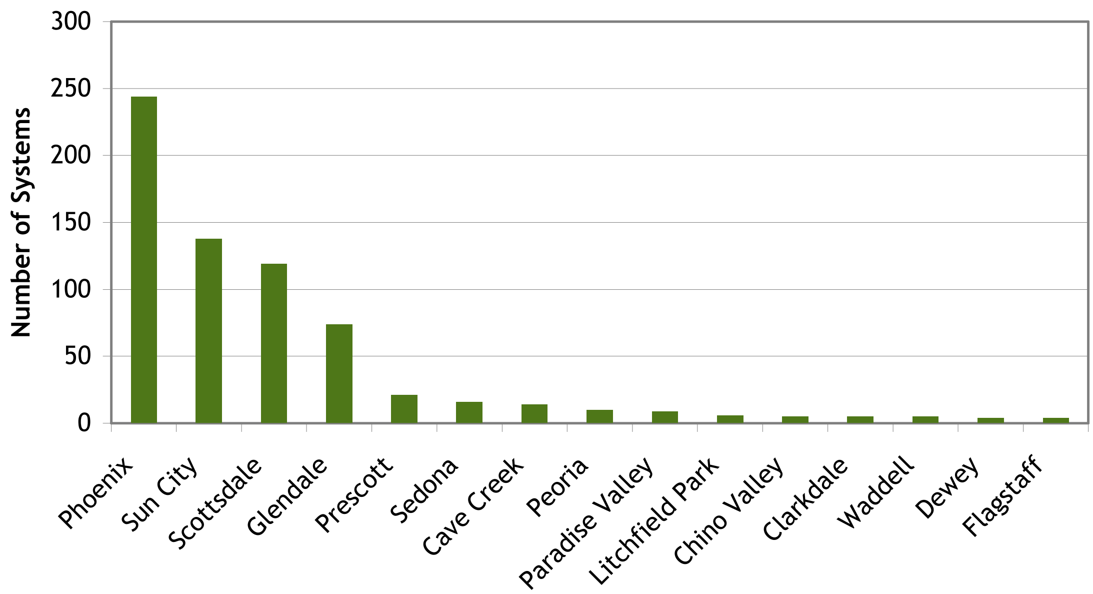
Figure 1-6: Number of SHW Installations by Year



Source: APS Data
Note: 2008 value is annualized based on 11½ months of data.

SHW deployment follows the same geographic deployment patterns as PV. As shown in Figure 1-7, North Phoenix, Sun City, and Scottsdale represent the majority of system deployments.

Figure 1-7: Number of SHW Installations by Community



Source: APS Data

Solar Daylighting Systems

Solar daylighting employs active control of lighting systems, replacing electric illumination with architecturally directed sunlight. These systems have strict requirement for ensuring adequate brightness (lumen) illumination and require the active discontinuation of artificial lighting. Due to the roof structure requirement and active systems, this program is offered to commercial customers only.

Solar daylighting incentives are offered to customers on a first year energy savings ($/kWh) basis (similar to the SHW systems, the daylighting incentives are designed to be a one-time "up-front" payment). Table 1-4 shows the current schedule of rebate offerings through 2013.

Table 1-4
Commercial Daylighting Rebates

APS Rebates $/kWh	2008	2009	2010	2011	2012	2013
Commercial Daylighting	$0.200	$0.200	$0.180	$0.180	$0.150	$0.150

Source: APS
Note: The incentives are for first year energy savings only and are a one-time, "up-front" payment.

Currently, no daylighting installations have received a rebate incentive through the APS program, although applications are underway. In the absence of sufficient APS specific data, the Study utilized program results from other regions of the country, as well as discussion with stakeholders on their experiences in the greater Phoenix area.

1.3 APS Customer Usage Characteristics

The identification of the customer characteristics was developed in parallel with the technology characterization process. For this Study, customer characteristics were used to determine the mix of customers, the number of customers by type, their representative electric load profiles, the total number of customers who meet the technical requirements to install the technology, and the size of system that a customer is likely to install. APS provided customer counts by tariff and their representative annual electric load profiles. Additionally, APS provided specific customer location data from its customer information system. Other data sources included U.S. Census Data on number of households, mix of housing types and household income by zip code.

Table 1-5 presents the APS tariffs with the largest number of customers. The primary residential tariffs are the E12 and the ET-1 with 46.2 percent and 31.9 percent of the residential customers, respectively. The most popular tariff for commercial customers is the E32 rate. The customers in the E32 class have been separated into five categories based on the peak demand and are as follows: extra small (0 kW to 20 kW), small (21 kW to 100 kW), medium (101 kW to 400 kW), large (> 400 kW), and extra large, which are industrial customers. Most of the commercial customers (77.5 percent) are in the extra small category.

Table 1-5
APS Tariffs with Highest Number of Customers

Tariff	Description	Customers (2007)	Percent of All Customers	Percent of Residential Customers	Percent of Commercial Customers
E10	Residential Classic Rate	69,731	6.56%	7.4%	
E12	Residential Standard Rate	437,213	41.13%	46.2%	
ET-1	Residential Time Advantage 9:00 PM – 9:00 AM	339,594	31.94%	35.9%	
ET-2	Residential Time Advantage 7:00 PM – noon	36,083	3.39%	3.8%	
ECT-1	Residential TOU (9-9) with demand charge	54,789	5.15%	5.8%	
ECT-2	Residential TOU (9-9) with demand charge	8,566	0.81%	0.9%	
E32 xsmall	Commercial 0 – 20 kW	90,811	8.54%		77.5%
E32 small	Commercial 21 – 100 kW	20,496	1.93%		17.5%
E32 medium	Commercial 101 – 400 kW	4,535	0.43%		3.9%
E32 large	Commercial > 400 kW	893	0.08%		0.8%
E32 xlarge	Industrial	196	0.02%		0.2%
E32 TOU xsmall	Commercial TOU 0 – 20 kW	52	0.00%		0.0%
E32 TOU small	Commercial TOU 21 – 100 kW	91	0.01%		0.1%
E32 TOU medium	Commercial TOU 101 – 400 kW	47	0.00%		0.0%
E32 TOU large	Commercial TOU > 400 kW	20	0.00%		0.0%
E32 TOU xlarge	Industrial TOU	8	0.00%		0.0%
Total		**1,063,125**			

Composite load profiles for each of the tariff classes were provided by APS. The load profiles represent an average load profile for the class of customer that was derived from a group of actual customers throughout the APS service territory. These data were utilized to evaluate the impact of the solar DE technologies for these customers, which are typical of the customer class represented by the rate tariff.

Table 1-6 shows a summary of energy consumption for the tariff classes evaluated in this Study. More detailed energy consumption information and hourly load data for these tariffs is included in Appendix D and Appendix E, respectively.

Table 1-6
Energy Consumption for Selected APS Tariffs

Tariff	Annual Consumption (kWh)	Demand During Peak Month (kW)	
		Maximum	Minimum
Residential E12	8,676	2.6	0.7
Residential ET-1	17,546	5.6	1.6
Commercial E32 Extra Small	26,103	7.2	2.2
Commercial E32 Small	189,058	43.3	17.5
Commercial E32 Medium	928,847	193.7	87.1
Commercial E32 Large	3,379,799	597.8	319.5

1.4 Study Description

There are 12 renewable technologies addressed in the Arizona Renewable Energy Standards and APS has implemented incentive programs for all of them. While each will help APS achieve its required goals for renewable energy, APS specifically limited this Study to three distributed solar technologies that can be broadly deployed across its electrical system. The Study looked at the financial, technical, policy and business case issues surrounding a significant successful penetration of solar DE into residential and commercial applications. The Study focused on solar PV in commercial and residential applications, solar hot water in the residential sector only, and solar daylighting for commercial customers. The Study uses standard utility-industry methodologies to analyze the impacts of solar DE resources on three key dimensions of utility operations: distribution systems, transmission systems, and overall system planning.

This Study sought to develop common understanding among internal and external stakeholders through a process of education and stakeholder involvement, all intended to help APS achieve its intended goal for solar penetration. The Study design used a building block approach and was organized into five distinct yet interrelated tasks. Each task formed the basis for the succeeding tasks, and afforded critical internal and external stakeholder input. The task structure continued throughout the study effort and is reflected in the organization of this Report.

Task 1 focused on characterizing the specific solar DE technologies addressed in this Study, in terms of the current technical attributes and future potential improvements. The evaluation was tailored to the specific conditions for use in Arizona, and then further narrowed to the APS service territory and major customer locations in Phoenix and Yuma. Task 1 also focused on modeling the deployment of these solar technologies across the APS system, and understanding customer electrical usage across different customer classes.

Tasks 2, 3 and 4 provided a technical assessment of how these specific solar DE technologies could provide value to APS in terms of distribution, transmission and power supply planning. Task 2 utilized the results from the solar characterization to study the distribution system benefits, which were used as a foundation for Task 3, where the Study examined the transmission system as a whole. In Task 4, these results were reviewed on a consolidated system basis to understand potential impacts and opportunities on energy and capacity planning.

Finally, in Task 5, all of the results were combined into a business case which examined the aggregate value of solar to the APS system under different forecast scenarios.

1.4.1 Study Strategy

The strategy employed by the Study team involved bringing together experts in the fields of solar PV, solar hot water, and solar daylighting who had specific knowledge of the APS service territory, as well as the ability to communicate and model its implications. These experts were teamed with engineering professionals in the areas of distribution, transmission and system planning to utilize their knowledge and to extrapolate it across the APS system. Utility rates and business case professionals created a means to aggregate the results in common monetary metrics and to collate the results across all tasks and articulate the strategic implications.

From the outset, it was understood that extensive analytical efforts would be required. The Study team brought in expertise in technology characterization and deployment modeling, and teamed them with APS technical staff in the areas of distribution, transmission and power supply modeling and analysis. The Study team worked collaboratively with APS resources to design the analytical effort. This ensured a high standard of care in the design and careful validation of the Study results. Additionally, the Study team relied on the knowledge and experience of the renewable energy staff at APS who contributed greatly to the analytical requirements and who worked diligently to ensure APS-specific territory and system attributes were built into the Study parameters. This was fortunate, since APS is among the leaders in solar technology and deployment with more than 20 years of active involvement.

A study of this nature necessarily involves an enormous number of assumptions and hypotheses. Accordingly, the Study invited a broad community of stakeholders to participate in the effort by providing periodic review and comment as the Study progressed. As the Study team worked through the technical and financial aspects, the stakeholders brought invaluable insights from their first-hand knowledge of the local market. Their active engagement in the process added considerable resiliency to the Study results. Stakeholder involvement also included the contribution of technical studies and materials to help bridge the gap between published reports and on-the-ground experience.

1.4.2 Study Team

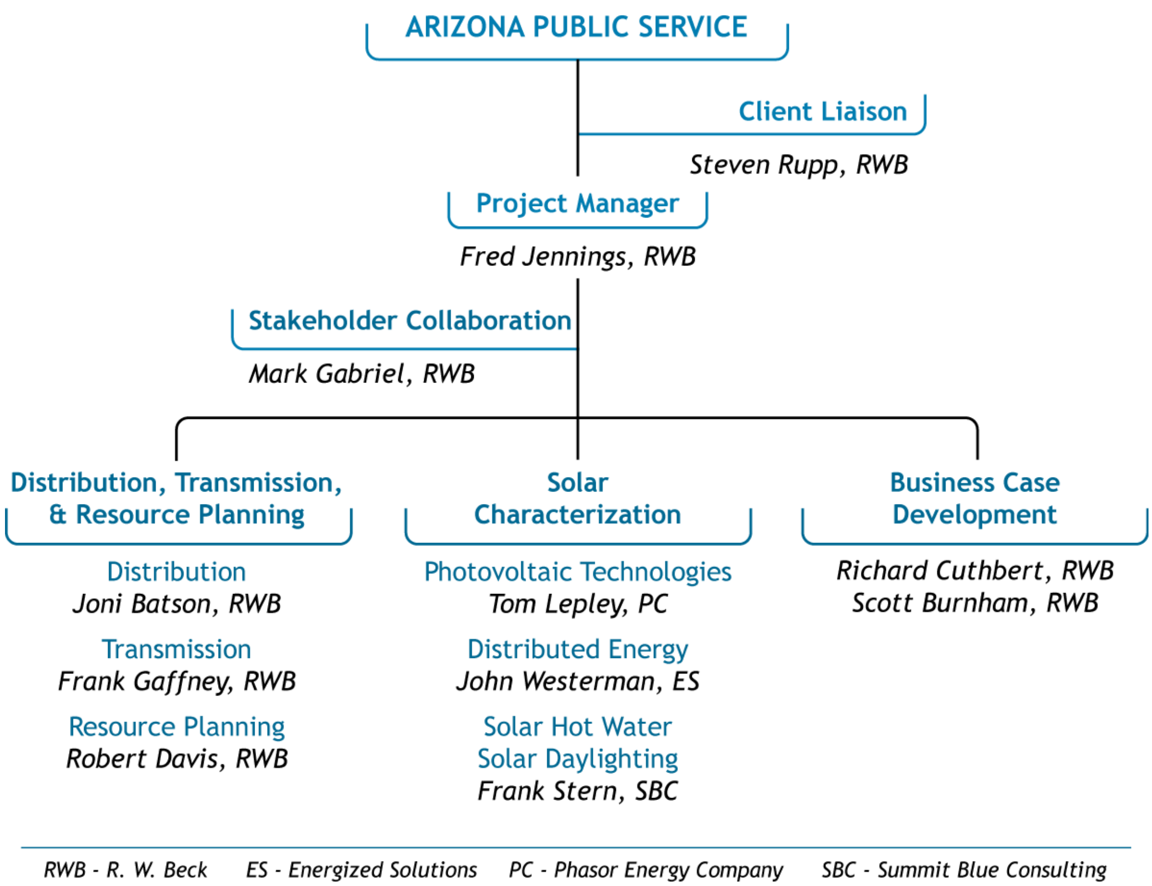
R. W. Beck assembled a nationally recognized team with in-depth technical and project management expertise to support this Study (see Figure 1-8). The individuals brought subject matter expertise as well as a broad perspective and experience. Their interaction throughout the Study added testament to the importance of stakeholder engagement and experience transfer. The Study team consisted of individuals from several leading companies in the solar DE arena. The Study team included individuals from the following companies:

- **R. W. Beck** is a company of technically based business consultants who provide planning, financial and engineering solutions to the energy, water, and solid waste industries. R. W. Beck supplied team members with specific relevant experience in utility program design; distribution, transmission and resource planning; business case development; and stakeholder involvement.
- **Summit Blue Consulting, LLC** (Summit Blue) provided professional services related to modeling and data. They brought particular expertise in solar daylighting and solar hot

water applications as well as experience in developing demand management and incentive programs that help stimulate the market. Summit Blue also utilized its proprietary simulation model that enables analysis of solar hot water and solar daylighting impacts at the level of individual buildings. Additionally, Summit Blue utilized its proprietary Bass diffusion model to project deployment of solar DE technologies by APS customers.

- **Phasor Energy Company, Inc.** (Phasor) specializes in developing practical, innovative applications of PV technologies for commercial and industrial applications in the greater Phoenix area. Phasor provided valuable insight on the practical application of PV technology through all phases of the project development cycle from conceptual planning and design to engineering, installation and performance evaluation that was critical in creating Task I deliverables of solar characterization.
- **Energized Solutions, LLC** (ES) provided renewable resources planning, energy efficiency and technology consulting services. ES provided its in-depth knowledge of solar implementation in general, and in California specifically, as well as its deep technical understanding of how distributed energy integrates the solar characterizations results across technologies, markets and customers.

Figure 1-8: Study Team



1.4.3 Stakeholder Involvement

A cornerstone of the Study has been the involvement of a wide array of stakeholders representing solar vendors, academic institutions, solar advocates, local builders and land developers, solar related construction firms as well as representatives of the regulatory community. More than 60 individuals representing 35 companies, universities, trade associations and national laboratories were actively participating in the process.

The stakeholders are critical to building support for the ultimate deployment of solar DE technologies as well as bridging between technical potential and practical reality. The stakeholders' diverse opinions offered the Study team insights, as well as core data and touch points to the community, that will ultimately served to enhance the successful integration of solar DE technology into the APS service territory.

The initial group of stakeholders was suggested by APS. This was supplemented with individuals who opted into participation during the process based on relationships with other stakeholders or through public dissemination of information primarily through the Study's web site, www.solarfuturearizona.com.

Stakeholders in the project represented the following organizations:

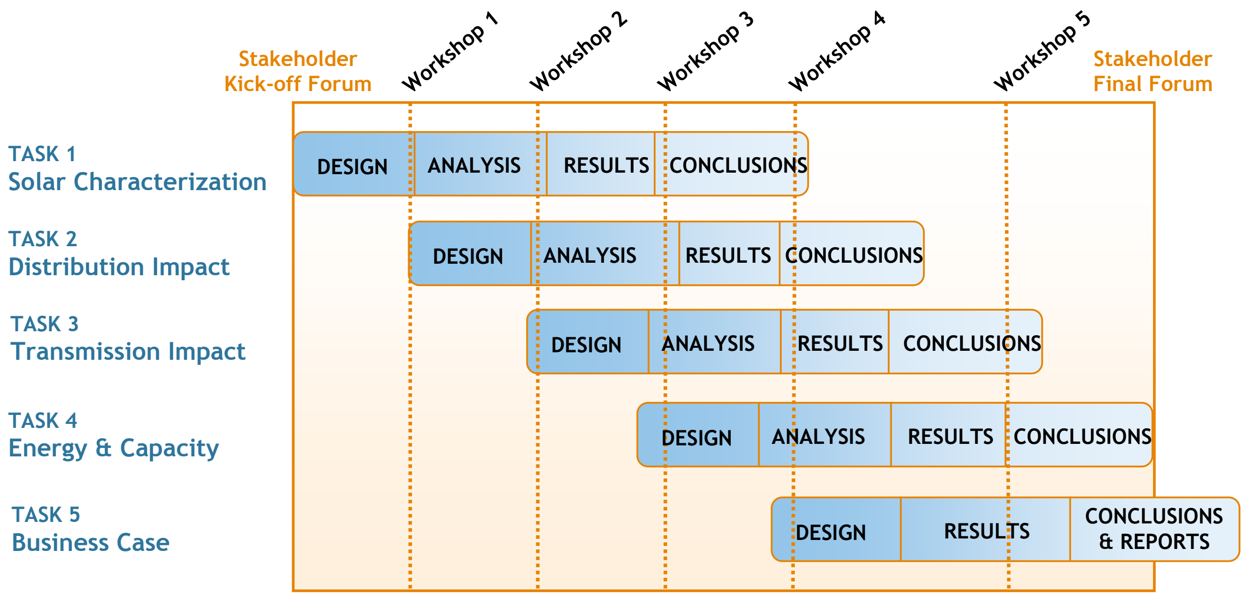
- American Solar Electric Inc.
- Arizona Corporation Commission
- Arizona Department of Commerce
- Arizona State University Research Park
- Arizona State University School of Global Management
- Desert Sun Solar
- DMB Associates
- El Dorado Holdings
- Electric Power Research Institute
- IREC
- Keyes & Fox, LLP
- Kyocera
- Lawrence Berkeley National Laboratory
- Lennar Homes
- National Renewable Energy Laboratory (NREL)
- Natural Lighting Company
- Newland Communities
- Pederson Inc.
- Pulte Homes
- Solar City
- Solar Electric Power
- Salt River Project
- Sun Earth Inc.
- Sun Systems Inc.
- Sunbelt Holdings
- SunEdison
- The Vote Solar Initiative
- Tucson City
- Tucson Electric Power
- Venture Catalyst
- University of Arizona
- ViaSol Energy Solutions
- Western Resource Advocates

Stakeholder Process

Given the critical nature of the stakeholder engagement, participation in the Study took a number of forms including two open forums, five workshops, numerous informal working groups, as well as interaction via the Study web site (www.solarfuturearizona.com). The goal was to engage a variety of interested parties in the process during the analysis of the data and the creation of the Study to build a robust, supportable outcome for the longer term.

The Study was initiated June 6, 2008, with an open forum to outline the process to be followed, and to explore the concerns of the various stakeholders. This forum was followed by five workshops spread across the ensuing months, each tied to the specific task. Given the building block nature of the Study, each successive workshop reported on the initial findings of the prior task, and outlined the steps being taken for the next phase of the Study. The schedule and iterative nature of the forums / workshops is shown in Figure 1-9. All materials presented during the forums / workshops were posted on the Study web site for access by stakeholders.

Figure 1-9: Project Progress



The workshops were designed to be interactive with stakeholders encouraged to question results, offer suggestions for strengthening the Study and to bring new data to the attention of the Study team. The Study team took the input and often recast model results based directly on the stakeholder suggestions.

1.4.4 APS-Specific Conditions

The Study approach specifically focused on calculating the value of solar DE generation to APS. In contrast to many other published efforts seeking to assess far-reaching societal benefits, this Study objective reflected APS specific conditions, demographics and system design. Each organization on the Study team was selected for the strategic value they brought in this regard and their ability to contribute to evaluating the impacts and values that solar DE technologies will have on the APS system.

The Study team capitalized on combining its functional strength in electric delivery system analysis with APS resources to properly quantify the benefits of distributed solar generation for

APS. The Study leveraged a broad base of knowledge that transcended technical know-how and evaluated benefits and opportunities from a variety of perspectives.

Additionally, local experts were engaged to bring an understanding of issues specific to Arizona and the APS service territory. To add additional perspective, Study team expertise was augmented with individuals familiar with other jurisdictions heavily engaged in distributed solar generation, specifically those in California and New Jersey.

1.4.5 Primary and Secondary Research/Analysis

This Study combined nationally recognized modeling tools and discrete APS data in an effort to create a defensible and tailored result. In several instances, APS specific data and test results were utilized either directly or to validate model results. Examples include:

- The Prescott Airport feeder was opened during high solar production (10:00 AM) to test feeder power quality and inverter recovery (feeder has approx 2 megawatts (MW) of solar generation).
- A representative residential feeder (Deadman Wash Feeder 4) was selected and separately modeled by the Electric Power Research Institute (EPRI) using their best-available modeling technology to conduct a highly accurate loss calculation based on solar DE deployment along a distribution feeder.
- Specific solar technology production characteristics were modeled in APS generation forecasting models (PROMOD) to calculate energy and capacity values for solar PV, daylighting and solar hot water technologies.
- Typical Meteorologic Year (TMY) weather data was used for much of the solar production modeling. Additionally, two years of specific weather data was purchased and used for specific APS locations to enhance the accuracy for selected distribution analyses and to validate the applicability of TMY data usage.

1.5 Study Approach

The overall study approach employed consisted of three phases, which encompassed the five key tasks mentioned earlier. The overall structure is shown in Figure 1-10. The study effort began with *Task 1 – Solar Characterization,* during which the Study team built a technical base for characterizing future solar production. Using alternative scenarios, the Study employed a series of models and simulations to understand how these specific solar DE installations might be deployed and their production potential.

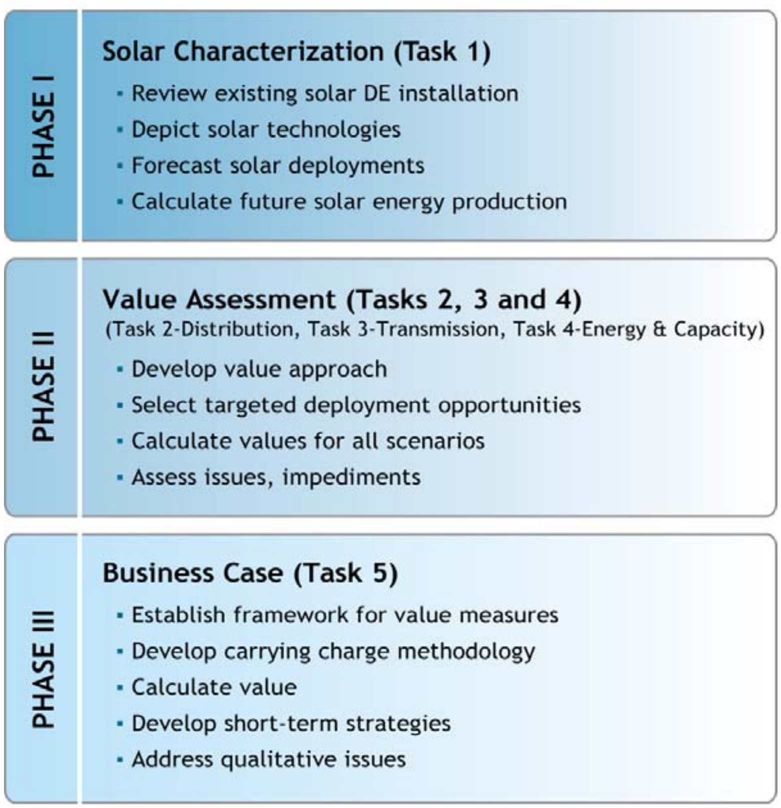
The second phase of the Study, building on Task 1, identified specific value to the APS system from the solar DE technologies. Each of the specific tasks, *Task 2 – Distribution, Task 3 – Transmission,* and *Task 4 – Power Supply Capacity and Energy,* focused on developing models to assess discrete monetary value in the electric system.

The third phase, contained *Task 5 – Developing a Winning Business Case for Solar DE Deployment,* provided an integrated value assessment and discussed associated impediments and obstacles to value achievement by APS. Importantly, Task 5 provided an opportunity for the Study team and APS to explore strategies for meeting RES goals in the near term.

For both solar characterization and for value assessments, the Study looked at three discrete points in time – 2010, 2015 and 2025. These future milestones are continued across all analyses in the Study.

The Study design specifically combined the analytical capabilities of the Study team with those from APS. APS has acquired a wealth of PV data from its customers, and its own operations and research that was incorporated into the Study. Similarly, in the value assessment, the Study team leveraged distribution and transmission network models in use by APS, and extensively utilized APS generation forecast models. A combined effort oversaw the methodology and accuracy of the inputs and the Study team assessed the reasonableness of model outputs. This coordinated effort effectively leveraged APS resources, encouraged knowledge transfer to support future analytical efforts by APS, and reinforced the value calculations for specific applications relevant to APS.

Figure 1-10: Study Approach

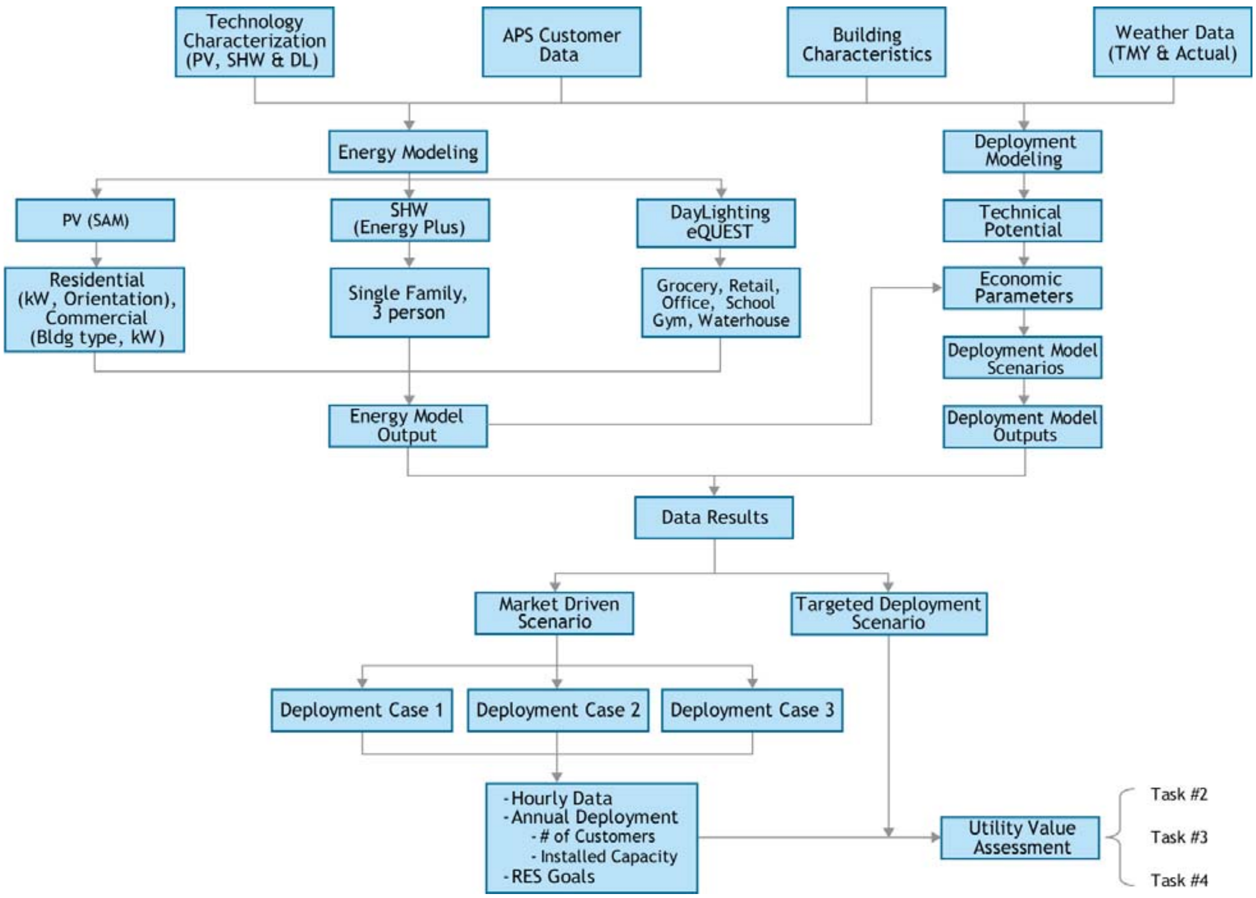


1.5.1 Solar Characterization Approach

Characterization Modeling

Characterizing solar DE generation from three targeted technologies was the cornerstone of subsequent value assessment. Solar energy output, the pivotal metric for assessing value, is dependent upon many factors, including specific technology, customer type demographics, customer energy usage, building orientation, season and weather. Each of these factors was methodically addressed in developing a solar characterization output model. The approach is explained in more detail in Section 2 of this Report; however, a schematic of the modeling approach is shown below in Figure 1-11. The results from this modeling provided solar DE production capacities by technology for use in the value assessment.

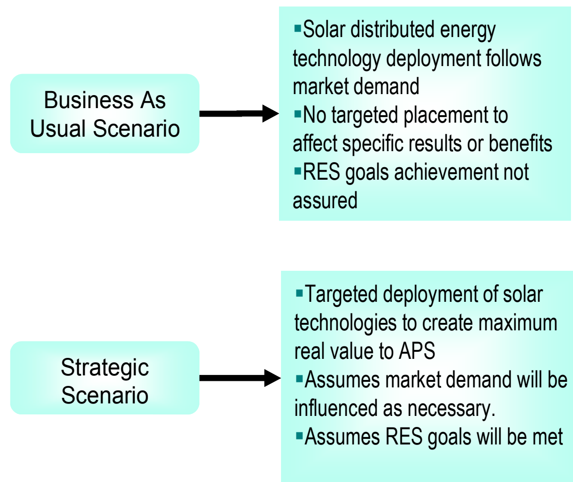
Figure 1-11: Solar Characterization Modeling Approach



Scenarios and Cases

To structure the value assessment, the RFP called for a study approach consisting of two basic scenarios for review:

- **Business As Usual** – This scenario assumed solar deployment was dictated by the market with no changes or influence by APS. Solar deployment was driven by market forces and the value calculation is dictated by market deployment without influence.
- **Strategic –** This scenario was intended to maximize value for APS by strategically deploying solar DE technologies to derive the greatest value. This scenario represents a hypothetical maximization of value by allowing APS to pick and choose various targeted deployments for the exclusive goal of maximizing value.

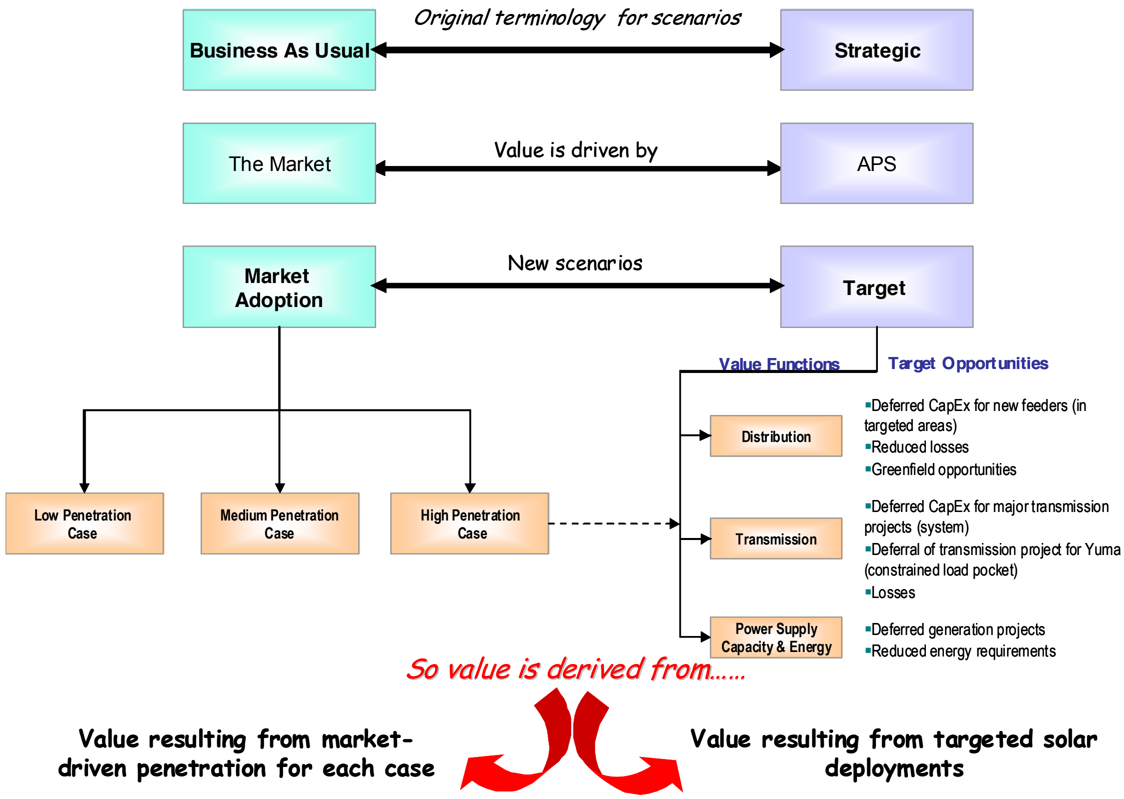


Thus, these two scenarios represented the hypothetical value boundaries or "bookends" of the analysis. Additionally, a third scenario, **Semi-Strategic**, was intended to identify particular target opportunities to pursue in the near term. At the start of the Study, it was expected that the Semi-Strategic scenario would be driven by the Strategic scenario results and would identify a sub-set of options from the broader set of targeted value opportunities.

However, as the Study progressed it became apparent that there was no single deployment that adequately represented the Business as Usual scenario for future solar DE deployment. Stakeholders provided strong commentary that suggested the Study use a broader range of potential deployments. In due course, the Study team found that the payback period, which is the key determinant of solar DE penetration in the market, is highly sensitive to several forecast parameters, most particularly the declining cost of technology and APS tariff forecasts. Given the uncertainty of these and other economic parameters, the initial analytical framework was modified and expanded. Concurrently, discussions with APS made clear that there were only a limited number of opportunities to strategically target solar deployment in order to gain added value.

The overall framework remained essentially the same but was made more robust to better reflect how the Study results were emerging. Figure 1-12 shows the modified approach for the Study.

Figure 1-12: Modified Value Approach



Each penetration case used specific parameters reflecting a range of future assumptions regarding economic factors that affect payback periods and, thus, the extent and timing of solar DE deployment. This Study does not attempt to define a particular future forecast, but instead offers alternative plausible scenarios reflecting conservative and optimistic assumptions (Penetration cases Low and High). The Medium Penetration Case modifies the investment tax credit forecast and demonstrates the sensitivity of the results to this one important variable. Therefore, for the purposes of this Study, we have utilized the terms "Low, Medium and High Penetration Case" to refer to the relative penetration of solar DE systems, as more fully described in Section 2 of this Report.

1.5.2 Value Assessment

The value calculation flows primarily from the solar DE deployments. For the three Market-Adoption deployment cases, value is calculated and presented in the Study results in Sections 3, 4, and 5 of this Report for distribution, transmission, and power supply, respectively. Under the Target Scenario, APS can also pursue value by targeting specific solar deployments in specific locations. In reality, only targeting specific distribution projects offered strategic value. Since the study goal was to examine the maximum theoretical value to APS, the Study also created an additional case off of the Target Scenario in which the flat plate commercial PV was replaced with single-axis tracking solar production. By adding the Single-Axis Sensitivity case, the Study could better create insight into the "bookends" in evaluating how APS could benefit from widely deployed, distributed solar technology in distribution, transmission, and power supply.

The objective of the Study centers on value from solar DE generation. Value takes on different meanings based on a variety of perspectives. The Study was directed by the potential value to APS, but different perspectives should be understood, and are summarized as follows:

- **Value to the utility.** This was the central focus of the Study. The utility derives value by reducing the need to generate or purchase energy to meet load, especially at peak hours. Value to the utility also stems from avoiding or deferring capital expenditures. This happens when solar DE production reduces the need for additional distribution, transmission or generating facilities. The value is generally greatest when the utility can use solar DE to reduce it peak demand, which is what electrical system facilities are designed to meet. Thus, utility value is maximized when the solar generation is coincident with it peak customer demand (or load). There may be instances where, under certain conditions, sufficient solar production might affect the system design and permit smaller (and less expensive) transformers and conductors to be installed for certain segments of the distribution system. Value can also be found if energy loses from the transmission of electrical energy (referred to as "load losses") can be reduced, and/or if system constraints are freed through lower demand. Finally, in an era where carbon is regulated and/or traded, the reduction in conventional energy production may have additional value to the utility beyond the cost to produce.
- **Value to the customer.** Most customers see value as the savings they receive between paying the prevailing utility rates and the cost of an alternative source of supply. Thus the more *energy* a customer can generate by solar to displace the delivered energy from the utility the higher their savings. However, while solar DE can decrease the amount of energy that has to be provided by the utility, it may or may not reduce the utility's need to provide *capacity* for that customer.
- **Value to society.** This is the most difficult to judge, although there is certainly some perceived value in the use of solar and other renewables from an environmental standpoint, such as in the reduction of greenhouse gas emissions. As a result, various studies have placed a "stipulated" value on the elimination of thermal resources. However this Study did model externality costs (i.e. social and environmental costs that are not otherwise captured through regulated emission allowance costs and credits).

Distribution

The value assessment concept for distribution focused on understanding how solar DE production could affect distribution equipment needs, sizes and operations. The approach utilized a combination of empirical testing, system modeling, and information review from myriad sources including APS, other electric utilities, research institutions, and the stakeholder group.

The assessment looked at the impact of solar DE on reducing annual peak demand. A screening analysis developed individual customer load models (representative of their customer class), feeder load flows and annual hourly system usage to simulate the impact of a range of levels of solar DE deployment on annual peak demand and energy losses. This effort analyzed the ability to defer distribution capital projects at feeders and substations. By examining energy use for individual customers, the Study tested the impact on customer equipment and sizing as well.

The assessment also looked at the impact of solar DE on reducing losses. Since both demand and solar output vary significantly on an hourly basis, an hourly analysis of loss savings was conducted. Projected annual hourly system load profiles, with and without solar, were compared to determine both annual energy and peak demand losses at the system level for each case. In addition, EPRI's Distribution System Simulator (DSS) tool was used to analyze the hourly impact of different levels and types of solar DE deployment on a particular feeder to validate annual distribution loss calculations.

In addition, the assessment looked at the impact of solar DE in power quality. Empirical testing involved utilizing existing solar DE installations owned and operated by APS to test certain conditions. By dropping high amounts of solar production on an individual feeder, for example, the Study was able to test operating impacts, including voltage and harmonics. The DSS tool also analyzed the effect on annual peak demand for capital deferment or possible equipment size reduction.

Much of the value assessments determined for the distribution system came from examining discrete feeders, customers, loadings and locations. The system-wide capacity value calculations are based on the solar dependable capacity for distribution and transmission systems, which is defined as the amount of solar DE capacity expected to be available 90 percent of the time for a given deployment case, including the peak demand loss reductions. System-wide energy value calculations are based on the combined loss savings in the distribution and transmission systems, which are described in Section 4, "Technical Value – Transmission System."

Transmission

The value assessment for transmission centered on evaluating how solar DE deployment could reduce the flow of power through the distribution and transmission systems. A reduction in power flow across the transmission system can potentially reduce the need for capital expenditures by deferring transmission investments, as well as reducing electrical line losses across the transmission and distribution systems.

Deferring transmission investment affects the planning, design and operation of the transmission system which is highly regulated by North American Reliability Corporation (NERC) Reliability Standards. The reliability criteria are deterministic and are based on allowable system performance following contingencies. Thus the methodology for determining the ability to defer transmission investments requires determining the "dependable capacity" of the solar DE generation and thus the dependable load reduction for transmission and the resulting impact on reliability. The approach employed in the Study used statistical analyses to determine the level of solar output that would be at least equivalent to typical generating units and thus allow transmission deferral without impacting system reliability.

Perhaps the most certain solar DE value comes from the reduction of power losses resulting from reducing the current flowing through transmission and distribution system equipment. To evaluate loss savings the analysis focused on estimating the system resistance and evaluating the hourly impact of solar DE for each year based on energy use forecasts. The approach calculated the current to supply the load, with and without solar DE, and then calculated the associated losses with and without solar DE. From the difference, the energy loss savings could be determined and then factored into the analyses of Section 5, "Technical Value – Power Supply Capacity & Energy," to determine a dollar amount associated with energy loss savings.

Power Supply Capacity & Energy

Solar DE deployments can provide value to APS through the avoidance of power supply costs that fall in two primary categories: the delay of future resource additions and the avoidance of marginal costs of energy production. The assessment was designed to investigate the quantity of capacity and energy that solar DE implementations could avoid through analyses that determined the dependable capacity of various solar DE technologies and simulated how generation commitment and dispatch on the APS system would change with different solar DE penetration rates.

The dependable capacity that can be obtained from solar DE technologies was determined through an analysis of the reliability of the solar DE resources. The analysis was performed using an industry-accepted technique that measured the reliability of meeting the APS system load with a given portfolio of resources. By comparing portfolios that contain solar DE technologies to those developed with traditional power supply resources, the dependable capacity of the solar DE technologies was determined.

Additionally, because large implementations of solar DE resources have the tendency to delay the APS system peak to a later hour when solar DE resources are less dependable, the reliability analysis was extended to address how the value of solar DE capacity diminishes with increasing penetration. Combining these analyses with other factors such as marginal losses and the estimated solar DE penetration rates provided projections of dependable solar DE capacity. The projected dependable solar DE capacity for each penetration case was then compared to the APS capacity expansion plans and projected capital and fixed operating costs to develop projections of avoided and deferred power supply capacity costs.

The implementation of solar DE resources also causes changes in the commitment and dispatch of power supply resources. Energy that no longer needs to be produced from the APS resources as a result of solar DE implementations results in reduced energy production costs (energy that can be avoided by APS). To assess this value, a resource expansion plan for each of the solar DE penetration cases was identified. Each case was simulated by APS in its generation production simulation software. Comparing the results of these cases to the simulated production costs for the APS base case expansion plan yielded the change in energy costs that could be derived from the solar DE installations.

Business Case

The business case analysis, described in Section 6 of this Report, provides a framework for assessing the value of solar DE deployment in the APS service territory. This includes a quantitative evaluation of the savings potential from solar DE deployment under the various cases defined in the Study, such as the reduction of line losses, energy savings for customers, and reduced or deferred capital expenditures. Value can also be derived from qualitative benefits such as increased job opportunities for installers, a more sustainable environment, and as yet unquantifiable benefits that may become economic in the future. These broader economic benefits may include improved worker productivity and a more robust solar DE manufacturing industry. The winning business case for solar DE in Arizona must include consideration of the quantitative and qualitative benefits.

In order to estimate an annual economic savings in the target years of 2010, 2015, and 2025 for the APS distribution, transmission, and generation business sectors under the solar DE deployment scenarios, the first step was to separate capacity and energy savings. This separation was made because capacity savings represent value in terms of either deferral or avoided investment costs by the utility, while energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in energy requirements of the utility. The analysis measures reduced or avoided energy and capacity costs that APS will not incur if solar DE is successfully deployed.

On the energy side, the operational cost savings for each business unit roll up to reduced fuel, purchased power, and losses associated with reduced production requirements on the APS system due to solar DE deployment. Additional reductions in fixed operation and maintenance (O&M) requirements for APS have been quantified and included as annual cost savings in this evaluation. These values were used to estimate annual energy savings and cost reductions for the total entire APS system at energy and operational levels.

For capacity savings, the identified reduction or deferral in total capacity investments in the distribution, transmission, and generation sector for the target years of 2010, 2015, and 2025 were used to estimate annual reductions in APS' revenue requirements. This was accomplished by the use of levelized carrying charges calculated separately for each business sector. These carrying charges represent the annual costs associated with specific discrete investments, including the accumulated capital recovery and depreciation elements for utility investment rate-base elements. These annual capacity values were totaled for each sector and were added to the annual energy and O&M savings for each test year in the Study.

The present value of these future energy and capacity savings as of the end of 2008 was determined using a real (inflation-adjusted) discount rate for APS. The results are presented in nominal terms as well. This provides a range of economic values for the solar DE deployment options. More specifically, it represents the range of estimated current value potential in the solar DE deployment scenarios, and incorporates uncertainties of various time periods for solar deployment impacts. It also provides estimates of the value of future solar DE deployment in a framework that is similar to that used by APS in its evaluation of other resource options in its integrated resource planning process.

One key finding identified in the Study is that solar output is not coincident with peak demand for either the customer or the utility. This is critical when considering capacity considerations (either payments or incentives) as the impact is on the energy side of the equation, not capacity in any great measure. Since solar output peaks earlier than the load, steps that can shift solar output to later in the day will increase the value of solar DE. One example of this would be technology changes in solar DE energy storage that would help extend solar output during peak. In addition, there is greater coincidence of solar and customer peak production for commercial class than residential class. Section 6 includes a quantification of value for solar DE to APS and discusses the non-quantifiable aspects of value and their implications on direct monetary value to APS.

The characterization of the solar DE technologies provides a basis for their deployment within the APS service territory and the subsequent value analysis for this Study.

SECTION 2 — SOLAR CHARACTERIZATION

The objective of the solar characterization is to describe how the specific solar DE technologies would typically be deployed in the APS service territory and to develop a framework for their deployment. This forms the building blocks to support all subsequent analyses in this Study. This section includes a characterization of the eligible solar DE technologies; the sizes and types of systems in use, their typical output or savings, and how they were modeled for the purposes of the Study. Additionally, this section develops the potential deployment of solar DE in the APS service territory for the three cases of the value approach. The results indicate that:

- In a **"High Penetration" Case,** which assumes significant PV capital cost reductions, continued federal tax credits, and increased retail tariffs, APS would likely meet or exceed the RES goals set for these technologies by approximately 2020.
- In a **"Low Penetration" Case,** which assumes constant PV capital costs (in real terms), an expiration of most federal tax credits, and retail tariffs limited to inflation, APS would likely fall far short of the RES goals for all years in this Study.
- In a **"Medium Penetration" Case,** which assumes significant PV capital cost reductions, limited continued federal tax credits, and increased retail tariffs, APS would likely meet the RES goals set for these technologies by 2023.

2.1 Introduction

This section provides a description of the key technological findings utilized for this Study. This section presents an individual overview of the three technologies including capital costs, a description of the modeling efforts utilized to measure the technology with model inputs and modeling results. This section reviews PV technology, as it is applied to residential and commercial customers. Thereafter, the study reviews solar hot water heating (SHW), applicable to residential customers, and then it reviews solar daylighting, as applicable to commercial customers.

The findings are incorporated into the development of the deployment cases, which includes calculations and discussions related to the technical potential of each technology. The deployment cases are a function of the market simulation modeling effort, utilizing a payback calculation to determine how customers will adopt the three technologies over the period of the Study and with variations to certain economic factors. The results of the market simulation modeling are compared to the projected RES goals as they apply to APS.

2.2 PV Modeling

This subsection describes the PV distributed technologies selected for this Study, the performance modeling that was conducted, and the results of the modeling. The modeling results described in this section were used in subsequent analyses to determine the potential value to APS of distributed PV generation.

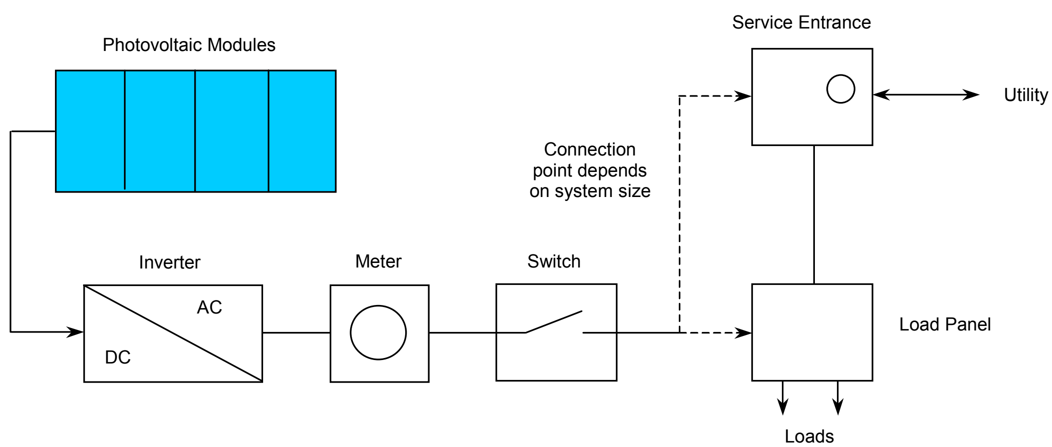
2.2.1 Technology Description

Overview

PV systems use solar cells to convert sunlight directly into electricity. The most commonly used solar cells are made from highly purified crystalline silicon. Solar cells have no inherent storage – when sunlight strikes the cell, a voltage and current are produced. When the solar cell is not illuminated it does not generate any electricity.

Groups of solar cells are packaged into PV modules, which are sealed to protect the cells from the environment. Modules are wired together in series and parallel combinations to meet the voltage, current, and power requirements of the system. This grouping is referred to as a PV array. The PV array produces DC power, which is then converted to AC power by an inverter to produce utility-grade electricity. Figure 2-1 is a diagram of a basic PV system.

Figure 2-1: Basic Photovoltaic System



Photovoltaic modules can be characterized as flat-plate or concentrator systems. While flat-plate modules can be moved with a tracker to increase energy production, they typically do not include a tracker mechanism. Concentrator systems, on the other hand, generally require a tracker to follow the sun. For distributed PV systems, the most common type of installation uses flat-plate modules mounted in a fixed position. However, several companies are developing tracking systems and concentrating PV technologies for distributed applications. These technologies are discussed in more detail below.

Flat-Plate PV Technologies

Crystalline Silicon Technology

The most common PV technology in use today is based on crystalline silicon. These cells were originally produced by processing wafers that were sliced from ingots. Today there are several other approaches, such as multicrystalline cells cut from blocks of silicon, or growing a crystal silicon ribbon.

Thin-Film Technologies

Thin-film technologies are being developed as an alternative to crystalline silicon. These technologies hold the promise of lower cost, but there are tradeoffs involved. The thin-film technologies typically have lower efficiency than crystalline technology. The three leading thin-film technologies at this point are amorphous silicon, cadmium telluride (CdTe), and copper indium gallium selenide (CIGS). Because thin-film is still being developed, it was not utilized as a basis for this Study.

Concentrating PV Technologies

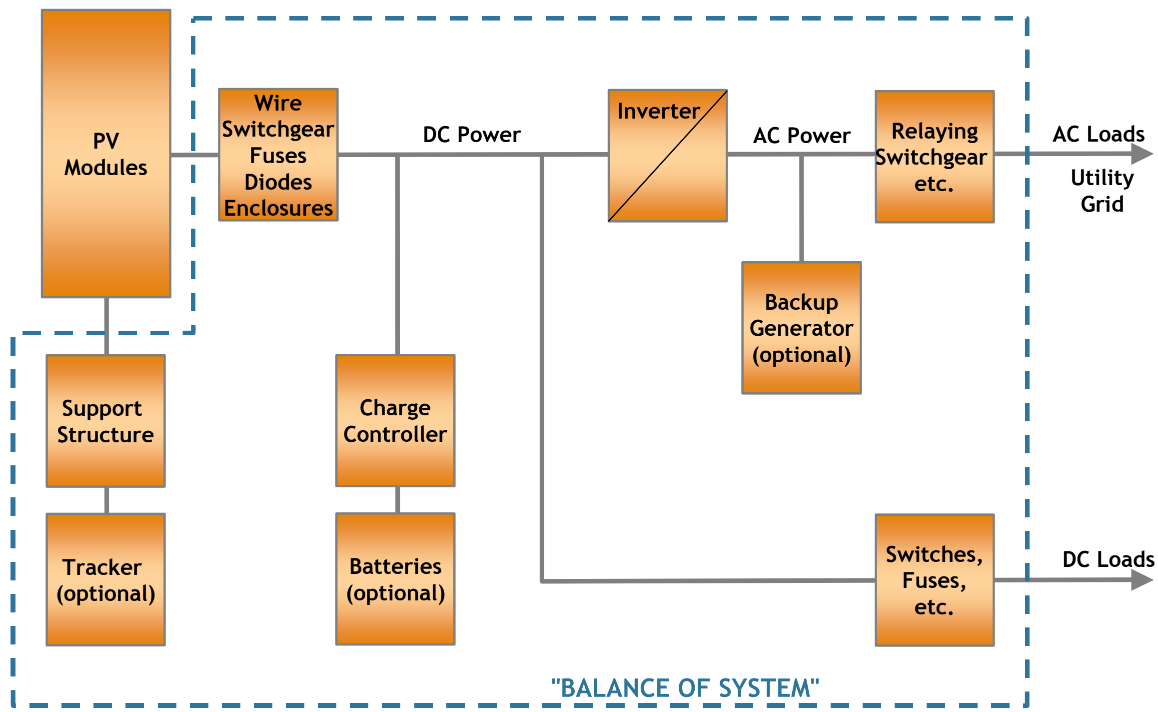
Sunlight can be concentrated onto solar cells using a lens, thereby reducing the number of solar cells required. Special high-efficiency cells have been developed for these applications. Typically, the optics and cell assemblies are required to track the sun because they only use the direct component of sunlight, not the diffuse component. In theory, concentrating photovoltaics can eventually produce electricity at a comparable price to regular grid power.

High-concentration PV has historically been developed for larger utility-scale power plants. Several companies are developing systems for distributed applications, typically for flat rooftops. However, for the purposes of this Study, concentrating PV technologies were not used.

Balance-of-System

The remainder of the PV system, aside from the PV modules, is called the balance-of-system. Figure 2-2 shows the primary components in the balance-of-system. Most distributed grid-connected PV systems being installed today do not have tracking or backup systems. The significance of the balance-of-system to this Study is the operating characteristics of the inverters, the limitations imposed by lack of efficient storage mechanisms (i.e. batteries), and the impact of tracking. These concepts are discussed within the appropriate sections of this Report.

Figure 2-2: Photovoltaic Balance-of-System



System Rating Conventions

Photovoltaic systems are rated in various ways. The most basic is the direct current (DC) rating, which is simply the sum of the nameplate DC ratings of the PV modules. One popular alternating current (AC) rating is the PTC rating. PTC stands for PVUSA Test Conditions; PVUSA is a PV demonstration facility in California. For this Study, the DC ratings have been used, unless otherwise noted. For example, one figure of merit to evaluate PV systems is kilowatt-hours per kilowatt per year (kWh/kW_{DC}). This means the number of AC kilowatt-hours (kWh) produced per DC kilowatt per year.

System Performance

Research into empirical results on PV energy production was surprisingly varied. Reported annual performance ranged from 1,300 kWh/kW_{DC} to 1,800 kWh/kW_{DC}. There appears to be considerable variation in performance of PV modules from manufacturer to manufacturer, and there are even noticeable variations between production runs of the identical make and model. A complete analysis of these variations is beyond the scope of this Study.

For purposes of this Study, annual performance of approximately 1,600 kWh/kW_{DC} was modeled and used for the baseline residential system (south-facing with an 18.4 degree tilt). This performance value was based on the analysis completed for this Study, empirical testing results, and the professional experience of the Study team.

PV System Costs

Capital Costs

Installed system costs from APS's customer PV program are summarized in Tables 2-1 and 2-2 for residential and commercial PV systems, respectively.

Table 2-1
Cost of Residential PV Systems Installed under the APS PV Incentive Program

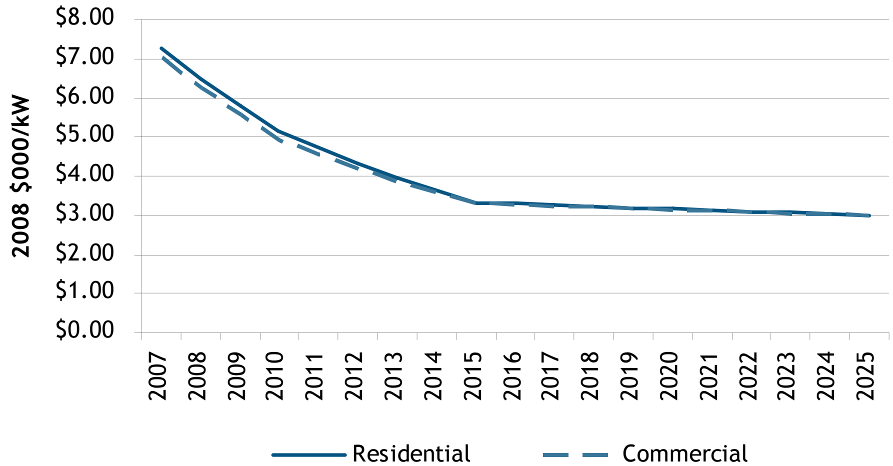
Year	# of Systems	Total installed Capacity (kW_{DC})	Average System Size (kW_{DC})	Total Installed Cost ($)	Average Installed Cost per System ($)
2002	2	4.9	2.5	$36,952	$18,476
2003	8	54.2	6.8	$274,665	$34,333
2004	42	154.1	3.7	$1,144,337	$27,246
2005	59	236.6	4.0	$1,541,550	$26,128
2006	175	798.5	4.6	$5,865,557	$33,517
2007	208	1089.6	5.2	$7,725,983	$37,144
2008	87	481.3	5.5	$3,303,396	$37,970
Total	**581**	**2819.3**		**$19,892,440**	
Average			**4.9**		**$34,238**

Table 2-2
Cost of Commercial PV Systems Installed under the APS PV Incentive Program

Year	# of Systems	Total installed Capacity (kW_{DC})	Average System Size (kW_{DC})	Total Installed Cost ($)	Average Installed Cost per System ($)
2002	2	4.0	2.0	$29,200	$14,600
2003	1	2.3	2.3	$38,051	$38,051
2004	1	25.3	25.3	$148,096	$148,096
2005	14	162.5	11.6	$1,614,241	$115,303
2006	8	258.5	32.3	$2,082,548	$260,319
2007	11	357.6	32.5	$3,197,715	$290,701
2008	1	11.3	11.3	$93,379	$93,379
Total	**38**	**821.5**		**$7,203,230**	
Average			**21.6**		**$189,558**

When weighted by capacity, the installed costs in 2007 were \$7,280 per kW_{DC} for residential and \$7,050 per kW_{DC} for commercial, adjusted for 2008 dollars. (Note: These values do not match those presented in the tables above, based on various adjustments made.) PV costs are expected to decline as technology improves. A U.S. Department of Energy forecast[1] projects a decline of approximately 55 percent from 2007 costs by 2015. Figure 2-3 shows this trend applied to costs in the APS program in 2007, with a trend to \$3,000 per kW_{DC} by 2025.

Figure 2-3: U.S. Department of Energy Cost Trends Applied to APS PV Program Costs (2008 \$000/kW)



This type of cost projection can be controversial. Many factors impact the actual installed cost of a PV system, including some which cannot be controlled by the local installers or by APS. Most notably, government programs in other countries (such as Germany) are currently creating a demand for PV hardware, which is keeping prices up. The installed capital cost data from APS shown in Tables 2-1 and 2-2 do not reflect a significant reduction in installed cost over the past few years. To accommodate concerns about future capital costs for PV systems, two “bookends” of the future price of PV have been considered.

This Study assumes a standard ownership structure, where an individual or business owns the PV assets. The stakeholder group has indicated that in the future, new financing options now being introduced may result in more installations of PV systems than the traditional ownership structure assumed for this Study. The impacts of these new financing options have not been reviewed for this Study.

Operation and Maintenance Costs

Operation and maintenance costs for PV systems are not well documented. In part this is due to the periodic nature of maintenance requirements. A PV system may operate for many years with no expense at all for O&M, but then there may be a problem with an inverter that requires servicing. Inverter manufacturers and PV system suppliers are beginning to offer extended

[1] U.S. Department of Energy, *Solar Energy Industry Forecast: Perspectives on U.S. Solar Market Trajectory*, Solar Energy Technologies Program, 2008.

warranties. For example, one manufacturer offers a 10-year warranty on a 15-kW inverter for about $1,600 (about $0.10 per watt). However, for the purposes of this Study, no O&M costs were assumed for PV systems.

PV Technical Considerations

To fully understand the impact of PV on the utility grid, it is important to consider some important technical characteristics of PV systems.

PV systems are designed to trip off-line when certain disturbances occur on the utility feeder. A situation could occur on a feeder where the PV system is generating a significant portion of the load, but a disturbance might cause the feeder to trip momentarily and then reclose. In this situation, the PV generation could be off-line for five minutes, causing the feeder to be overloaded. Such a situation could occur during a significant and fast moving thunderstorm event, which typically occur during the "monsoon" season in Arizona.

Another disturbance of the electric system could occur that may affect the transmission system, such as an electrical fault or "trip". During such an event, the PV inverters would ideally be able to ride through a transmission system disturbance lasting four cycles. However, if such an event lasted longer than four cycles, the inverters may drop the PV systems. Additional information to measure the actual trip characteristics of inverters is provided in Section 3 of this Report.

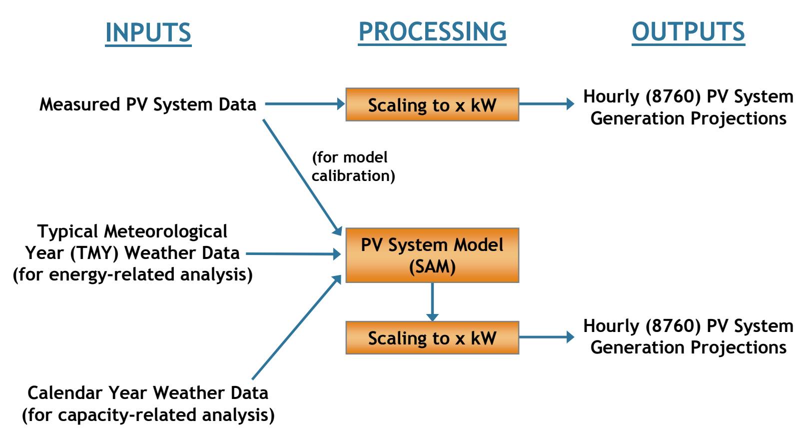
2.2.2 Model Description

Performance Modeling Approach

The basic modeling plan for PV is illustrated in Figure 2-4. Empirical data is generally not available for the range of orientations to be considered in this Study, especially in an 8,760 hourly format (the total hours in a year). As a result, most of the analysis is based on computer simulations. The key variables addressed in the computer model were:

- Typical system size by customer type
- Range of orientations
- Range of tilt
- Various technologies
- Location-based weather impacts

Figure 2-4: PV Modeling Plan



PV Model Inputs

Two baseline systems, with sensitivities, were modeled, one for residential systems and one for commercial systems. Their characteristics are as follows.

Residential Baseline System:

- Nominal Capacity : 5.6 kW_{DC}
- Collector Technology: Multicrystalline PV modules
- Inverter Characteristics: Typical single-phase, 240-volt inverter
- Orientation: South-facing array
- Tilt: Typical 4:12 roof pitch (18.4 degrees)

In addition, a sensitivity analysis was conducted for residential PV by varying the following parameters:

- System Capacity: 2 kW_{DC}, 3 kW_{DC}, 4 kW_{DC}, 5 kW_{DC}, and 6 kW_{DC}
- Orientation: Southwest, west, southeast, and east
- Tilt: 10 and 33 degrees

Commercial Baseline System:

- Nominal Capacity: 105 kW_{DC}
- Collector Technology: Multicrystalline PV modules
- Inverter Characteristics: 100-kW_{AC} three-phase, 480-volt inverter
- Orientation: South-facing array
- Tilt: 10 degrees

In addition, a sensitivity analysis was conducted for commercial PV by varying the following parameters:

- Collector Technology: Single-axis tracking system and two-axis tracking concentrator system
- Orientation: Southwest and west
- Tilt: Flat, 5 degrees, 20 degrees, and 30 degrees

Note that the baseline results can be scaled linearly for different PV system sizes. For example, if projections are needed for a 200-kW commercial system, the results from the 100-kW system can simply be multiplied by a factor of two.

PV Model

The Solar Analysis Model (SAM 2.0) by National Renewable Energy Laboratory (NREL) was used for PV system modeling. This model performs an hourly simulation. Assumptions for various loss factors are input, but the model uses a current-voltage (I-V) curve to represent the PV modules, and an efficiency-load curve for inverters. The model was “calibrated” by adjusting the input variables to produce output projections that are in line with empirical PV system data, as measured in Phoenix by APS. Additional information on model selection and calibration is provided in Appendix F.

Weather Data

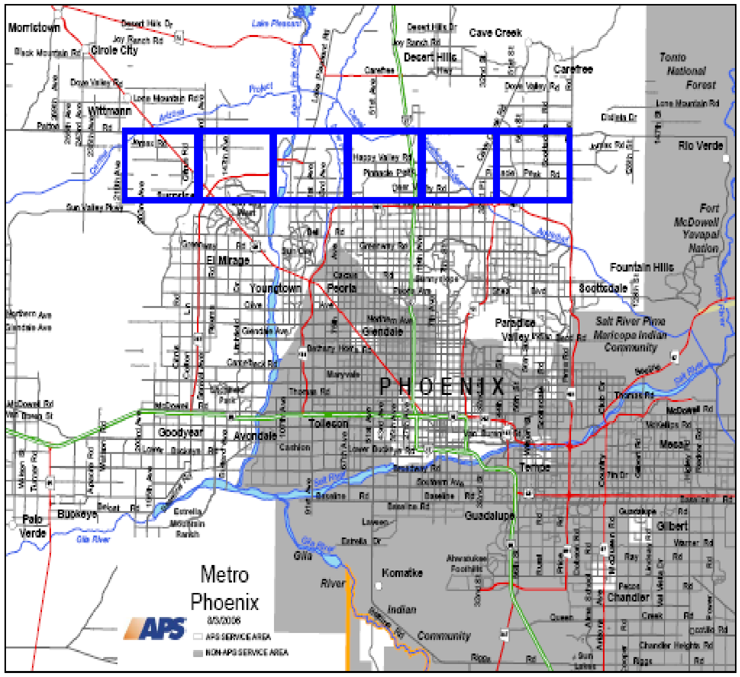
Each of models used to characterize the operational characteristics of the solar DE technologies has a default typical metrological year (TMY) weather file for the Phoenix area and the results are assumed to be representative of "typical" performance. The development of TMY data is an empirical approach that selects individual months from different years of the period of record. A typical month is based on nine daily indices consisting of the maximum, minimum, and mean for dry bulb and dew point temperatures; the maximum and mean wind velocity; and the total global horizontal solar radiation. Final selection of a month includes consideration of the indices identified and the persistence of weather patterns. For example, a TMY data set that covers a period of the most recent 30 years contains 30 years of data, all 30 Januarys are examined and the one judged most typical is selected to be included in the final TMY data set. The other months of the year are treated in a like manner, and then the 12 selected typical months are concatenated (linked in a series) to form a complete year. Because adjacent months in the TMY may be selected from different years, discontinuities at the month interfaces are smoothed for 6 hours on each side. TMY data sets are routinely used to estimate the anticipated performance of energy technologies to forecast future operation and savings. It should be noted that this Study utilized what is technically referred to as "TMY2" data developed by NREL, that represents a more recent and accurate data set than TMY data. However, for the purposes of this Study, the TMY2 data set is referred to as TMY.

In order to conduct the analysis required for the subsequent Study tasks, calendar year data for 2006 and 2007 were required. At the onset of this Study, it was projected that weather data for subsections of the APS service territory would be required to accurately reflect the sun resource during the monsoon season. This was a potentially important aspect for the analysis to determine the reaction of the utility electrical infrastructure if a large solar DE resource quickly changed capacity as a large cloud passed over the area.

To test this theory, appropriate calendar-year data was identified and licensed from Clean Power Research. The Clean Power Research data is based on satellite data, and reflects cloud cover to a resolution of about 5.23 miles north/south by 6.21 miles east/west. Analyzing the entire APS service territory to this granularity could not be conducted within the constraints of this Study. Therefore, a representative section of the service territory was selected for analysis. Figure 2-5 shows the six data regions that were licensed for the Phoenix area and represented in the grid. These specific locations were selected based on the following considerations.

- The easternmost tile reflects the North Scottsdale area, where many PV systems are being installed today.
- The westernmost tile reflects conditions in the West Valley, where there may be future opportunities for large greenfield solar projects.
- The data set includes data that is adequate for the analysis of Phoenix metro region.
- The selected region is anticipated to have the most drastic variability in cloud movement patterns due the geological attributes.

Figure 2-5: Phoenix Area Represented by Weather Data



Customer Classes

This analysis considered both residential and commercial PV systems. The results of the systems modeled are applicable to both new construction and retrofit applications.

Methodology

The first step was to create and calibrate the baseline models for the residential and commercial PV systems. Next, the various options (different orientations and different PV technologies) were modeled. These results (both summary information and complete 8,760 hourly data strips) were used by the Study team to conduct detailed analyses of the customers and the APS power system.

2.2.3 Modeling Results

Key Findings for PV Technology Modeling

- The most common PV technology in use today is based on crystalline silicon.
- The most common slope of residential PV arrays in the Phoenix area is a standard 4:12 roof pitch (18.4 degrees).
- Commercial PV arrays are commonly mounted onto flat roofs or on parking canopies, at a slope of 0 to 15 degrees and oriented to the south.
- The average residential PV system utilized for this Study has an installed cost of approximately \$7,280 per kW_{DC} (in 2008 dollars).
- The average commercial PV system utilized for this Study has an installed cost of approximately \$7,050 per kW_{DC} (in 2008 dollars).

Residential and Commercial PV

PV modeling was conducted for the baseline systems (residential and commercial) as well as variations of the baseline with respect to tilt, orientation and technologies. Appendix F provides additional detail on the description of the PV performance modeling.

All modeling output was in the form of 8,760 hours of system production over the course of the year. As a sensitivity, these systems were evaluated to determine if additional utility benefits could be achieved by increasing the PV electric production later in the day where they are more likely to have an impact on the utility peak demand.

Figures 2-6 and 2-7 show typical hourly simulation results for residential PV systems for a summer and a spring day, respectively. The summer day represents a day with the most hours of sunlight (near the summer solstice) and the spring day presents a day near the maximum capacity (kW_{AC}) of the systems modeled. The figures indicate that by orienting the PV array toward the west, instead of the south (baseline), the production curve shifts by about one hour. Thus, the PV system continues to produce for about one hour later than it would if it were south-facing, and it produces more electricity during the utility's higher demand periods. (APS's daily summer system peak typically occurs between around 5:00 PM on a summer weekday, which corresponds to hour 17 in these graphs.)

Figure 2-6: Typical Summer-Day Residential PV System Output

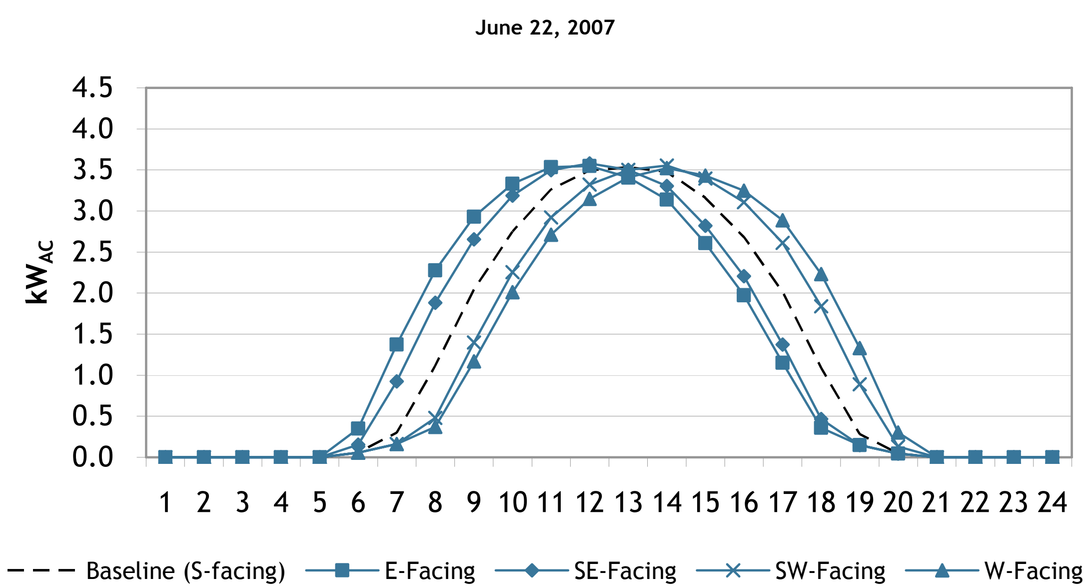
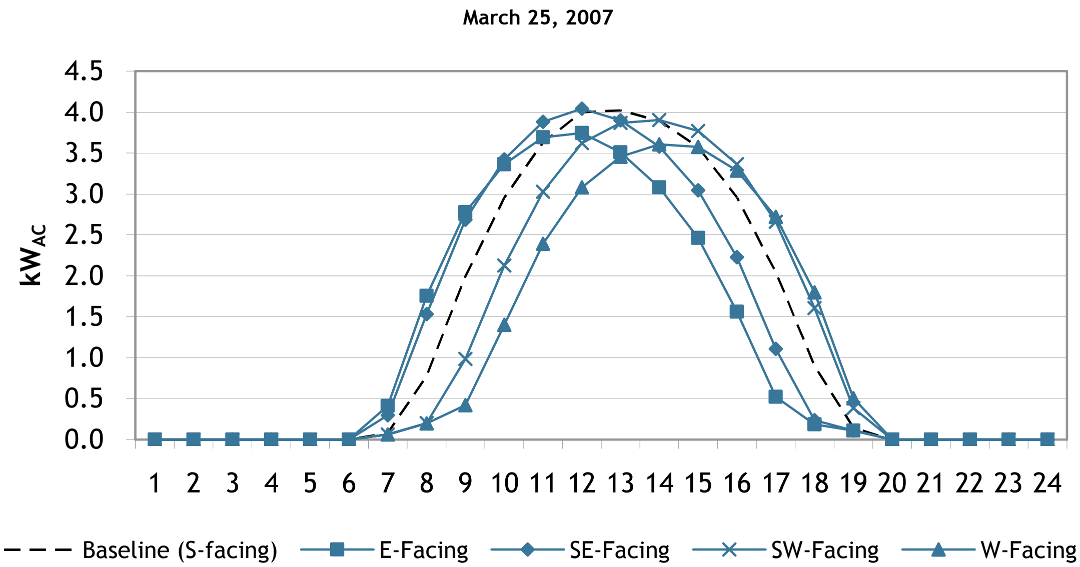


Figure 2-7: Typical Spring-Day Residential PV System Output



The summer data show that changing the orientation of the PV array shifts the hours in which electric production takes place with no major impact on the peak rate of production for the day. The spring data show a similar shifting of the production curve, but during this time period the daily peak electric production is impacted by orientation. The south, southeast, and southwest orientations have similar peak-day electric output while the east and west orientations produce slightly less (approximately 94 and 90 percent of the daily peak production, respectively.)

Figures 2-8 and 2-9 show typical simulation results for commercial PV systems for the baseline and various orientations for the same summer and spring days as the previous graphs. The commercial results illustrate the impact of tilt (zero and 10 degree) and single-axis tracking. In addition to the simulation results for the commercial PV systems, actual PV system production from APS's OPV2 and Solar Test and Research (STAR) Center facilities (as measured on the right-hand axis in watts per square meter). Note that the PV model matches very well with actual PV system production.

Figure 2-8: Typical Summer-Day Commercial PV System Electric Production Profiles

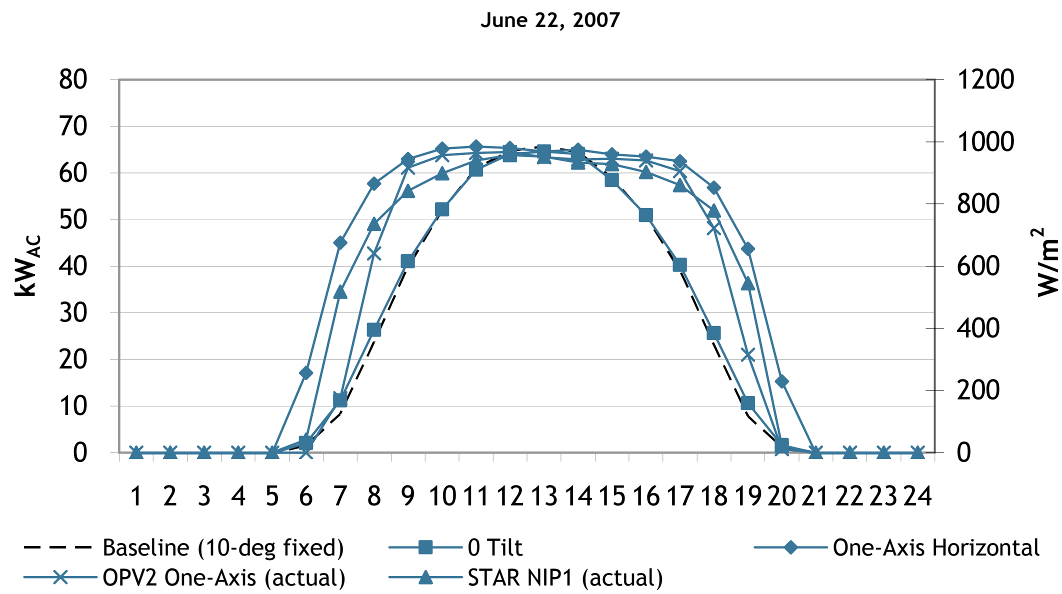
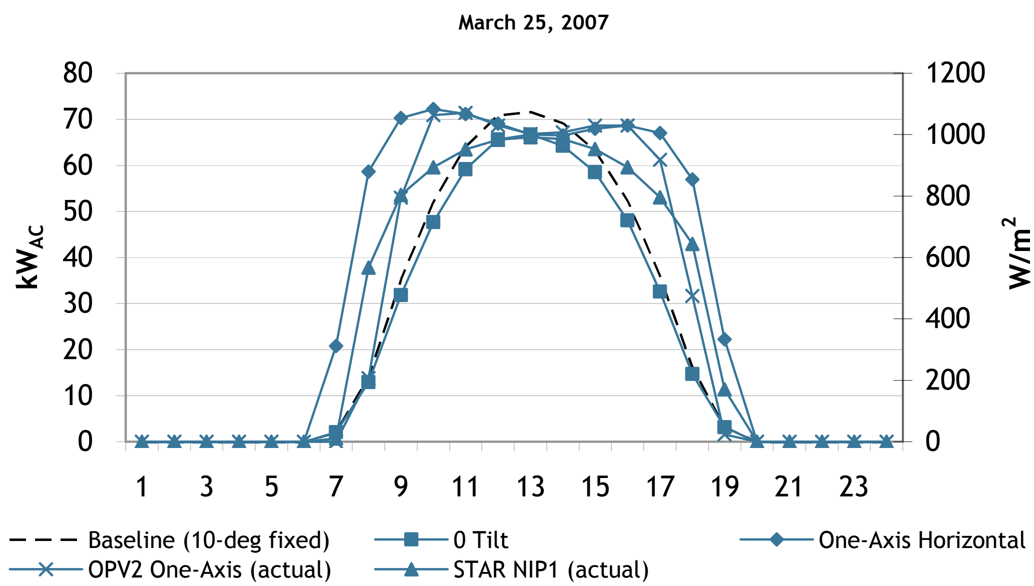


Figure 2-9: Typical Spring-Day Commercial PV System Electric Production Profiles



The commercial data show that during the summer (June 22), the rate of electric production for single-axis tracking is fairly flat but during the spring (and fall, which is not shown), the system production dips at the time when the fixed array is peaking. Note that a comparison of the modeled tracker system to the actual tracker system at the beginning and end of the day is not in complete agreement. The actual tracker system is impacted by control sequences that take into account shading at the horizons due to buildings, landscapes, and/or co-located tracking systems. The model was not calibrated for these site-specific attributes.

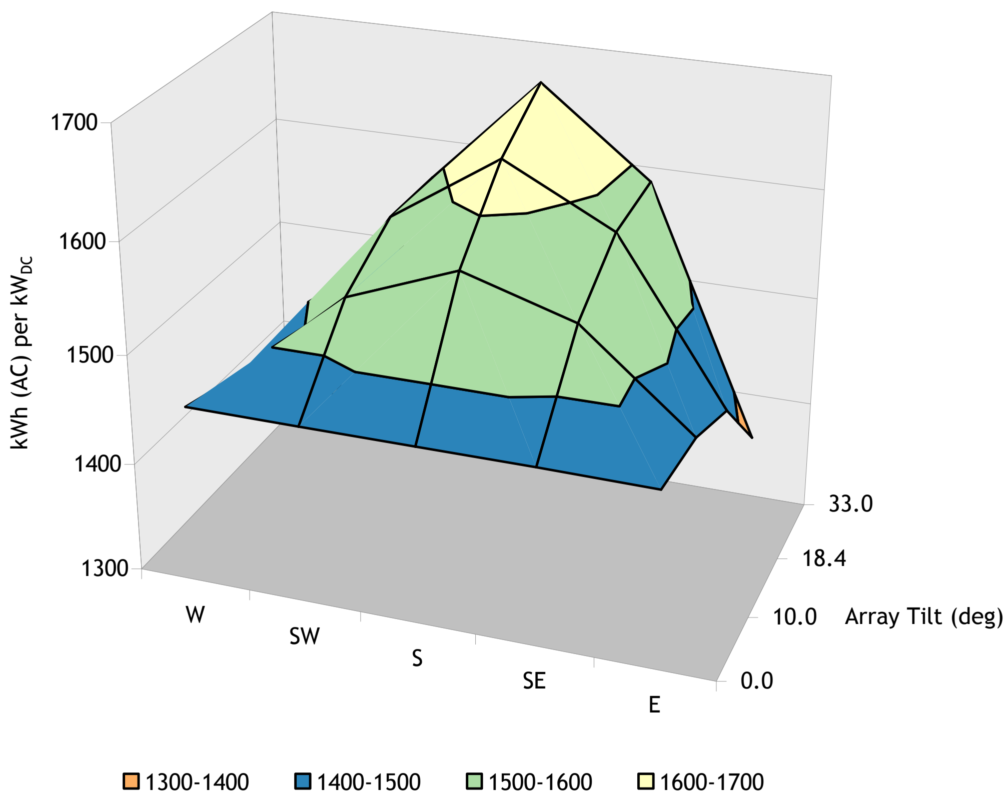
Table 2-3 summarizes the modeled energy production for different locations within the APS service territory and at various orientations. There is very little variation among the different locations, but changes in orientation or tracking result in fairly significant differences in energy production. Additionally, Table 2-3 suggests that TMY data tracks well with the actual solar data utilized for the modeling analysis for 2006 and 2007.

Table 2-3
PV System Modeled Energy Production (kWh per kW_{DC} per year)

	Phoenix	North Scottsdale		North Phoenix		West Valley		Yuma	
	TMY	2006	2007	2006	2007	2006	2007	2006	2007
Commercial									
Baseline: South-facing, 10-deg tilt	1,540.7	1,523.9	1,522.9	1,518.5	1,520.6	1,516.5	1,534.0	1,517.1	1,513.6
South-facing, 0-deg tilt	1,434.7	1,403.4	1,407.5	1,400.0	1,405.9	1,395.7	1,415.8	1,402.1	1,400.5
Single-axis tracker, N/S axis, 0-deg tilt	2,039.9	2,075.3	2,089.6	2,065.8	2,078.7	2,075.4	2,118.3	2,040.6	2,036.8
Residential									
Baseline: South-facing, 18.4-deg tilt	1,630.8	1,625.0	1,619.9	1,618.0	1,617.1	1,618.0	1,633.4	1,614.7	1,609.6
East-facing, 18.4-deg tilt	1,432.8	1,404.5	1,409.8	1,402.7	1,409.7	1,398.2	1,420.4	1,423.8	1,421.6
SE-facing, 18.4-deg tilt	1,579.4	1,564.5	1,563.2	1,559.9	1,561.8	1,558.1	1,576.7	1,573.3	1,568.8
SW-facing, 18.4-deg tilt	1,565.0	1,558.9	1,556.1	1,551.4	1,552.2	1,551.4	1,567.4	1,532.3	1,528.2
West-facing, 18.4-deg tilt	1,414.2	1,395.5	1,399.1	1,390.6	1,395.3	1,388.2	1,406.7	1,371.2	1,369.1

Figure 2-10 shows a three-dimensional illustration (contour map) of the impact of orientation and tilt on the annual energy production of a PV system installed in the Phoenix area. The contour map shows that the maximum annual electric production for a system is 1,600 to 1,700 kWh/kW_{DC} as represented by the lighter shaded region of the map. This maximum annual production range takes place for a system oriented between the southwest and southeast at a tilt of 15 to 33 degrees. The results show that the system selected as the residential baseline on a 4:12 roof pitch (18.4 degrees) in Phoenix is within this desirable range that maximizes annual energy production. The graph also illustrates that for the commercial baseline system (south-facing at a tilt of 10 degrees), the annual electric production in the Phoenix area is in the range of 1,500 to 1,600 kWh/kW_{DC} and the zero tilt system will have an annual production rate of 1,400 to 1,500 kWh/kW_{DC}.

Figure 2-10: Effect of Orientation and Array Tilt on Annual Residential PV Performance



Key Findings of PV Modeling

- Overall:
  - There are no significant differences between the weather data sets of the TMY, and the 2006/2007 weather data sets (i.e., 2006 and 2007 are consistent with the TMY data).
  - The modeling results yielded minimal differences in annual production values across the region when modeling with the 2006 and 2007 data files.
  - Orientations has the largest impact of any of the key variables on annual PV electric production.
  - The PV model predicts 1,630.8 kWh/kW$_{DC}$ from this system in typical year (for residential systems). As a check on the validity of scaling, a 2.8-kW$_{DC}$ system was also modeled. The model predicted 1628.2 kWh/kW$_{DC}$ for that case. Since the rating is in kWh/kW$_{DC}$ (i.e., normalized), a similar rating for two different system sizes indicates that using the same rating (in normalized units) for different system sizes is reasonable. The results were nearly identical and simple scaling of the results to alternative system sizes was found to be valid.

- Residential:
  - A south-facing system oriented at 18.4 degrees has its highest monthly production during the month of April.
  - A south-facing system oriented at 18.4 degrees has its summer maximum hourly output around 1:00 PM.
  - A west-facing system oriented at 18.4 degrees has a summer maximum hourly output around 2:00 PM.
  - Typical peak PV production is not coincident with the peak demand of either the residence or the utility.
- Commercial:
  - During the summer months, both a flat and 10-degree tilt system will have similar maximum production rates during the same hour of the day.
  - During the spring months, the 10-degree tilt system will have a 10 percent higher maximum production rate than a flat system during the peak production hour of the day, which occurs around 1:00 PM.
  - Typical peak PV production is not coincident with the peak demand of either the commercial building or the utility.

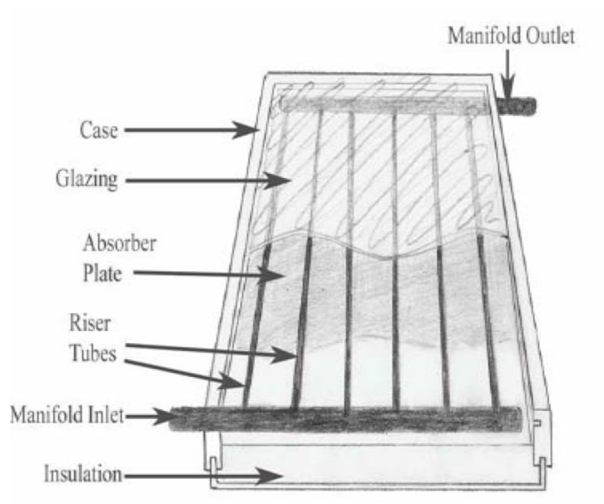
2.3 SHW Modeling

2.3.1 Technology Description

Overview

Solar hot water (SHW) systems have two main parts: a solar collector and a storage tank. The collector uses the sun to heat a fluid in either a flat-plate or evacuated tube collector. The most common type of collector used is the flat-plate collector, pictured in Figure 2-11.

Figure 2-11: Flat Plate SHW Technology



Source: Wisconsin's Focus on Energy, www.focusonenergy.com

Heated water is then held in the storage tank ready for use, with a conventional water heater providing additional heating as necessary. The storage tank can be a modified standard water heater, but it is usually larger and very well insulated.

Active vs. Passive Systems

Solar hot water systems can be either active or passive. Active SHW systems, the most common type, rely on electric pumps and controllers to circulate water, or other heat-transfer fluids, through the collectors. Passive SHW systems rely on gravity and the tendency for water to naturally circulate as it is heated.

There are three types of active solar hot water systems; one is considered direct, and two are indirect:

- **Direct-circulation systems** use pumps to circulate pressurized potable water directly through the collectors. These systems are appropriate in areas that do not freeze for long periods and do not have hard or acidic water. These systems are not approved by the Solar Rating and Certification Corporation (SRCC) if they use recirculation freeze protection (circulating warm tank water during freeze conditions) because that requires electrical power for the protection to be effective. SRCC approval is required for federal tax credits and APS incentives. These are also called active open loop systems.
- **Indirect-circulation systems** pump heat-transfer fluids through collectors. Heat exchangers transfer the heat from the fluid to the potable water. Some indirect systems have "overheat protection," which is a means to protect the collector and the glycol fluid from becoming super-heated when the load is low and the intensity of incoming solar radiation is high. The two most common indirect systems are:
  - **Antifreeze.** The heat transfer fluid is usually a glycol-water mixture with the glycol concentration depending on the expected minimum temperature. The glycol is usually food-grade propylene glycol, which is non-toxic.
  - **Drainback systems,** a type of indirect system, use pumps to circulate water through the collectors. The water in the collector loop drains into a reservoir tank when the pumps stop. This makes drainback systems a good choice in colder climates. Drainback systems must be carefully installed to assure that the piping always slopes downward, so that the water will completely drain from the piping. This can be difficult to achieve in some circumstances.

Passive systems, because they contain no electrical components, are generally more reliable, easier to maintain, and possibly have a longer work life than active systems. The two most popular types of passive systems are integral-collector storage systems and thermosyphon systems.

- **Integral-collector storage systems** consist of one or more storage tanks placed in an insulated box with a glazed side facing the sun. These solar collectors are suited for areas where temperatures rarely go below freezing. They are also good in households with significant daytime and evening hot-water needs; but they do not work well in households with predominantly morning draws because they lose most of the collected energy overnight.

- **Thermosyphon systems** are an economical and reliable choice, especially in new homes. These systems rely on the natural convection of warm water rising to circulate water through the collectors and to the tank (located above the collector). As water in the solar collector heats, it becomes lighter and rises naturally into the tank above. Meanwhile, the cooler water flows down the pipes to the bottom of the collector, enhancing the circulation. Some manufacturers place the storage tank in the house's attic, concealing it from view. Indirect thermosyphons (which use a glycol fluid in the collector loop) can be installed in freeze-prone climates if the piping in the unconditioned space is adequately protected.

Typical Installations

In general, SHW systems are mounted on a south-facing roof, or adjacent to the house at ground level. In either case, the SHW system is generally remote from the backup and supplementary storage water heater and its tank. This distance, or the amount of finished space the loop must traverse in a retrofit installation, impacts the method and cost of installation. The most fundamental distinction is between systems that must resist freezing (closed-loop systems), and those located in climates where freezing is very rarely severe enough to threaten the integrity of the system (open-loop systems). Because closed-loop systems require either drain-back provisions or a separate freeze-protected loop to indirectly heat water in the storage tank, they generally have active components (pumps) and are more complex.

Current Market

Currently, the U.S. market for SHW systems, excluding pool heating, is in the range of 6,000 units per year, with more than half of these sales in Hawaii.[2] This number compares with annual sales of almost 10 million conventional gas and electric storage water heaters.[3] In general, SHW systems have not been a priority for many organizations seeking to promote energy conservation. Indeed, the principal solar trade association, the Solar Energy Industries Association (SEIA), gives this set of technologies only passing reference. Groups that have been more active in promoting, testing, and/or certifying solar hot water technologies include the Florida Solar Energy Center and the SRCC.

SHW technology is relatively simple and the materials and manufacturing involved have been well understood for decades. Historically, market penetration and promotional activity have depended primarily on financial incentives that lower the up-front cost burden to consumers.[4]

System Performance

The SRCC currently administers a certification, rating, and labeling program for complete SHW systems. Appendix G presents the SRCC certification information. The SRCC also provides estimates of annual SHW system performance in the Phoenix area. SRCC uses a computer model to estimate the thermal performance of SHW systems under specified conditions.

A total of 445 different systems, produced by 23 different manufacturers, have been rated by the SRCC for Phoenix. Table 2-4 shows the spread of energy savings for these units. According to the SRCC, over two-thirds of the installed units save their owners more than 2,700 kWh per year.

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[2] U.S. Department of Energy, *Solar and Efficient Water Heating, a Technology Roadmap,* Washington, D.C., 2005.
[3] American Council for an Energy-Efficient Economy (ACEEE), *Emerging Technologies Report: Solar Water Heaters*, April 2007.
[4] ACEEE *Emerging Technologies Report: Solar Water Heaters* (2007) and discussions with manufacturers..

Table 2-4
Spread of Energy Savings for SHW Systems Installed in Phoenix

Energy Savings (kWh/year)	% of Systems
1500 – 1800	1.4%
1800 – 2100	3.6%
2100 – 2400	8.1%
2400 – 2700	16.7%
2700 – 3000	34.5%
3000 – 3300	34.3%
3300 – 3400	1.4%

Source: Annual Performance of OG-300 Certified Systems in Phoenix, Arizona, March 2008, Solar Rating and Certification Corporation

Peak demand savings for SHW systems are more difficult to estimate. In theory, any water heating that would normally be done during APS's peak load times (summer afternoons around 5:00 PM.) would be offset by SHW. However, the inlet water temperature during APS's peak load times is already high due to ground temperatures, so relatively little water heating would be required at that time. Therefore, savings would likely be less on a percentage basis during the summer than would be expected on an annual basis.

SHW Costs

Capital Costs

System costs vary depending primarily on size but also on the technology (i.e., closed, open, etc.). Current closed systems cost roughly $2,500 to $4,000 for equipment. Open systems typically costs around $2,600.[5]

Systems that were installed by APS customers between 2003 and 2008 cost between $1,323 and $26,000 (in 2008 dollars), with the average being $4,764. The cost per kWh, weighted by savings, is $1.83.

Operation and Maintenance Costs

Minimal yearly maintenance is required for SHW, plus a more detailed maintenance operation at periodic intervals. The Arizona Solar Center estimates O&M costs at $20 per year, with a detailed maintenance at 15 years costing $70.[6]

Typical Customer Savings

Electricity bill savings will depend on the customer's particular rate schedule and the times of the day when the regular water heater demand is offset by the SHW system. Based on data for

[5] ACEEE *Emerging Technologies Report: Solar Water Heaters* (2007) and discussions with manufacturers..
[6] Arizona Solar Center, www.azsolarcenter.com

existing systems installed in the APS service territory, savings for SHW systems in the APS DE program range from 1,600 kWh/year to 5,800 kWh/year, with an average of 2,550 kWh/year.

2.3.2 Model Description

Performance Modeling Approach

There are several simulation models that can be used to estimate savings from SHW in a particular climate, such as RetScreen and TRNSYS. The Study team selected the EnergyPlus model, which gives hourly demand for both the baseline water heating system and the SHW system.

EnergyPlus models heating, cooling, lighting, ventilating, and other energy flows as well as water in buildings. EnergyPlus includes many simulation capabilities such as time steps of less than an hour, modular systems and plant integrated with heat balance-based zone simulation, multizone air flow, thermal comfort, water use, natural ventilation, and photovoltaic systems.

Baseline Model Description

The baseline model is a typical single-family residence, designed to include the following characteristics:

- 1-unit detached house built in 1990
- 3 bedrooms, 2 stories
- 1,867 square feet total floor area
- standard electric water heater rated at 0.88 energy factor, with a 50-gallon tank
- 3-person household

These data come from the 2006 American Community Survey for Yuma and Phoenix, APS load data, and from the APS Energy Efficiency Baseline Study.[7]

SHW Model

The SHW model has a standard active SHW system added to it with a minimum solar fraction of 0.8.[8] The solar fraction reflects the portion of the water heating load supplied by solar energy.

Weather Files

Weather files taken from NREL web site for TMY for Phoenix were used for the model. Because of the storage capabilities of water heating, transient effects of clouds are not as significant to SHW savings as is the case for PV.

Customer Classes

This analysis is for residential customers only.

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[7] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.

[8] Based on simulated solar fractions using current technology (for the Phoenix area), taken from: P. Denholm, *The Technical Potential of Solar Water Heating to Reduce Fossil Fuel Use and Greenhouse Gas Emissions in the United States*, NREL Technical Report, March 2007.

Methodology

The first step was to create and calibrate a baseline model for the typical house. Peak demand and annual energy use were calibrated to APS's "Residential End Consumption Standards": peak demand of 7.8 kW, annual energy use of 18.3 MWh, and energy for water heating at 13 percent of total annual energy, or 2,379 kWh.

The model was then created with SHW, based on the baseline model. The SHW model was compared to expected kWh savings for the type of units being modeled, according to the SRCC ratings for those types of systems. In addition, the SHW system was modeled such that it meets the requirements of APS's Renewable Energy Rebate Program. The output of the modeling is the energy impacts in each hour of the year.

2.3.3 Modeling Results

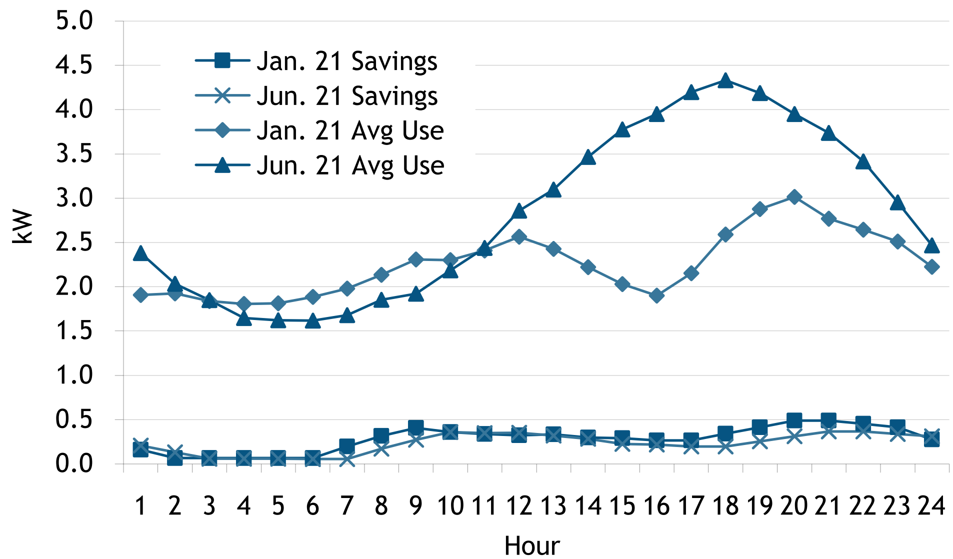
Key Findings for Residential Solar Hot Water Characteristics

- SHW systems have two main parts: a solar collector and a storage tank. The collector uses the sun to heat collector fluid in either a flat plate or evacuated tube collector. The most common type of collector used is the flat-plate collector.
- SHW systems can be either active or passive; the most common are active systems.
- SHW systems are typically mounted on a south-facing roof, or adjacent to the house at ground level.
- SHW technology is relatively simple and the materials and manufacturing involved have been well understood for decades.
- Systems that were installed by APS customers between 2003 and 2008 cost between $1,323 and $26,000 (in 2008 dollars), with an average cost of approximately $4,760.
- Maintenance costs for SHW systems has been estimated at approximately $20 per year, with a detailed maintenance expense at 15 years estimated at approximately $70.

Key Findings of SHW Modeling

Modeling was conducted for the baseline house, with and without SHW. Without SHW, the energy consumed for water heating is estimated to be 2,379 kWh per year. The same house, retrofitted with a solar hot water system, is estimated to use 274 kWh per year for water heating, a savings of 2,105 kWh, or 88 percent. Figure 2-12 illustrates the hourly savings along with baseline customer usage on the winter and summer solstices (which represent the shortest and longest days of the year, respectively). As the graph shows, the demand reduction is 10 to 20 percent of baseline usage in most hours. At hour 18 (the typical summer peak time of 6:00 PM for hot water use) the reduction is significantly less than the non-coincident demand reduction, which occurs at hour 21 to 22.

Figure 2-12: Hourly SHW Savings and Baseline Customer Use (ET-1 customers) on Winter and Summer Solstices



Key Findings of SHW Modeling

- The residential annual baseline electric hot water load is 2,379 kWh.
- The SHW system can reduce the baseline load by 2,105 kWh or 88 percent.
- SHW has a higher impact on residential electric consumption in the winter than in the summer:
  - Due to the continual high temperature periods in the summer season, the domestic water entering the home and the water in the home water distribution piping system is at an elevated temperature, which reduces the energy required for domestic hot water heating.
  - A properly sized SHW system should be capable of supplying 100 percent of the hot water requirements of a typical residence during the summer months (e.g., with a SHW system, a typical residence will not need supplemental heating from the conventional electric domestic hot water system).
- Typical peak SHW production is not coincident with peak demand of either the residence or the utility.

2.4 Daylighting

2.4.1 Technology Description

Overview

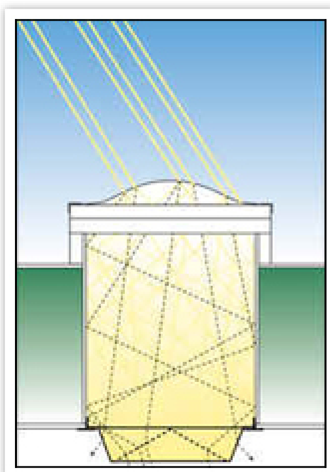
Daylighting is the practice of using natural light to illuminate building spaces. Rather than relying solely on electric lighting during the day, daylighting brings indirect natural light into the building, reducing the need for electric lighting.

In the U.S. market, dimmable fluorescent ballasts make up about 4 percent of commercial lighting. Daylighting control solutions are installed in less than 2 percent of new commercial buildings and in a negligible portion of retrofit applications. This is due to the costs and restrictions associated with re-wiring components. At least three lighting manufacturers in the United States currently market "packaged" integrated daylighting control systems. Each is relatively new, having entered the market within the six years and brings a different set of advantages and drawbacks. None of them claim more than a few thousand systems installed.[9]

There are two basic types of daylighting systems: passive and active. Both types use electronic controls to dim the electric lighting when there is sufficient daylight.[10]

Passive daylighting systems use a prismatic dome, reflective light shaft and diffusing lens to light the building interior. They have no moving parts. Figure 2-13 represents a schematic diagram of a passive daylighting installation.

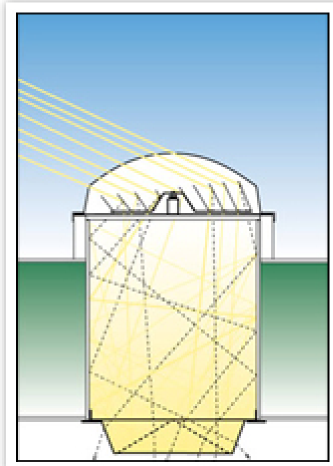
Figure 2-13: Passive Daylighting System



Active daylighting systems, as shown in Figure 2-14, use sun-tracking mirrors to redirect sunlight into a reflective light well and onto a diffusing lens. They provide a building's interior with high levels of well-diffused light, up to an average of 10 hours per day on sunny and bright cloudy days.

[9] ACEEE, *Emerging Technologies Report: Integrated Daylighting Systems (Dimming Ballasts)*, June 2006.
[10] Data taken from www.daylighting.com

Figure 2-14: Active Daylighting System



The sun tracking mirror assembly is driven by a low voltage gear motor. The mirror assembly has a number of reflective panels set to various angles to redirect light from low sun angles into the light shaft. The mirrors also provide shading in high sun angles to prevent excess light levels, which can produce radiant heat.

Controls

Lighting controls may include two-stage programmable logic controllers (PLC), ceiling- and wall-mounted sensors, and/or wall switch replacements. Daylighting, lighting, and controls are often bundled together in a single installation.

Diffusers

Interior diffusers available on the market include drop, pyramid, flat and parabolic lens styles, in a wide array of sizes and visible light transmittance, in acrylic or polycarbonate materials.

Estimated System Performance

Table 2-5 shows estimated operating hours of daylighting systems, both active and passive. The operating hours have been derived from the times of sunrise and sunset in each month. In general, active daylighting systems start to work one hour after sunrise and stop working one hour before sunset; they produce approximately two hours more daylighting per day than passive systems.

Table 2-5
Hours of Operation per Day for Daylighting

Month	Hours of Operation Active	Hours of Operation Passive	Start Time Active	End Time Active	Start Time Passive	End Time Passive
January	8.18	6.18	8:32 AM	4:43 PM	9:32 AM	3:43 PM
February	9.02	7.02	8:12 AM	5:13 PM	8:12 AM	4:13 PM
March	9.97	7.97	7:38 AM	5:36 PM	7:38 AM	4:36 PM
April	11.03	9.03	6:57 AM	5:59 PM	6:57 AM	4:59 PM
May	11.90	9.90	6:27 AM	6:21 PM	6:27 AM	5:21 PM
June	12.37	10.37	6:17 AM	6:39 PM	6:17 AM	5:39 PM
July	12.15	10.15	6:29 AM	6:38 PM	6:29 AM	5:38 PM
August	11.40	9.40	6:50 AM	6:14 PM	6:50 AM	5:14 PM
September	10.38	8.38	7:11 AM	5:34 PM	7:11 AM	4:34 PM
October	9.35	7.35	7:33 AM	4:54 PM	7:33 AM	3:54 PM
November	8.43	6.43	7:59 AM	4:25 PM	7:59 AM	3:25 PM
December	7.93	5.93	8:25 AM	4:21 PM	8:25 AM	3:21 PM

Source: Data provided by Natural Lighting Company Inc., Glendale AZ

When estimating total savings, these hours need to be reduced to reflect the number of days that are cloudy or partly cloudy, leading to reduced hours in which the daylighting replaces artificial lighting. Table 2-6 shows these percentages. May has the highest percentage of cloudy or partly cloudy days (80 percent), and September has the highest percentage of clear days (45 percent).

Table 2-6
Percentage of Days Clear, Partly Cloudy, and Cloudy

Month	% of Days Clear	% of Days Partly Cloudy	% of Days Cloudy
January	33%	29%	38%
February	29%	31%	41%
March	25%	33%	43%
April	23%	36%	42%
May	20%	39%	41%
June	32%	41%	28%
July	29%	51%	20%
August	32%	45%	24%
September	45%	30%	26%
October	43%	29%	27%
November	34%	32%	34%
December	35%	31%	34%

Source: Data provided by Natural Lighting Company Inc., Glendale AZ

Daylighting Costs

Capital Costs

Active systems are the least expensive on a per-kWh-saved basis, at an average of $0.54 per kWh saved. The higher costs of the fittings for active systems are offset by the additional operating hours. Passive systems are slightly more expensive at an average of $0.81 per first-year kWh saved. Hybrid systems (involving both daylighting and electric illumination) are significantly more expensive, at an average of $4.30 per first-year kWh saved; however, this includes the cost of a specific type of light fixture. Hybrid systems have the benefit of being fully automated and compact, with all the controls, daylighting, and artificial lighting in one unit. Table 2-7 shows typical costs per fitting for hybrid, active, and passive systems.

Table 2-7
Costs per Fitting and per kWh Saved for Daylighting

Project Description	Type of System	Cost per Fitting	Energy Savings per Fitting (kWh)	Cost of Energy Savings ($/first-year kWh)
Big Box Retail – Active	Active	$2,150	3,654	$0.59
PSI	Active	$1,305	2,694	$0.48
High School Gym	Hybrid	$3,150	757	$4.16
ADOT Maintenance Facility	Hybrid	$3,285	742	$4.43
Industrial Plant	Passive	$690	2,224	$0.31
Warehouse 1	Passive	$1,150	2,220	$0.52
Big Box Retail – Passive	Passive	$2,700	1,379	$1.96
National Guard Hangar	Passive	$1,200	1,462	$0.82
Warehouse 2	Passive	$1,500	1,818	$0.82
Marine Air Station Hangar	Passive	$1,300	2,869	$0.45

Source: Data provided by Natural Lighting Company Inc., Glendale AZ

2.4.2 Model Descriptions

Performance Modeling

Simulation Modeling Programs

The eQuest model was used to simulate the hourly effects of daylighting systems. This model is an enhanced version of the DOE-2 building simulation model, which is a widely used and accepted industry standard. The model allows daylighting to be easily added to a building model, and it outputs hourly load shapes for end use categories such as lighting and HVAC. The eQuest model has a specialist module for daylighting that includes the ability to specify controls and control strategies, light wells, skylights, and diffusion lenses.

Baseline Models

The daylighting characterization process entailed building simulation models for the following sectors: grocery, large retail, small office, school gym, and warehouse. Based on discussions with stakeholders, these building types were found to be the most suitable for daylighting.

Baseline models were created for each of the five sectors. The small office, large retail, and grocery baseline models were calibrated to match APS end-use data, including total building energy use and internal lighting energy use. The warehouse was calibrated to match lighting and miscellaneous energy use. The school gym was calibrated to match lighting energy use. The building characteristics for the baseline models are shown in Table 2-8.

Table 2-8
Building Characteristics for Baseline Model

Sector	Size (sq.ft.)	Total Annual Energy Use (kWh/sq.ft.)	Total Peak Demand (W/sq.ft.)	Lighting Annual Energy Use (kWh/sq.ft.)	Lighting Peak Demand (W/sq.ft.)	Lighting Annual Operating Hours
Grocery – Large	30,000	51.19	7.95	10.9	1.59	6,867
Retail – Large	50,000	19.67	4.71	7.24	1.61	4,496
Office – Small	6,000	15.19	4.64	5.47	1.50	3,647
School Gym	6,000	-	-	-	1.4	3,247
Warehouse	100,000	-	-	2.87	-	-

Source: All data comes from the APS EUDAP Study[11] and the APS Energy Efficiency Baseline Study[12], except for the Warehouse and School Gym category, which comes from ASHRAE Standard 90.1-2004[13] and EERE Building Energy Data Book 2007.

Note: '-' indicates lack of data. Warehouse and School Gym parameters were based on pre-existing models of these building types in Arizona.

Daylighting Models

Daylighting was then added to the baseline model to estimate the effects of daylighting systems. For the purposes of the model run, the daylighting technology was set to meet the minimum requirements for APS's Renewable Energy Rebate Program.[14] The equipment qualifications are as follows:

- A roof-mounted skylight assembly with a dome having a minimum 70 percent solar transmittance.
- A reflective light well to the interior ceiling or a minimum 12 inches below roof deck in open bay areas.

[11] Quantum Consulting, Inc., *APS End-Use Data Acquisition Project (EUDAP)*, November 1997.
[12] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.
[13] American Society of Heating, Refrigerating and Air-Conditioning Engineers, Inc. (ASHRAE), "Energy Standard for Buildings Except Low-Rise Residential Building," Standard 90.1-2004.
[14] APS Renewable Energy. Non-Residential Solar Daylighting Equipment Qualifications and Installation Guidance. APS Renewable Energy Incentive Program.

- An interior diffusion lens.
- A minimum of one thermal break/dead air space in the system between the skylight dome and the interior diffuser.
- If artificial lighting systems remain a part of the installation, the system shall include automated lighting control(s) that are programmed to keep electric lights off during daylight hours.
- The system must provide a minimum of 70 percent of the light output of the artificial lighting system that would otherwise be used for all of the claimed period of energy savings, as measured in foot-candles.

Table 2-9 compares the modeled skylight to two skylights in are use in APS's territory that have participated in the APS non-residential solar daylighting program. Note that the skylight used in the eQuest model is meant to model a skylight that meets the requirements of the APS program; the other skylights shown may exceed the requirements. Appendix H shows the APS requirements matched to the eQuest building simulation methods for daylighting.

Table 2-9
Comparison of Modeled Skylight to Skylights Used in the APS Region

Skylight Type	U-Value	Solar Heat Gain Coefficient (SHGC)	Visible Light Transmittance
Natural Lighting Company: 4'x4' Passive Daylighting System Model NL-SM 5252 from test results	0.33-0.35	0.04-0.58 (depending on solar altitude angle)	Not available
Ciralight: SunTracker™, Active System	0.35	0.3196	0.91
Skylight for eQuest model	0.43	0.49	0.70

Data Sources for Building Simulation Models

Multiple sources were used to create the building simulation models. The sources and their use are as follows:

- APS End-Use Data Acquisition Project (EUDAP)[15]: data for calibrating the baseline eQuest models.
- American Society of Heating, Refrigeration, and Air Conditioning Engineers (ASHRAE)[16]: design ventilation in the eQuest model and data for school gym calibration on lighting energy use.
- APS Energy Efficiency Baseline Study[17]: data for calibrating the baseline eQuest models and data on the building specifications.

[15] Quantum Consulting, Inc., *APS End-Use Data Acquisition Project (EUDAP)*, November 1997.
[16] ASHRAE, "Ventilation for Acceptable Indoor Air Quality," Standard 62-1999, Table 2 Outdoor Air Requirements for Ventilation.

- 2007 Buildings Energy Data Book[18]: data for calibrating the warehouse building model.
- CBECS 2003 Commercial Buildings Energy Consumption Survey[19]: hours of operation for the office building model.
- Safeway, Fry's, and Whole Foods in the Phoenix area: hours of operation for the grocery building model.
- Wal-Mart, Kmart, and Target in the Phoenix area: hours of operation for the retail building model.
- Mechanical and Electrical Equipment for Buildings[20]: data on skylight properties including U-value, shading coefficient, and visible light transmittance.
- Natural Lighting Company[21]: data on skylight properties including product type and frame type.
- Ciralight[22]: data on skylight properties.

Weather Files

Weather files for TMY from the eQuest software and weather files for actual years (2002–2004) were used to model the impacts of daylighting.

2.4.3 Modeling Results

Key Findings for Commercial Daylighting Modeling

- Daylighting reduces the need for electric lighting.
- In the U.S. market, installations of daylighting systems have been limited to a few thousand customers.
- Daylighting is best suited to one- or two-story buildings. The daylighting characterization entailed building simulation models for the following sectors: grocery, large retail, small office, school gym, and warehouse.
- Costs per fitting vary significantly. Recent installation costs for systems (excluding hybrid systems that have light fixtures added) range from approximately $690 to $2,700.

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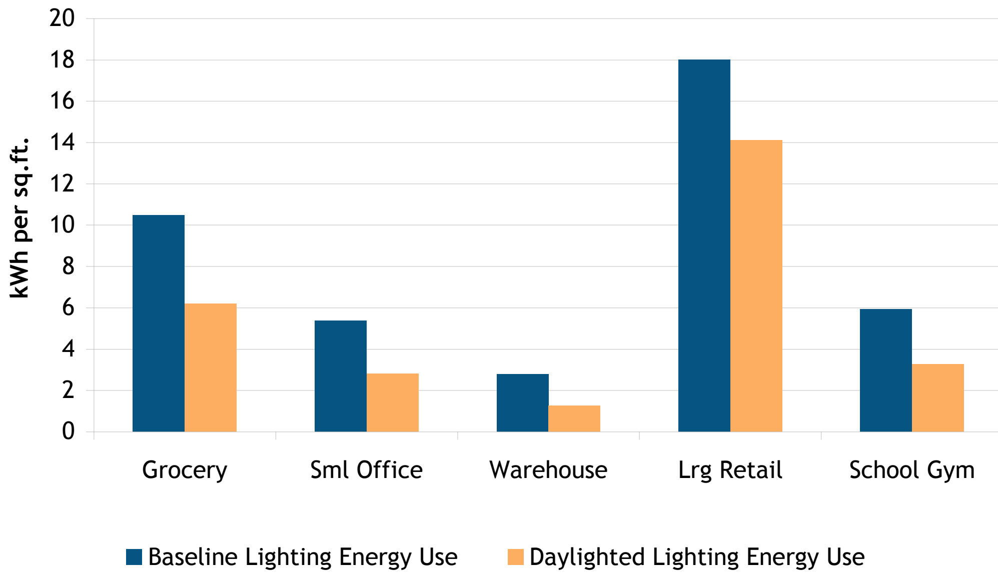
[17] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.
[18] D&R International, Ltd., *2007 Buildings Energy Data Book*, prepared for the U.S. Department of Energy, September 2007, 7.4 Typical Commercial Buildings.
[19] http://www.eia.doe.gov/emeu/cbecs/contents.html. 2003 data.
[20] Stein, B., J.S. Reynolds, W.T. Grondzik, and A.G. Kwok, *Mechanical and Electrical Equipment for Buildings*, 10th edition, 2006.
[21] http://www.daylighting.com
[22] http://www.ciralight.com

Key Findings of Commercial Daylighting

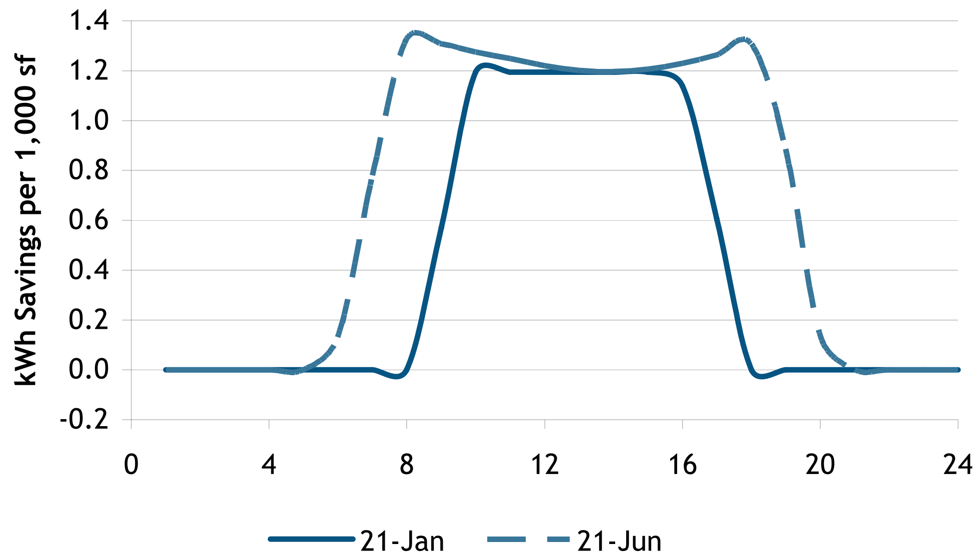
- The baseline usage and savings vary significantly by building type, as can be seen in Figure 2-15.
- The largest usage for lighting and the largest savings in terms of kWh per square foot are in large retail.
- The largest percentage savings is in warehouses.

Figure 2-15: Lighting Usage and Savings by Building Type



The peak demand impact is seasonally dependent, as can be seen in Figure 2-16, which shows the impact on a grocery store for the winter and summer solstice. The longer hours of sunlight result in more savings as a result of daylighting. The impact on peak demand is quite sensitive to time of year. As can be seen in the figure, the savings are about zero at hour 18 on January 21 (winter solstice), but are at a maximum on June 21 (summer solstice).

Figure 2-16: Daylighting Energy Savings in kWh per 1,000 sf of Roof Area (Grocery Example)



- The most cost effective applications for commercial daylighting are in the following building types:
  - Large grocery stores
  - Large retail stores
  - Small office buildings
  - School gyms
  - Warehouses
- Savings differ substantially across building types:
  - The application with the highest annual electric savings per square foot is large retail stores: 14 kWh per square foot per year.
  - The application with the highest percent reduction in electric lighting load is warehouses, at around 50 percent, although the energy savings is less than 2 kWh per square foot per year.
- Daylighting savings are only partially coincident with APS peak demands. The maximum impact is 5:00 PM to 6:00 PM on June 21, the summer solstice, when days are longest, but savings decline significantly as days shorten.

2.5 Deployment Analysis

2.5.1 Methodology

The data from the performance modeling described in Sections 2.2 through 2.4 consist of annual hourly data for each technology for each type of application identified. The remainder of this section develops a forecast of the deployment of those technologies for the period of this Study. The deployment analysis analyzes the economics of the technologies, the number of customers that could potentially adopt the technology (technical potential), other economic benefits, such as incentives and tax benefits, and the baseline cost of electricity to estimate an adoption curve. The results of these forecasts were aggregated to estimate if APS will be capable of meeting the solar DE requirements of the RES goals.

The Market Adoption deployment analysis reflects the likely impacts of the current APS DE program through 2025 in terms of electricity savings. Because of the uncertainty related to major external factors, such as PV technology costs, APS tariff escalation, and federal tax credits, two cases were examined to provide a "bookend" of possible deployment cases: a "High Penetration" Case and a "Low Penetration" Case. A third case, falling between the bookends, was also developed as is referred to in this Report as the "Medium Penetration" Case.

The Market Adoption deployment analysis entails two steps. The first step combines the hourly projections of load impacts with the number of potential solar DE installations to produce an estimate of the technical potential in a given year. In the second step, a diffusion model (explained later in this section) is applied to project the realistic participation in each year. The diffusion rate is based upon the economic attractiveness of each solar DE technology, which is in turn based upon the payback period. The results of this diffusion model analysis are annual and hourly impacts at the system level, which are carried forward into later sections of this Report.

The following subsections describe the estimated technical potential for the residential sector and the commercial sector. This format is different that that previously presented in this section (which followed specific technology). The reason for this change in format is that the RES goals are specific to customer classes (residential and commercial), not specific technology. Therefore, the deployment values predicted have been grouped by customer class to facilitate comparison with the RES goals. The diffusion model is then discussed, followed by the results of the Market Adoption analysis.

Technical Potential - Residential Sector

The key inputs used to analyze the technical potential for the residential sector were the number of residences and roof area. For the SHW and PV technologies, single-unit detached and attached residences were considered (this excludes multifamily housing). This comprises 63.5 percent of housing units, or 600,433 residences in 2007 in the APS service territory. It was assumed that the number of such housing units would grow at a rate of 2.4 percent per year, based on growth data provided by APS.

The average floor area of a residence is 1,867 square feet.[23] The 4:12 slope of a typical roof implies a roof area of 1,963 square feet. Sixty-three percent of residences are single-story.[24] Of

[23] U.S. Census data for Phoenix.
[24] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.

the total roof area, only a portion is suitable for SHW or PV due to inappropriate orientation, shading, or obstructions. Based on analysis from California's systems, it was estimated that 27 percent of the roof area was suitable for installations.[25] These values imply a total available roof area in 2007 of 262 million square feet. The parameters are shown in Table 2-10.

Table 2-10
Available Roof Area for all Solar DE Technologies in APS Territory (2007)

Single Family Houses	600,433
Average Roof Area (SF)	1,963
Share Single Story	64%
Total Roof Area (million SF)	964
Fraction of Roof Area Available	27%
Available Roof Area (million SF)	262

Technical Potential – Residential PV

For the purposes of determining the total technical potential for residential PV systems, it was assumed that PV installation would be limited to the residence peak demand or available roof area, whichever is less. It is recognized that many actual residential installations have been sized in excess of a customer's peak demand, in order to "offset" energy usage during non-sunlight hours. However, for the purposes of this Study, the installation size has been limited to peak demand. The impact of this assumption is to provide a "theoretical cap" on the market simulation modeling assumption across the APS service territory. If this assumption is relaxed, the impact would be a higher cap; however, it would not necessarily impact the amount of capacity predicted by the market simulation model to be installed.

Based on APS demand data for each customer class and a PV power density of 100 square feet of roof per kW_{DC}, plus 20 percent margin,[26] the total required roof area to meet peak demand would be 472 million square feet. However, as indicated in the analysis presented in Table 2-10 above, only 262 million square feet of residential roof space is estimated to be available for all solar DE technologies. Therefore the capacity was scaled by the ratio of the available roof area to required area. That capacity was then multiplied by the number of customers and an energy yield of 1,613 kWh/kW_{DC} (weighted average of modeling results for S, SW, and SE orientation). The resulting installed capacity associated with the 2007 technical potential would be 2,100 MW_{DC}. The total technical potential for energy in 2007 was estimated to be 3,387,300 MWh. Average size was assumed to be 3.5 kW_{DC}. Details are shown in Table 2-11.

[25] Derived based on estimates of the breakdown of pitched vs. flat roofs, tree and other shading, and orientation, from California Energy Commission Public Interest Energy Research Program, *California Rooftop Photovoltaic (PV) Resource Assessment and Growth Potential by County,* CEC-500-2007-048, 2007.
[26] California Energy Commission Public Interest Energy Research Program, 2007.

Table 2-11
Residential PV 2007 Technical Potential

Tariff	Customers (2007)	Single Family Housing	Peak Demand (kW_{AC}/ customer)	Total demand (MW_{AC})	Available Roof Area (million sf)	Installed Capacity (MW_{DC})	Installed Capacity (MW_{AC})	Total Energy (MWh)
E10	69,731	44,279	3.12	138	13.9	116	89	187,247
E12	437,213	277,630	2.74	761	76.7	639	492	1,031,045
ET-1	339,594	215,642	5.26	1,134	114.4	953	734	1,537,374
ET-2	36,083	22,913	6.37	146	14.7	123	94	197,823
ECT-1	54,789	34,791	7.63	265	26.8	223	172	359,792
ECT-2	8,566	5,439	10.04	55	5.5	46	35	74,019
Total	**945,976**	**600,433**		**2,499**	**252.0**	**2,100**	**1,617**	**3,387,300**

Technical Potential - Residential SHW

The saturation of electric water heaters is 42 percent, according to the APS Energy Efficiency Baseline Study[27]. Based on the estimated number of single-family houses in APS's service territory, the total number of residences that could have potentially hosted SHW in 2007 was 252,182.

The roof space needed for a typical SHW collector is relatively modest: 41 square feet plus 20 percent margin.[28] Based on the Study team's experience, it was assumed that a maximum of 80 percent of homes that could potentially host SHW would be applicable. This would equate to a total roof area of approximately 10 million square feet, which is approximately 4 percent of the total roof space available for residential solar DE technologies (SHW and PV). Therefore, this analysis assumes that the remaining 252 million square feet of available residential roof area can be allocated to PV. The SHW savings per unit, as indicated previously, is 2,105 kWh (annual). Therefore, the total technical potential for SHW in 2007 is approximately 424,674 MWh, as indicated in Table 2-12.

[27] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.
[28] SRCC system specs for typical system.

Table 2-12
SHW 2007 Technical Potential

Total Single-Family Homes	600,433
Fraction of Homes with Electric Water Heating	42%
Single-Family Homes with Electric Water Heating	252,182
Roof Area Needed for SHW (sq.ft./house)	49.2
Fraction of Homes where SHW is Applicable	80%
Total Roof Area Needed for SHW (million sq.ft.)	9.9
Fraction of Total Available Roof Area	3.8%
Savings per Unit (kWh)	2,105
Total Technical Potential (MWh)	424,674

Technical Potential - Commercial Sector

The key inputs used to analyze the technical potential for the commercial sector were the estimated number of buildings per sector and square feet of roof space per building. These were derived from the following data sources:

- APS Energy Efficiency Baseline Study[29]
- DOE Commercial Buildings Energy Consumption Survey (CBECS) data[30]
- APS Commercial End Use Study (EUDAP) [31]

The commercial demographic results are shown below in Table 2-13.

Table 2-13
Commercial Demographics

	Avg Bldg Size (EUDAP/ CBECS)	% of Bldg sf as Roof Space	Roof Space per Bldg (sf)	Energy Use kWh/sf (EUDAP)	% Total APS System MWh (Baseline)	Total MWh per sector	MWh/ Avg Bldg	Number of Buildings	Bldg Demand (W/sf)
Education	80,902	77%	62,317	14.9	11.1%	1,718,072	1,206	1,424	3.6
Small Office	4,000	51%	2,039	15.2	9.8%	1,516,856	61	24,965	4.6
Large Office	140,000	51%	71,359	27.0	14.2%	2,197,894	3,773	583	6.0
Small Retail	2,500	85%	2,135	11.7	6.0%	928,687	29	31,750	4.6
Large Retail	36,500	85%	31,177	19.7	13.4%	2,074,069	718	2,889	4.7
Large Grocery	41,600	85%	35,533	51.2	5.2%	804,862	2,129	378	8.0
Other	94,554	81%	76,410	30.0	22.3%	3,451,622	2,837	1,217	5.3
Industrial	41,000	87%	35,750	21.6	18.0%	2,786,062	887	3,140	5.7

[29] ICF International, *APS Energy Efficiency Baseline Study*, prepared for Arizona Public Service, March 2007.
[30] http://www.eia.doe.gov/emeu/cbecs/contents.html. 2003 data.
[31] Quantum Consulting, Inc., *APS End-Use Data Acquisition Project (EUDAP)*, November 1997.

Commercial PV

PV systems were sized to be equal to either the maximum size that can be fit onto the roof area (100 square feet per kW_{DC}) or the size needed to meet estimated demand of the typical building per sector, if smaller. The PV energy yield from the modeling exercise is 1,540 kWh/kW_{DC} for commercial applications. Therefore, the estimate of PV power density used for the commercial analysis was 74 percent peak kW_{AC}/rated kW_{DC}. Based on California's renewable program, it was assumed that 60 percent of commercial roof space would be suitable for PV.[32] Table 2-14 summarizes the PV technical potential for commercial applications for 2007. As with the residential technical potential, it was assumed that the commercial technical potential would increase by 2.4 percent per year, as indicated by APS.

Table 2-14
Commercial PV 2007 Technical Potential

Application	Potential Roof Area (ksf)[1]	Energy Production (kWh/ksf)[2]	Technical Potential (MWh)
Education	88,728	8,332	443,567
Small Office	50,899	8,671	264,812
Large Office	41,569	17,342	432,543
Small Retail	67,799	11,305	459,877
Large Retail	90,066	5,738	310,063
Large Grocery	13,430	8,671	69,873
Other	92,977	13,524	754,465
Industrial	112,255	6,742	454,122
Total			**3,189,322**

1. Assumes 60% applicability
2. Determined from results of modeling effort.

Commercial Daylighting

It was assumed that, where applicable, daylighting would be installed in conjunction with PV. Obstructions and other structural complications were assumed to limit applicability to 90 percent for all commercial customer segments. Table 2-15 summarizes the potential roof space, the energy savings, and the total technical potential of 351,034 MWh.

[32] California Energy Commission Public Interest Energy Research Program, 2007.

Table 2-15
Commercial Daylighting Technical Potential

Application	Potential Roof Area (ksf)	Energy Savings (kWh/ksf)	Technical Potential (MWh)
School Gym	26,280	1,267	29,955
Small Office	50,899	1,273	58,292
Large Retail	90,066	1,966	159,363
Large Grocery	13,430	2,284	27,601
Warehouse	112,255	751	75,823
Total			**351,034**

Note: Assumes 90% applicability

Tariffs

As presented in Section 1 of this Report, APS customers fall into more than a dozen tariff classes, with different corresponding rates for electricity. The average residential energy price applicable to the SHW and PV measures evaluated in this Study was calculated to be $0.123 per kWh. The average commercial tariff was calculated to be $0.064 per kWh, based on a weighted average of commercial tariffs, commercial use by tariff, and number of commercial customers on each tariff. Detailed tariff information for APS customers is presented in Appendix I.

2.5.2 Model Description

Market Simulation Modeling

A diffusion model was used to predict the actual adoption of the solar DE measures by APS customers. A diffusion model considers the cost of the measures, the energy savings, the energy cost and resulting payback period, as well as the dynamics that result in an "S-shaped" growth pattern of technology adoption. This section describes the model utilized for this Study, the baseline and sensitivity cases modeled, and the modeling results.

Description of Bass Diffusion Model

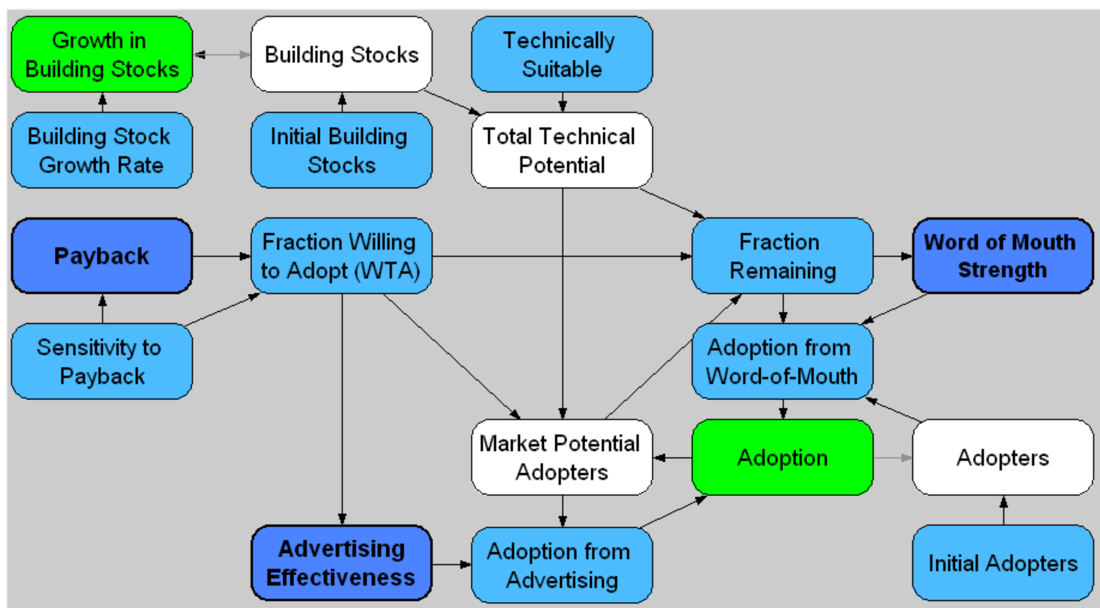
To simulate adoption of PV, SHW, and daylighting, a dynamic market simulation model was created based on a customized version of the highly esteemed Bass diffusion model.[33] The Bass diffusion model is arguably the most highly cited and referenced model in marketing literature. It

[33] For further reference see:
Bass, Frank M. 1969. "A New Product Growth Model for Consumer Durables." *Management Scientist* 13(5):215-227.
Mahajan, Vijay, Eitan Muller, and Yoram Wind. 2000. "New Product Diffusion Models." *International Series in Quantitative Market*. Ch. 12.
Sterman, John D. 2000. *Business Dynamics: Systems Thinking and Modeling for a Complex World*. Boston: Irwin McGraw-Hill, 332.

was conceived by Frank Bass in 1969 and has since been the subject of countless articles, extensions, modifications, and verifications. Dozens of case studies have been conducted that estimate Bass diffusion parameters for various products. The strength of the Bass model lies in its physical explanation of the forces driving both the exponential stage of product adoption (the first half of the S-curve) and the saturation stage of product adoption (the second half of the S-curve). When simulated in a dynamic model such as that built for this Study, it is possible to further enhance the original Bass model. For instance, for this Study, the "Potential Adopters" variable of the Bass model was made a function of the product features (e.g., payback time).

A graphical representation of the key variables included in the diffusion model is provided in Figure 2-17.

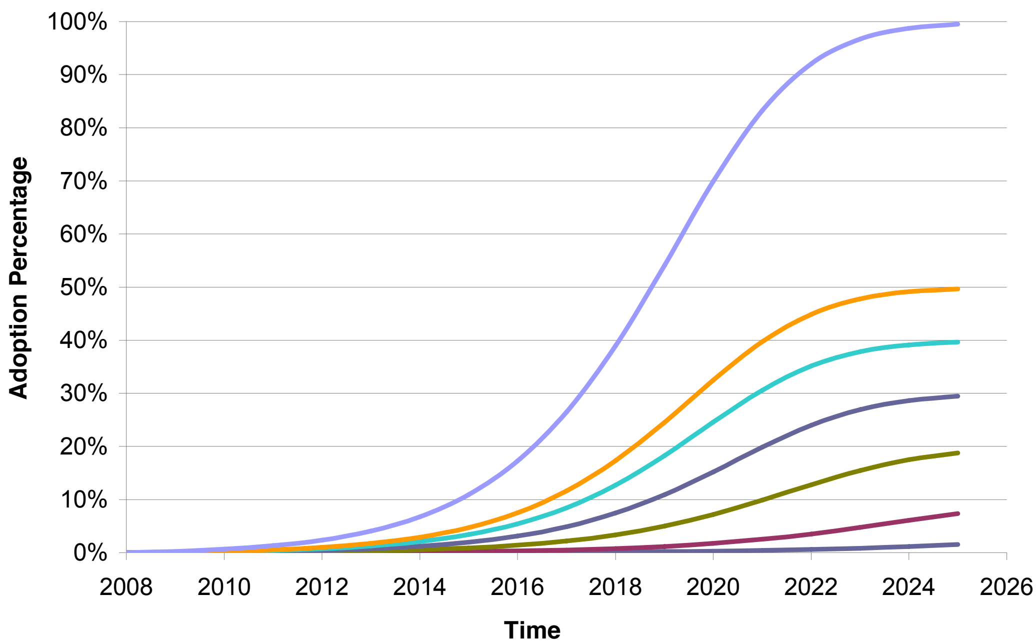
Figure 2-17: Graphical Depiction of SolarSim Model



Key coefficients of the Bass diffusion model, namely the "*advertising effectiveness*" and "*word of mouth strength*", were estimated by optimizing parameters to match market growth for solar PV observed in other markets. These parameters affect the rate at which S-shaped adoption of a product is estimated to occur in the market; that is, how quickly the market saturates to its final adoption percentage. Using the Bass formulation as a starting point, the model was further developed by creating an endogenous effect on the *word of mouth strength* and *advertising effectiveness* that is a function of the ultimate market share of the product. An inspection of solar adoption in Germany, California, and New Jersey indicated that dramatic changes in these parameters can occur upon implementation of significant policy changes, thereby altering the dynamics of adoption.

Figure 2-18 illustrates the S-shaped growth that can occur in the diffusion model for various values of final adoption percentage. These curves are for illustrative purposes only to show the range of potential adoption. It is important to note that these curves are presented for a case where a) initial adopters are zero, and b) the ultimate market potential is static – that is, it is the same for the duration of the simulation. In the market simulation model used for this Study, however, initial adopters vary by technology and customer segment. Further, the equilibrium market share for a given technology will change over time and is a function of assumptions regarding technology costs, electricity costs and usage, tax credits, and incentives. Thus, the final shape of the diffusion curve will vary depending on the behavior of all these key variables over time.

Figure 2-18: Example Technology Diffusion Curves



Note: This figure is for illustrative purposes only and does not represent the results of this Study (see text for discussion).

The fraction of customers ultimately willing to adopt a technology was estimated based on the calculated simple payback time of the technology. The formulation for the ultimate market share[34] is calculated as:

$$\textit{fraction willing to adopt} = e^{(-\,\textit{sensitivity to payback} \,*\, \textit{payback time})}$$

where:

sensitivity to payback is estimated to be 0.3, and

payback time is calculated in years based on installed cost, annual savings, and electricity cost.

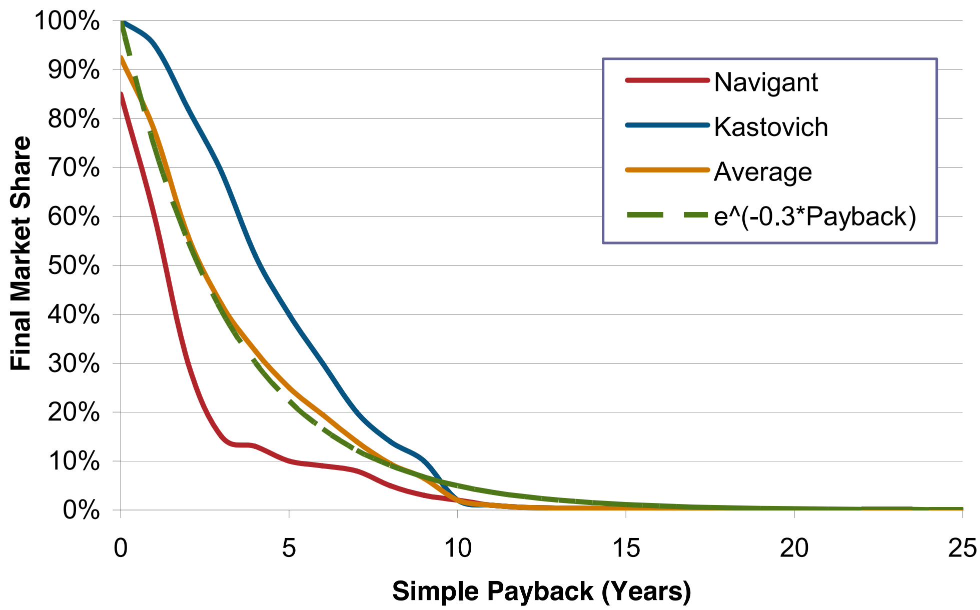
For comparison, Figure 2-19 illustrates the formulation described above as it compares with the baseline curve assumed in a recent Arizona Department of Commerce study.[35] The baseline value used in that study is the average of two estimations provided by Navigant Consulting and

[34] That is, the market share that would occur given sufficient time for the technology to diffuse per the parameters affecting the S-shaped adoption.

[35] See Arizona Department of Commerce's "Arizona Solar Electric Roadmap Study," January 2007. [http://www.azcommerce.com/doclib/energy/az_solar_electric_roadmap_study_full_report.pdf]

Kastovich.[36] The formulation used in this Study, which was chosen for simplicity, ease of conducting sensitivity analyses, and for its reasonable estimation of market share consistent with other studies, is shown as the dashed line in Figure 2-19. The formulation used for this Study matches up very well with the baseline value used in the Department of Commerce study.

Figure 2-19: Final Market Share vs. Payback



Deployment Cases

As mentioned in Section 1, three cases were modeled for this Study: a "Low Penetration" Case, a "High Penetration" Case, and a "Medium Penetration" Case. The first two cases are intended to "bookend" the range of reasonable conditions. The last case represents the results of modifying some of the assumptions that frame the first two cases. The assumptions for the three cases are summarized in Table 2-16.

[36] Kastovich, J.C., Lawrence, R.R., Hoffman, R.R., and Pavlak, C., *Advanced Electric Heat Pump Market and Business Analysis,* 1982.

Table 2-16
Description of Key Input Variables to Deployment Cases

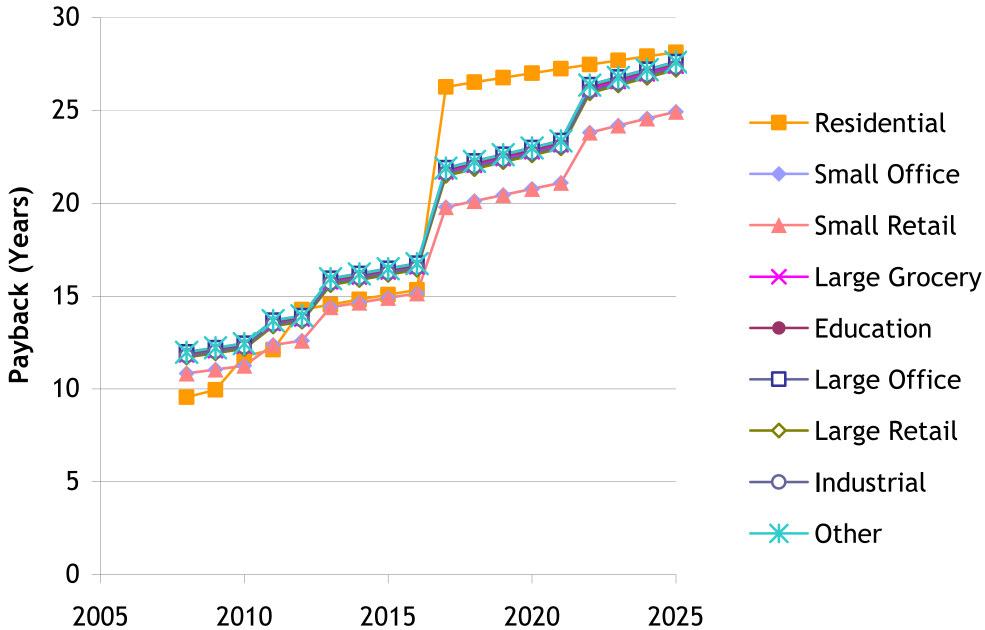
Low Penetration	Medium Penetration	High Penetration
State tax credits for residential PV and SHW (25% of purchase cost, up to $1,000).	State tax credits for residential PV and SHW (25% of purchase cost, up to $1,000).	State tax credits for residential PV and SHW (25% of purchase cost, up to $1,000).
State tax credits for commercial PV (10% of purchase cost, up to $25,000).	State tax credits for commercial PV (10% of purchase cost, up to $25,000).	State tax credits for commercial PV (10% of purchase cost, up to $25,000).
Federal tax credits for residential PV and SHW (30%) through 2016.	Federal tax credits for residential PV and SHW (30% declining to 10% in 2017 and 0% in 2022).	Federal tax credits for residential PV and SHW (30%).
Federal ITC of 30% for commercial PV through 2016, then decrease to 10%.	Federal ITC of 30% for commercial PV, declining to 10% in 2017.	Federal ITC of 30% for commercial PV.
APS rebates per schedule. Final year values persist.	APS rebates per schedule. Final year values persist.	APS rebates per schedule. Final year values persist.
Current electric tariffs escalate with inflation (2.5%).	Electric tariffs escalate greater than inflation (5.1%)	Electric tariffs escalate greater than inflation (5.1%)
PV costs remain constant in real terms.	PV costs decline by approximately 45% in real terms by 2015, trend to $3,000/kW by 2025.	PV costs decline by approximately 45% in real terms by 2015, trend to $3,000/kW by 2025.

For all cases, APS rebates were assumed to decline according to the schedule provided by APS. It was assumed that incentives after year 2013 would persist until 2025, the last year of this Study for all three cases. Current APS incentive schedules are presented in Appendix J.

Payback Calculation

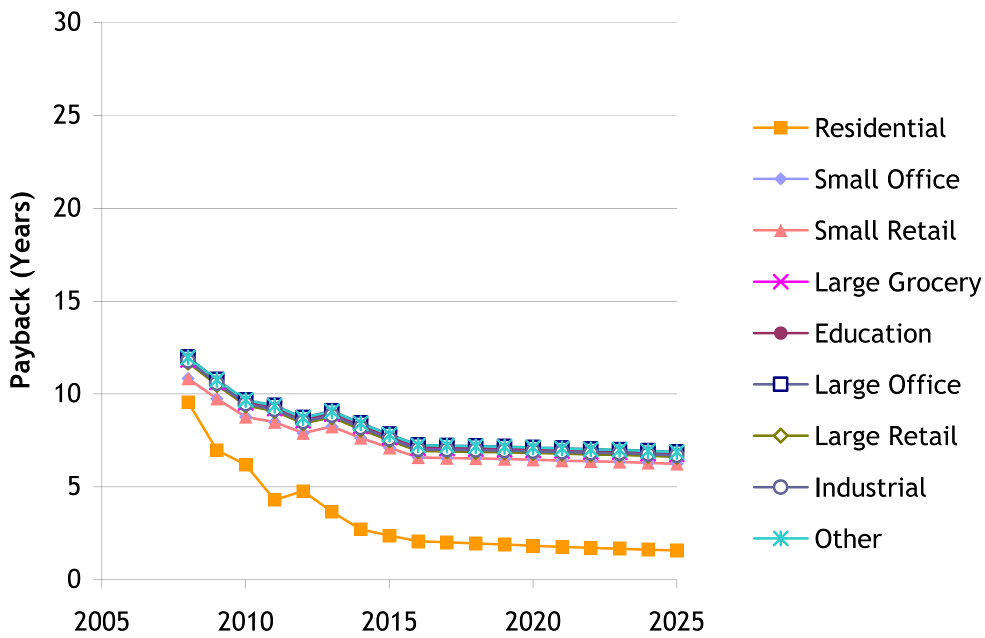
The payback calculation is a key input to the diffusion model. The payback calculation reflects the installed cost of the measure, less any tax credits or incentives, divided by the product of the annual energy savings and electricity rate. Figures 2-20 through 2-25 present the paybacks in each year for the solar DE technologies installed in that year for the Low, Medium, and High Penetration Cases.

Figure 2-20: PV Payback - Low Penetration Case



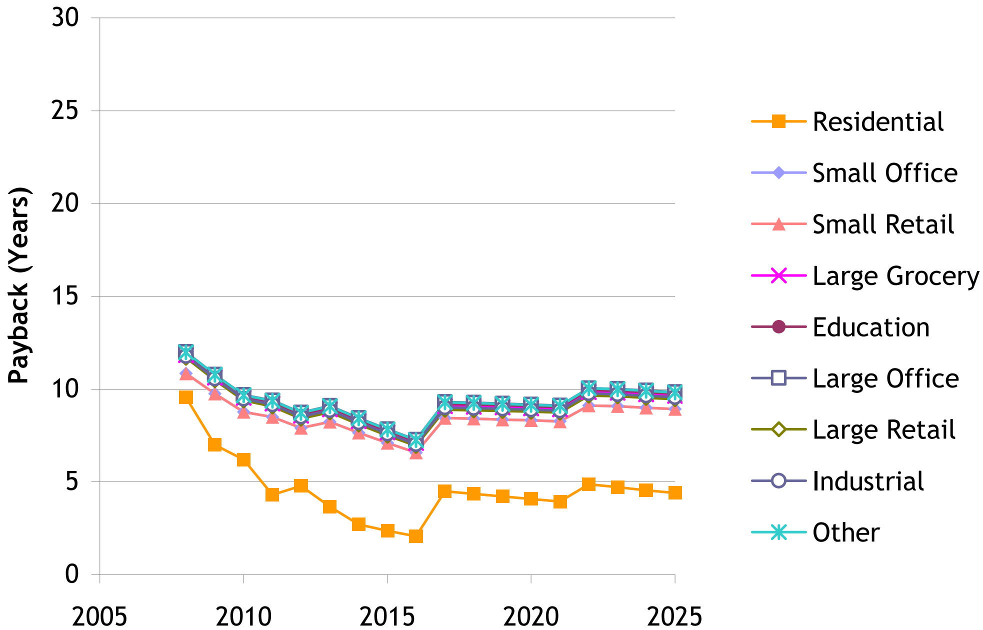
In the Low Penetration Case, the payback is calculated to range from about 10 to 12 years in the initial portion of the Study (2008) for all customer groups. However, in this case, the payback increases in the later years as the federal tax incentives decrease, the capital costs of the PV systems remain the same, and the retail electric tariffs increase with inflation. The residential payback increases over the other customer types due to the assumption of a decrease in the federal tax credits from 30 percent to zero in 2016.

Figure 2-21: PV Payback - High Penetration Case



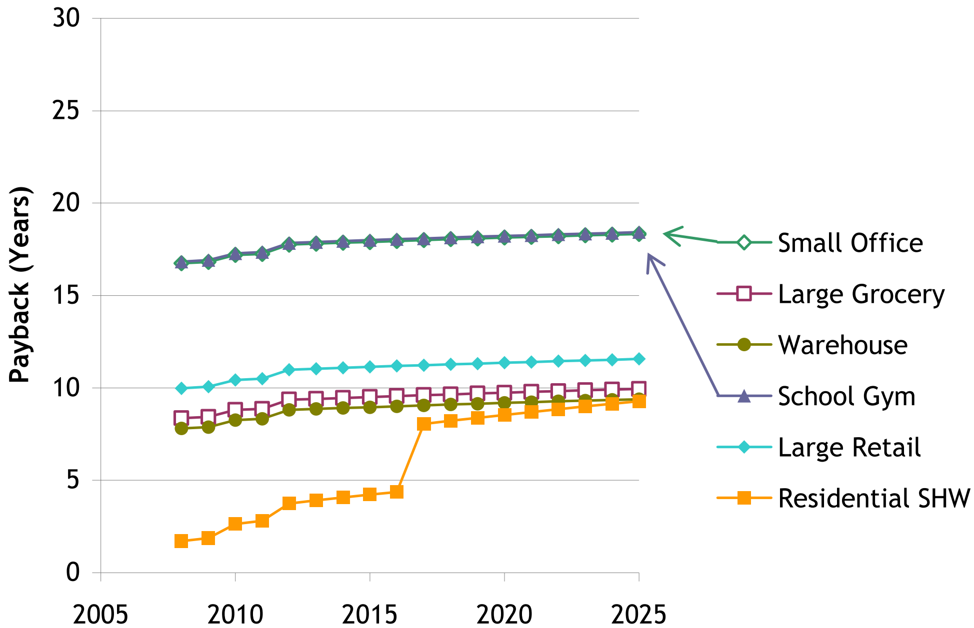
In the High Penetration Case, the payback is calculated to range from about 10 to 12 years in the initial portion of the Study (2008) for all customer groups. However, in this case, the payback decreases in the later years as the federal tax incentives remain in place, the capital costs of the PV systems decrease, and the retail electric tariffs increase greater than inflation. In this case, the residential payback decreases more than the other customer types primarily due to the assumption of the increase in APS tariffs.

Figure 2-22: PV Payback - Medium Penetration Case



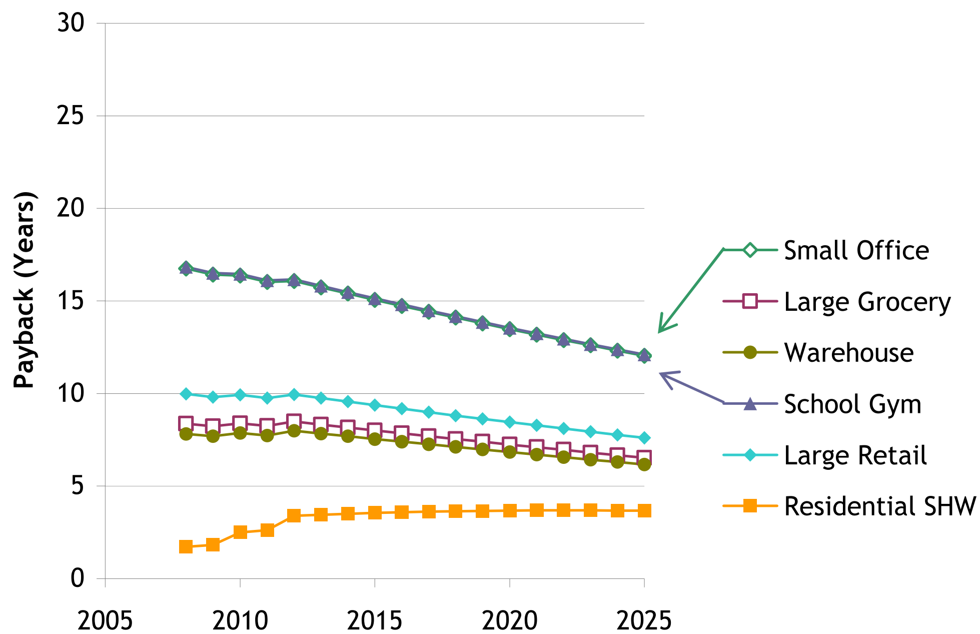
In the Medium Penetration Case, the payback is calculated to range from about 10 to 12 years in the initial portion of the Study (2008) for all customer groups. However, in this case, the payback decreases in the initial years as the federal tax incentives remain in place, the capital costs of the PV systems decrease, and the retail electric tariffs increase greater than inflation. However, the paybacks increase as the federal tax incentive is reduced and discontinued. In this case, as with the High Penetration Case, the residential payback decreases more than the other customer types primarily due to the assumption of the increase in APS tariffs.

Figure 2-23: Daylighting and SHW Payback – Low Penetration Case



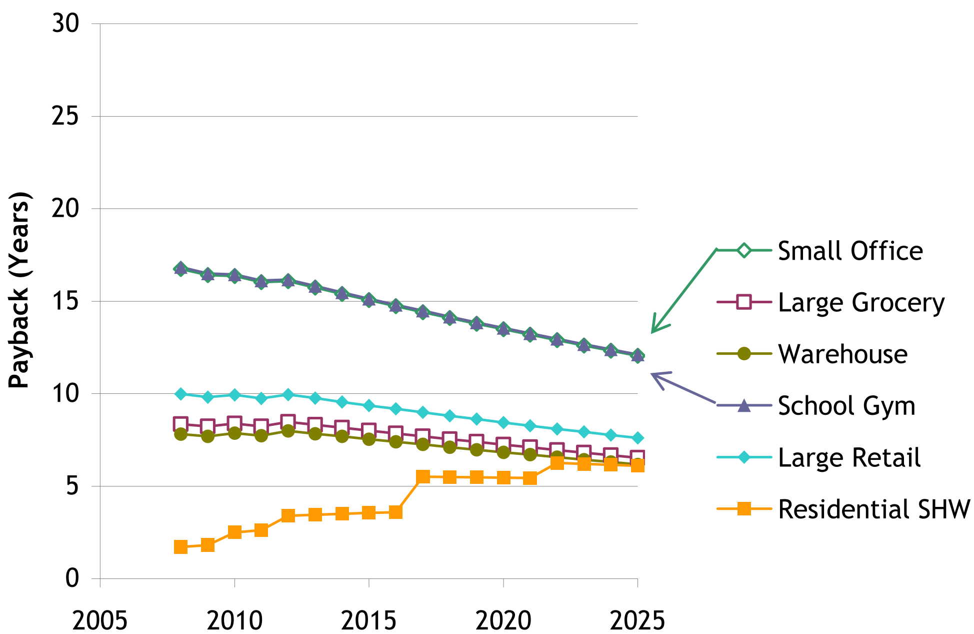
In the Low Penetration Case for daylighting and SHW, the payback is calculated to be approximately two years for SHW and range from about 7 to 16 years in the initial portion of the Study (2008), depending on customer groups. However, in this case, the payback increases in the later years as the federal tax incentives are removed and the retail electric tariffs increase is limited to inflation.

Figure 2-24: Daylighting and SHW Payback – High Penetration Case



In the High Penetration Case for daylighting and SHW, the payback is calculated to be approximately two years for SHW and range from about 7 to 16 years in the initial portion of the Study (2008), depending on customer groups. However, in this case, the payback decreases in the later years as the federal tax incentives remain in place and the retail electric tariffs increase greater than inflation.

Figure 2-25: Daylighting and SHW Payback - Medium Penetration Case



In the Medium Penetration Case for daylighting and SHW, the payback is calculated to be the same as the previous cases for the initial portion of the Study (2008), depending on customer groups. However, in this case, the payback remains the same for the daylighting as with the High Penetration Case, but increases for the residential SHW, due to the reduction in the federal tax incentives.

2.5.3 Modeling Results

The modeling reveals payback to be one of the key factors in technology diffusion. Using the assumptions of the High Penetration Case, the years required for payback decline rapidly and diffusion increases significantly. In the Low Penetration Case, the opposite occurs; the years for payback increase, inhibiting technology adoption.

Key Findings from Market Simulation Modeling

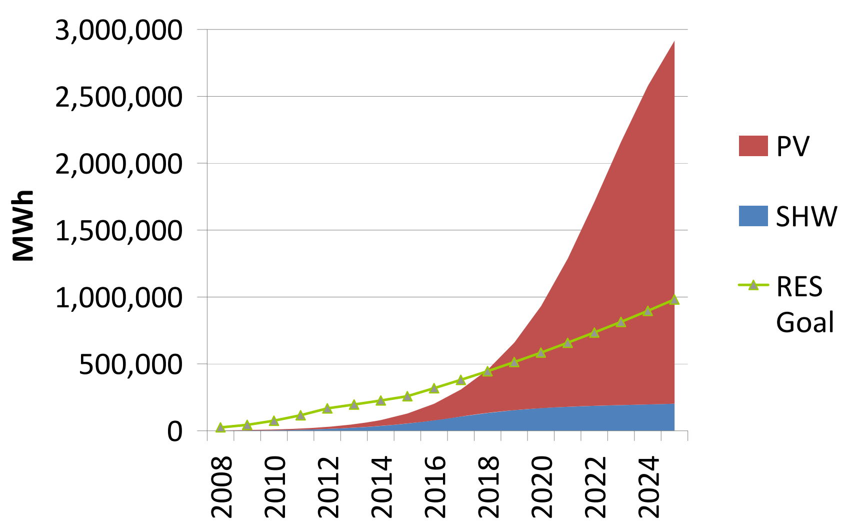
- Under the High Penetration Case for the residential technologies, the program exceeds the RES goals for those technologies.
- Under the Low Penetration Case for the residential technologies, the program falls far short of the RES goals for those technologies.
- Under the High Penetration Case for the commercial technologies, the program exceeds the RES goals for those technologies.
- Under the Low Penetration Case for the commercial technologies, the program falls far short of the RES goals for those technologies.

- The forecast of the anticipated future costs of PV systems has a major impact on the technology adoption. As a result, the DOE forecast showing aggressive cost reductions over a fairly short period of time in the near future (see Figure 2-3) swing the level of adoption of PV systems from one extreme to the other. This is the major driver in the differences between the High and Low Penetration Cases.
- In trying to establish an upper and lower limit of the level of deployment for the Market Adoption scenario, a number of key factors were identified and modeled. The values and the timing of the factors need to be investigated in more detail to ensure that both scenarios present realistic forecasts. Areas of further investigation and model refinement may include the following:
  - Tax credits are assumed to remain in effect throughout the duration of the period of analysis.
  - While the level of incentives is modeled to decrease, it is assumed that some level of rebates will be offered throughout the duration of the period of analysis.

Results of Market Simulation Modeling - Residential

As can be seen in Figure 2-26, with the assumptions in the High Penetration Case, residential installations of PV and SHW result in a combined annual energy impact of roughly 2,917,000 MWh in 2025, which significantly exceeds the target RES goal of 913,475 MWh. The total energy impact is attributable largely to PV installations, which represent about 93 percent (2,713,000 MWh) of the total, with SHW installations accounting for the remaining seven percent (203,000 MWh). Continued incentives for PV combined with assumed technology cost reductions over the simulation period are largely responsible for PV capturing a much greater share of the energy impact than SHW in the High Penetration Case.

Figure 2-26: Residential Market Potential – High Penetration Case



In the Low Penetration Case, however, PV represents a much smaller fraction (~24 percent) of the total energy impact of roughly 123,000 MWh in 2025, which falls far short of the RES goal, as illustrated in Figure 2-27. The impact of both technologies is substantially lower with the assumption of no federal tax credits for residential, although PV fares much worse in the Low Penetration Case due to the assumption of constant installation costs in real terms.

Figure 2-27: Residential Market Potential - Low Penetration Case

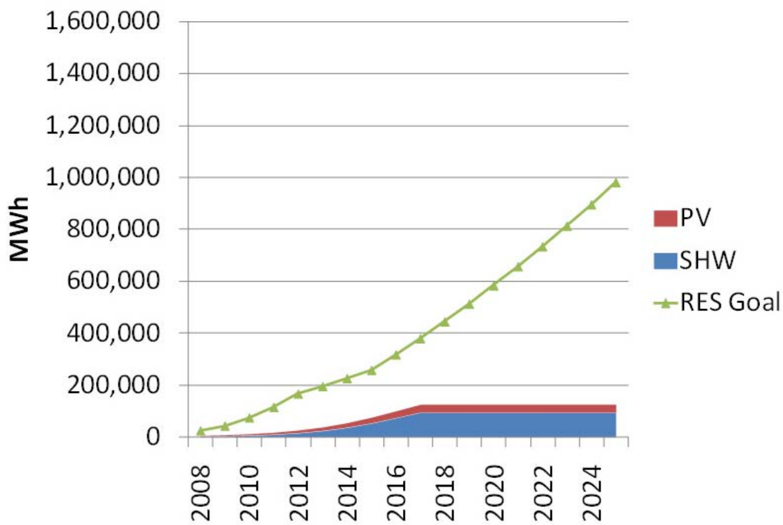
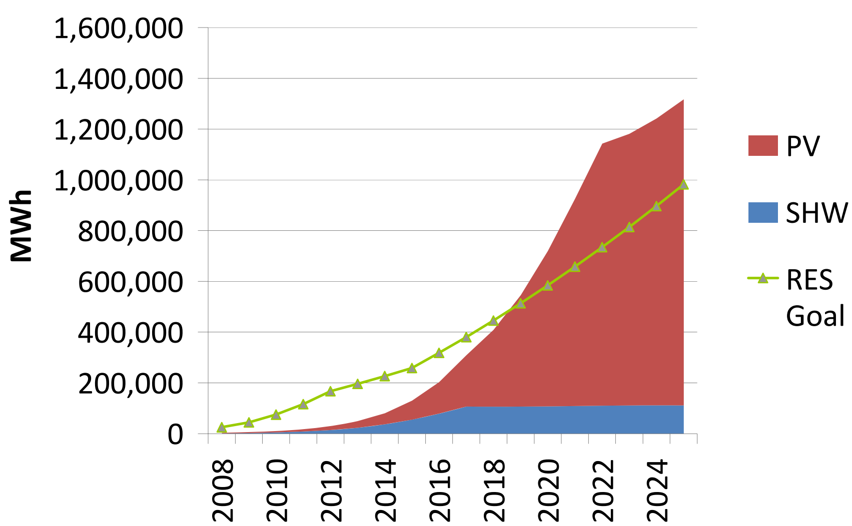


Figure 2-28 provides the results for the Medium Penetration Case for residential PV and SHW. As can be observed, this case suggests that APS will achieve its RES goal in approximately 2018 (for these technologies).

Figure 2-28: Residential Market Potential - Medium Penetration Case



Results of Market Simulation Modeling - Commercial

In the commercial area, Figure 2-29 illustrates that the combined impact of PV and daylighting also exceeds the RES goal in 2025 for the High Penetration Case, with an estimated 555,000 MWh of combined energy impact. This impact is largely attributable to PV (513,000 MWh), driven by technology cost reductions as well as existing tax credits and utility incentives. With no tax credits for daylighting, however, and with the assumption of constant (in real terms) installation costs for daylighting, installations of daylighting are estimated in this scenario at 43,000 MWh.

Figure 2-29: Commercial Market Potential – High Penetration Case

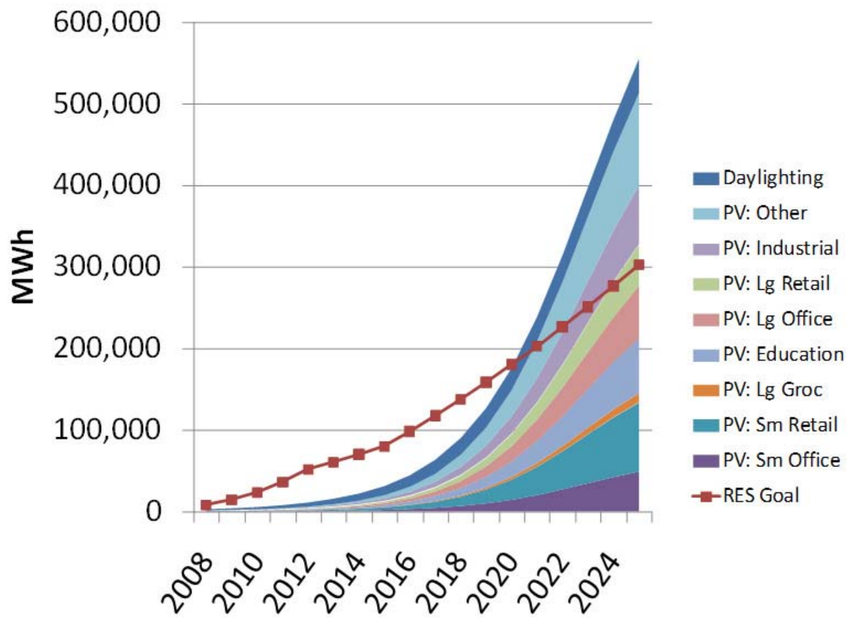


Figure 2-30 illustrates that for the Low Penetration Case, commercial market impacts fall far short of the RES goal with roughly 34,000 MWh of combined installations (~45 percent from daylighting).

Figure 2-30: Commercial Market Potential – Low Penetration Case

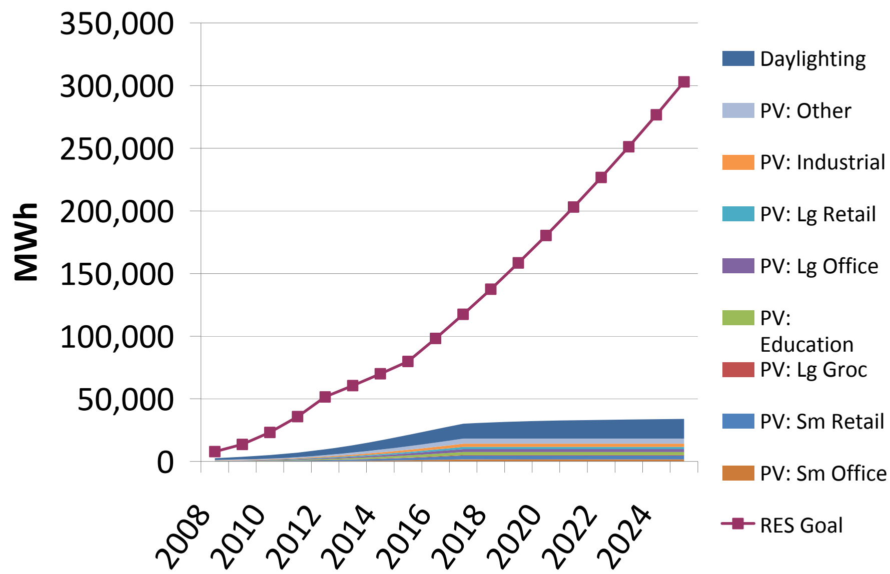
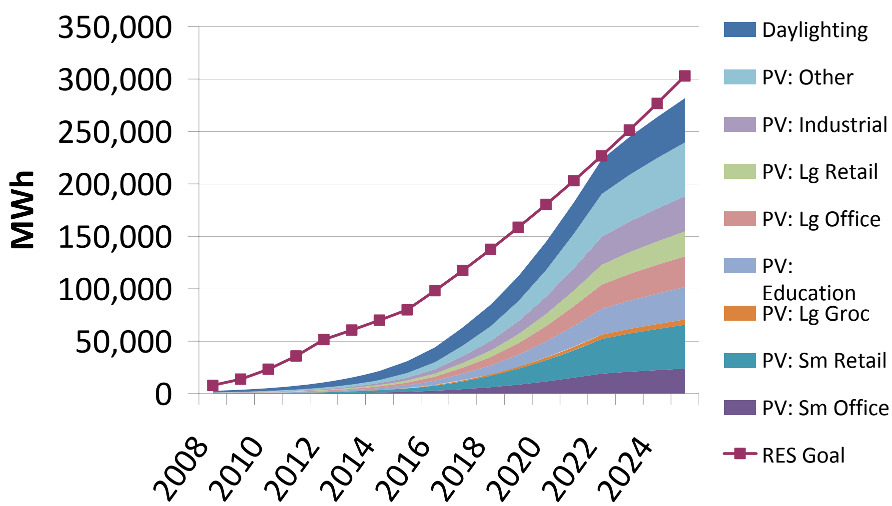


Figure 2-31 provides the market deployment for the commercial PV and daylighting for the Medium Penetration Case. As can be observed, the results indicate that the deployment of these technologies will almost meet APS's commercial RES goals by approximately 2023.

Figure 2-31: Commercial Market Potential – Medium Penetration Case



SECTION 3 — TECHNICAL VALUE - DISTRIBUTION SYSTEM

Solar DE can potentially provide value to APS by decreasing line losses and reducing capital expenditures related to the distribution system.

The objective of this section is to identify the potential value of deployment of solar DE technologies to the APS distribution system. Based upon discussions with APS and the stakeholders, four sources of potential value to the distribution system were identified: a reduction in line losses, a deferment of capital expenditures, an extension of service life for distribution equipment and a reduction in initial capital investment (associated with equipment sizing). Additionally, this section reviews potential limitations to the deployment of solar DE on the distribution system.

The analysis shows that the value associated with the reduction in line losses when solar DE is applied to the distribution system can be calculated by comparing hourly projected loads to hourly solar output for a given feeder. The system-wide value associated with reducing line losses, on both the distribution and transmission systems, can be found in Section 4 of this Report.

The value of solar DE increases if it can be utilized to defer capital expenditures by effectively lowering the load required to be served by APS. The key to maximizing this capital deferment value is to identify strategic locations which can optimize the benefits. By installing solar DE in specific, targeted load growth areas, for example, capital expenditures may be deferred and the value of those installations can be increased.

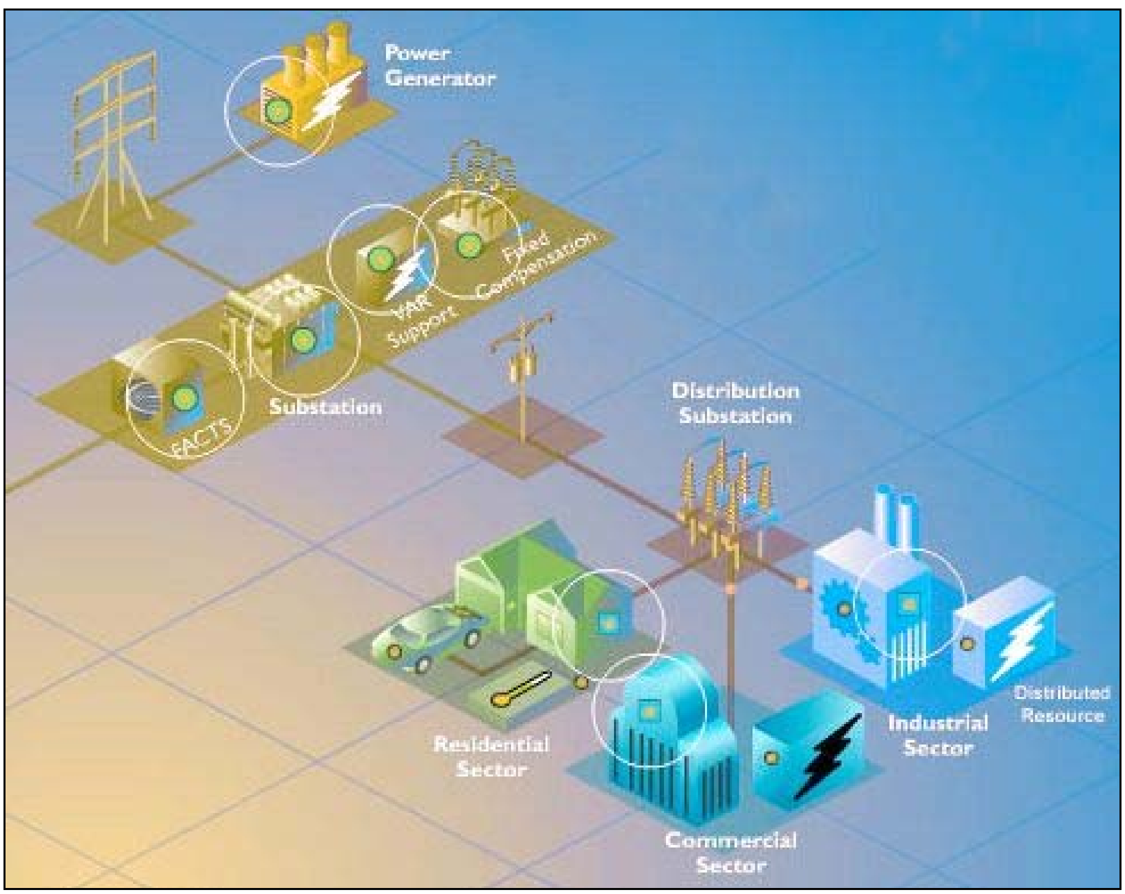
Extension of equipment service life could add value if solar DE prevents transformer overloading. However, APS data for transformer overload events and durations was not available to quantify these potential savings for this Study. Another potential source of value could be a reduction in initial capital investment associated with reduced equipment sizing. However, analysis indicates this is not expected because solar output at the time of customer peak demands is typically not sufficient to downsize the infrastructure.

The Study also looked at a number of possible limitations to the value of solar DE on the distribution system. Limitations in the form of performance and power quality issues were determined to be not significant. However, technological barriers, such as efficient energy storage mechanisms that would improve reliability and generation during peak loads, were determined to present potential limitations to the value of solar DE.

3.1 Introduction

For the purposes of this Study, the distribution system is defined as the equipment required to transport power from the transmission system to the customer, including the distribution substation and the residential and commercial sectors as illustrated in Figure 3-1. The distribution system consists of substation equipment that transforms high voltage power (69 kV and above) to distribution voltage power (12 kV), along with the distribution feeders that originate from the substation and carry power to the customers, the distribution transformers that transform distribution feeder voltage to customer voltage (120/240 V or 277/480 V), and the secondary equipment that serves the customer from the distribution transformer.

Figure 3-1: Power System



Source: EPRI

This section discusses the analysis used by the Study team to determine the value for each of four potential sources of value: line losses, deferment of capital expenditures (capex), extension of service life, and reduction in equipment sizing. The section includes a description of the methodology used to determine value, a description of the various models utilized in that effort, and a discussion of the modeling results. These modeling results are then presented for each of the deployment scenarios described in Section 2 of this Report. A discussion of some of the technical limitations associated with Solar DE on the distribution system is also included.

A description of how the four value sources roll up to provide an aggregate value for the total distribution system is presented at the end of this section. Depending on the level of detail required for the analysis, supplemental analysis and information may be presented in the appendices to this Report.

The overall approach used by the Study team in this section included a combination of empirical testing, system modeling, and reviewing information provided by APS, other electric utilities, research institutions, and the stakeholder group. Empirical testing included utilizing existing solar DE installations owned and operated by APS to test certain conditions. The energy production from a large APS solar facility on a feeder, for example, was dropped momentarily from the electrical system to study the effect on feeder voltage and harmonics.

System modeling included the development of customer load models, feeder load flows and annual hourly system usage to simulate the impact on annual peak demand and energy losses from a range of installed levels of solar DE technologies. The models were used to perform a screening analysis for actual APS residential and commercial customers, as well as feeders and substations, utilizing 2006 and 2007 load and weather data to estimate demand savings associated with solar DE.

The residential and commercial customer screening analysis supported the analysis of the potential value source associated with a reduction in equipment sizing. The feeder screening analysis was used to evaluate potential solar impact to determine the level of solar DE required to defer capex.

Since demand varies on an hourly basis, and solar output varies on an hourly basis — both relatively significantly — an hourly analysis of loss savings was conducted. Projected annual hourly system load profiles, with and without solar, were compared to determine annual energy losses, as well as peak demand losses at the system level. The methodology and results for this analysis are included in Section 4, which incorporates loss savings for both the distribution and transmission systems.

Hourly projected solar DE data was used to calculate "dependable capacity" at the time of the annual system peak load for the distribution and transmission system. This was use to determine a targeted capacity deferment value at the system level for the distribution and transmission systems (a slightly different calculation of "dependable capacity" was utilized for the generation system described in Section 5). An average cost of distribution improvements per MW of non-coincident load growth was used to calculate the value to the distribution system.

In addition, EPRI's DSS tool was used to analyze the hourly impact of different levels and types of solar DE deployment on a particular feeder to validate annual distribution loss calculations and the effect on annual peak demand for capital deferment or possible equipment size reduction.

The EPRI tool was also used with sub-hourly data to simulate short-term load changes due to inverters switching off line and the resulting effect on feeder voltage.

3.2 Reduction in Losses

3.2.1 Methodology

Solar DE provides electricity at the site of application and therefore reduces the load needed to be served by a centralized power generating facility. A reduction of load at the site of a solar DE application results in energy savings due to the energy generated by the solar DE and a reduction of generation at a centralized facility. This reduction in load also results in a reduction in the electricity losses that occur during delivery of electricity from the centralized generating facility to the load. This is referred to as line losses. If less electricity is required to be transmitted to a specific location, then there will be a reduction in the line losses associated with that reduction in power transmission.

The discussion and analysis associated with the value of the energy savings associated with the generation of energy from solar DE is provided in Section 5 of this Report. Because the distribution system and transmission system are inextricably linked when discussing line losses, the results of the analysis for line losses are presented in Section 4.

In addition to energy losses, there are demand losses that occur at the time of a peak load. Similarly to the energy, a reduction in peak current (or load) results in reducing peak demand losses proportional to the square of the reduced load. The demand losses affect the system capacity that is required to be built from the centralized generating station to the customer's meter.

3.2.2 Modeling Description

System Loss Model

As mentioned above the modeling, analysis, and results for the system level energy losses, including the distribution and transmission, is discussed in Section 4. The system energy loss model is also used to calculate the annual peak demand loss reduction due to solar DE. The distribution specific portions of the modeling efforts undertaken for this Study are described below.

Feeder-All Distribution Feeder Model

APS and the Study team performed analysis on specific distribution feeders to understand the effect of peak load reduction on distribution demand losses. APS models distribution feeders using ABB's Feeder-All software to perform load flow studies that evaluate conductor loading, voltage drop, and losses at specific load levels. Only the main three-phase lines are modeled in Feeder-All; therefore, results do not include loading or losses on single-phase taps, distribution transformers, or customer service conductors. APS and the Study team performed load flow analysis on some of the distribution feeders to determine the relationship of feeder loading to the losses on the main three-phase lines.

DSS Distribution Feeder Model

A more detailed loss analysis was performed on a distribution feeder to validate the system level analysis. The APS Geographic Information System (GIS) data for Deadman Wash Feeder #4 was provided to EPRI to develop a working electrical model in the DSS tool. The model included 295 customer distribution transformers and 1,429 customer services as well as 56 miles of 12 kV primary conductors. The same feeder had only 5 miles of primary modeled in Feeder-All. Customer loads were modeled by allocating the peak feeder load and scaling the 2007 hourly feeder current measured at the substation. To understand the existing conditions (without solar DE), hourly load flows were simulated and compared to actual hourly feeder measurements with less that 2.5 percent error in total, average or maximum kWh for the year.

To determine the impact of the projected 2025 high deployment level (High Penetration Case), the 8,760-hour solar technology curves developed in Section 2 for 2007 weather data were applied to random customers proportionately to the projected penetration rates as follows:

- 52 percent of residential customers with PV
- 11 percent of residential customers with SHW
- 100 percent of commercial customers with PV and daylighting (only 2 identified on this circuit)

In addition, a sensitivity was developed for a "greenfield" case with 100 percent penetration of each technology and single-axis tracking for commercial PV. The analysis determined annual losses for each scenario. Additional modeling details, assumptions and results are provided in Appendix K.

3.2.3 Model Results

System Loss Model

Based on the deployment scenarios described in Section 2 and projected annual hourly system load profiles, the avoided demand losses that can be realized at system peak are summarized in Table 3-1. As expected, the demand losses increase with increased solar DE generation. These values were added to the dependable capacity provided by solar DE to calculate the total peak load reduction and associated values.

Table 3-1

Avoided Losses (MW) at System Peak

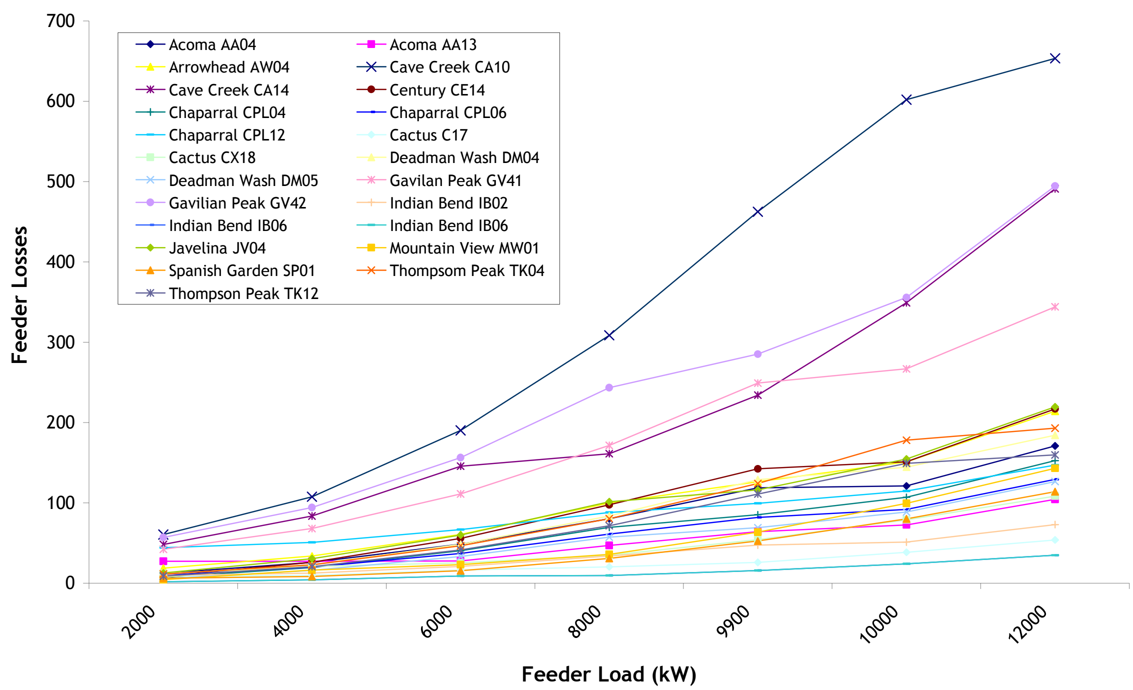
Year	Low Penetration Case	Medium Penetration Case	High Penetration Case	Single-Axis Sensitivity
2010	0.354	0.367	0.367	0.383
2015	1.986	3.635	3.635	3.808
2025	3.283	39.452	70.551	72.869

Feeder-All Distribution Feeder Model

APS and the Study team performed a Feeder-All analysis on several feeders to evaluate the effect of reduced load on losses. The results are presented in Figure 3-2. Since the Feeder-All model includes only the primary three-phase lines, only the losses in those lines are reported.

The difference in losses between different feeders with the same load is due to the difference in the resistance of each feeder. Resistance is a function of the length, size and type of conductors. Since each feeder is unique, the impact of solar DE on a feeder's losses varies greatly. The Feeder-All analysis illustrates the load/loss relationship and supports the value statement that solar DE will reduce demand losses as peak load is reduced.

Figure 3-2: Feeder-All Loss Analysis



DSS Distribution Feeder Model

The energy loss analysis results from the DSS modeling effort are summarized in Table 3-2.

Table 3-2
DSS Annual Energy Loss Analysis Results

	Existing Condition	High Penetration Case	% Dif	Greenfield Case	% Dif
Total Energy (MWh)	25,296	20,360	19.5%	10,606	58.1%
Losses (MWh)	690	597	0.4%	514	0.7%
% Losses	2.7%	2.9%		4.8%	
No-load Losses (MWh)	191	193		195	
Load Losses (MWh)	499	404	19.0%	319	36.1%

The results indicate that high penetration of solar DE on this feeder will save energy each year in losses, which will also result in additional value through generation fuel savings (as described in Section 5). The results also show that while the solar DE can have a large impact in the annual energy consumed on this feeder, the resulting decrease in annual losses is very modest. In addition to energy losses, the peak demand losses for the DSS modeling effort are shown in Table 3-3.

Table 3-3
Peak Demand Losses

	Existing Condition	High Penetration Case	% Dif	Greenfield Case	% Dif
Feeder Peak Demand (kW)	10,276	9,835	4.3%	8,876	13.6%
Peak Demand Losses (kW)	479	440	8.1%	362	24.4%
% Peak Demand Losses	4.7%	4.5%		4.1%	
No-load Losses (kW)	20	20		20	
Load Losses (kW)	459	420	8.5%	342	25.5%

These results reinforce the system analysis that calculates the additional value of reduced peak demand losses when peak demand is reduced. The solar deployment in the High Penetration Case results in a 4.3 percent reduction in peak load and an 8.5 percent reduction in peak demand load losses from the existing condition; the Greenfield Case includes a 25.5 percent peak demand load loss reduction for a 13.6 percent peak demand reduction.

The DSS model did not restrict the hourly generated PV to the each customer's maximum load; as a result, during some hours PV systems were back-feeding into the grid. If back-feeding were not allowed, the percentage loss reduction would be greater. The system level energy loss analysis in Section 4 does not include reduced losses due to backfeed. As previously indicated, complete results of this analysis, including a breakdown of loss contributors by equipment type, is included in Appendix K.

3.3 Deferment of Capex

3.3.1 Methodology

Solar DE can potentially provide value to APS by decreasing the capacity requirements of the distribution system based on the reduction in demand as described earlier. Decreased capacity requirements reduce or defer capex for capacity upgrades.

Distribution equipment is sized to serve the projected annual peak load. Capital improvement projects (capex) are planned when projected loads will exceed the planning load limit of a feeder or substation. Solar DE can provide value by reducing load (demand) on a particular feeder or substation sufficiently to defer a capital improvement project.

APS has developed a "2008-2010 Three Year Plan" for capex projects in each division of the Phoenix metropolitan area of the distribution system. Table 3-4 summarizes the proposed capital budgets based on the projected non-coincident load growth of each feeder in each division. Over the three-year period, the capital budget for distribution infrastructure additions and improvements averages approximately $115,000 per MW of non-coincident load growth. This value is used to approximate the potential capacity savings system-wide based on the Target scenario analysis.

Table 3-4
Regional Load Growth and Budget Projections

	2008		2009		2010		Average
	Load Growth (MW)	Capital Budget ($000)	Load Growth (MW)	Capital Budget ($000)	Load Growth (MW)	Capital Budget ($000)	$/MW ($000)
Metro Eastern Division	40	$7,957	27	$13,983	101	$11,866	
Metro Central Division	128	$14,300	99	$8,710	84	$6,126	
Metro Western Division	151	$18,145	180	$17,090	196	$15,660	
Totals	**319**	**$40,402**	**306**	**$39,783**	**381**	**$33,652**	
$/MW Load Growth		**$126**		**$130**		**$88**	
Average $/MW Load Growth[1]							**$115**

Source: "2008-2010 Three Year Plan" APS, 2007

1. Value is rounded

Because distribution capacity is solely based on local peak loads, distribution capacity savings can only be realized if solar DE is strategically located to relieve distribution congestion or to delay specific upgrades required for future growth. Additionally, APS could allow capacity upgrade deferrals only if the load would not exceed the equipment's emergency rating when the solar DE is not available due to cloud cover. APS design standards include an emergency rating that allows loading most distribution equipment 10 percent over the planning rating. Without a storage mechanism to maintain solar DE reliability during cloud cover, solar DE can only provide dependable capacity within that 10 percent bandwidth to provide increased capacity during normal conditions without overloading the equipment when the inverters have switched off.

Deferral of transmission and distribution system upgrade projects is based on the dependable capacity of solar DE during annual peak load. Determination of dependable capacity involves a comparison of hourly solar output to hourly load for potential peak load days.

To test the feasibility of utilizing solar DE to defer a capital project, a constrained area was analyzed where a capital improvement project has been identified to relieve an overloaded feeder. As an example of a constrained area, a screening analysis of the Thompson Peak Substation Feeder 10 project was conducted. Thompson Peak Feeder 10 is projected to be loaded to maximum capacity in 2008, and a new feeder is planned to relieve it. Solar DE could be used to reduce load to the planning level to postpone the upgrade. Loss of the solar DE due to cloud cover during peak loads would increase loading back to the present operating level.

Solar DE can only be used to defer upgrade projects for feeders loaded between the planning and emergency ratings. Additional growth on Thompson Peak Feeder 10 would result in the equipment being overloaded if solar DE is not available and will require the upgrade until storage is available.

The Study team also explored the possibility of implementing solar DE in a "greenfield" area of new development with the idea that each customer would install the appropriate technology. To review the impacts on a greenfield area, a feeder from the Deadman Wash Substation (Deadman Wash Feeder 4) was analyzed. While the Deadman Wash Feeder #4 is not in a greenfield area, which by definition would not have feeders, it is located in the Anthem master-planned community, which was identified as a proxy for future development areas.

3.3.2 Modeling Description

The modeling effort to determine the potential for deferment of capex on the distribution system consisted of three distinct components. The first consisted of determining the potential dependable capacity for the distribution and transmission systems associated with solar DE. The second consisted of a screening analysis of specific feeders and their actual loads with solar DE production (specifically related to PV systems). The third consisted of reviewing impacts to specific feeders utilizing EPRI's DSS model (which included the Deadman Wash Feeder #4 analysis).

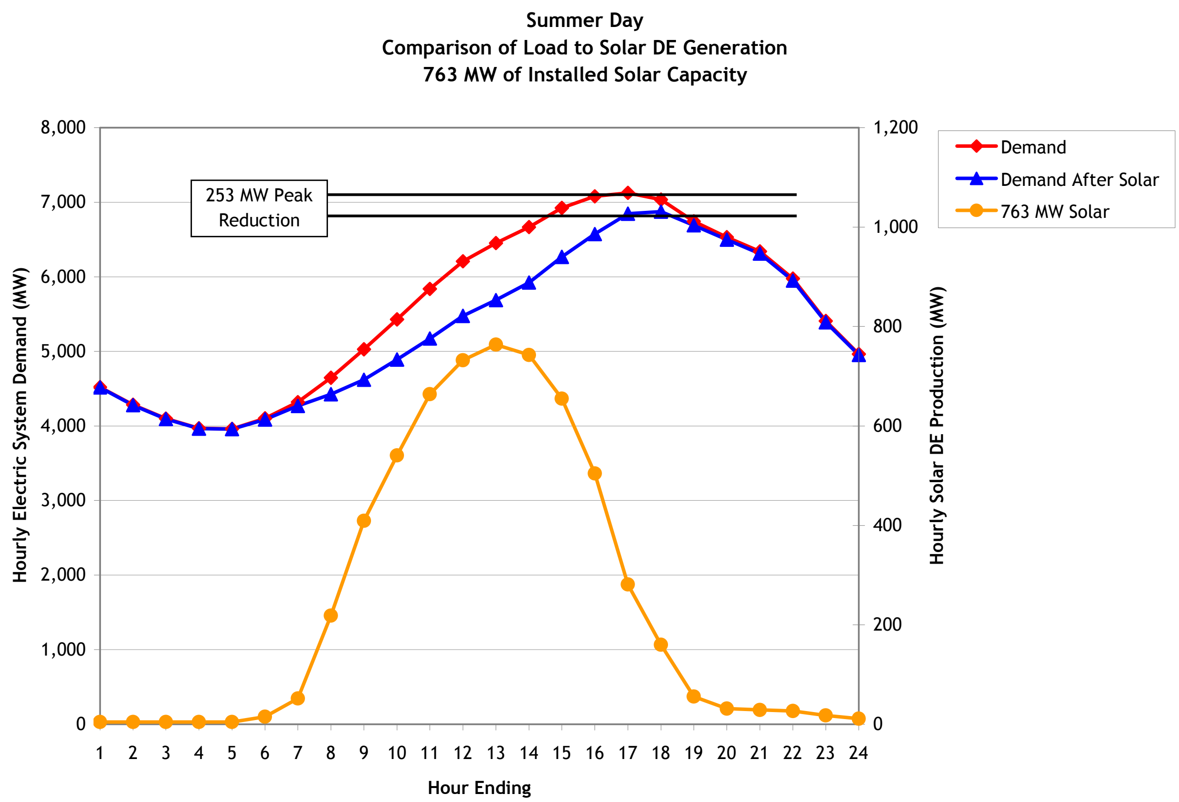
Dependable Capacity Modeling Effort

Figure 3-3 depicts an example of savings from solar DE by comparing peak load on a summer day before and after installing significant amounts of solar DE generation. The example shows a 253 MW reduction in peak demand. This graph is intended as an example to illustrate the implications of system load and solar DE coincidence, and is not meant to provide an actual measurement of coincidence.

As can be seen in Figure 3-3, the APS peak load hour occurs at approximately 5:00 PM (hour 17). While demand at 6:00 PM is not significantly less than demand at 5:00 PM, the solar output at 6:00 PM is much less than the solar output at 5:00 PM. Likewise, the demand at 4:00 PM is similar to that at 5:00 PM, but the solar output is much greater.

There is a possibility that the solar output could "shift" the peak load hour to 6:00 PM, and with increasing solar output, further shift the peak hour to 7:00 PM or even 8:00 PM. As a result, the methodology examines each hour from 4:00 PM to 8:00 PM independently.

Figure 3-3: Example Depiction of Peak Load Day and Peak Solar Output



The analysis was conducted using the following steps:

- For each hour, the maximum annual demand for that hour was determined from the load forecasts provided by APS.
- The solar output at the hours of 4:00, 5:00, 6:00, 7:00 and 8:00 PM for the summer months (June through August) was extracted from the solar output profiles projected in the Solar Characterization effort (Task 1, described in Section 2 of this Report). From these patterns, a statistical analysis was conducted to determine the solar output at which the Study team is 90 percent confident that the solar output would be greater than the value for the hour analyzed.
- For each hour, the amount of power the transmission and distribution systems must be able to transmit was determined by subtracting the dependable solar DE capacity for that hour from the projected annual peak load for that hour (system peak delivery). The maximum

system peak delivery was determined by comparing the results for 4:00, 5:00, 6:00, 7:00 and 8:00 PM. (In fact, for High Penetration Case for 2025, the system peak delivery was shifted from 5:00 to 6:00 PM due to larger projected solar DE contributions.)

- If the system peak delivery remained at 5:00 PM, then the dependable capacity for transmission and distribution is simply the 90 percent confidence that solar output will be a certain amount of capacity (MW) or greater at 5:00 PM. However, if the transmission peak delivery shifted to a different hour, then the dependable capacity for transmission and distribution was determined to be the annual peak load at 5:00 PM, minus the net of the annual peak load for the hour of maximum system peak delivery, minus the solar DE output at which there is a 90 percent confidence that the solar DE output will be that much or greater for the hour of system peak delivery. For instance, in Figure 3-3, 763 MW of installed solar DE generation shifts the electric system demand from 5:00 PM to 6:00 PM and reduces the peak demand by 253 MW.

Feeder Screening Model

The feeder screening model required PV system production to be time-correlated with specific feeder load. This correlation was needed to determine what feeder peak load reduction was possible from solar DE systems. Baseline solar DE models were run with weather data files that were coincident with the feeder load data provided by APS. In addition, APS performed solar storage analysis, simulating storage by shifting the solar profile by two and four hours. The years of analysis were 2006 and 2007.

APS and the Study team performed a screening-level analysis on 14 APS feeders with various parameters. The feeders selected were in newer areas with dense populations and primarily underground services. They included varying mixes of residential and commercial customers, and both long and short feeders were included in the analysis.

Table 3-5 provides a summary of the feeders reviewed for this screening analysis.

Table 3-5
Summary of Screening Analysis Feeders

			Type of Customers					
Substation	Location	Region	Commercial	Industrial	Irrigation	Residential	Length	# of Customers/ Xfmr
Arrowhead 4	N Phoenix - 101 & 75th Ave	Western	11			1082	Short	Dense
East Valley-Acoma 4	N Phoenix - Scottsdale Air	Eastern	679	64		90	Short	Dense
East Valley-Acoma 13	N Phoenix - Scottsdale Air	Eastern	169	5		1	Short	Dense
East Valley-Cave Creek 10	N Phoenix - Cave Crk & School House Rd	Eastern	218	4	1	1289	Long	Sparse
East Valley-Cave Creek 14	N Phoenix - Cave Crk & School House Rd	Eastern	185	7		500	Long	Sparse
East Valley-Chaparral 4	N Phoenix - Shea & Scottsdale	Eastern	117			1537	Short	Dense
East Valley-Chaparral 6	N Phoenix - Shea & Scottsdale	Eastern	203	2	1	543	Short	Dense
East Valley-Chaparral 12	N Phoenix - Shea & Scottsdale	Eastern	350	4		135	Short	Dense
East Valley-Thompson Peak 12	N Phoenix	Eastern	35			1356	Short	Dense
Galvin Peak 41	N Phoenix - 16th & Jomax	Eastern	146	7	2	1099	Short	Dense
Galvin Peak 42	N Phoenix - 16th & Jomax	Eastern	101	1		1063	Short	Dense
Indian Bend 2	N Phoenix - Cactus & Tatum	Eastern	96	1		704	Short	Dense
Indian Bend 6	N Phoenix - Cactus & Tatum	Eastern	4				Short	Dense
Javalina 4	Bell & Sev	Western	20			1510	Short	Dense
Mountain View 1	N Phoenix - 99th Ave & Bell	Western	23		1	848	Short	Dense

This screening analysis also included an in-depth review of the Thompson Peak Substation Feeder 10, which serves 76 commercial customers and 1,238 residential customers. The feeder is projected to be loaded to its maximum rating of 12.6 MW in 2008. A new feeder is proposed to reduce load below the planning rating of 9 MW. To defer this project, budgeted at $544,000, solar DE will need to provide 3.6 MW of new generation to reduce the feeder's annual peak loading down to the planning level.

DSS Model Analysis

EPRI's DSS software was also used to evaluate potential impacts of distributed solar technologies on the peak feeder demand. EPRI modeled the sample feeder, Deadman Wash Feeder #4, to analyze the effects of various levels of solar DE deployment and the annual hourly peak demand. The peak demand without solar DE was compared to High Penetration Case and Greenfield Case (100 percent) levels of solar deployment to determine the resulting demand reduction and to evaluate potential capex deferment.

3.3.3 Model Results

Dependable Capacity / Capex Deferment Modeling Results

The APS annual system peak typically occurs around 4:00 PM or 5:00 PM (1600 or 1700 hours) in the summer months of July and August as shown in Table 3-6.

Table 3-6
APS – Historical Peak Loads

Year	Peak	Date	Hour Ending
2003	5,969	Monday, July 14, 2003	17
2004	6,018	Wednesday, August 11, 2004	16
2005	6,573	Monday, July 18, 2005	17
2006	7,220	Friday, July 21, 2006	16
2007	7,127	Monday, August 13, 2007	17

The peaks for various types and locations of distribution load show considerable variance, although most peak between 4:00 PM and 8:00 PM. Dependable solar DE that might be available at peak was estimated for purposes of the analysis for 2010, 2015, and 2025, as summarized in Table 3-7. Distribution projects can only be deferred if solar DE is strategically located to reduce peak loads in the specific project region (as defined under the Target scenario). The additional capacity available with single-axis tracking (for commercial customers) is deployed is also presented in Table 3-7.

Table 3-7
Dependable Capacity Results

Case	Hour of Peak Delivery 2010	Dependable Capacity 2010	Hour of Peak Delivery 2015	Dependable Capacity 2015	Hour of Peak Delivery 2025	Dependable Capacity 2025
Target Scenario	17:00	3	17:00	25	18:00	494
Single-Axis Sensitivity	17:00	3	17:00	26	18:00	510

Table 3-8 presents estimates of the solar generation available during the time of a typical system peak load based on the Target scenario utilizing the High Penetration Case. These have been adjusted for loss reduction, and the resulting potential decrease in distribution capex requirements. The "Dependable Capacity Including Losses" column indicates the reduction in peak load expected in the target years for the High Penetration Case, with and without single-axis tracking assumed for the commercial customers, and the corresponding reduced capacity requirement. Assuming the peak load reduction can defer a capacity increase at the average cost of $115,000 per MW, the cumulative potential savings in capex are calculated.

Table 3-8
Potential Targeted Capex Reductions

	Capacity Savings		
	Dependable Solar Capacity @ System Peak (MW)	Dependable Capacity Including Losses (MW)	Potential Capex Reduction (2008 $000)
Target Scenario			
2010	3	3	$345
2015	26	29	$3,335
2025	494	564	$64,860
Single-Axis Sensitivity			
2010	3	3	$345
2015	26	30	$3,450
2025	510	583	$67,045

To achieve these savings, APS must first identify areas of potential growth in peak loads coincident with sufficient solar generation to influence future upgrades, and then deploy the solar DE in those areas well in advance of capex requirements. Additionally, these areas of potential growth must be within the 10 percent bandwidth limitation discussed above.

If for example, a feeder was overloaded beyond 10 percent, the installation of solar DE would not be sufficient to fully reduce the overloaded condition. This is because the solar DE could instantly “trip” off (meaning the inverter would disconnect the solar DE from the load) during a sudden drop in solar output, such as could occur during cloud cover. If such an event occurred and was widespread, the feeder would become overloaded again, which could threaten the reliability of the feeder, and potentially damage equipment.

The potential capex reductions identified above are believed to be achievable, given that APS has over $30 million in projects each year intended to relieve overloaded distribution equipment. However, the targeted upgrade project must have potential for the quantity and types of solar DE required to reduce load sufficient to defer the project.

3.3.4 Feeder Screening Analysis Results

This subsection describes the value of deferring the new Thompson Peak Substation feeder project, estimated at $544,000. The analysis determined that 100 percent of the customers located on the feeder would be need to install solar DE to provide enough demand reduction to effectively postpone the project. Beyond the 10 percent contingency limitation, additional value could be achieved if effective storage were available, to carry the load through cloud cover that may occur during the peak load period and provide additional peak demand reduction. Therefore, both the use of the 10 percent “emergency” bandwidth and the requirement for effective storage were identified as constraints to potential value from solar DE on the distribution system.

The analysis of the impact of solar DE on customers, feeders and substations indicates that the potential for energy production during non-cloudy days is proportional to the available capacity of the solar DE installed. Capacity reduction, however, is very dependent on individual customers and the time of their particular peak loads. Additionally, until solar storage is commonplace, solar DE can provide only limited dependable peak load capacity, as described herein.

Figure 3-4 summarizes the screening analysis results for the Thompson Peak Substation. Results reflect the percent reduction of Thompson Peak Substation's 62 MW peak load. The vertical axis represents the annual peak demand savings modeled for each solar DE technology. The horizontal axis represents the percent of the peak substation demand installed for a particular solar DE technology (penetration level). The base amount of installation represents 15 percent of peak demand (approximately 9.3 MW), with the exception of the SHW curves which assume a base of 10 percent or 20 percent as indicated in the legend. The scale along this axis represent multiples of the amount of installed capacity (i.e., Base*1.5 is 9.3 MW times 1.5 or approximately 14 MW).

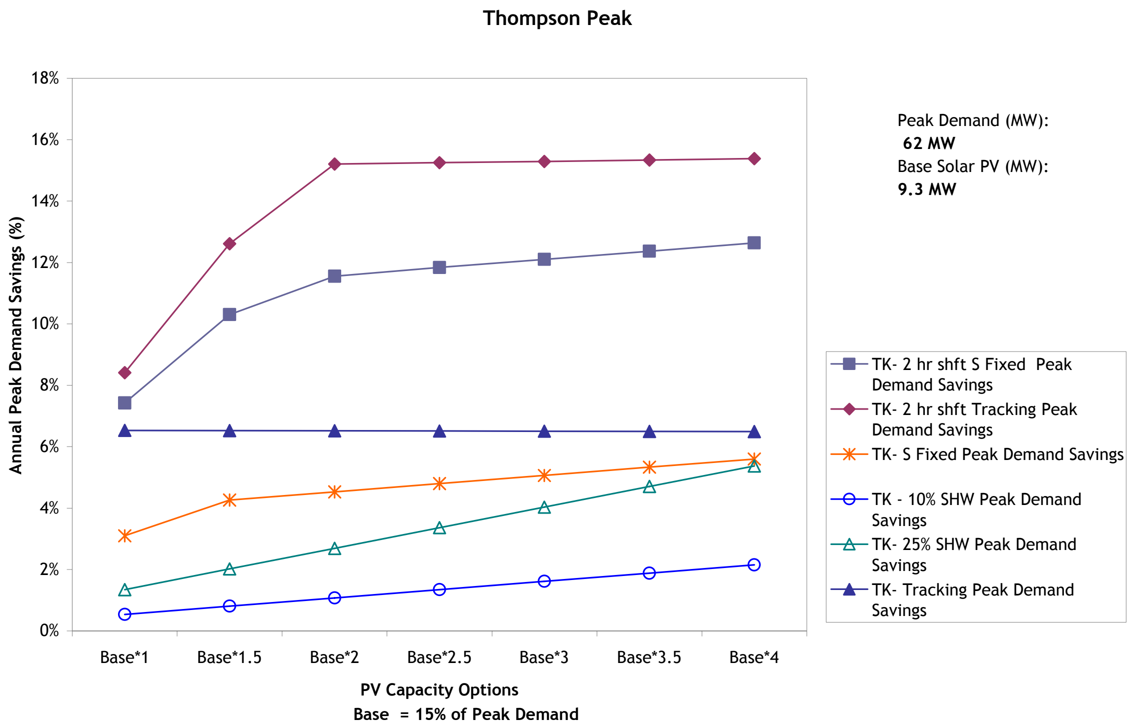
The lines on the graph indicate the annual peak demand reduction that could be expected for a particular type of solar DE if installed at the various penetration levels. The types of solar DE modeled include:

- Single-axis tracking PV (Tracking)
- Single-axis tracking PV with a two-hour shift to simulate storage (two-hour shift tracking)
- Fixed south-facing PV (S Fixed)
- Fixed south-facing with a two-hour shift to simulate storage (two-hour shift S fixed)
- Solar hot water with base level penetration of 10percent (10 percent SHW)
- Solar hot water with base level penetration of 25 percent (25 percent SHW)

The results indicate that installation of single-axis tracking commercial PV systems provided a demand reduction of about 6 percent (3.7 MW) at the base PV level, with no additional reduction as the quantity of PV is increased. The value, in terms of reducing annual peak demand, was increased by theoretically introducing a "storage" component to the analysis (by manually shifting the peak savings by two hours). However, this reduction was limited to approximately 15 percent, even with 60 percent of the peak demand installed as PV (equivalent to approximately 37 MW, which is the Base*4).

A similar result was observed for the south-facing residential PV systems, as well as the SHW systems. South-facing residential systems with a two-hour shift to simulate storage increased demand reduction to approximately 12 percent at Base*2 (or approximately 18.6 MW installed). Beyond that, however, the additional installation of PV did not significantly reduce the peak demand savings above the 12 percent level.

Figure 3-4: Thompson Peak Substation Annual Peak Demand Savings



The figure above represents a "theoretical" level of installation on the Thompson Peak Substation. Specifically, the amount of PV that can be installed is limited by the number of commercial and residential customers.

Thompson Peak Feeder 10 is projected to be loaded to its maximum rating of 12.6 MW in 2008 and is being analyzed as a candidate for Target scenario analysis to defer a proposed upgrade. To defer the upgrade, the feeder load must be reduced to its planning level of 9 MW, a 3.6 MW reduction. Figure 3-4 indicates that single-axis tracking and south-facing residential PV provide the greatest peak load reduction, assuming storage is not available.

Based on the chart above for Thompson Peak Substation with 62 MW peak demand, at the base PV level of 15 percent substation load (9.3 MW), single-axis tracking PV can provide a 6 percent demand savings (3.7 MW). In other words, an installation of 9.3 MW of single-axis tracking PV would reduce peak load by 3.7 MW.

Assuming this quantity of single-axis tracking can be located on the Thompson Peak Feeder 10, the peak load can be reduced sufficiently to defer the upgrade. If each commercial customer installs a typical 105 kW single-axis tracking PV device, the ability to achieve the targeted reduction using single-axis tracking PV on Feeder 10 is based on the following:

76 commercial customers x 105 kW single-axis tracking PV system each = 8 MW

Since 8 MW is approximately 85 percent of the 9.3 MW that would be required to reduce the peak load 3.6 MW, it is estimated that the peak load reduction would be 85 percent of 3.6 MW, or 3 MW. Therefore, residential PV will also be required to meet the target peak demand reduction. Per the above chart, a base installation of 9.3 MW of south-facing, fixed residential PV would reduce the peak load approximately 3 percent (1.8 MW). Assuming a 2 kW residential, south-facing, fixed PV installation for each residential customer, the potential for this technology on Thompson Peak Feeder 10 is estimated as:

1,238 residential customers x 2 kW south-facing PV system each = 2.5 MW

The residential solar DE potential of 2.5 MW is approximately 25 percent of the 9.3 MW required for a 1.8 MW demand reduction. Thus, it is estimated that the peak load reduction due to residential solar DE would be 25 percent of 1.8 MW, or 0.5 MW.

The total peak load reduction estimated from the commercial tracking and residential PV is 3.5 MW, still short of the 3.6 MW goal. It is likely that deployment of SHW in addition to the PV installations would be required. This analysis indicates that deferral of the new Thompson Peak Substation feeder will require 100 percent participation of the feeder's customers to install these systems. To pursue this solution and realize the potential capacity value, APS will need to identify the potential customer installations and analyze the individual customer profiles in each target project deferral area to determine if solar DE can provide the needed capacity reduction.

DSS Distribution Feeder Model Analysis Results

As mentioned above, the Deadman Wash Substation Feeder #4 serving the Anthem master-planned community was analyzed under two scenarios: first, a random deployment of solar DE based on High Penetration Case developed in Section 2 of this Report, and second, an assumed 100 percent solar DE penetration utilizing the Target scenario with single-axis tracking PV being deployed for the commercial customers (the single-axis sensitivity to the Target scenario). This analysis was conducted to determine the impact of high penetration levels of solar DE on the peak demand of a feeder, and the potential value in reduced infrastructure needs for a potential greenfield community.

The analysis results are summarized in Table 3-9. The analysis results confirm the Study team's results that even high concentrations of solar DE have only a marginal impact on annual peak demand. The 9 percent decrease in peak demand for the Greenfield Case is not sufficient to impact the infrastructure or equipment sizes required to serve these customers. However, it could offset a 2 to 3 percent per year load growth for 3 to 4 years and potentially postpone a future upgrade.

Table 3-9
DSS Annual Peak Demand Analysis Results

	Existing Condition	High Penetration Case	% Dif	Greenfield Case	% Dif
Peak Demand (MW)	10.3	9.8	5%	8.9	9%

3.4 Extension of Service Life

Solar DE may reduce capital investment requirements by reducing loading on the equipment to extend equipment life. Equipment life is significantly affected by operating temperature, which is a combination of ambient conditions and loading. Industry standards define the impact of loading transformers above nameplate on the life of the transformer.

Solar DE can reduce or prevent transformer overloads if sufficient solar generation is available during peak demand hours on heavily loaded transformers. Therefore, the extension of service life is a potential source of solar DE value to the distribution system. However, APS does not maintain the hourly data on the quantity and frequency of overload occurrences and durations of individual distribution transformers needed to calculate the cost, if any, of reduced transformer life, or the impact that solar DE might have on reducing that cost. Consequently, the value associated with extension of service life could not be quantified for the purposes of this Study.

3.5 Reduction in Equipment Sizing

3.5.1 Methodology

Solar DE can reduce capital investment by reducing loading on the equipment enough that size requirements can be decreased. Distribution system equipment is sized to serve the anticipated annual peak load, and is typically sized to anticipate growth in the peak load over time.

The cost to install, maintain, repair, upgrade, and replace equipment is affected by its size. As a result, solar DE that can reduce the annual peak load sufficiently to reduce the required equipment size can potentially provide value to the distribution system. However, this would require that the life of the solar DE be similar to the life of the equipment proposed. If solar DE was removed or terminated early, for example, the utility would need to resize the remaining equipment at a considerable expense.

3.5.2 Modeling Description

The Study team performed screening analysis on sample APS residential and commercial customers, feeders, and substations to estimate the demand savings for various sizes of PV, SHW, and daylighting. The goal of the modeling approach was to simulate annual hourly solar production for a variety of solar technologies and orientations, and to determine the impact on annual energy and peak demand requirements for typical residential and commercial customers on the APS system. Results from the customer analyses were then rolled up to the feeder, substation, and system level to estimate potential energy and capacity savings.

The baseline systems were modeled utilizing the solar characterization profiles developed in Section 2 of this Report. The results of both summary information and complete 8,760 hourly data strips were used to conduct the screening analyses of the customers and the APS distribution feeders and substations. Variations to these baseline systems, for different orientations and technologies, were also obtained from the Solar Characterization modeling effort.

The screening analysis allowed for review of various sizes of installations using the linear relationship explained in Section 2 of this Report. Specifically, the base sizes for the specific applications were multiplied by identical constants (1.5, 2.0, etc), to determine the potential impact of increased production. This does not suggest that the technical limitations discussed in Section 2 have been relaxed, as these "sensitivities" were only applied for this screening-level analysis.

PV Modeling Plan

Baseline PV systems were modeled for residential and commercial systems. The results of the systems modeled are applicable to both new construction and retrofit applications. Table 3-10 summarizes the assumptions used in the customer PV screening-level modeling analysis.

Table 3-10
Solar PV Screening-Level Modeling Assumptions

	Commercial	Residential
Dates	2006 & 2007	2006 & 2007
Base Case System Size	½ Peak Demand for 2006	2 kW_{DC}
Sizes Analyzed	Base Case x 1.5, 2, 2.5, 3, 3.5, 4	Base Case x 1.5, 2, 2.5, 3, 3.5, 4
Fixed Array Assumptions	Roof-mounted Flat roof 10° tilt South-facing	Roof-mounted Pitched roof 18.4° elevation South-facing
High Peak/Value Assumptions	Single-Axis tracking (1x) N/S axis	Roof-mounted Pitched roof 18.4° elevation Southwest-facing

As indicated in Section 2, the baseline results can be scaled linearly for different PV system sizes. For example, if projections are needed for a 200 kW commercial system, the results from the 100 kW system can be simply multiplied by a factor of two. Specific PV screening-level modeling included:

- Residential - 44 customers, 9 zip code areas
- Commercial – 32 customers, 9 commercial types

SHW Modeling Plan

Residential SHW installations were modeled to estimate the annual and hourly electricity offsets (i.e., reductions in demand) over a calendar year. The output of the modeling was in terms of kWh impacts for each hour of the year.

Table 3-11 summarizes the assumptions used in the residential SHW screening-level modeling analysis.

Table 3-11
SHW Screening-Level Modeling Assumptions

	Residential SHW
Dates	2006 & 2007
Base Case System Size	Standard electric Rated 0.88 EF 50-gallon tank
Household Size	Single-family, 3-person 3 bedrooms, 2 stories 2600 sq ft
Baseline Usage (Solar)	3,940 kWh/year (3,485 kWh/year)
Sizes Analyzed	Base Case x 1, 1.5, 2, 2.5, 3, 3.5, 4

As with the PV, the baseline results can be scaled linearly for different SHW system sizes. Practically, SHW generation is limited to the customer's tank size and usage of hot water. The 4x base means the tank would be 4 times bigger than the standard size. SHW screening-level modeling included 34 residential customers in seven zip code areas.

Daylighting Modeling Plan

The solar daylighting characterization entailed building simulation models for the types of commercial buildings most likely to be suitable for daylighting. Table 3-12 summarizes the assumptions used in the commercial SHW screening-level modeling analysis.

Table 3-12
Daylighting Screening-Level Modeling Assumptions

	Grocery (Large)	Office (Small)	Retail (Large)	School Gym	Warehouse
Size (sq ft)	30,000	6,000	50,000	6,000	100,000
Total Annual Energy Use (kWh/sq ft)	51.19	15.19	19.67	14.29	11.22
Total Peak Demand (W/sq ft)	7.95	4.64	4.71	2.71	-
Lighting Annual Energy Use (kWh/sq ft)	10.9	5.47	7.24	4.20	2.87
Lighting Peak Demand (W/sq ft)	1.59	1.50	1.61	1.20	0.90
Lighting Annual Operating Hours	6,867	3,647	4,496	3,247	-
Technology	Meets the minimum requirements for APS' Renewable Energy Rebate Program				
Light Output	Must provide ≤70% of the light output of the artificial lighting system that would otherwise be in use				

Note: See Table 2-8 and associated text for discussion of modeling assumptions.

3.5.3 Modeling Results

Residential PV

APS modeled the impact of residential PV installations ranging from 2 kW_{DC} to 8 kW_{DC} on 44 customers in nine different zip codes based on 2006 and 2007 solar profiles.

Figure 3-5 shows the range of percent savings in demand at increasing levels of solar DE for five customers in the 85020 zip code area. The analysis was conducted for three different fixed PV orientations for each customer:

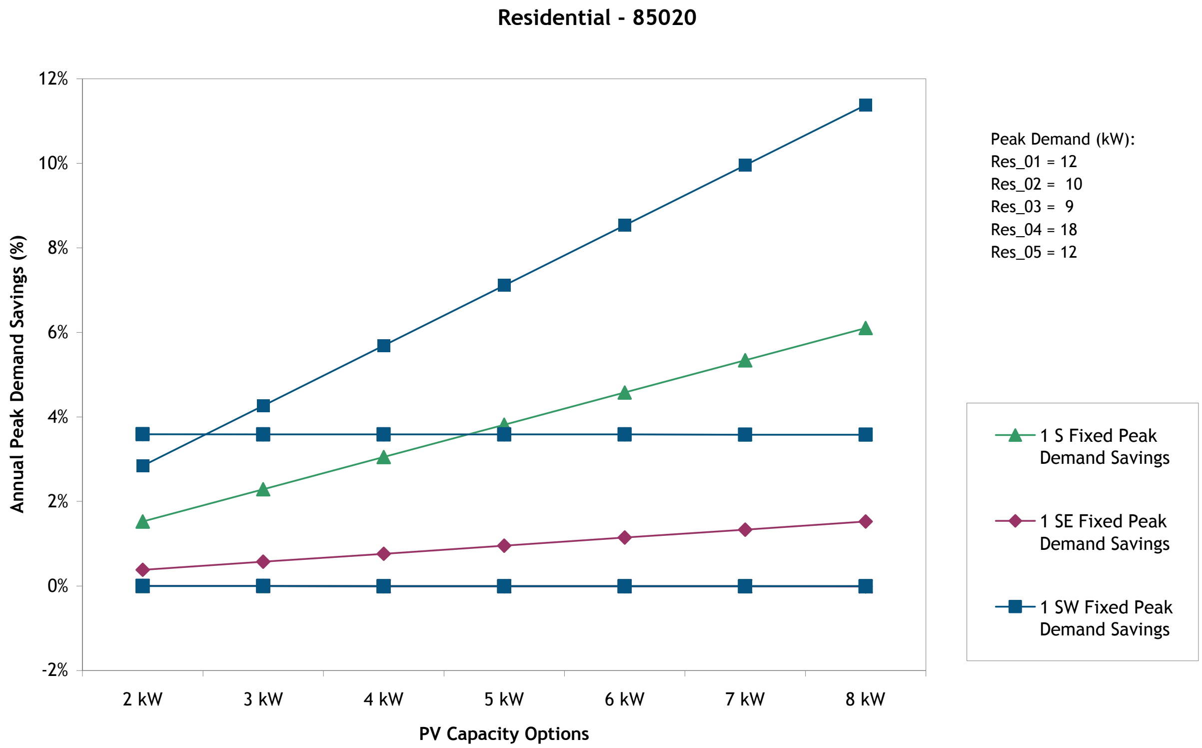
- South-facing (S)
- Southeast-facing (SE)
- Southwest-facing (SW)

The lines on the chart indicate the annual peak demand savings at increasing PV capacity sizes for each customer at each orientation. Each line represents one or more customers. Because of the variability in the hourly demand for each customer, no obvious trends related to demand reductions emerged from this analysis. For example, the SW fixed peak demand savings was zero for some customers but ranged from approximately 3 to 11 percent for others.

Demand reductions vary between individual customers due to differences in household sizes, work habits, lifestyles, business hours, and building characteristics. Some key results are as follows:

- In many cases, no demand reduction occurs because the customer's load peaks after the time of solar generation.
- The analysis also indicates that south-facing PV resulted in slightly higher demand reduction and energy savings than southeast- or southwest-oriented systems, although results varied with each customer.
- Rarely did customer demand savings exceed 10 percent, regardless of the size of the solar DE system installed, due to non-coincidence of the customer peak and solar generation peak; therefore, reduction in residential customer equipment sizing is not warranted.

Figure 3-5: Residential 85020 Annual Peak Demand Savings



Note: Each line represents the annual peak savings at various PV capacity options for one or more specific customer (see legend to list of customers and their peak demands). See text for more discussion.

Reductions in energy were also analyzed; however, energy reductions do not support the value source associated with reduction in equipment sizing. As mentioned above, equipment is sized based on peak demand, not energy. The results of the screening analysis (for both demand and energy) for each customer are summarized by zip code in Appendix L.

Commercial PV

The results of the commercial PV screening analysis show varying levels of summer peak demand savings for different commercial customer types, as summarized in Table 3-13. The range of demand reduction results from the effect of the PV sizes modeled, which ranged from one-half to double each customer's peak demand. Some key results are as follows:

- Commercial customers with business hours more coincident with solar generation experience the greatest demand reduction, but it is not consistent and would need to be evaluated on a case by case basis for consideration of a reduction in equipment sizes at the customer level.
- Businesses that operate into the evening, such as distribution centers, groceries, realty offices, and storage facilities, typically experienced less than 10 percent demand reduction, which would not affect equipment sizing.
- Single-axis tracking usually provided additional energy savings, but did not significantly improve demand reduction.
- In most cases there is not much difference between the south and southwest orientations based on the 2006 and 2007 solar profiles and customer load profiles modeled.
- As with the residential PV, the energy savings associated with the commercial PV were modeled; however, it does not support the objective of reducing equipment sizing. The results of the commercial PV screening analyses (both demand and energy) are provided by customer type in Appendix L.

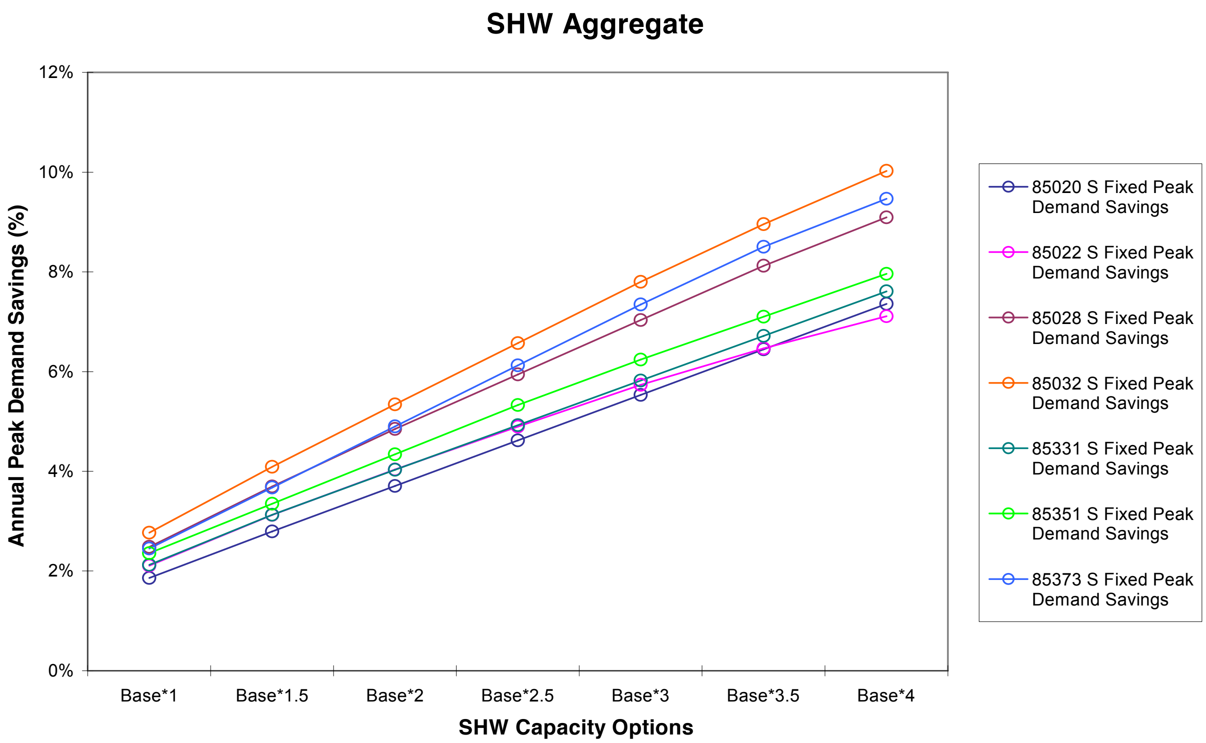
Table 3-13
Demand Reduction Due to Solar DE for Commercial Applications

Customer Type	Peak Demand Reduction
Distribution Centers	0% - 2.5%
Grocery	0% - 11%
Healthcare Office Bldg.	7% - 18%
Large Commercial	0% - 20%
Medium Retail	2% - 26%
Realty	0% - 5%
Storage	0%
Schools	0% - 30%
Churches	0% - 30%

Solar Hot Water Heating

Based on the SHW analysis, both energy and demand reductions are proportional to the SHW capacity. The minimum energy savings per the model were 10 percent. Summer peak demand savings ranged from approximately 2 percent to over 5 percent for the more realistic capacity of double the base size, as shown in Figure 3-6. Peak demand savings are limited because the ambient water temperature during peak summer days is so high that little energy is required to heat water during peak hours.

Figure 3-6: Solar Hot Water Annual Peak Demand Savings



Daylighting

APS modeled the impact of daylighting on several types of commercial customers based on the solar profiles for 2006 and 2007; however, not all locations had available data to determine the impacts of the screening. The availability of screening data is summarized in Table 3-14.

Table 3-14
Summary of Commercial Daylighting Screening Data Availability

Customer Type	Screening Data Available
Grocery	2006 & 2007 completed for 4 Locations
Large Retail	2006 & 2007 completed for 8 Locations
School Gym	2006 & 2007 completed for 5 Locations
Warehouse (some possibly manufacturing)	2006 & 2007 completed for 6 locations

Similar to PV and SHW applications, daylighting provided energy savings proportional to the daylighting size, or capacity, beginning at about 8 percent for the base size modeled. The range of summer peak demand savings observed for each customer type is shown in Table 3-15.

Table 3-15
Demand Reduction Due to Daylighting for Commercial Applications

Customer Type	Peak Demand Reduction
Grocery	0% - 9%
School	0% - 5%
Warehouse	0% - 2.5%
Large Retail	0% - 0.5%

Results indicate that, while daylighting is a good source of energy reduction for the customer, it has little impact on peak demand.

Feeder and Substation Analysis

As mentioned previously, the Study team conducted an analysis of demand reduction associated with solar DE at the feeder and substation level to determine the potential for reduction in distribution equipment sizing. This analysis was conducted at a screening level, as well as a more detailed model (EPRI's DSS Model).

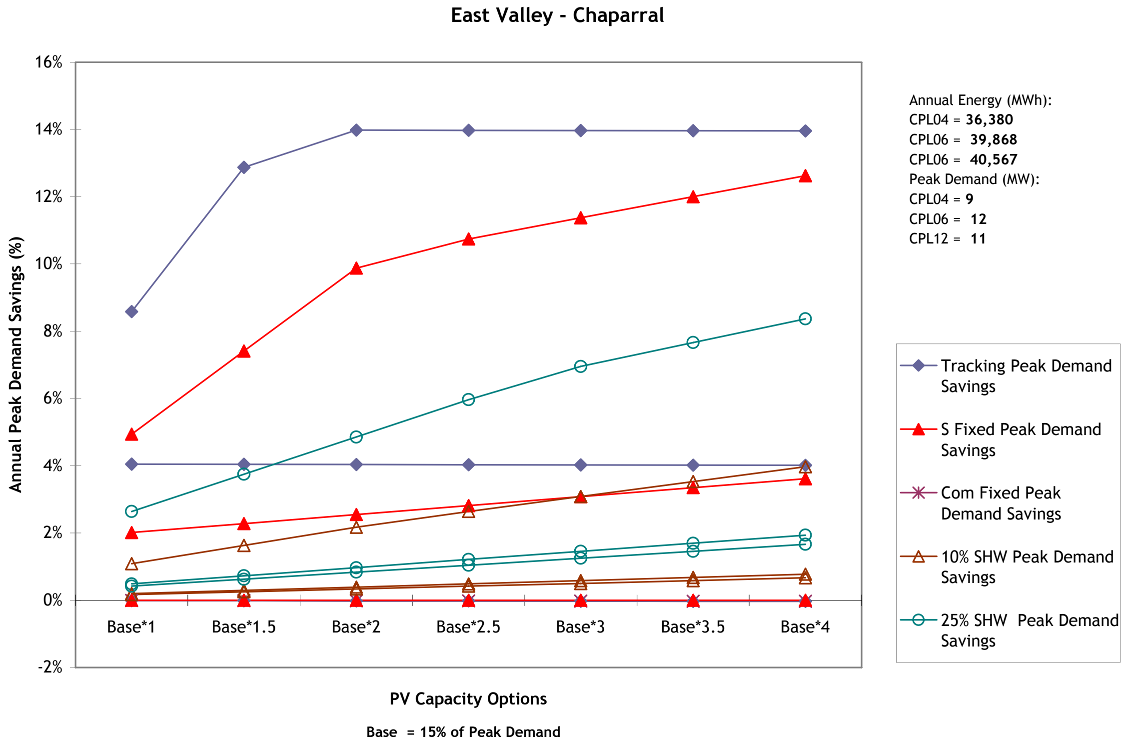
Screening Level

Screening analysis of feeders and substations was performed by modeling increasing levels of PV and SHW capacity ranging from 15 percent to 60 percent of feeder load. In other words, the base level of installed capacity for each type of solar DE deployed is equivalent to 15 percent of the feeder peak, or 15 percent penetration. Figure 3-7 shows the demand savings of three feeders at the Chaparral Substation in the East Valley. The annual energy and peak demand of each feeder is indicated in the legend. Each feeder is modeled with the following types of solar DE individually:

- Single-axis tracking PV (Tracking)
- South-facing fixed PV (S-Fixed)

The graph indicates the variance between the feeders and, in some cases, between the solar orientations. Similar to the analysis conducted for specific residential customers, the lines in the figure below represent one or more specific feeder. The results varied widely depending on the hourly demand characteristics of the customer types located on the feeder. For example, the single axis tracking demand savings held steady at approximately 4 percent for one feeder type, but ranged from approximately 9 percent to 15 percent for another feeder type. The analysis reveals that at the feeder level, the maximum demand reduction is approximately 15 percent reduction, even with 60 percent solar DE penetration.

Figure 3-7: Chaparral Feeders Annual Peak Demand Savings

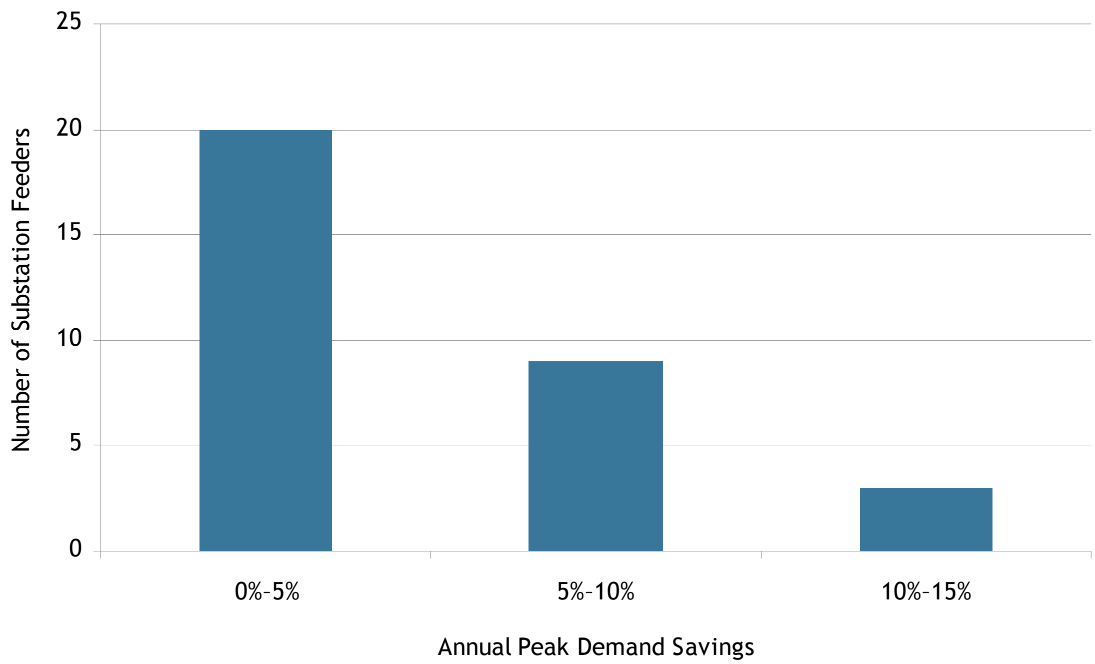


Note: Each line represents the annual peak savings at various PV capacity options for one or more specific feeder (see legend for feeder characteristics). See text for discussion.

None of the solar DE technologies provide enough demand reduction for APS to consider downsizing the feeder equipment. However, adequate penetration of some technologies, particularly commercial tracking and PV, may be available on some feeders to reduce peak feeder load and offset new growth, potentially deferring a capital improvement project (as discussed previously).

Figure 3-8 below summarizes the annual peak demand savings calculated from the substation and feeder screening-level analysis. Demand savings ranged from 0 percent to 15 percent for increasing levels of solar DE capacity, ranging from 15 percent to 60 percent of peak feeder load; with no clear trends regarding feeder type or customer mix (see Table 3-16). Only about half of the feeders modeled show potential for reducing peak demand and deferring capital improvement projects. As a result, APS should be very selective in identifying target areas to deploy solar DE for the purpose of postponing upgrades. Results of the individual feeder and substation screening results are included in Appendix L.

Figure 3-8: Substation Screening-Level Analysis Summary



Figures 3-9 and 3-10 below illustrate the effects of two-hour or four-hour storage for fixed residential and single-axis tracking technologies on a peak day feeder load profile at 15 percent and 30 percent penetration. It should be noted that this analysis was performed for a specific feeder in APS service territory, Feeder CA14.

The graphs indicate that two-hour storage would provide additional capacity savings during the time of the feeder peak, approximately 5:00 PM. Four-hour storage reduces load well into the evening, but provides minimal peak load reduction beyond the two-hour storage scenario as the peak load continues to shift into the evening.

Figure 3-9: Effects of Two-and Four-Hour Storage on Fixed PV

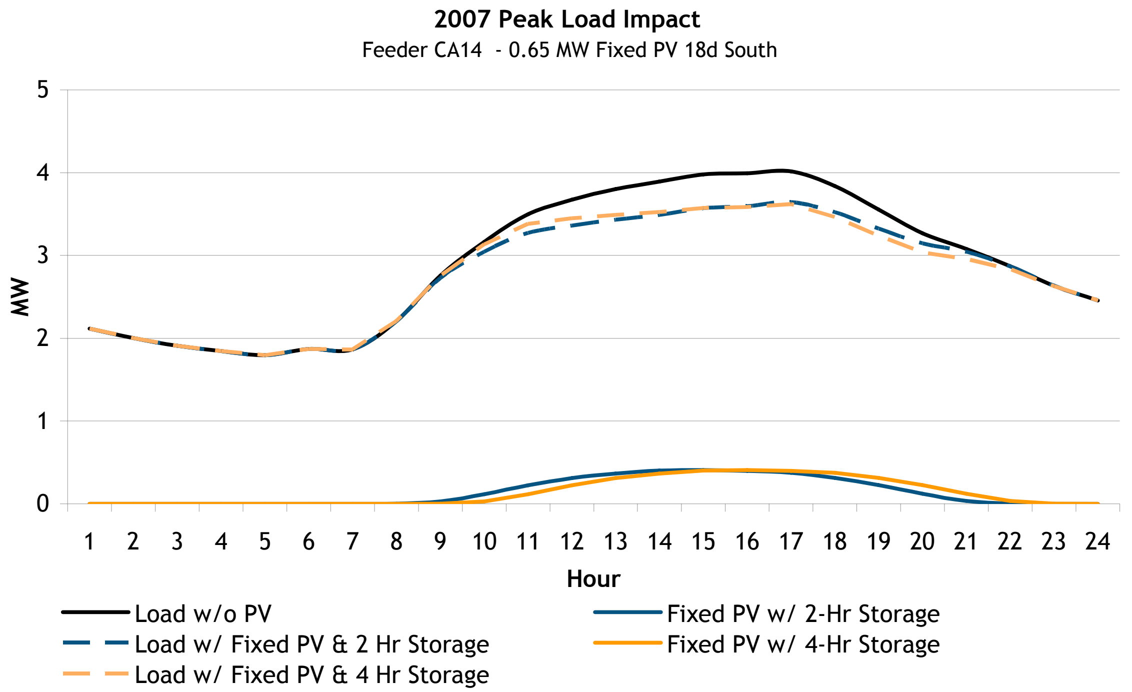
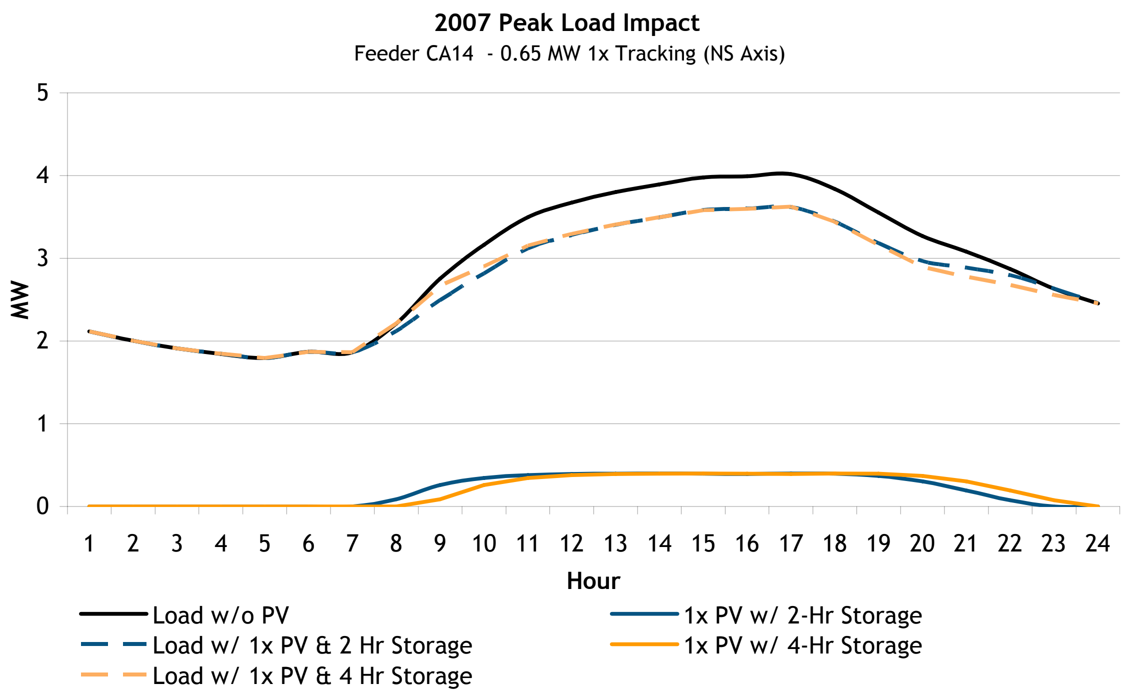


Figure 3-10: Effects of Two- and Four-Hour Storage on PV with Single-Axis Tracking



EPRI/DSS

As discussed in Section 3.2.3, one feeder was modeled in EPRI's DSS software to evaluate the impact of solar DE on peak demand. The analysis was performed to determine the potential for reducing feeder equipment sizes as well as deferring future capital upgrades.

3.5.4 Modeling Results

The incremental demand reductions realized in the screening analysis were generally not significant enough to reduce customer equipment sizes. The analysis performed for entire feeders and substations and the DSS feeder analysis revealed similar results.

Solar storage, energy efficiency and demand response/control may eventually change this paradigm. Solar storage could be used to provide power two to four hours beyond existing solar PV limits. Smart Grid and advanced metering infrastructure (AMI) technologies would allow the customer and/or the utility to reduce the peak load through individual customer load reduction even more.

Storage would also address the cloud cover issue that threatens the availability of solar DE when it is required to serve peak loads. Until storage is common practice, APS and other utilities will be reluctant to reduce the equipment sizes or infrastructure requirements necessary to serve customers' peak loads.

3.6 System Performance Issues

3.6.1 Methodology

Although a few utilities in the United States have begun to experience areas of high solar DE deployment, very little system performance data is available. The APS Solar Test and Research Facility (STAR) has been collecting performance statistics on various types and sizes of solar DE installations for several years. APS provided historical data from the STAR test facility to illustrate the effect of cloud cover on solar DE generation. In addition, field tests on existing solar installations on the APS system were conducted in conjunction with this Study to evaluate the effects of transients, power factor, and power quality or harmonics issues.

3.6.2 Model Descriptions

On October 22, 2008, APS performed a field test to determine if transients, which are defined as large fluctuations in voltage or current, would occur during the opening or closing of the breaker at the Prescott PV station near the Prescott airport. The plant, served by feeder Sturm Ruger 10, includes 33 PV concentrator units, 29 single-axis horizontal units, and two single-axis tilted units. Total solar DE capacity is approximately 3,630 kW_{DC}. Test equipment measured feeder parameters during the breaker operations.

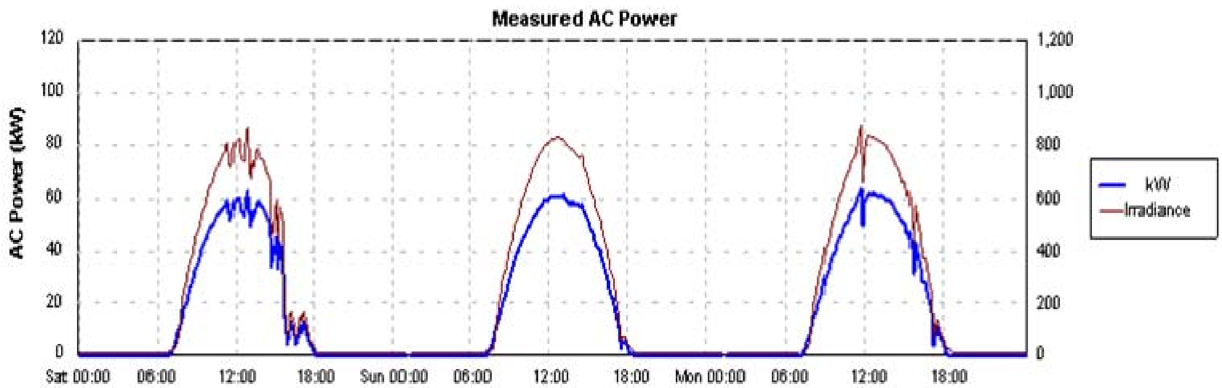
In addition, EPRI performed voltage analysis with the DSS tool using three days of ten-minute data to evaluate the effect of solar DE switching on feeder voltage. In addition, EPRI conducted a study to show the effects on voltage regulation for the Greenfield Case if the system were to sporadically lose the entire PV supply.

3.6.3 Modeling Results

Cloud Cover

APS provided data from the STAR center to illustrate the effect of cloud cover on PV generation. Figure 3-11 shows the PV generation in kW over a three-day period with intermittent clouds. Reduction in PV generation is evident when cloud cover reduces irradiance.

Figure 3-11: Effect of Clouds on PV Generation

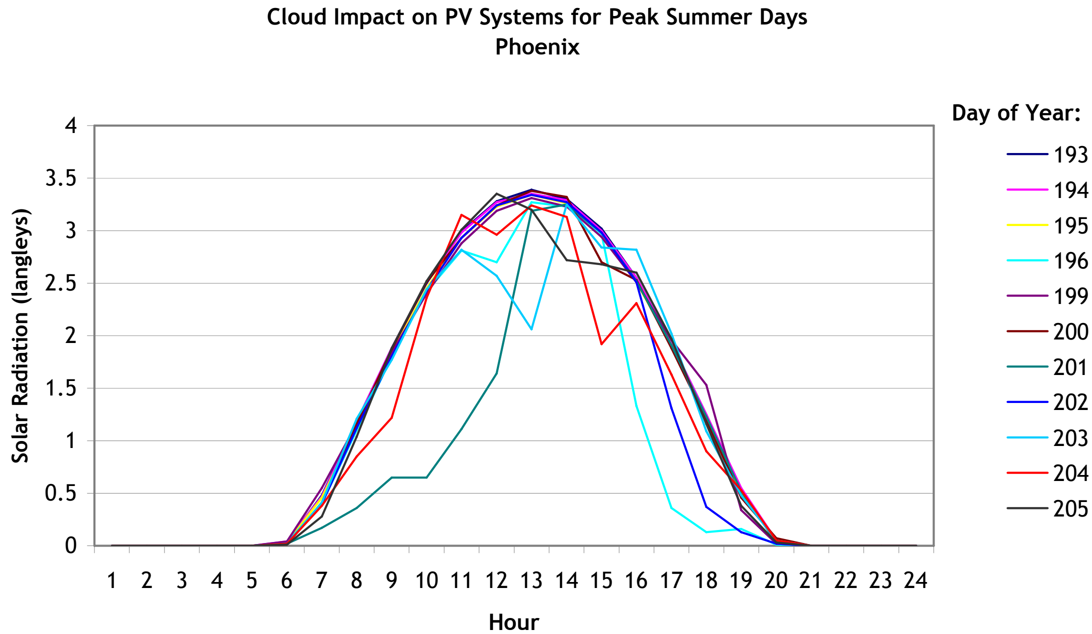


Source: APS

While solar DE can provide generation throughout the year, the dependence of PV generation on clear sunlight and the possibility of clouds reducing or removing the clear sunlight requires the distribution facilities to be capable of carrying the full load at any time. Even during peak load periods, clouds can reduce PV generation substantially as indicated in Figure 3-12, which shows the hourly irradiance for several peak load days. The various lines indicate the day of the year on which the peak PV production occurred.

Since adjustments in distribution capacity require dependable local solar DE to reduce load during peak periods, this analysis re-enforces the finding that capacity deferral can only be accomplished if the loss of PV output does not increase feeder load above the 10 percent contingency level, or if solar DE storage is economically viable.

Figure 3-12: Cloud Impact during Peak Load Days



Transient Analysis

During a test for transients, the main breaker between the Prescott PV site and the distribution system was opened at 13:20:13 and closed at 13:24:24 on October 22, 2008.

When the breaker was opened, no triggered transients were measured. When the breaker re-energized about four minutes later, minor transients were recorded. This was likely due to line charging since at this time no inverters had switched in immediately. When each inverter closed, there were changes in the amount of current flowing into the substation.

The results do not indicate any transient issues that would detrimentally affect the customers on this feeder. Discussions with APS staff and other utilities with solar installations also revealed few problems or customer complaints related to breaker operations on feeders with solar installations or switching of PV inverters.

During the recent Solar Power International '08 Conference in San Diego, Pacific Gas and Electric (PG&E) staff presented information on feeders in their system with up to 30 percent solar concentrations. They did not report any major operational concerns, or anticipate any, at less than 50 percent feeder load.

When solar generation is greater than 50 percent of the feeder load, the possibility of backfeed through the substation exists. This would require additional protection and coordination schemes, as well as equipment, which could be quite costly and decrease the value associated with solar DE.

The EPRI DSS analysis also concluded that no adverse effects on voltage regulation were experienced due to PV operation based on the actual 10-minute solar data provided or the modeled loss of the PV on the entire greenfield feeder. The maximum voltage deviation calculated was 0.7 percent.

Power Factor

Power factor defines the ratio of real power (watts) to total power (volt amperes). Total power includes watts to serve resistive loads and VARs to serve inductive loads such as motors. Distribution systems operate most efficiently with minimum VAR flow. To achieve this, APS strives to maintain a power factor at near unity (when real power equals total power). Capacitors are placed on the distribution system to provide VARs to inductive loads and can be automatically switched off or on to maintain a power factor close to unity.

Currently, PV inverters provide only real power; therefore, the power factor could fluctuate as solar power varies causing capacitors to switch off or on. The power factor measurements from the field test indicate very little variance in system power factor during the breaker operations, indicating that excessive capacitor switching is not an issue. APS staff also reported no power factor or capacitor switching problems associated with the existing solar PV installations.

While power factor is the typical reference for estimating VAR flow on a feeder, the actual VAR flow determines the operational impact. Since solar PV reduces the real load on a feeder but does not affect VAR flow, the measured power factor on a feeder with high penetration PV may decrease; however, there are no detrimental effects on the feeder voltage since the VAR flow is the same. The DSS analysis confirmed this by calculating only a 0.7 percent voltage difference with and without PV on the modeled greenfield feeder.

Harmonics

The field test at Prescott airport also measured waveform harmonics on the feeder serving the solar installation. No problematic harmonic distortions were recorded, indicating solar DE does not adversely affect power quality. Although earlier generations of solar inverters had some power quality issues, the standards in place for manufacturing inverters today include strict requirements for limiting harmonics. APS reported they have not experienced power quality complaints related to the existing solar DE installations.

Summary of Performance Issues

No performance or power quality issues were identified for the purposes of this Study. APS staff also reported that no significant problems related to power quality have been identified with existing customer-owned solar installations on the system.

Solar DE could improve customer reliability if industry standards allowed “islanding” so that solar DE could provide power during a local or system outage. Existing standards do not allow this practice because generation into the power grid without utility knowledge or control poses a safety hazard to utility personnel. This practice would also require sophisticated metering and control systems to match the load with the solar DE at any given instance. AMI and Smart Grid technology could provide the communications link to address these concerns and lead to changes in these restrictions. The results of these studies and the analysis for system performance issues are presented in Appendix M.

3.7 Summary of Section Findings

Solar DE has limited impact on the summer peak demands that drive distribution infrastructure installations and upgrades, due to the non-coincidence of peak solar generation and peak customer, feeder, substation and system loads. Increased penetration or sizes of solar DE also have little effect on annual peak load reduction. While solar generation peaks around 1:00 PM, the annual system peak is typically 5:00 PM and most customer and feeder peaks are in the 4:00 to 6:00 PM time range. During this time period, solar production decreases rapidly, from about 70 percent output at 4:00 PM to less than 25 percent output at 6:00 PM. As a result, the decrease in annual peak demand at the customer or feeder level due to solar DE may be nonexistent and rarely exceeds 15 percent.

Customer equipment sizing cannot be reduced by small decreases in annual peak demand. However, if the feeder or substation demand reduction exceeds the projected annual growth, the solar DE can provide value by deferring capital improvement upgrades required to address projected overloads. If solar DE can be targeted to specific locations, distribution capacity savings can be realized as summarized in Table 3-16. (Note: this is the same table presented earlier as Table 3-8).

Table 3-16
Potential Targeted Capex Reductions

	Capacity Savings		
	Dependable Solar Capacity @ System Peak (MW)	Dependable Capacity Including Losses (MW)	Potential Capex Reduction (2008 $000)
Target Scenario			
2010	3	3	$345
2015	26	29	$3,335
2025	494	564	$64,860
Single-Axis Sensitivity			
2010	3	3	$345
2015	26	30	$3,450
2025	510	583	$67,045

SECTION 4 — TECHNICAL VALUE - TRANSMISSION SYSTEM

Solar DE can potentially provide value to APS by decreasing the capacity requirements of the transmission system.

The Study team has performed analyses evaluating the value of solar DE on APS's transmission system. Locating solar DE generation near the demand benefits the transmission system primarily in two ways:

- It reduces the line losses across the transmission system because less energy needs to be transmitted from large central station generation to the location of the demand.
- It reduces the burden on the transmission system at peak demands, possibly allowing deferral of transmission investments.

The intermittent nature of solar generation can impact the reliability of solar DE for purposes of determining its value to the transmission system. Additionally, the characteristics of solar DE operations may adversely impact transient stability and spinning reserve requirements of the transmission system.

4.1 Introduction

The APS transmission system was primarily built to transmit energy from large central station generation to load centers at the wholesale level. The energy is transmitted from these large central generating stations across the transmission system to "substations" in load centers where it is "stepped down" to retail distribution and transmitted across the distribution system to the customers.

Therefore, if solar DE is placed at the customer, it will not only reduce the flow of power on the distribution system as discussed in Section 3, it will also decrease the flow of power on the transmission system.

The reduction in power flow across the transmission system has two primary benefits:

- Reduction in line losses across the transmission system.
- Potential reduction in capital expenditures due to deferring transmission investments.

Both of these benefits are discussed in detail in this section, including assumptions, methodology and results of the analysis. The results of the analysis are summarized in Table 4-1.

There are also some potential detrimental impacts of solar DE. Solar generation is intermittent and, for reliability purposes, APS can rely on only a portion of the intermittent resources' capabilities. Output from PV systems depends on inverters that convert DC electricity to alternating current electricity. These inverters are sensitive to system voltage variations and can adversely impact the power system's response to disturbances (such as lightning strikes). These detriments were found to be insignificant, as explained later in this section.

Table 4-1
Summary of Results – Technical Value for the Transmission System

	Solar DE Deployed		Cumulative Capacity Savings			
Year	MWh	MW @ System Peak	Transmission and Distribution Dependable Capacity	Transmission Dependable Capacity Including Associated Avoided Transmission Demand Losses	Number of $125M, 400 MW Transmission Investments Deferred through 2025	Transmission and Distribution Energy Loss Savings (GWh)
Low Penetration Case						
2025	157,454	42	22	27	0	18.6
Medium Penetration Case						
2025	1,599,924	714	273	333	0	188.9
High Penetration Case						
2025	3,472,412	1,569	494	603	1	390.2
Single-Axis Sensitivity Case						
2025	3,638,634	1,649	510	622	1	407.1

For the purposes of this Study, the transmission system is defined to include the equipment at 69 kV (69 kV is sometimes referred to as the "sub-transmission" system) and above (e.g., the 230 kV and 500 kV systems).

APS's transmission system is typically planned, designed and operated to be able to supply the peak demand of the system during contingency conditions in accordance with the NERC Reliability Standards and APS's own planning criteria. Contingency conditions include a forced outage of usually one or two generators, transmission lines, transformers or other pieces of equipment. When the transmission system can no longer support peak load under these contingencies, then new transmission investments must be made to maintain the reliability of the power system. Solar DE can have an impact equivalent to reducing the peak demand, and, if that reduction is significant enough, solar DE can defer transmission investments.

The ability of the transmission system to transmit power is characterized by several technical limits. There are three limits that have a primary impact on a transmission system, and were reviewed for the purposes of this Study. The following is a description of those limits:

- **Thermal Limits**, the maximum operating temperatures of the transmission facilities before equipment damage occurs.
- **Transient Stability Limits**, a measure of how much the power system can be "stretched" while still being able to withstand a major power system disturbance (such as a major outage of a 500 kV line). A transmission system can be envisioned as a rubber band, with generation pulling on one end of that band and load/demand pulling on the other end. A lightning strike on the transmission system would be analogous to someone suddenly "twinging" the rubber band. The stability limit can be thought of as the amount that the rubber band can be stretched before "twinging" would cause the rubber band to break. Most major system-wide blackouts were caused by events that caused transient instability (e.g., the great Northeast blackouts of 1965 and 2003, and the western area blackouts of the late 1990s).
- **Voltage Stability Limits**, a measure of how much power can be transmitted across the transmission system before voltage "collapses." The partial differential equations of power flow are somewhat similar to the equations for fluid flow, with the flow of reactive power (measured in mega-vars, or MVAR) being somewhat similar to turbulent flow. If too much power is forced down a limited transmission path, then MVAR flow can cause a precipitous loss of voltage. This is similar to trying to push too much air too quickly through a pipe, creating a large amount of turbulent flow, and causing pressure (equivalent to voltage) at the other end of the pipe to drop to zero. The Northeast blackout of 2003 was partly caused by voltage instability (in addition to the transient stability described above).

The Study team held discussions with APS regarding the most problematic transmission limits that occur on their transmission system. As is typical in many parts of the country, the most problematic limits for APS are thermal limits; however, they do encounter other limits as well. In addition, the conversations included a qualitative discussion of the potential impacts that solar DE would have on these limits. A summary of these discussions follows:

- **Potential Benefits to Thermal Limits.** By locating the solar DE at the load, the transmission system will not have to carry as much power, benefiting thermal limits.
- **Potential Detriments to Transient Stability.** Although locating solar DE at the load helps to reduce the "stretch" of the analogous "rubber band" of the transmission system, there is one characteristic of PV systems that can cause issues with transient stability. PV inverters, for safety reasons for distribution operations, are designed to drop off-line automatically for low voltage events (e.g., including a fault, such as a lightning strike, on the transmission system). A fault on a major 500-kV line can cause widespread low voltages throughout APS's system, possibly causing large quantities of PV to trip off-line simultaneously. This can cause a transient stability impact on the power system to occur for a second time shortly after the initial disturbance.
- **Potential, Un-quantified Benefits to Voltage Stability.** Locating the solar DE at the location of the demand reduces the flow of real power (MW). SHW and daylighting will

decrease both real and reactive power flow; whereas PV will only reduce the flow of real power unless special adjustments are made to the inverters. For purposes of this Study, it was assumed that thermal limits would have a greater impact than voltage stability limits and the solar DE would have comparable benefits to both thermal and voltage stability limits. Hence, under these assumptions, by calculating the benefits to thermal limits, the benefits of voltage stability limits are imbedded in the analysis.

Therefore, the analysis focused on the impacts of solar DE on the following:

- Reduction in line losses across the transmission system.
- Potential deferral of transmission investment due to an equivalent slower load growth as a result of locating the solar DE at the load, thereby delaying the time at which the system would reach its thermal limits.
- Potential detrimental impacts of PV inverter systems dropping off-line for safety reasons impacting transient stability limits.

4.2 Reduction in System Losses

One value that solar DE provides to the transmission and distribution systems is reduction of the cost of lost power (losses) due to the heat created when current moves through specific types of equipment. The Market Adoption deployment described in Section 1 assumes solar DE technology will be placed at relatively random locations throughout the distribution system, implying homogeneous reduction of load and, therefore, of losses.

APS estimates losses account for eight percent of energy purchased and generated. Discounting for no-load losses, theft and company use that are not affected by load reduction, transmission and distribution "series" losses or "load" losses are estimated at six percent. Energy loss savings will occur every hour of every year and increase as solar deployment increases. Table 4-2 estimates the annual system wide energy loss savings in the target years for each of the deployment cases. As noted before, the losses calculation is not dependent on the specific location of the solar DE installations, therefore, the calculation of the losses for the High Penetration case is identical to the Target scenario (not shown in Table 4-2 below).

Table 4-2
Transmission and Distribution System Savings Potential - Summary (Reduced Losses)

	Solar DE Deployed	Annual Energy Loss Savings
	MWh-Generated	MWh-Savings
Low Penetration Case		
2010	15,019	1,829
2015	94,782	11,290
2025	157,454	18,607
Medium Penetration Case		
2010	15,798	1,929
2015	161,377	19,467
2025	1,599,924	188,907
High Penetration Case		
2010	15,798	1,929
2015	161,377	19,467
2025	3,472,412	390,248
Single-Axis Sensitivity Case		
2010	16,608	2,031
2015	167,804	20,262
2025	3,638,634	407,170

4.2.1 Deployment Cases

Methodology and Assumptions

Losses vary with the square of the current. Since demand varies on an hourly basis, and solar output varies on an hourly basis (both variations relatively significant), an hourly analysis of loss savings was conducted.

The methodology is based on the following assumptions and equations:

- APS estimates total system losses as 8 percent of annual consumption.
- System losses equal no-load losses plus theft plus "own use" plus resistance times the current squared.
- The value of solar DE is in reducing the "series losses" or "load losses" component of the above equation: resistance times current squared.

- A simplifying assumption that no-load losses plus theft plus own-use is a constant of approximately 25 percent of the annual losses, e.g., 2 percent of the 8 percent annual loss factor (as determined by APS).
- A simplifying assumption that system topology, hence resistance, is relatively constant throughout the year (ignoring impact of temperature on conductor resistance).
- A simplifying assumption that system topology, and therefore resistance, will change from year to year based on APS's investment program, but that the investments made will serve to keep APS's total system losses at about 8 percent from year to year. In other words, although current grows with load growth, the Study team assumed that the reduction in resistance from year to year due to investments will serve to keep losses constant through the term of the Study.
- The annual losses are the sum of the hourly losses. Since resistance is assumed to be constant, the annual series losses are equal to resistance times the sum of the square of the hourly currents.

Utilizing these assumptions and equations, the following methodology was developed:

1. Calculate system losses based on annual energy projections (e.g., 8 percent of energy projections).
2. Subtract out non-series losses, e.g., no-load, theft and own-use.
3. Convert series losses to per unit on a 100 MVA base.
4. Determine an hourly load pattern from the deployment cases identified in Section 2.
5. Calculate the hourly system current (in per unit) through a per unit system calculation on a 100 MVA and nominal voltage basis.
6. Calculate a system equivalent resistance for a specific year by dividing the annual series losses by the annual sum of the hourly square of the current.
7. Calculate a solar DE modification of the hourly current by subtracting the hourly solar output forecast from the hourly load forecast. Although both forecasts were developed independently with different assumptions, and therefore, do not correlate properly, it is assumed that, over the course of a year, the errors in this assumption will average out.
8. Calculate new annual series losses by multiplying the resistance in per unit times the annual sum of the square of the solar DE modified current in per unit
9. Convert to MWh from per unit.
10. The loss savings will be the difference in series losses without solar DE and the calculated series losses with solar DE.
11. Repeat for each target year and for each deployment case.

Results

Table 4-3 presents the results for the Low, Medium, and High Penetration Deployment Cases and presents annual MWh loss savings.

Table 4-3
Transmission and Distribution System Savings Potential (Reduced Losses)

	Solar DE Deployed	Annual Energy Loss Savings	MWh Savings in Losses / MWh Solar Generated
	MWh-Generated	MWh-Savings	
Low Penetration Case			
2010	15,019	1,829	12.2%
2015	94,782	11,290	11.9%
2025	157,454	18,607	11.8%
Medium Penetration Case			
2010	15,798	1,929	12.2%
2015	161,377	19,467	12.1%
2025	1,599,924	188,907	11.8%
High Penetration Case			
2010	15,798	1,929	12.2%
2015	161,377	19,467	12.1%
2025	3,472,412	390,248	11.2%

The results reveal another significant finding of this Study; that the "Law of Diminishing Returns" applies to solar DE installations. In other words, the more solar DE installed, the less incremental value of each additional solar DE installation. This is illustrated in Table 4-3 in the decreased average value of loss reduction between the Low, Medium, and High Penetration Cases in the year 2025 (e.g., the High Penetration Case, with the most solar DE installed in 2025, has the lowest loss savings [MWh] per solar generated [MWh] at 11.2 percent, compared to 11.8 percent for the Low Penetration Case).

4.2.2 Single-Axis Sensitivity

Methodology and Assumptions

Further loss savings can be achieved by implementing single-axis tracking on commercial solar PV installations. Single-axis tracking increases the daily solar production, providing additional load reduction and loss savings into the early morning and late afternoon hours. The hourly load analysis was repeated for this case.

Results

The effects of assuming single-axis tracking for the commercial PV installations in the High Penetration Case are summarized in Table 4-4. The results indicate less than a 5 percent improvement in annual system losses if single-axis tracking is assumed for the commercial PV installations (407,170 MWh for the single-axis tracking in Table 4-4 compared to 390,248 MWh for the High Penetration Case in Table 4-3)

Table 4-4
Effects of Assuming Single-Axis Tracking for Commercial PV

	Solar DE Deployed MWh-Generated	Annual Energy Loss Savings MWh-Savings	MWh Savings in Losses / MWh Solar Generated
Single-Axis Sensitivity			
2010	16,608	2,031	12.2%
2015	167,804	20,262	12.1%
2025	3,638,634	407,170	11.2%

4.2.3 Capacity Value of Avoided Losses

In addition to savings in energy losses, there is also a benefit of avoided losses on capacity, or the ability to defer distribution, transmission or generation investment. For transmission, the loss savings at the 90 percent confidence interval was 22 percent of the dependable capacity (see the following section for discussion of dependable capacity calculation for distribution and transmission systems).

4.3 Potential Deferral of Transmission Investment

When the transmission system is no longer able to transmit energy from central generating stations to growing demand because a technical limit is reached, transmission investment is needed to increase those limits. Solar DE has the potential to reduce the peak demand that the transmission system needs to support by locating the generation at the demand, thereby potentially deferring the need for new transmission investment.

If the distribution system is envisioned as the retail delivery/micro-economic system where individual customers and the impacts of individual customer decisions are critical, and central generation plants are envisioned as the wholesale/macro-economic system where statistical analyses can be used to evaluate market behavior (as opposed to individual customer behavior at the retail level), then transmission can be envisioned as the nexus between the two. The analysis of the benefits to the transmission system incorporates the following:

- Wholesale/macro-economic impacts of solar DE, such as the impact of solar DE on plans to increase the total transmission import capability, or "Scheduling Rights," into the APS system, and

- Retail/micro-economic impacts of solar DE such as the impacts of solar DE on the transmission facilities supplying individual substations that may serve a community (e.g., the local transmission supplying Yuma as an example).

Due to the intermittent nature of solar DE, and the low correlation between peak output of solar DE and peak demand, solar DE has higher value at the wholesale/macro-economic level than at the retail/micro-economic level. At the wholesale level, a statistical average of numerous solar DE installations can be depended on with a higher level of confidence than at the retail/micro-economic level, where there are fewer installations on which to depend. In addition, at the retail/micro-economic level, localized weather events, such as cloud cover, can cause numerous solar DE installations in the same geographic/retail/micro-economic region to reduce their output simultaneously.

The analysis for this Study was performed at the following levels:

- Wholesale/macro-economic level. Transmission investment required to increase total import capability from new central power plants to all of APS's service territory ("scheduling rights") was reviewed.
- Retail/micro-economic level. For example, the transmission investment required to meet growing demand in a specific area (Yuma) was reviewed.

Like most utilities, APS has a 10-year transmission plan. In general, due to the nature of typical "S" curve adoption rates of new technologies, as described in Section 2 of this Report, solar DE will not have a significant impact until the end of that 10-year plan. Therefore, in order to realistically estimate the benefits of deferring transmission investments, simplifying assumptions were utilized to determine what types of investments might be necessary on APS's transmission system beyond the 10-year transmission plan.

4.3.1 Wholesale Level Transmission Investment: Increasing Scheduling Rights

APS projects that their current transmission investment plan will give them sufficient scheduling rights through 2012. After that point, for every 500 MW of load growth, the analysis suggests that APS will need another 500 MW of scheduling rights at a cost of $110 million in 2008 dollars. This project size was determined through defining a "typical" transmission upgrade from APS's currently 10-year transmission plan, and can be thought of as the "median" of the major projects that APS currently has planned.

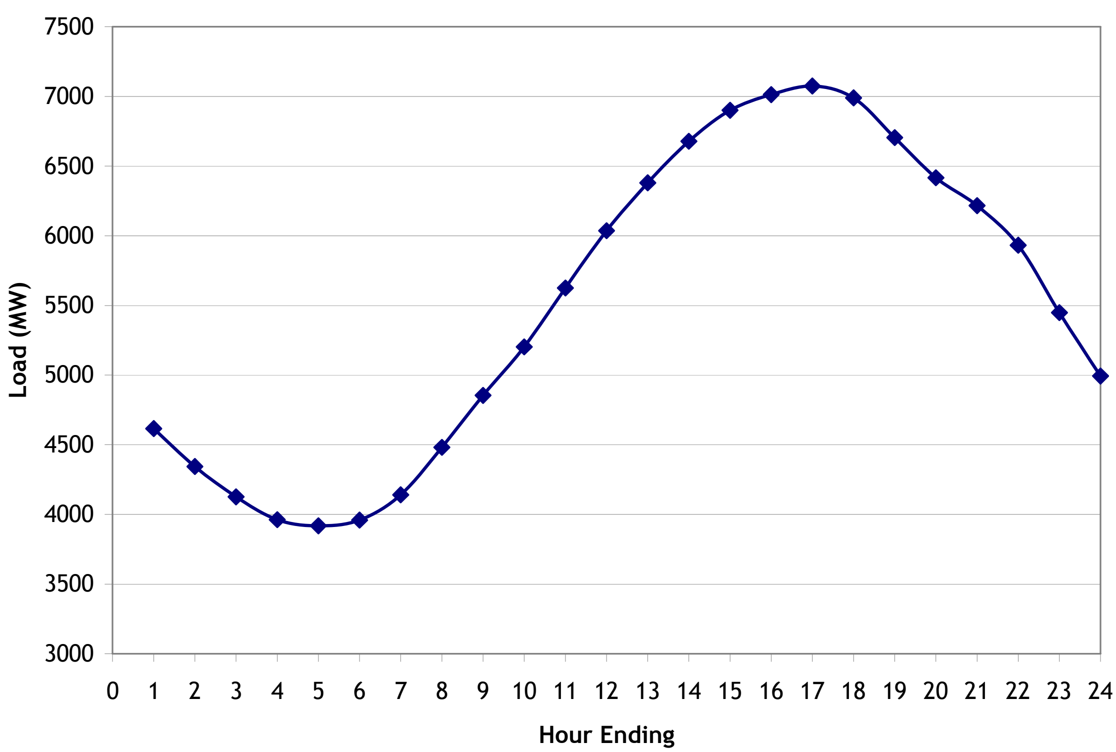
At the wholesale level, there are typically two reasons that transmission upgrades may be required: 1) for reliability purposes, e.g., to meet NERC's Reliability Standards, or 2) to gain additional scheduling rights for power supply to the load. As is typical of many utilities across the country, transmission investment for APS is usually needed first for new scheduling rights (e.g., firm transmission service) before the same investments would be needed for reliability. By solving the issue of a shortage of scheduling rights by investing in more transmission, future reliability issues are also addressed. Therefore, for purposes of this analysis, the Study team focused on transmission upgrades for increased scheduling rights.

Transmission investments are "lumpy" in nature. In other words, in order to gain new scheduling rights, often new 500 kV transmission line(s) are needed, whether there is a need for 10 MW or 500 MW of new scheduling rights. Therefore, for some time (potentially years), APS may have excess scheduling rights for each new major transmission investment it makes. The analysis reflected this "lumpy" nature of transmission investments.

In addition, transmission upgrades are typically required annually before the summer peak, with a targeted in service date before late spring of each year. Therefore, to have any beneficial impact on deferring transmission investment for scheduling right purposes, solar DE must have a coincidence with the summer peak that is at least equal to a single year's load growth to be able to defer investment for a year's time. Assuming a load growth of approximately 2 to 2.5 percent, this means that the coincident output of the solar DE with the summer peak load must be at least 200 to 320 MW (depending on the year of the forecast). If solar DE coincident output is any less than that amount, there will be no benefit of the solar DE in deferring wholesale level transmission investments.

In addition, without energy storage, there is a maximum achievable benefit to solar DE. This is because the electrical load on APS's system continues to "peak" hours after the sun sets. This is illustrated in Figure 4-1 for the peak load day of July 18, 2007. The peak load occurred at 5:00 PM at a peak of 7,075 MW. The sun set at about 8:00 PM that day, when the load was still about 6,416 MW, which is approximately 90 percent of the peak value (by comparison, for utilities in the Northeast United States, the load three hours after peak would be significantly less than 90 percent of peak). Therefore, the maximum possible benefit of solar DE (without storage) is to reduce the peak during the remaining hours of daylight, which would be approximately 600 MW (7,075 less 6,416). This would effectively make 8:00 PM the new peak hour.

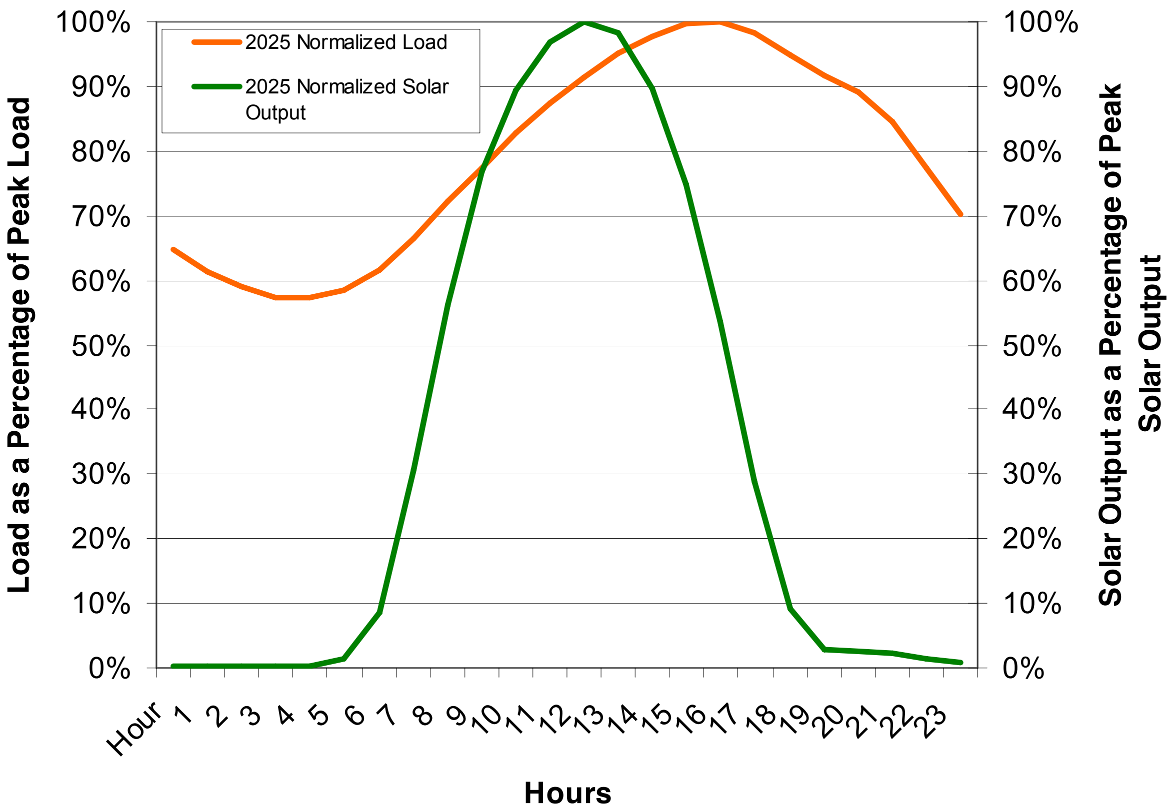
Figure 4-1: Load Curve for July 18, 2007, the Peak Load Day for 2007 on APS's System



The benefits of deferring wholesale transmission investments were analyzed by assuming there is no energy storage and depending on the coincidence of solar DE output with peak load. There may be an increased benefit to deferring transmission investments by installing sufficient energy storage PV system installations. Note that by adding energy storage, such as batteries, there is an efficiency loss in the system. A cost/benefit analysis of the value of the losses and the costs of the storage technology was not included in this Study.

The duration of energy storage is also an important consideration in achieving the capacity benefit associated with solar DE. Figure 4-2 illustrates a normalized forecasted peak load day in 2025 with a High Penetration level of solar DE installations. As can be seen from the figure, the peak load of the day occurs at about 5:00 PM, whereas the peak solar output occurs at about 1:00 PM. Hence, to maximize capacity value, a minimum of three to four hours of storage is required to correlate the solar output peak with the peak of the load shape. In addition, the load shape has a broader distribution than the solar output shape; hence, as more solar DE with storage is installed, the duration of energy production from those installations needs to become longer to be able to cover the broader load shape.

Figure 4-2: Normalized Forecast of Peak Load Day and Peak Solar Output in the Summer of 2025



4.3.2 Local Reliability/Retail/Micro-Economic Level

The considerations for the retail/local reliability issues are much the same as for the wholesale/scheduling rights discussion, with the following exceptions:

- The load shape will be location-specific.
- Load growth is location-specific.
- The types of investment needed are location-specific.
- There is increased influence of individual consumer/community preferences.
- There is increased influence of regional events, such as cloud cover.

For the purposes of this Study, it was assumed that the Yuma area would be used as an example of the types of benefits that could be achieved on the 69-kV, more retail / micro-economic sub-transmission system. The analysis cannot be averaged throughout APS's service territory due to the location-specific characteristics of the 69-kV system; however, the results for Yuma can be indicative of the overall benefits to the sub-transmission system.

For the Yuma example, it was assumed that the deployment within Yuma was similar to an average deployment throughout the APS service territory, and the amount of solar DE deployed was taken as a weighted ratio of residential dwellings in Yuma to the rest of APS.

Working with APS staff, the Study team determined that a new 69-kV upgrade (e.g., reconductoring of existing lines, or other similar measures) would be needed for every 30 MW of load growth at a cost of about $7 million in 2008 dollars.

4.3.3 Single-Axis Sensitivity

The original intent of the Target scenario was to identify additional location-based value for targeted deployment, utilizing the deployment values in the High Penetration Case. However, the High Penetration Case ends in 2025 with roughly a 30 percent market penetration throughout APS. It seems unreasonable to expect a more significant market penetration without serious diminishing returns. As a result of these findings, and discussions with APS, it was decided that the single-axis sensitivity analysis for transmission would not focus on location-based value, but would instead focus on the potential of single-axis tracking PV installations on commercial buildings to cause an increase in capacity value, and the potential for deferring transmission investments.

4.3.4 Methodology

As previously mentioned, planning, design and operation of the transmission system is regulated by the NERC Reliability Standards. The criteria to which the transmission system is planned, designed and operated are deterministic in nature within those reliability standards, and are based on allowable system performance and allowable operator action for single contingencies (loss of any one transmission or generation facility), double contingencies (loss of any two facilities), and "extreme" contingencies. The basic philosophy of the methodology is to define what constitutes a "contingency" for solar DE.

A typical generator has an "availability" in the order of 90 percent during peak load months, meaning that one can be confident that the generator will be available 90 percent or more of the time during peak loads. Hence, the basis of the methodology focuses on statistical analyses to determine the solar output at which one can be confident that the actual solar output is at least that much or greater than that amount 90 percent of the time. This value of solar output with 90 percent confidence is referred to in this Study as the Transmission and Distribution Dependable Capacity. The calculation was performed on the cumulative amount of solar DE installed up to and including the year analyzed.

The detailed methodology to determine the Transmission and Distribution Dependable Capacity is described in Section 3. The additional avoided demand losses that result from the reduced load due to this capacity are estimated in Section 4.2.3. The combination of those methodologies was used to determine the total Dependable Capacity for Transmission (DCT) for the Low, Medium, and High Penetration Cases, as well as the single-axis sensitivity, for the wholesale-level transmission investment deferral.

4.3.5 Results

Table 4-5 and Figure 4-3 present the results of the DCT analysis for the wholesale level.

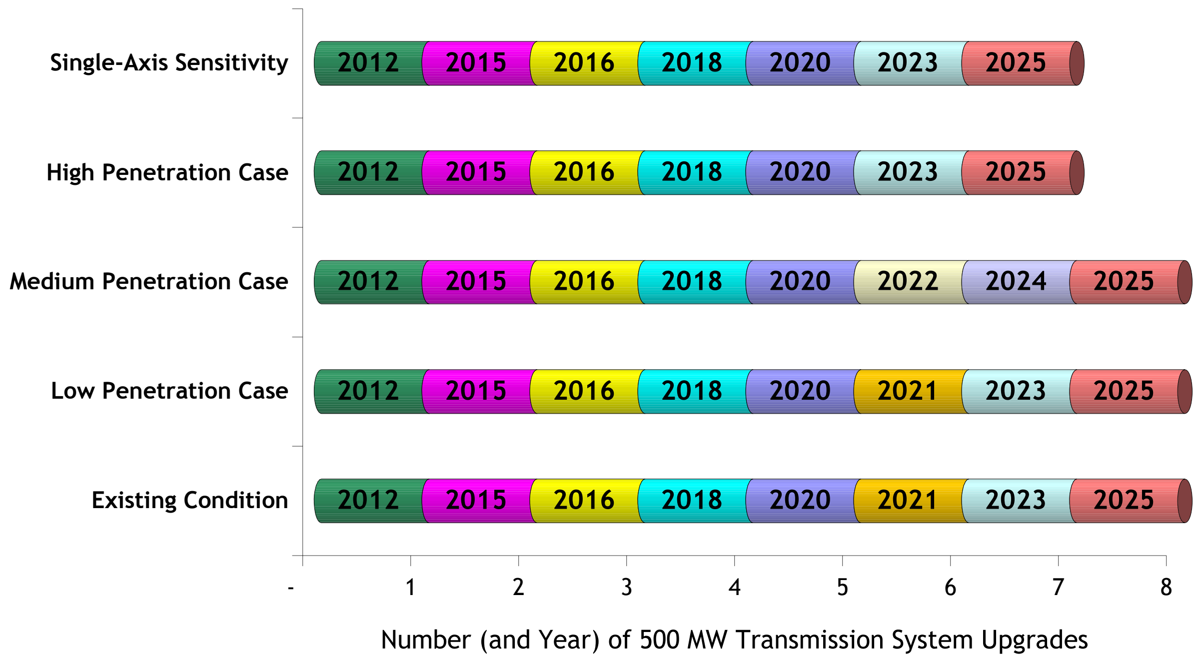
Table 4-5
Dependable Capacity for Transmission Results Based on Year 2025

Case	Hour of Transmission Peak Delivery	Dependable Capacity for Transmission (MW)	Maximum Annual Solar Output (MW)	DCT (MW) per Maximum Annual Solar Output (MW)
Low Penetration	17:00	27	42	64%
Medium Penetration	17:00	333	714	47%
High Penetration	18:00	603	1569	38%
Single-Axis Sensitivity	18:00	622	1649	38%

The results of Table 4-5 illustrate the same decrease in incremental unit for deferred investment as was observed in the line loss analysis (i.e. the “Law of Diminishing Returns”). Specifically, the more solar DE installed, the less incremental value associated with each additional solar DE installation. This is illustrated in the average value of DCT per Maximum Annual Solar Output in the last column of Table 4-5. As can be seen, the High Penetration Case (and the single-axis sensitivity), which have the highest solar DE installation, have the lowest average value of DCT per Maximum Annual Solar Output.

Figure 4-3 shows how DCT translates into deferred transmission investments. Each colored segment in the bar chart below represents a 500 MW transmission upgrade and the year in which it is expected to occur.

Figure 4-3: $110 Million (500 MW) Transmission System Infrastructure Investment Years



In Figure 4-3, the "Existing Condition" represents the projected number (and year) of 500 MW transmission system upgrades currently estimated by APS. The results of the Study indicate that the Low Penetration Case does not meet the "threshold" for being able to defer a transmission upgrade by one year, and therefore achieves no benefit from DCT. This is indicated in the figure above as the projected number (and year) of transmission upgrades for the Low Penetration Case is identical to those projected for the Existing Condition.

The Medium Penetration Case is marginal in its impact, but does succeed at deferring one transmission system upgrade from 2021 to 2022, and another from 2023 to 2024. However, the Medium Penetration Case ends up with the same number of upgrades at the end of the projection, 2025, as the Existing Condition (a total of eight upgrades). The High Penetration Case and the single-axis sensitivity both defer one transmission investment from 2021 to beyond the forecast horizon.

As can be seen from the Table 4-5 and Figure 4-3 above, the single-axis tracking does not result in any additional value compared to the High Penetration Case (the increase in DCT from 603 MW to 622 MW is too small to result in any additional deferrals). This is in part because for both the High Penetration Case and the single-axis sensitivity, the peak load hour was "pushed" to 6:00 PM (18:00 in Table 4-5), when the sun is setting.

The results for the Yuma example (not shown) indicate that the Low Penetration Case has no DCT benefits on the sub-transmission system. The Medium and High Penetration Cases and the single-axis sensitivity all resulted in one $7 million, 30 MW sub-transmission investment deferral to beyond the forecast horizon. Again, as with the system-level review, the increased output associated with the single-axis sensitivity had no discernable increase in DCT value.

4.4 Potential Detrimental Impacts to Transient Stability and Spinning Reserve

The PV inverters are designed to turn disconnect the PV systems for low voltage events due to safety reasons. If a failure on the distribution system occurs, causing an outage on the distribution system, there is a concern that the PVs could "back-feed" to the distribution system when utility operations personnel are working on the line. Therefore, it is necessary to turn off the PVs to prevent this back-feed. This necessary design for safety reasons on the distribution system can have a detrimental impact on the transmission system.

A fault on the 500-kV system can depress voltages throughout the Phoenix area. If the drop in voltage is significant, and if the duration of the low voltage event is long enough, many PV inverters may turn off simultaneously (potentially hundreds of megawatts with full adoption). This may result in two potential concerns:

- Potential impact on spinning reserve requirements
- Potential decreased transient stability performance

The results of the analysis found that there were no impacts to spinning reserve requirements, and that detrimental impacts to transient stability performance were minor. As a result, no negative value was quantified for either of these effects. The analyses to support these conclusions are described below.

4.4.1 Potential Impacts to Spinning Reserve Requirements

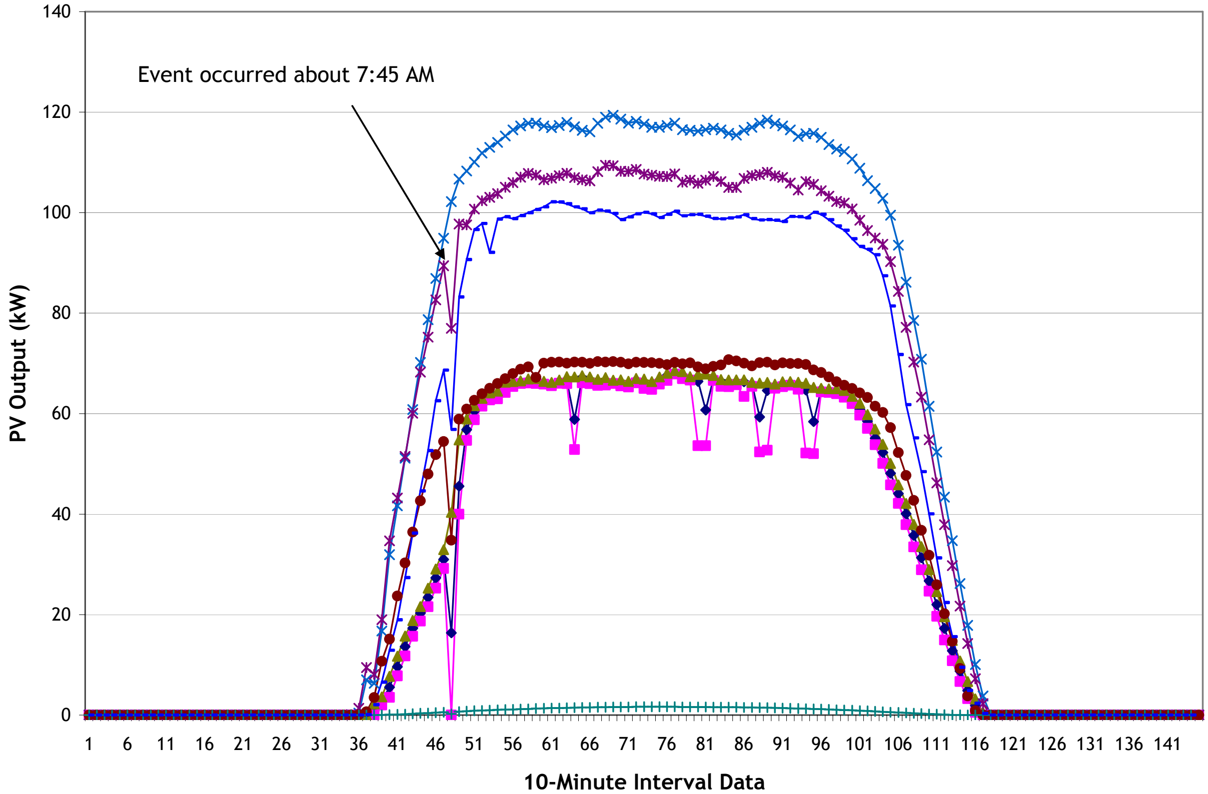
To evaluate the potential detrimental impacts on spinning reserve requirements, a scenario where a 500-kV fault occurred on the high side of the generator step-up transformer on one of the three Palo Verde units was theorized (Palo Verde is a 3,200-MW nuclear-fueled generating station that is partially owned by APS). Such an event could not only cause a loss a Palo Verde unit, but also hundreds of megawatts of PV, thereby potentially increasing spinning reserve requirements.

In order to test the hypothesis, a review of historical events was conducted to determine if those events caused extensive loss of the existing APS PV installations. Three historical events were analyzed:

- June 14, 2004 fault at the West Wing 500-kV substation with a failure of a protection system.
- July 4, 2004 fault at the West Wing 500-kV substation due to a fire.
- July 20, 2004 fault at the Deer Valley 230-kV substation.

The June 14, 2004 fault on the 500-kV system at the West Wing 500-kV substation was a slow cleared fault, meaning that there were multiple contingencies causing the low voltage event to be sustained on the 500-kV system for a longer duration than for a single contingency. Figure 4-4 shows the behavior of the existing PV systems at the time of the fault (7:45 AM). The six facilities in the figures below represent existing APS systems which have sophisticated metering equipment on them to record 10-minute interval data. The point of the figures below is to indicate the impact to these systems as a result of fault events.

Figure 4-4: Historical PV Output from Various Existing PV Installations for the Event of June 14, 2004

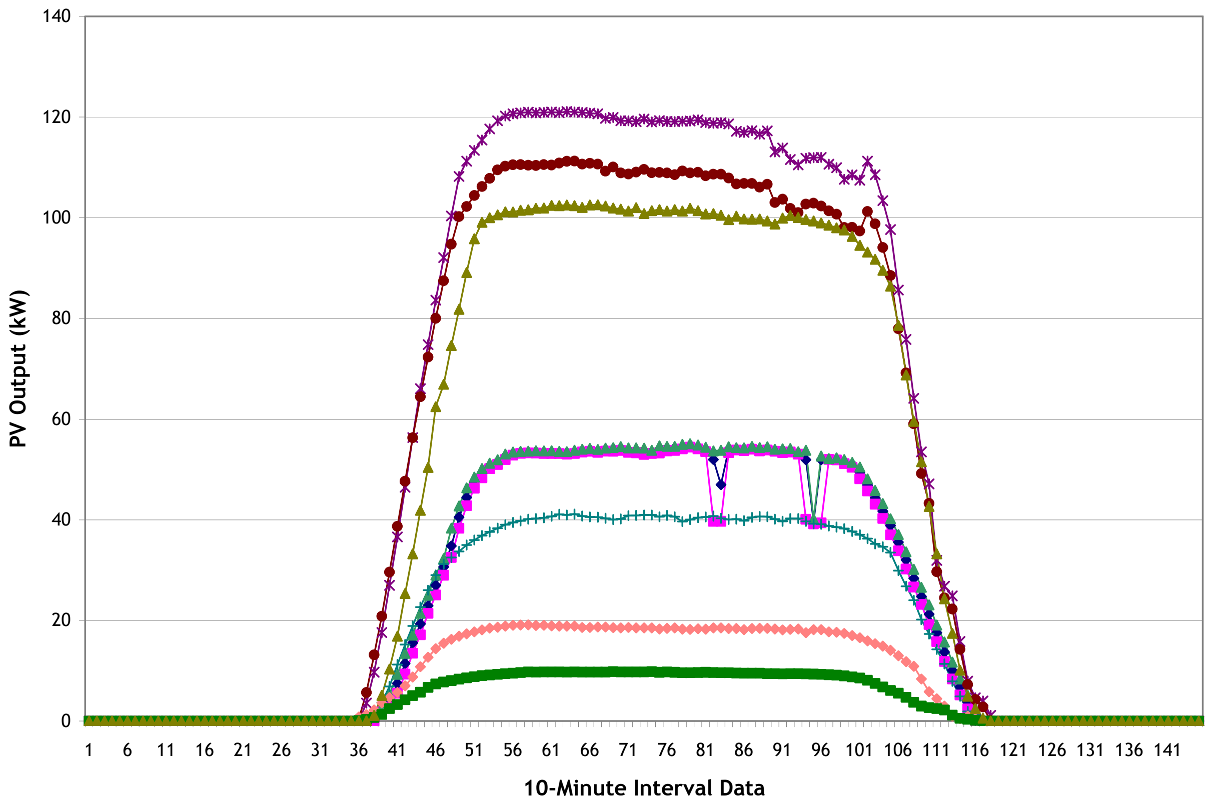


Note: The output values in this graph are from various existing PV installations (of various sizes). The names and locations of these systems are not relevant to the point that all systems behaved similarly during the identified event.

As can be seen from the PV output at the time of the event, many of the PVs on the system did drop off-line for several minutes.

The July 4, 2004 West Wing fire event was a normally cleared fault, meaning that the low voltage was not sustained for as long as the June 14, 2004 event. Figure 4-5 illustrates the PV output for July 4, 2004, and, as can be seen from the graph, the PVs did not drop off-line for that event.

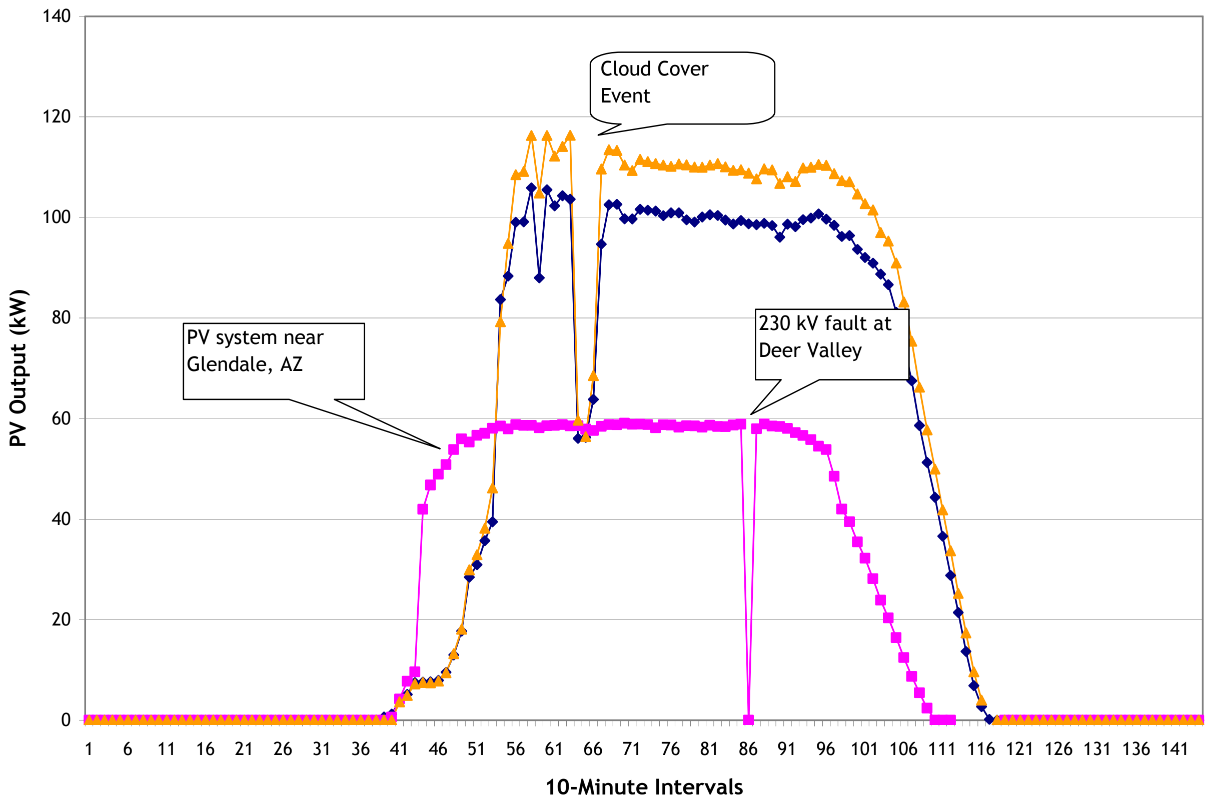
Figure 4-5: Historical PV Output (kW) From Various Existing PV Installations for the Event of July 4, 2004



Note: The output values in this graph are from various existing PV installations (of various sizes). The names and locations of these systems, and the time of the event, are not relevant to the point that the PV systems did not drop off-line during the event.

Similarly, the July 20, 2004 fault on the 230-kV system at Deer Valley substation was a normally cleared fault. This event was relatively close to one PV installation at Glendale, which also happens to be an older type of inverter design. As can be seen in Figure 4-6, the Glendale PV turned off for this event, but other PV systems did not.

Figure 4-6: Historical PV Output (kW) From Various Existing PV Installations for the Event of July 20, 2004



Note: The output values in this graph are from three existing PV installations (of various sizes). The top two lines indicate a response to a localized weather event (cloud cover). The drop in the lower line represents the impact from the fault that occurred at the Deer Valley substation and was likely due to an older type of inverter design (see text).

Note that 2004 was an abnormal year with multiple transmission events and there have been few similar events since that time. Although these do not represent a statistically significant sampling of events, the following conclusions can be made from these events:

- Newer inverter designs do not seem to automatically shut off PV systems for normally cleared, single contingency transmission events (e.g., July 4 and July 20, 2004 events).
- For slow clearing, multiple contingency transmission events, there is a danger of a significant amount of PV systems turning off simultaneously (e.g., June 14, 2004 event).

Industry practice to determine spinning reserve requirements is to use the largest single contingency event (e.g., loss of a Palo Verde unit). Since PV systems have not automatically turned off for single contingency events on an historical basis, then PV systems should not impact spinning reserve requirements as a result of the phenomena of inverters automatically turning off for low voltage events due to multiple contingencies. Hence, it would seem that it is unlikely that solar DE would impact spinning reserve requirements unless a cloud cover event suddenly caused a loss of source greater than the size of a Palo Verde unit, which is beyond the amount of solar DE contemplated in this analysis.

4.4.2 Potential Detrimental Impacts to Transient Stability Response

Recognizing that single contingency events on the transmission system do not appear to cause widespread PV system automatic shutdowns, the analysis of potential detrimental impacts to transient stability response focused on multiple contingency events. The typical worst-case event studied is a three-phase fault on the 500-kV system with a stuck breaker, causing the fault to remain on the transmission system for an extended amount of time.

Based on discussions with the Study team, APS modeled two 500-kV, three phase, stuck breaker faults at the West Wing and Pinnacle Peak substations. A comparison was conducted between a system without PV installations (exiting condition) and with PV installations. For purposes of the analysis, it was assumed that a total of 300 MW of PV was installed on APS's system and that half of this, 150 MW, would turn off automatically as a result of the low voltage event (based on a rough, conservative analysis of the June 14, 2004 event). The results of this modeling effort indicate that for both faults, the transient stability response was only marginally worse for the PV systems than for the existing condition, however, the difference was determined to be insignificant.

SECTION 5 — TECHNICAL VALUE - POWER SUPPLY CAPACITY & ENERGY

Solar DE can provide value to APS by avoiding or delaying investments in future generation projects and avoiding generation operating costs. However, care must be taken to account for the impact that solar DE may have on system reliability.

Installing solar DE across the APS electric system will cause changes in the planned expansion and operation of APS generating facilities and purchase power resources, in the following ways:

- Solar DE reduces the APS system peak demand and thus reduces the need for APS to add generating resources to meet peak demand growth.
- Capital and fixed operating costs of the avoided generation units are not incurred.
- Demand charges for power purchases that are no longer needed to meet peak demand growth are reduced.
- Solar DE reduces the load requirements on APS, thereby reducing the operation of APS generating units and purchase power resources, which in turn reduces the total cost of fuel, variable O&M, emissions, and power purchases.
- Solar DE resources may increase APS requirements for ancillary services.

The Study team has performed analyses to evaluate the value of solar DE on APS's resource planning and operations. This section discusses the assumptions, methodology and results of that effort.

5.1 Introduction

5.1.1 Solar DE Impacts on Capacity

APS maintains a portfolio of generating units and power purchases that total approximately 8,200 MW as of 2008. These resources, which include nuclear, coal-fired, and natural gas-fired units, as well as purchased power, and renewable energy resources, are used by APS to reliably serve the load of its retail customers. When planning for resource expansion, APS adds generating resources or makes purchases from the wholesale market in sufficient quantity to meet the projected peak demand of its customers, plus an additional 15 percent to meet planning and operating reliability requirements.

APS is in the process of finalizing its most recent resource expansion plan to meet the future needs of the APS electric customers. This document, to be filed with the ACC in 2009, will describe a plan for adding resources to the existing APS portfolio to meet the 15 percent reserve margin criteria at low cost while meeting APS's broader objectives of fuel and technology diversity. The preliminary version of this plan indicates the need for APS to add approximately 6,000 MW of new resources through 2025, including renewable energy resources, base-load generating facilities, intermediate combined-cycle units, combustion turbine peaking units, and wholesale power purchases, as well as implementing approximately 600 MW of energy efficiency programs.

It is the capital and fixed costs of these future planned resources that APS can potentially avoid or delay through the implementation of solar DE resources.

5.1.2 Solar DE Impacts on Energy

The resources that make up the APS portfolio are committed – resources are started and readied for operation – by APS in sufficient quantity to assure that all APS loads in each hour can be met in a reliable fashion. APS then dispatches the committed resources – determines the amount of power to be produced by each committed resource at each point in time – to serve the load of APS at the lowest possible cost, while maintaining the reliability of the electric system. Resources are generally dispatched in order of increasing variable cost, or merit order, so that the lowest variable cost resources are utilized first, and the highest variable cost resources are utilized last. As a practical matter, the high cost units are utilized only when necessary during daily and seasonal peak load periods. As new resources are added to the portfolio, they are dispatched in merit order along with the existing resources.

Typically, when determining the energy value of utility programs that impact customer loads, such as energy efficiency programs and solar DE resources, the load being displaced is assumed to be the last increment of load being served by the utility. In other words, if load is reduced by a solar DE installation, the utility's load is reduced in each hour by the quantity of the solar output, and adjusted for electric system losses. Therefore, the utility experiences a lower load and needs to commit and dispatch fewer resources to serve the modified load.

Solar DE resources implemented in the APS system will reduce the load of APS during the periods that the solar DE resources operate, thus potentially avoiding the operation of all or portions of the last resource(s) committed and dispatched by APS each hour. This determines the marginal cost of the resources being displaced. Furthermore, because the energy produced by the solar DE resources predominantly occurs during the middle of the day when load is typically higher, the solar DE resources have the potential to avoid generation from some of the highest cost resources dispatched throughout each day. As a result, use of solar DE during times of high cost operation increases their value to the system.

5.1.3 Solar DE Impacts on Reliable Operations

In addition to avoiding resource expansion and marginal energy production, solar DE resources may have an impact on system requirements for certain ancillary services. Ancillary services can generally be described as the amount of generating capacity that APS must have up and running (committed) but constrained from running at full or optimum output to ensure that sufficient capacity reserves are available, on a nearly instantaneous basis, to meet contingencies that may occur on the system. For instance, if a generating resource trips off-line due to a mechanical problem, the load it was serving still exists and, therefore, the power the failed generator was providing must be produced from the reserves available.

A key concern for solar DE resources is that ancillary services may increase as solar DE implementation increases. For instance, a cloud passing over a solar PV array would cause the array to virtually stop producing electricity until the shadow of the cloud cleared the array. If the PV array is a solar DE resource (i.e., connected to and affecting an APS customer's load), then during the transient cloudy period when the array stopped producing power, APS would experience an increase in load, followed by a sudden reduction in load once the shadow cleared the array. Such fluctuations in load could require APS to provide for additional generating reserves anytime the solar DE resource was expected to be operating.

As discussed in Section 4.4, solar DE resources are not expected to contribute significantly to APS requirements for spinning or operating reserves. This is due to the highly improbable nature of double contingency events that would necessitate additional spinning or operating reserves for solar DE. However, APS requirements for regulation reserves may be affected by solar DE installations when solar DE is installed in significant quantities.

5.1.4 Single-Axis Sensitivity

Power supply planning and development generally occurs on a system-wide level. Electric utilities plan to meet the load and reserve requirements of the total electric system peak demand with the total of all their generating units and power purchases. On rare occasions, when a transmission network is constrained from serving a load pocket and there are no reasonable alternatives to upgrade the transmission system, an electric utility may decide it is cheaper to build a generating resource inside the load pocket rather than upgrade the transmission system to fix the constraint. However, APS is not planning for any such conditions and there are no generating assets that can be avoided though strategically located solar DE installations.

Other possible strategic considerations for power supply planning would include solar DE resources that are more readily matched to the system peak demand hour and could provide greater capacity value. Such technologies could involve solar DE systems that have a westward orientation, solar tracking facilities, and solar storage facilities. Configuring solar facilities with a westward orientation could prove valuable to APS, but the diminished energy output from these facilities would potentially reduce the economic value to the customers and, hence, possibly the level of customer adoption. Solar tracking, on the other hand, is reasonably comparable to a fixed plate installation on a total economic basis. A solar tracking facility may have a higher cost than a fixed plate configuration, but typically produces enough additional energy value to compensate for the increased cost.

With regard to battery storage, it is possible that customer installations could prove valuable to APS. However, from the perspective of power supply planning, APS is generally indifferent as to whether it adds storage though a utility installation (e.g., pumped hydro, compressed air storage, flywheels, batteries, etc.) or whether the customer adds the storage as part of a solar DE installation. Additionally, APS has not identified any storage technologies that can compete favorably with more traditional resources.

If APS can install utility-grade storage equal to or less expensively than the customer can install battery backup, then APS would likely opt for the utility-grade installation for resource planning purposes since it would permit direct utility control and higher long-term reliability at a lower cost. For APS to consider customer installed storage a viable alternative for power supply planning purposes, the customer would need to be willing to absorb the cost of the storage and likely receive only partial cost compensation from APS. The compensation would be in proportion to the value that storage provides APS as compared to traditional technologies or utility-built storage facilities. Customers might also be required to submit to certain assurances of long-term maintenance and battery reliability to receive compensation for storage.

Given these considerations, the best "targeted" solar DE alternative for power supply planning is a single-axis tracking PV resource. For the purposes of the single-axis sensitivity, assumptions for the High Penetration Case were adopted, except that all of the commercial fixed plate PV resources were replaced with an equivalently sized single-axis tracking resource.

5.1.5 Solar DE Capacity & Energy Cost Impacts

To address the benefits and potential costs that solar DE may have on APS resource planning and operation, the following analyses were conducted:

- The quantity of capacity available from the solar DE installations that APS can reliably depend on when planning future generating resources was determined.
- The amount of avoided or deferred capital and fixed operating costs that could be derived from the "dependable solar DE" capacity was projected for each solar DE penetration case.
- The amount of avoided variable operating costs that could be derived from each solar DE implementation was projected for each Study year. This was based upon a simulation of the commitment and dispatch of APS generation and purchase power resources.
- An assessment of the impact that solar DE may have on APS regulation and spinning reserve requirements was performed.

Based upon the Study team's analysis, which is described in greater detail within this section, summary level results for the avoided quantity and costs of power supply capacity and energy are shown in Table 5-1. Avoided costs are further summarized and reported in Section 6 of this Report.

Table 5-1

Avoided Total Capital & Fixed Operating Costs

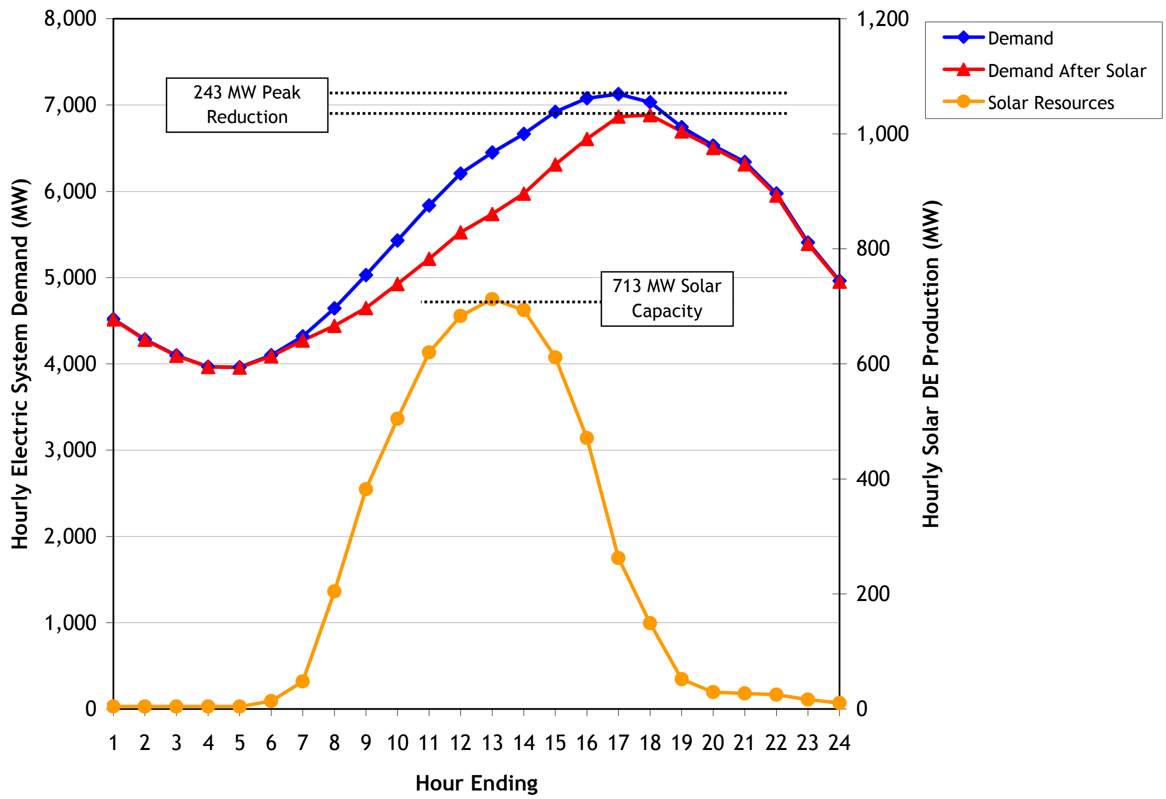
	2010	2015	2025
Low Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	16	25
Total Solar DE Energy (GWh at Generation Level)	17	106	176
Cumulative Avoided Capital Investments (2008 $000)	0	0	0
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	659	3,728
Total Avoided Annual Energy Cost (2008 $000)	936	5,606	8,547
Medium Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	32	265
Total Solar DE Energy (GWh at Generation Level)	18	181	1,789
Cumulative Avoided Capital Investments (2008 $000)	0	0	184,581
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,351	18,946
Total Avoided Annual Energy Cost (2008 $000)	980	10,100	96,596
High Penetration Case			
Dependable Solar DE Capacity (MW at Generation Level)	3	32	348
Total Solar DE Energy (GWh at Generation Level)	18	181	3,863
Cumulative Avoided Capital Investments (2008 $000)	0	0	299,002
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,351	20,965
Total Avoided Annual Energy Cost (2008 $000)	980	10,100	182,009
Single-Axis Sensitivity			
Dependable Solar DE Capacity (MW at Generation Level)	4	36	351
Total Solar DE Energy (GWh at Generation Level)	19	188	4,046
Cumulative Avoided Capital Investments (2008 $000)	0	0	299,002
Total Avoided Annual Fixed O&M Costs (2008 $000)	0	1,546	21,444
Total Avoided Annual Energy Cost (2008 $000)	1,031	10,578	188,846

5.2 Solar DE Capacity Value

5.2.1 Solar DE Dependable Capacity

As previously discussed in Sections 3 and 4 of this Report, output from the solar DE resources is only partially coincident with the peak demand of the APS load (see Figure 5-1). As such, the amount of capacity that can be relied upon from the solar DE resources is less than the total installed capacity of the solar DE resources.

Figure 5-1: Coincidence of Solar DE Output with the APS System Load Shape, Solar DE at 10% of Peak



Transmission and distribution planning is usually concerned with the peak demand placed on the electric facilities; therefore, an analysis of the coincidence of the solar DE capability at the time of the peak on the electric facilities is sufficient to determine the impact of solar DE capacity. However, power supply planning is concerned with the ability of a given resource portfolio to reliably serve the total system load – not just at the time of the peak but across all hours of the year. The capability of solar DE resources to displace power supply resources must, therefore, be determined through a different analysis than that used for the transmission and distribution analyses.

Determining Power Supply Capacity Reliability

Power supply planning is typically performed such that resources are added to meet a given level of capacity reserves above the forecast peak demand, or reserve margin. In the case of APS, the planning reserve margin is 15 percent. While a planning reserve margin reflects a reasonable rule-of-thumb for long-term planning purposes, the 15 percent reserve margin is actually derived through a more rigorous analysis of the quantity of resources needed to maintain a minimum level of reliability to serve customer loads. The electric industry has adopted several similar methods to compute such reliability metrics; generally they are all related to a specific measure of how likely a utility will be able to serve the loads of its customers.

Common measurements for power supply reliability targeted by electric utilities include *one hour in 10,000 hours* and *one day in 10 years*, which can be interpreted as follows: the electric utility will be able to serve all customer loads but for one hour in 10,000 hours (there are 8,760 hours in a year), or will be able to serve all daily peaks but for one day in 10 years, respectively. These metrics reflect the very high levels of reliability demanded by utility customers and the regulatory bodies that govern electric utilities.

Common analytic approaches and reliability measurements include loss of load expectation (LOLE), loss of load probability (LOLP), and loss of load hours (LOLH), with approaches varying for the specific time interval and dependent variable being measured. A utility will typically evaluate the ability of its power supply portfolio to meet a desired target based upon these metrics, and will develop a plan for resource additions that will ensure that they achieve their target. The quantity of capacity that meets a given target is usually stated in terms of the more commonly discussed reserve margin, which experience indicates will usually be in the range of 12 to 18 percent for the equivalent reliability criteria.

Besides a general 15 percent reserve margin used for long-term planning, APS uses an LOLE approach when evaluating the reliability of a given portfolio. The LOLE approach measures the likelihood (expectation) that customer loads will or will not be served by a given portfolio. For the purposes of this Study, APS, the stakeholders, and the Study team determined that an LOLE approach applied to the solar DE resources would provide a highly defensible approach for measuring the “dependable capacity” available from the solar DE resources.

Solar DE Dependable Capacity

To evaluate the dependable capacity of solar DE resources, APS performed a series of LOLE simulations of its existing portfolio after adding 100 MW of the solar DE technologies being investigated for this Study, as described in Section 2 of this Report. Because the LOLE measurement can vary significantly depending on the underlying load shape, the LOLE computations were performed for five recent historical annual hourly load profiles: 2003 through 2007. Additionally, the LOLE was computed for forecast load conditions over the next five years by simulating load growth on each of the historical load profiles.

The average LOLE over the forecast period was computed and recorded for the simulated resource portfolios including 100 MW of the various solar DE resources. These values were then compared to the LOLE computed from an evaluation of the APS resource portfolio without the solar DE resources. In the analysis, combustion turbine resources were added to the resource portfolios without solar DE until the average LOLE recorded for the *traditional portfolio* equaled the LOLE for the *solar DE portfolio*. With an equivalent LOLE, the two portfolios provide the same level of reliability, or dependability, for serving the APS system loads.

For a given pair of *traditional* and *solar DE portfolios*, the ratio of the combustion turbine capacity to the solar DE capacity represents the relative quantity of traditional capacity needed to provide the same level of reliability as the solar DE resource or, conversely, the percent dependable capacity provided by the evaluated solar DE resource. Table 5-2 provides the percent dependable capacity (for power supply planning) computed for each of the solar technologies that make up the solar DE cases evaluated by this Study.

Table 5-2
Percent Dependable Solar DE Capacity
100 MW Installation

	Base Case Resource Plan					
Solar DE Technology	2007	2006	2005	2004	2003	Average
Solar Hot Water	47.8%	41.8%	43.9%	46.3%	43.1%	44.6%
Daylighting:						
Low Penetration Case	72.7%	64.1%	N/A	58.7%	62.0%	64.4%
High Penetration Case	73.3%	66.2%	N/A	59.0%	63.6%	65.5%
Residential PV:						
18.4° Tilt, S-Facing	41.5%	52.5%	48.4%	41.1%	42.3%	45.2%
18.4° Tilt, SE-Facing	28.4%	40.8%	36.5%	28.7%	32.5%	33.4%
18.4° Tilt, SW-Facing	54.2%	63.4%	58.8%	53.1%	50.7%	56.0%
Commercial PV:						
10° Tilt, S-Facing	43.7%	55.2%	50.8%	42.9%	44.3%	47.4%
0° Tilt, N/S Single-Axis Tracking	73.1%	75.3%	74.0%	68.3%	60.4%	70.2%

Diminishing Dependable Capacity

In addition to the analysis of dependable capacity for a small quantity (100 MW) of solar DE, an analysis was performed to determine the amount of dependable solar DE capacity that might diminish as installation of solar DE resources increased on the APS system. As discussed in Section 4, as more solar DE resources are added to the electric system, the APS system peak demand will be pushed to a later hour in the day (e.g., the summer peak demand will move from the traditional hour ending at 5:00 PM to 6:00 PM, or even 7:00 PM). Because the output of the solar DE resources becomes significantly less as the available sunlight diminishes at dusk, the delay of the peak hour to a later hour could significantly diminish the ability of the solar DE resources to meet the electric system peak demand and satisfy reliability planning criteria.

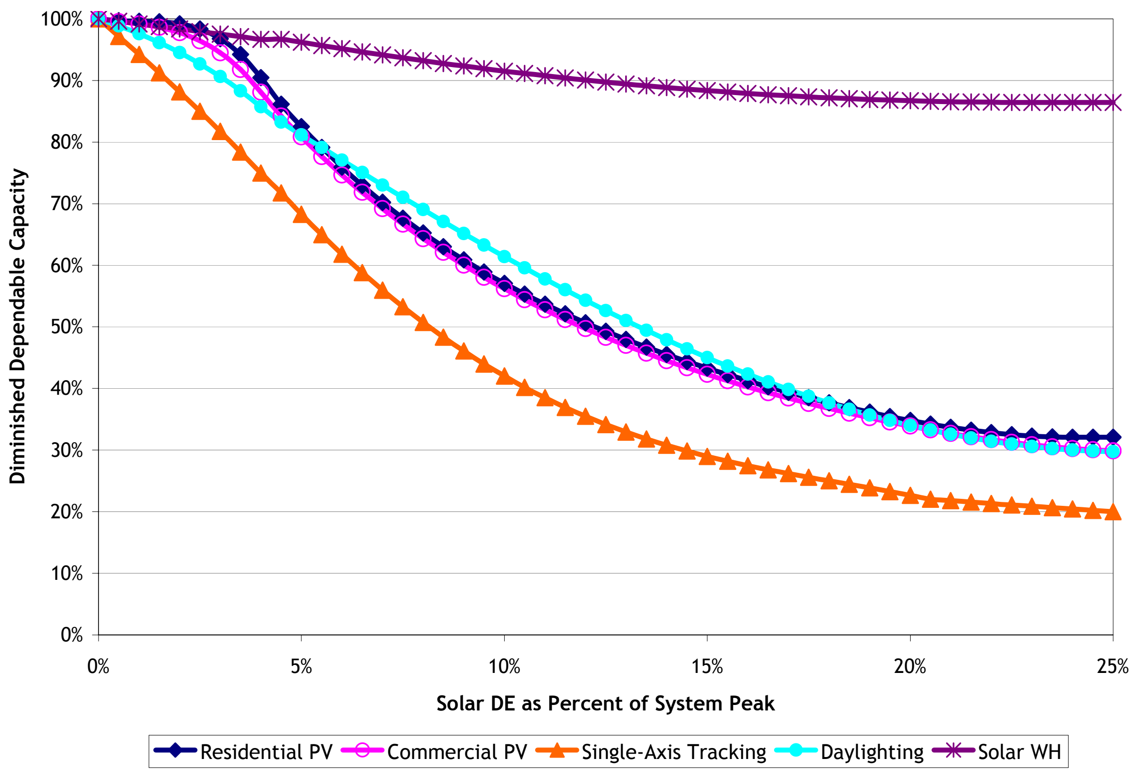
To analyze this effect, the LOLE analysis was repeated but this time using incrementally increasing quantities of solar DE resources. This LOLE analysis was performed by APS for each technology comprising the solar DE cases. Computational requirements limited the analysis to a single historical year, 2006, for daylighting, and 2005 for the other solar DE technologies.

As depicted in Figure 5-2, as installed solar DE resources became large relative to the peak demand of the APS system, the dependable capacity of the solar DE resources declined. The commercial single-axis tracking PV technology (simulated for the single-axis sensitivity) is most notably affected by the impact of diminishing capacity dependability with increasing implementation. Solar hot water technology is the least affected. These effects can be understood by considering the typical daily profiles for the solar DE technologies.

Since solar hot water incorporates natural storage characteristics, the dependable capacity of the solar hot water technology is not affected significantly by the coincidence of available sunlight with the electric system peak. The electric load avoided by a solar hot water system is minimal, since a traditional electric water heater operates throughout a 24-hour period, and commonly after sunset.

At the other end of the spectrum are solar PV technologies that track the sun. At low implementation rates, these solar resources provide relatively high dependable capacity due to the higher output that these resources provide across a greater number of hours, and a higher coincidence with the system peak load hour. However, this "longer duration" and more coincident output profile tends to push the electric system peak to a later hour more readily than the other evaluated solar DE technologies. This attribute, coupled with the steep drop-off of the solar electrical output as the sun sets, causes the dependable capacity of single-axis tracking PV technology to diminish more rapidly than the other technologies as installations are added to the APS system.

Figure 5-2: Diminishing Value of Solar DE Capacity



Total Dependable Capacity by Solar DE Case

Projections of total dependable capacity for each solar DE involved several steps. First, the results of the solar DE dependable capacity analysis, including diminishing values with increased implementation, were applied to the general capacity characteristics for each solar DE technology and the different customer adoption rates described in Section 2. Coincidence of maximum capacity ratings for solar DE technologies and marginal peak demand loss factors, as described in Section 4, were also applied to the customer-level technology characteristics to determine the total dependable capacity for each solar DE case. The installed and dependable capacity for each case is depicted below in Table 5-3.

Table 5-3
Total Dependable Solar DE Capacity

	2010	2015	2025
Low Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	32.7	52.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	81.7%	80.5%
Incremental Demand Losses	21.8%	22.2%	22.5%
Weighted Dependable Capacity Factor	49.6%	47.6%	47.7%
Weighted Diminishing Value Adj. Factor	100.0%	100.0%	100.0%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	15.5	24.8
Medium Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	63.3	730.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	88.3%	97.7%
Incremental Demand Losses	21.8%	22.1%	22.2%
Weighted Dependable Capacity Factor	49.6%	46.8%	45.9%
Weighted Diminishing Value Adj. Factor	100.0%	99.6%	66.3%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	31.8	265.2
High Penetration Case			
Total Solar DE Capacity (Max MW at Meter)	4.0	63.3	1597.7
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.0%	88.3%	98.2%
Incremental Demand Losses	21.8%	22.1%	22.0%
Weighted Dependable Capacity Factor	49.6%	46.8%	45.6%
Weighted Diminishing Value Adj. Factor	100.0%	99.6%	39.9%
Dependable Solar DE Capacity (Summer MW at Generation)	2.1	31.8	348.2
Single-Axis Sensitivity			
Total Solar DE Capacity (Max MW at Meter)	4.3	66.4	1677.4
Adjustment Factors:			
Intra-Technology Coincidence Factor	87.7%	88.7%	98.3%
Incremental Demand Losses	21.8%	22.1%	22.0%
Weighted Dependable Capacity Factor	55.6%	51.1%	50.1%
Weighted Diminishing Value Adj. Factor	100.0%	98.9%	34.9%
Dependable Solar DE Capacity (Summer MW at Generation)	2.5	36.4	351.3

An interesting result of the analysis of the dependable capacity under the single-axis sensitivity (which reflects assumptions consistent with the High Penetration Case except that single-axis tracking PV resources are assumed for all commercial PV installations) is that the total dependable capacity is virtually identical to that of the High Penetration Case by 2025. While intuition might suggest that single-axis tracking resources would provide higher levels of dependable capacity because of the greater coincidence with APS's system peak demand, the degree to which the dependable capacity diminishes for the single-axis technology at the high implementation levels almost completely offsets the higher dependable capacity that can be derived from smaller implementation levels.

5.2.2 APS Resource Expansion Plan & Projected Avoided Capacity

As previously mentioned, APS is in the process of finalizing its most recent resource expansion plan to meet the future needs of the APS electric customers. This plan is preliminary and subject to change, however, has been relied upon for the purposes of this Study. The plan reflects the best available data at this time concerning the future resources of APS.

APS maintains a mix of power supply resources, which total approximately 8,200 MW, to reliably meet the needs of its customers as of 2008. The generating resources in the existing APS portfolio include approximately:

- 1,150 MW of nuclear capacity,
- 1,750 MW of coal-fired capacity,
- 1,850 MW of natural gas-fired combined cycle capacity, and
- 1,500 MW of natural gas-fired peaking and steam generating resources.

Additionally, APS purchases approximately 1,900 MW of wholesale power from others, and currently purchases 55 MW of capacity from renewable resources.

By 2025, in its base case resource plan, without considering future installations of solar DE resources, APS would need to add the following resources to its existing portfolio to meet anticipated growth in load, as well as planned changes in existing resource capability:

- Approximately 800 MW of renewable generating resources (other than solar DE),
- Approximately 1,300 MW of intermediate and base-load generating resources,
- Approximately 3,300 MW of combustion turbine peaking resources,
- Purchase approximately 500 MW of wholesale power, and
- Reduce load through the implementation of approximately 600 MW of energy efficiency programs.

It is these future planned resources that APS can potentially avoid or delay through the implementation of solar DE resources in their system. However, certain of the future planned resources are immutable and cannot be delayed or avoided through the implementation of solar DE resources. These immutable resources include energy efficiency programs, planned renewable resources required to meet RES requirements, and planned base-load resources needed to enhance fuel and technology diversity in the APS portfolio. Future planned resources that can be potentially avoided or delayed through solar DE installations include combustion turbine peaking resources, intermediate combined cycle resource, and wholesale power purchases.

Existing and planned resources for the APS base case resource plan (without solar DE) and for each of the solar DE cases depicted for the Study are provided in Tables 5-4 through 5-7. Planned APS generating and purchase power resources have been reduced by the quantity of dependable solar DE described in Section 5.2.1.

For each solar DE case, the cumulative quantity of dependable solar DE capacity in each target year was compared to the planned APS generating resources. To the extent dependable solar DE capacity is projected to be sufficient to displace the installation of one or more planned generating resources, the APS resource plan was modified to avoid or delay the installation of the generating resource(s). To the extent the projected dependable solar DE capacity was insufficient to displace a planned generating unit, wholesale purchases were reduced for the quantity of available dependable capacity.

In all cases, dependable solar DE capacity was projected to be insufficient to avoid the installation of the planned combined cycle resource. Therefore, the combined cycle resource planned by APS for installation in 2020 was not simulated in any case to be avoided through the installation of solar DE resources.

As depicted in Table 5-4, projected dependable solar DE capacity under the Low Penetration Case is insufficient to avoid or delay the installation of any of the planned APS generating resources. However, planned wholesale purchases equal to 15.5 MW in 2015, and which increase to 24.8 MW by 2025, can be avoided. As depicted in Table 5-5, dependable solar DE capacity is projected to be sufficient under the Medium Penetration Case to avoid two 94 MW combustion turbine resources by 2025, along with avoided wholesale purchases of 31.8 MW in 2015 and 101.5 MW in 2025.

For the High Penetration Case and the single-axis sensitivity, as depicted in Tables 5-6 and 5-7, respectively, dependable solar DE capacity is projected to be sufficient to avoid three 94 MW combustion turbine resources by 2025. Additionally, wholesale purchases of 31.8 MW in 2015 and 13.7 MW in 2025 can be avoided in the High Penetration Case. Similarly, avoided wholesale purchases of 36.4 MW in 2015 and 15.3 MW in 2025 are projected for the single-axis sensitivity.

Table 5-4
Comparison of APS Resource Plans: Base Case and Low Penetration Case

	Base Case Resource Plan			Low Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	16	25
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,290
Short-term Purchases	0	38	487	0	23	462
Total Resources	8,068	8,746	12,483	8,071	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	0
Planned Purchases				0	(16)	(25)

Table 5-5
Comparison of APS Resource Plans: Base Case and Medium Penetration Case

	Base Case Resource Plan			Medium Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	32	265
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,102
Short-term Purchases	0	38	487	0	7	410
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(188)
Planned Purchases				0	(32)	(77)

Table 5-6
Comparison of APS Resource Plans: Base Case and High Penetration Case

	Base Case Resource Plan			High Penetration Case		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	3	32	348
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,008
Short-term Purchases	0	38	487	0	7	421
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,234	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(282)
Planned Purchases				0	(32)	(66)

Table 5-7
Comparison of APS Resource Plans: Base Case and Single-Axis Sensitivity

	Base Case Resource Plan			Single-Axis Sensitivity		
	2010	2015	2025	2010	2015	2025
Peak Demand (MW):						
Peak Demand	7,372	8,316	11,442	7,372	8,316	11,442
Less Energy Efficiency	(55)	(230)	(587)	(55)	(230)	(587)
Less Firm Purchases	(480)	(480)	0	(480)	(480)	0
Net Peak Demand	6,838	7,606	10,855	6,838	7,606	10,855
Existing Resources (MW):						
Generating Resources	6,270	6,270	6,270	6,270	6,270	6,270
Renewable Resources	61	326	315	61	326	315
Purchases & Other	1,738	1,793	0	1,738	1,793	0
Cumulative Planned Resources (MW):						
Solar DE	0	0	0	4	36	351
Renewable Resources	0	320	793	0	320	793
Base-load Generation	0	0	800	0	0	800
CC Resource	0	0	528	0	0	528
Peaking CT Resource	0	0	3,290	0	0	3,008
Short-term Purchases	0	38	487	0	2	418
Total Resources	8,068	8,746	12,483	8,072	8,746	12,483
Capacity Reserves	1,231	1,141	1,628	1,235	1,141	1,628
Reserve Margin	18%	15%	15%	18%	15%	15%
Cumulative Avoided Capacity (MW):						
Planned CT Resources				0	0	(282)
Planned Purchases				0	(36)	(69)

5.2.3 Projected Avoided APS Capacity Costs

Based upon the avoided generating assets and wholesale purchase power capacity described in Section 5.2.2, it is possible to assign capital and fixed operating costs that APS would have incurred for these resources. Several fixed costs can be avoided, as follows:

- Capital costs associated with the avoided generating assets.
- Capital costs for transmission interconnection and system upgrades specifically assigned to the avoided generating assets.
- Fixed operating and maintenance costs of the avoided generating assets. These include annual maintenance costs, labor costs, rents and utilities, etc. that APS would incur for a generating unit whether the unit operates or not.
- Natural gas pipeline reservation fees. These are the fixed annual costs paid to the natural gas pipeline company to reserve a portion of the pipeline to serve the natural gas requirements of any avoided gas-fired generating asset.
- Avoided short-term market demand charges.

The assumptions APS is using in its base case resource plan for the fixed costs described above were reviewed and found to be reasonable and generally consistent with assumptions used by R. W. Beck and others in the industry for resource planning studies. As such, for the purposes of this Study, the capital cost and fixed O&M assumptions developed by APS for the General Electric LMS100 combustion turbine peaking resource modeled for installation in the APS resource plan were relied upon by the Study team. Additionally, the APS estimates for transmission capital costs, natural gas reservation fees, and demand charges for short-term market purchases were utilized for the purposes of this Study. Table 5-8 depicts the capital cost assumptions in real 2008 dollars per installed kilowatt (kW). Table 5-9 depicts the capital cost spending curve applied to the composite combustion turbine and transmission capital costs, and Table 5-10 depicts the fixed operating costs assumptions in real 2008 dollars per kilowatt-year (kW-yr) used for the Study.

Table 5-8

Potential Avoided Capital Costs

	2008 $/kW
Avoided Combustion Turbine Capital Cost	$ 1,006.00
Avoided Transmission System Investment	$ 82.40

Table 5-9

Capital Spending Curve

	Percent Capital Expenditure Per Year
Two Years Prior to Commercial Operation	10%
One Year Prior to Commercial Operation	50%
Year of Commercial Operation	40%

Table 5-10

Potential Avoided Fixed Operating Costs

Costs in 2008 $/kW-yr	2010	2015	2025
CT Fixed O&M	7.28	7.28	7.28
Natural Gas Pipeline Reservation Fee	31.81	31.81	31.81
Short-Term Purchase Power Demand Charge	42.76	42.47	150.27

Using the fixed costs described above and the avoided resource capacity described in Section 5.2.2 yields the total avoided costs for each of the solar DE cases (see Table 5-11).

Table 5-11
Avoided Total Capital & Fixed Operating Costs

	Avoided Cost (2008 $000)		
	2010	2015	2025
Low Penetration Case			
Cumulative Avoided Capital Investments	0	0	0
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	659	3,728
Avoided Generating Unit Fixed O&M	0	0	0
Avoided Generating Unit Natural Gas Reservation	0	0	0
Total Avoided Annual Fixed O&M Costs	0	659	3,728
Medium Penetration Case			
Cumulative Avoided Capital Investments	0	0	184,581
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,351	11,598
Avoided Generating Unit Fixed O&M	0	0	1,369
Avoided Generating Unit Natural Gas Reservation	0	0	5,980
Total Avoided Annual Fixed O&M Costs	0	1,351	18,946
High Penetration Case			
Cumulative Avoided Capital Investments	0	0	299,002
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,351	9,943
Avoided Generating Unit Fixed O&M	0	0	2,053
Avoided Generating Unit Natural Gas Reservation	0	0	8,970
Total Avoided Annual Fixed O&M Costs	0	1,351	20,965
Single-Axis Sensitivity			
Cumulative Avoided Capital Investments	0	0	299,002
Avoided Annual Fixed O&M Costs:			
Avoided Market Purchases	0	1,546	10,421
Avoided Generating Unit Fixed O&M	0	0	2,053
Avoided Generating Unit Natural Gas Reservation	0	0	8,970
Total Avoided Annual Fixed O&M Costs	0	1,546	21,444

5.3 Solar DE Energy Value

5.3.1 APS Costs of Dispatch

As previously mentioned, resources in the APS power supply portfolio are committed and dispatched in sufficient quantity to assure that all APS loads in each hour can be met in a reliable fashion at the lowest possible cost. Resources are generally dispatched in merit order so that low variable cost resources are utilized more often than high variable cost resources. As previously discussed, APS's existing portfolio is comprised of nuclear, coal-fired, natural gas-fired, purchase power, and renewable energy resources. To this portfolio, APS plans to add additional renewable resources, natural gas-fired combined cycle and combustion turbine resources, a new base-load resource, and make short-term (seasonal) market purchases in quantities sufficient to meet targeted planning reserves.

APS has developed models to simulate the hourly commitment and dispatch of the existing and planned resources over a long-term planning horizon (beyond 2025). These models use an industry-accepted simulation model called PROMOD, licensed by Ventyx, a major vendor of electric utility simulation software in the United States. APS uses PROMOD to simulate the operation of its generating and purchase power resources and to project variable operating costs of potential future power supply plans.

To perform these simulations, APS models all major operating characteristics of each existing and planned resource, including maximum and minimum capacity ratings, heat rate curves, variable O&M costs, start-up costs, minimum operating constraints, and emission rates, to name a few. These operating characteristics are combined with projected fuel prices, emission prices, forecasted hourly loads, and spinning and operating reserve requirements to simulate the operation of the APS resource portfolio in future years. Through this process, APS can make reasonable projections about the variable operating costs of a given resource portfolio and compare these costs to alternative resource plans, as appropriate.

For the purposes of this Study, the Study team has relied upon the PROMOD models maintained by APS. Specific scenarios necessary to analyze the operation of the solar DE cases were developed by the Study team and were executed by APS using their PROMOD model. While the Study team has not reviewed and verified the detailed assumptions used by APS in its PROMOD model, it conducted several interviews with the APS resource planning staff to determine that the approach, processes, and assumptions used by APS are generally consistent with R. W. Beck, and by those used by the electric utility industry as a whole. The PROMOD models used for the solar DE Study are reported by APS to be the same models that APS has relied upon to develop its current power supply plan to be filed with the ACC, thus providing an additional level of assurance that the models should be reasonable for the purposes of this Study. The hourly variable cost results from the APS PROMOD simulations, as described below, were also reviewed and utilized for this Study, thus providing an opportunity to review detailed results from the APS models.

Because APS energy costs that can be avoided by solar DE installations will more often than not be generating resources fired by natural gas, one of the most critical inputs to the PROMOD model was the price assumed for future natural gas prices. For purposes of its power supply planning efforts, APS has developed a forecast for natural gas prices based on forward prices observed for the New York Mercantile Exchange (NYMEX) on July 31, 2008, with appropriate adjustments for delivery to the APS system. The delivered natural gas prices modeled by APS are referenced in Table 5-12, below.

Recent market trends have caused prices for natural gas to fall below the values being used by APS in their resource planning studies. For purposes of this Study, the natural gas price forecast was not modified, since these prices provide the best conformance to the current APS resource planning results. Additionally, the use of higher natural gas prices will have the effect of increasing the energy value of the solar DE resources, thus providing a somewhat optimistic assessment of solar DE.

One change that was made to the APS simulations was the modeling of future costs for emissions of green house gases (GHG). An assumption implicit in the forecasted solar DE adoption curves for the Low, Medium, and High Penetration Cases described in Section 2 was a relatively high increase in future retail rates. This rate increase was assumed to be caused in-part by the anticipated institution of future GHG legislation. For these solar DE cases, the Study team made ex-post adjustments to projected hourly and annual energy costs projected by APS to reflect the addition of future carbon dioxide (CO_2) emission allowance costs. For this adjustment, the Study team relied on it current market forecast of CO_2 prices assuming the institution of a national cap and trade program in 2012. The CO_2 prices assumed for these cases are depicted in Table 5-12.

Table 5-12
Projected Natural Gas & CO_2 Prices
Nominal $

	2010	2015	2025
Delivered Natural Gas Price ($/MMBtu)	9.14	8.44	9.61
CO_2 Allowance Price ($/ton)	-	20.94	52.30

5.3.2 Impact of Solar DE on Resource Commitment & Dispatch

Typically, when determining the energy value of utility programs that affect customer loads, such as solar DE resources, the load displaced by the operation of the solar DE resource is assumed to be the last increment of load being served by the utility (the marginal cost of electricity production). As APS loads are reduced by solar DE installations, APS will modify the commitment and dispatch of resources to meet the lower load levels. Any change in the total variable costs of generation and purchased power caused by serving lower loads is directly attributable to the solar DE installations. So long as total variable costs are reduced, the solar DE installations can be said to provide an energy cost savings to APS.

Because the energy produced by the solar DE resources predominantly occurs during the middle of the day, when electric system loads and costs of dispatch are typically high, solar DE installations have the potential to provide significant savings in energy costs. In general, when incremental reductions in load are small, significant savings in energy production costs are possible. However, when incremental reductions in load are large, significant changes in resource commitment may be required, which can diminish the value of the reduced load. Additionally, as reported in Section 5.2.2, the resource expansion plan assumed for the APS base case plan and for each of the solar DE cases are different. As such, resource commitment and dispatch will necessarily be different between the base and each of the solar DE cases, regardless of the quantity of load reduced.

Figure 5-3 depicts resource commitment and dispatch patterns projected for a typical summer day in 2025, with incremental load impacts simulated for the Low Penetration Case. Energy produced by solar DE resources under the Low Penetration Case is small relative to the system load. As such, solar DE resources under this case are projected to avoid the highest-cost resources dispatch to serve load – generation from natural gas-fired peaking resources.

Figure 5-3: Typical Summer Day Dispatch, APS Base Case & Low Penetration Case, 2025

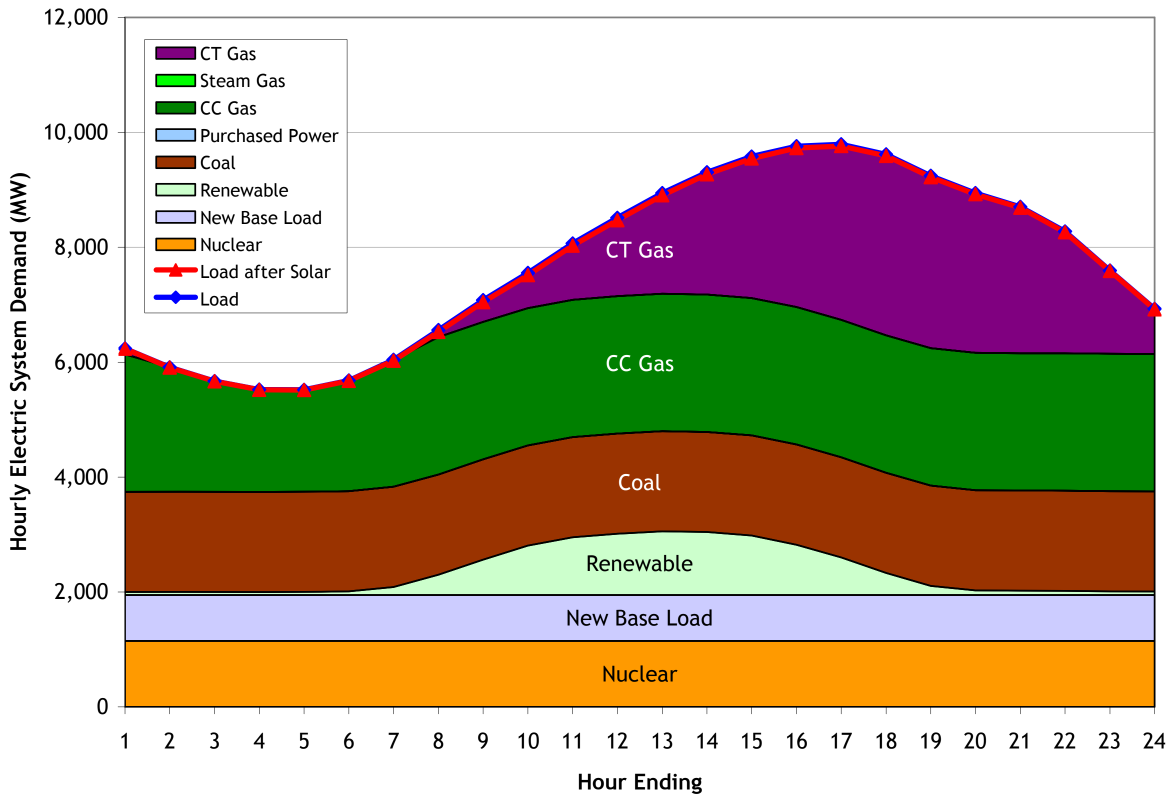


Figure 5-4 depicts the same conditions for the High Penetration Case. As seen in this figure, the solar DE energy under the High Penetration Case is projected to reduce operation of both natural gas-fired peaking and combined cycle resources. As such, while the total cost reduced for the High Penetration Case is larger than that for the Low Penetration Case (produced by the larger quantity of solar energy), the average value of the energy avoided through the High Penetration Case is lower.

Figures 5-3 and 5-4 readily demonstrate a characteristic common to utility resources and programs that reduce load – the most valuable implementations for the utility are typically the first increments installed and each increment thereafter has a lower marginal value to the utility.

Figure 5-4: Typical Summer Day Dispatch, APS Base Case & High Penetration Case, 2025

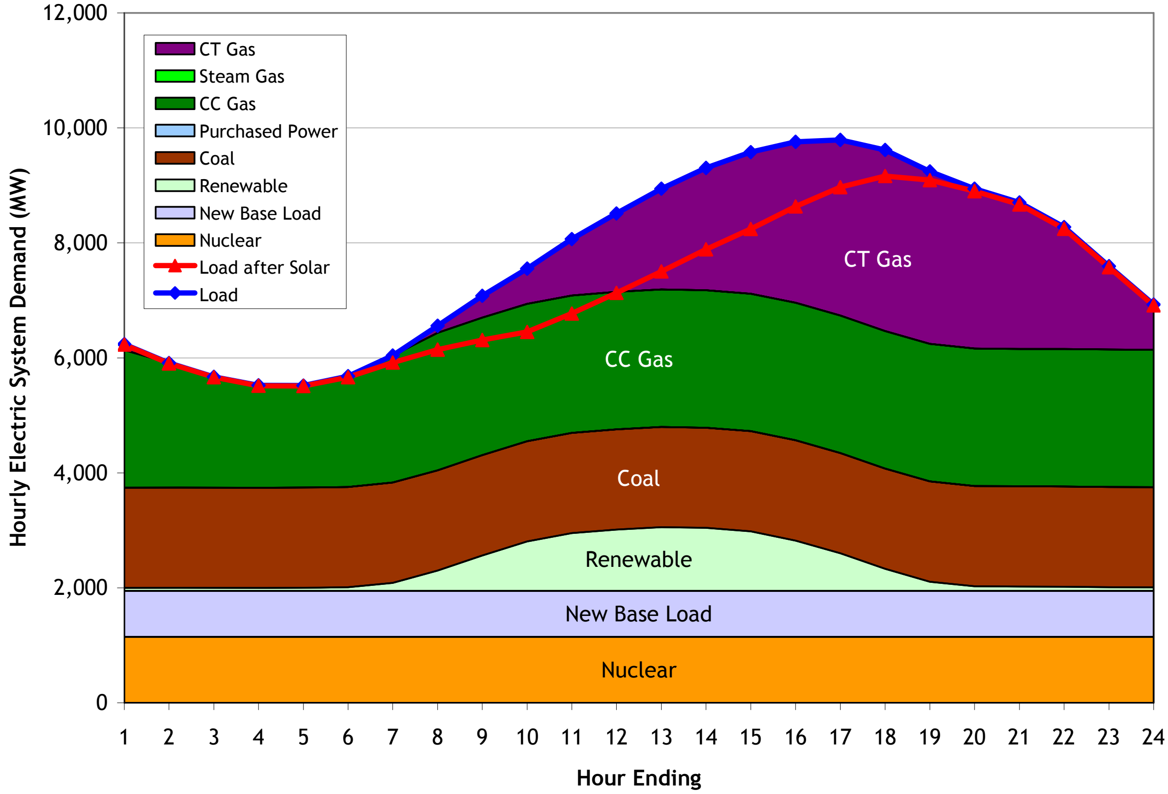
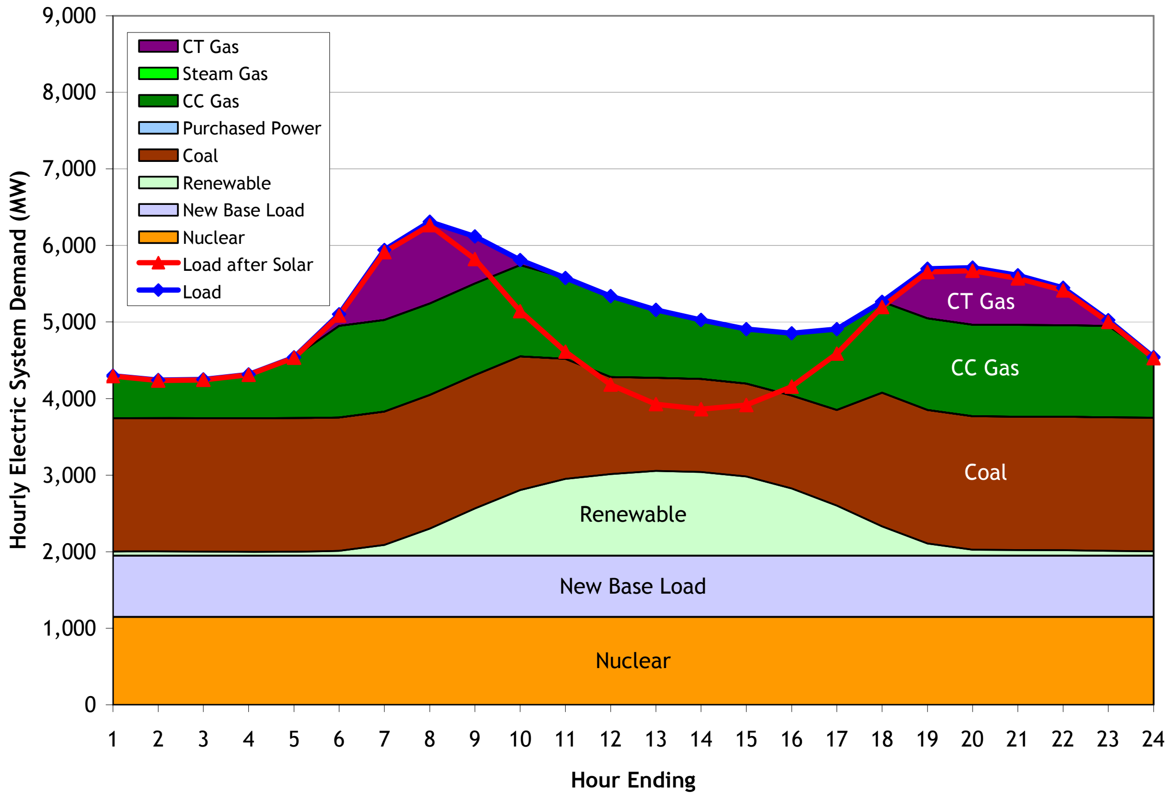


Figure 5-5 depicts resource commitment and dispatch patterns projected for a typical winter day in 2025 for the High Penetration Case. Winter days have load characteristics that are very different than a typical summer day. Winter loads on the APS system tend to peak both in the morning and in the evening, complicating decisions on resource commitment. It is common for utilities faced with a dual daily peak to dispatch intermediate and peaking resources to serve the morning peak and then not need these resources again until the evening peak. While peaking resources can sometimes be started, stopped and restarted in this manner, operating constraints such as minimum permitted cycling times and start costs many times prohibit shutting intermediate resources down during the middle part of the day. As such, as load drops off in the middle of the day, intermediate resources ramp down to their minimum permitted operating capacity and additional generation reductions must come from a lower-cost resource, many times a coal-fired or similar low variable cost resource.

During the winter, the peak output of the solar DE resource is antithetic to the APS system loads in the middle of the day. Solar DE energy is increasing as system load are declining in the late morning, then as load is increasing in the evening, solar DE energy is declining. As such, solar DE energy exacerbates the issues that APS already faces regarding unit commitment and dispatch in the middle of a winter day. Moreover, the variable operating costs that APS can avoid through solar DE energy in the middle of a winter day may reflect a much lower marginal value (may include the cost of coal-fired generation) than experienced during the summer. With increasing levels of solar DE implementation, APS can expect to experience such diminished value during many more hours and days of the year.

Figure 5-5: Typical Winter Day Dispatch, APS Base Case & High Penetration Case, 2025



5.3.3 Projected Avoided APS Energy Costs

Using the results of the PROMOD dispatch simulation provided by APS, with adjustments as described above, the Study team assessed the value derived for each of the solar DE cases. The avoided energy costs reflect differences in variable operating costs between the APS base case resource plan and each of the solar DE implementation cases, as described in Section 5.2.2. Avoided energy costs reflect changes in fuel costs, variable O&M costs, emissions costs, and power purchases created from changes in resource commitment and dispatch simulated in PROMOD for each of the Study years. Table 5-13 summarizes the results of the avoided energy cost analysis.

Avoided energy costs have been reported for total system energy impacts and incrementally for marginal energy losses. In reality, APS commits and dispatches resources to serve the total electric system load as experienced at the generation level, which includes customer loads with losses. However, since marginal losses are a significant component of the total avoided energy costs for the solar DE resources, a separate tally has been provided for the marginal losses.

Table 5-13
Avoided Energy Costs

	2010	2015	2025
Low Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	17.3	106.2	176.0
Total Avoided Energy Cost, Incl. Losses (2008 $000)	936	5,606	8,547
Average Avoided Energy Cost (2008 $/MWh)	54.13	52.79	48.56
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	1.9	11.3	18.6
Avoided Cost of Marginal Energy Losses (2008 $000)	102	501	701
Average Cost of Marginal Losses (2008 $/MWh)	54.36	44.31	37.67
Medium Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	18.1	180.8	1,788.6
Total Avoided Energy Cost, Incl. Losses (2008 $000)	980	10,100	96,596
Average Avoided Energy Cost (2008 $/MWh)	54.17	55.87	54.01
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.0	19.5	188.9
Avoided Cost of Marginal Energy Losses (2008 $000)	108	1,034	8,659
Average Cost of Marginal Losses (2008 $/MWh)	54.90	53.14	45.84
High Penetration Case			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	18.1	180.8	3,862.6
Total Avoided Energy Cost, Incl. Losses (2008 $000)	980	10,100	182,009
Average Avoided Energy Cost (2008 $/MWh)	54.17	55.87	47.12
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.0	19.5	390.2
Avoided Cost of Marginal Energy Losses (2008 $000)	108	1,034	14,529
Average Cost of Marginal Losses (2008 $/MWh)	54.90	53.14	37.23
Single-Axis Sensitivity			
Avoided System Energy Costs (Including Losses):			
Solar DE Energy (GWh at Generation)	19.1	188.0	4,045.7
Total Avoided Energy Cost, Incl. Losses (2008 $000)	1,031	10,578	188,846
Average Avoided Energy Cost (2008 $/MWh)	54.11	56.27	46.68
Avoided Marginal Energy Losses:			
Avoided Marginal Energy Losses (GWh)	2.1	20.3	407.2
Avoided Cost of Marginal Energy Losses (2008 $000)	114	1,074	14,925
Average Cost of Marginal Losses (2008 $/MWh)	54.81	53.04	36.66

5.4 Impact of Solar DE on Ancillary Service Requirements

5.4.1 Description of Ancillary Services

In addition to avoiding resource expansion and marginal energy production, solar DE resources may have an impact on system requirements for certain ancillary services. Ancillary services can generally be described as the amount of generating capacity that APS must have committed but constrained from running at optimum output to assure that sufficient reserves are available to meet contingencies that may occur on the system.

Electric utilities are required to provide a variety of ancillary reserves in order to maintain reliable operation of the electric system. These reserves generally fall into the following categories.

- Spinning Reserves – Requirement that each electric utility maintain a certain amount of generating capacity committed (operating) but not fully dispatched so that the utility can instantaneously meet system contingencies, such as the loss of a generator or major transmission interconnection.
- Operating Reserves – Requirement to maintain a certain amount of non-operating (uncommitted) capacity ready to be operated within a few minutes time (typically within 10 to 30 minutes) to handle major system contingencies.
- Regulation Reserves – Portions of committed generating resources that are reserved to meet the moment-by-moment fluctuations in utility loads. Regulation reserves are also used to meet the significant growth and decline in utility loads that occurs each morning and evening, respectively, and sometimes in the middle of winter days (as seen in Figure 5-5).

The concern for solar DE resources is that APS requirements to provide ancillary services may increase as solar DE implementations increase. Spinning and regulation reserves are many times provided by the largest, most efficient dispatchable resources owned by the electric utility. Generating resources that provide these ancillary services must be constrained from operating at their optimum performance, causing total variable cost of the utility to be higher than would otherwise be the case if no ancillary services were required. As a result, if solar DE were to increase APS's requirements for ancillary services, then their value to APS would be diminished.

For instance, a cloud passing over a solar PV array would cause the power output to stop and then resume, causing in turn the load displaced by solar to suddenly increase and then decrease. Such fluctuations in load could require APS to provide for additional regulation reserves anytime the solar DE resource was expected to be operating.

5.4.2 Impact of Solar DE on Spinning & Operating Reserves

APS could incur additional requirements for spinning and operating reserves related to solar DE installations if it was believed that a large portion of the solar DE resources could suddenly stop producing electricity (other than normal daily production patterns), thereby requiring another APS resource to provide the missing electric power.

One likely event that would cause a significant loss of solar DE output is the effect that an approaching storm front would have on solar PV and daylighting systems on the APS system. As the cloud cover associated with the frontal boundary moves across the APS electric system, PV and daylighting installations behind the cloud front would be shaded, thus reducing or eliminating the output from these facilities. The electric load that was originally served by the facilities would now need to be served by other APS generating resources. Similar, although possibly smaller, effects could be experienced from major thunderstorm events or merely increasing cloud cover. If the weather event was unanticipated, it could cause APS to rely on resources providing spinning and operating reserve to make up the shortfall of electric supply from the solar DE resources.

However, discussions with APS reveal that their system operators – APS staff that manage and administer the moment-to-moment operation of the electric system – monitor and predict the impact and timing of storm fronts on the APS system quite well. So long as the system operators have accounted for the quantity of solar DE on the APS system, APS believes that they should be able to reasonably predict the impact of a storm front on solar DE operation and, subsequently, on the electric system. They believe they will be able to commit and dispatch resources sufficient to manage potential adverse effects that weather events may have on solar DE operation and the electric system.

Another possible event that would cause a significant loss of solar DE output was discussed in Section 4 where an under- or over-frequency condition could cause a significant number of inverters for solar PV installations to trip off-line. However, such conditions would be rare since they effectively represent a double contingency event. As a result, PV inverter trips are typically not treated as a condition for which APS is required to maintain reserves.

While there may exist other events that could cause a significant number of solar DE resources to simultaneously stop producing, the two events described are thought to represent the preponderance of potential causes. As such, solar DE installations are not anticipated to result in a significant increase in spinning and operating reserve requirements for APS. However, because the quantity of solar DE electricity production is projected to be greater than the current levels of spinning reserves maintained by APS in some hours, the utility should carefully weigh its ability to predict and manage such events when determining whether to increase its spinning and operating reserve requirements as solar DE levels increase on the APS system.

5.4.3 Impact of Solar DE on Regulation Reserves

Regulation reserves represent the quantity of capacity that APS must have committed and available to meet instantaneous, moment-to-moment variations in load. These variations are generally caused by customer appliances and equipment turning off and on in unpredictable patterns. Much of the variability observed for any individual customer will be mitigated across the electric system since all customer loads do not turn on or off simultaneously. However, net variability in total load can still be large, varying by as much as 2 to 3 percent of the average load within an hour under normal operations. Variability is usually worse in the morning and evening hours when load is growing or declining significantly.

With regard to solar DE installations, the concern is that fluctuations in the output of individual or small groups of solar DE facilities could increase the variability already observed in system loads. Any increase could require APS to carry more regulation reserves, which would increase APS's operating costs. Variability in solar DE facility output could be caused by forced outage events (random electronic or mechanical failures of the solar DE facility) or by weather events, such as a random passing cloud. However, it is also anticipated that the distributed nature of the solar DE installations and the natural non-coincidence of outages that would occur across a large number of solar DE facilities could effectively mitigate the variability that might be observed for any one solar DE resource.

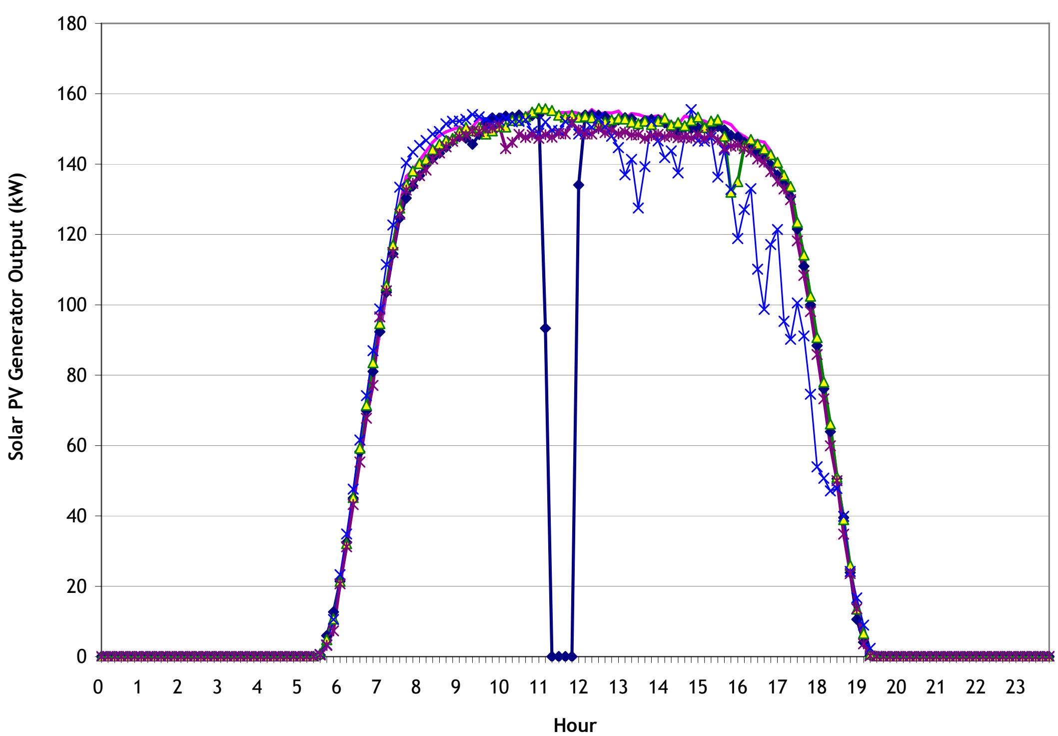
To appropriately evaluate the impact that solar DE facilities have on APS regulation reserves, it would be necessary to track a statistically significant sample of solar DE facilities randomly distributed over the entire APS service area. Data from these facilities would need to be monitored and recorded continuously, down to perhaps one-minute intervals for at least one year.

Such data does not currently exist. However, APS has been tracking data for a small sample of solar facilities in its service area for over a year. While not a statistically viable sample, the data provided by APS was analyzed to determine if any preliminary indications of solar DE facility impacts on regulation reserves could be derived.

The Study team examined the solar facility generation data provided by APS recorded over 2007 for 16 existing solar PV generation facilities located in the APS service area. Data for these facilities was recorded on 10-minute interval basis, which, while longer than appropriate for evaluating regulation reserve requirements, should be sufficient to examine intra-hour variability of solar facility operation. These observations included four installations located in close proximity, which were combined to control for the fact that they would likely be similarly impacted by localized weather conditions.

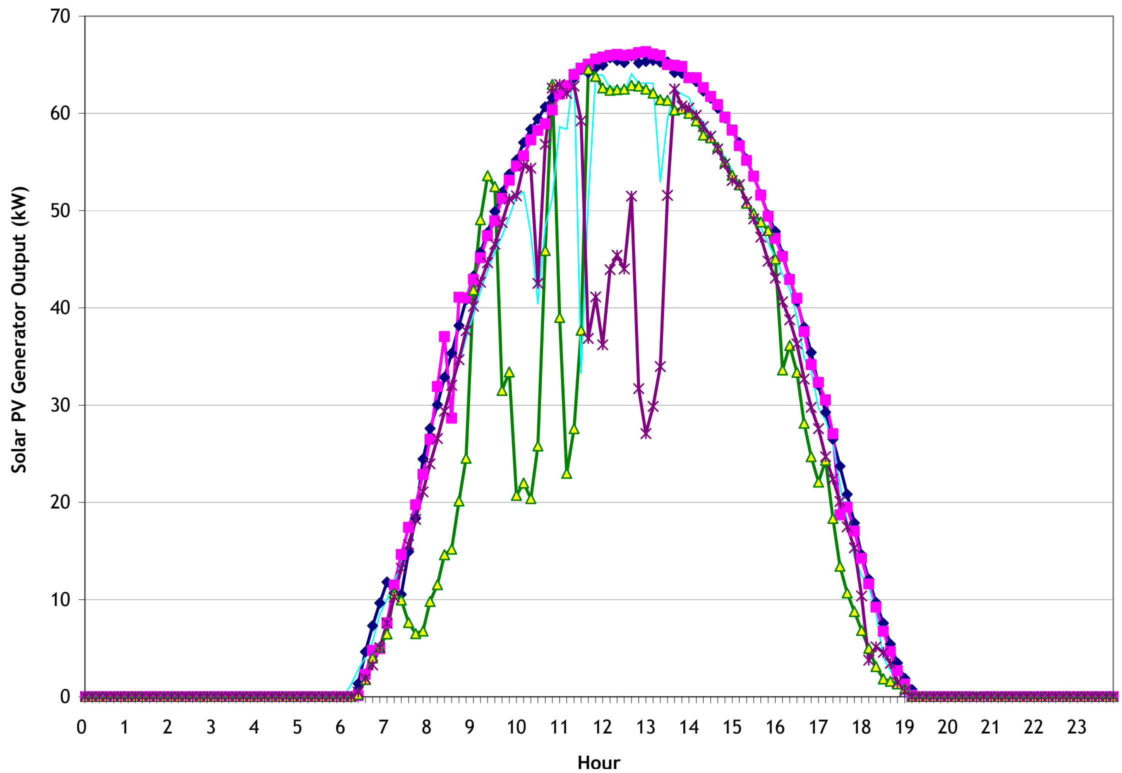
Figures 5-6 and 5-7, below, depict generation output for two selected PV facilities as measured over 10-minute intervals for several consecutive days. The facility depicted in Figure 5-6 is a single-axis tracking installation, while the facility depicted in Figure 5-7 is a fixed plate installation. The lines on these figures represent multiple days of output from the facilities. The specific days are not relevant to the analysis conducted; however, as seen in the figures, significant variability in solar PV output is possible.

Figure 5-6: Typical Output, Single-Axis Tracking PV, Multiple Days, 10-Minute Interval



Note: The output values above represent the "typical" output from a single-axis tracking PV system over multiple days. The specific days represented by the lines above are not relevant to the point that there can be significant variability in solar PV output.

Figure 5-7: Typical Output, Fixed Plate PV, Multiple Days, 10-Minute Interval



Note: The output values above represent the "typical" output from a fixed plate PV system over multiple days. The specific days represented by the lines above are not relevant to the point that there can be significant variability in solar PV output.

To perform the data analysis, the Study team developed an approach that compares the variability of the output of a single monitored installation to the variability of the aggregate output of all available monitored installations. The specific approached used for the analysis is described below:

1. The 10-minute output data for each of the 13 solar facility sites were unitized to the maximum output for any 10-minute interval in each month, meaning that each 10-minute output value within a month was divided by the monthly maximum to achieve a value ranging from zero (0) to one (1). For each site, the unitized data was averaged across each month for each 10-minute interval to achieve a "smoothed output curve." This smoothed curve was then re-based to a unitized shape.
2. The 10-minute output data for each site was also unitized to the daily maximum output to produce daily "normalized output curves" to compare to the smooth output curves. The daily normalized output curves were subtracted from the smooth curves, and the standard deviation of the difference across each month and 10-minute interval was then computed to approximate the volatility of each solar facility's actual output.
3. An aggregate solar output series was also created by averaging the monthly unitized shapes of the individual sites for each 10-miniute interval, which provided for equal weighting

across the generator sites. The resulting aggregate profile was then processed for daily normal and smooth monthly patterns in the same manner as used for the individual sites, from which the difference was computed and analyzed to determine the standard deviation for the aggregate series across each month and 10-minute period.

The analysis showed that the standard deviation of the interval solar output for the aggregate series is approximately one-half that of average standard deviation for the individual solar facilities. This result demonstrates a significant reduction in variability for just the 13 sites distributed across the APS system. It could reasonably be expected that as the number of solar installations increases, the variability of the aggregate sites would continue to diminish. It is also recognized that any measure of variability would likely asymptotically approach some lower limit as generator sites were added to the analysis. In other words, the level of regulation reserves required for the solar DE installations is not likely to be zero; however, insufficient data is available to determine the asymptotic result.

The analysis was also limited by data quality. The solar output data for many of the facilities were missing periodically and, for a few sites, for periods of multiple days at a time. In addition, the data appeared erroneous in limited instances. The analysis was carried out in a manner that effectively excluded or corrected for these instances to a great extent, but undiscovered erroneous data may still have impacted the analysis.

APS should consider expanding its metered solar dataset to permit a more complete analysis of this issue. Alternatively, APS could consider the simulation of geographically distributed, short duration meteorological events, coupled with a solar DE forced outage simulation, and incorporate these simulations within an evaluation of actual APS regulation reserve requirements. Such an analysis could permit a simulation of solar DE impacts on regulation reserve requirements.

SECTION 6 — DEVELOPING A WINNING BUSINESS CASE FOR SOLAR DE DEPLOYMENT

A winning business case for solar DE deployment must demonstrate quantitative value and address the many qualitative issues in order to achieve success.

Arizona's successful solar future requires an alignment between the business considerations, economic drivers, market readiness and societal needs. In order for solar DE to take its place along side traditional thermal resources, a case needs to be developed that supports the expansion of solar DE across residential and commercial markets. The support has to include customer-side issues, such as readiness for product acceptance; utility-side issues, such as system integration; and business-side issues, such as the financial support for solar DE investment.

This section identifies a framework for assessing the value of solar DE deployment in the APS service territory. This assessment is based on the goals, analysis, and current information outlined in this Report. It includes a comprehensive assessment of the benefits to APS, its customers, and other stakeholders, while promoting a sustainable solar DE deployment program in Arizona.

Value has a number of dimensions, some of which are purely economic or engineering based (such as those driven by savings potential), and those which have an element of perception (such as the consumer desire to have a reduced environmental impact). A supportable winning business case needs to take into account both types of value.

The foundation for the assessment in this Study is built upon:

(1) A quantitative evaluation of the savings potential from solar DE deployment under the diverse scenarios defined in this Study.

(2) A qualitative assessment of various factors and measures that could be undertaken to help further solar DE deployment sufficient to achieve the RES objectives in a financially and socially responsible manner.

Value is also viewed and measured from the varying perspective of individuals, the utility, businesses, and society at large. It is the alignment of multiple perspectives of values that allows for creating a successful and winning business case for solar DE deployment in which all constituencies benefit, or are at least held whole, in the process.

This section of the Report describes the objectives of the valuation task, the approach used to assess the value of solar DE deployment in the APS service territory, the methodology employed, and the results of the task.

6.1 Objectives

A principal objective of this Study is to assist APS in developing a winning business case for the promotion of solar DE technology; one that balances the needs and concerns of APS, its customers, and other stakeholders. A winning business case requires that APS meet its responsibilities to its shareholders and ratepayers while making meaningful progress towards achieving the RES objectives in a financially and socially responsible manner.

For the many diverse interests to support such a program, it is imperative to formulate a broad and solid business case and strategy. This requires developing and evaluating a framework to review the alternative deployment scenarios discussed earlier in this Report; and assessing the benefits of solar DE deployment to APS, its customers, and other Arizona stakeholders while considering the costs and viability of solar DE deployment. The approach used in this Study also considers possible strategies to help APS achieve the RES goals, while enhancing value for the stakeholders. Enhancing value is a key step toward creating a successful solar future for Arizona.

6.2 Approach

The approach used to assess the economic value of solar DE deployment in this Study is relatively straightforward:

- Quantify the savings from avoided or reduced energy usage costs due to solar DE deployment, based primarily on reduced fuel and purchased costs.
- Quantify the savings from reduced capital investment costs resulting from solar DE deployment, including the deferral of capital expenditures for distribution, transmission and generation facilities.
- Estimate the present value of these future energy and capital investment savings due to solar DE deployment.
- Consider the impacts of various qualitative factors that will impact solar DE deployment.

There may well be a myriad of changes happening in the solar industry that will influence solar deployment and value over the next 15 years. Improved technology opportunities, significant cost reductions, research breakthroughs, increased dedication and commitment to renewable options, and many other factors, may prove to have great impact in the future.

The Study team, however, has attempted to remain philosophically aligned with proven and defensible data, technologies and analytics. The purpose of this disciplined approach was to establish a clearly endorsable and unambiguous identification of value for discrete and specific conditions.

It is fully anticipated that APS and others will be able to use this Study as a starting point to form and evaluate other possible scenarios and outcomes which would be appropriate and proper for other forums to explore. Certainly, there are many potential industry pathways. The value of this more confined approach to the quantifiable evaluation of solar DE deployment comes from establishing a solid foundation upon which all parties can then build, and creating a supportable framework for discussion among all parties.

6.2.1 Approach to Quantification of Saving

The approach used in this Study to develop a winning business case for APS starts with the quantified benefits resulting from the potential capacity and energy savings levels found in the Study analyses. The cost savings to APS would arise from two primary sources: future reductions in fuel and purchased power associated with reduced APS energy needs, and future capital investment reductions associated with deferred or avoid APS capacity. These provide the key ingredients of quantifiable savings from solar DE deployment in all three of APS's business sectors—distribution, transmission, and generation – as summarized in Figure 6-1.

Figure 6-1: Quantification of Savings

Certain potential savings associated with various environmental and societal costs and benefits not otherwise captured through regulated emission allowance costs and credits discussed in Section 5 were not explicitly included in this quantification effort. This approach was purposely used in an attempt to keep the Study effort focused on the more readily quantifiable and less speculative savings that are identified in the Study.

6.2.2 Approach to Identification of Qualitative Savings

A second element of the approach included consideration of various barriers to full deployment of solar DE market development and possible strategies to minimize, remove or surmount these barriers. Included in this consideration of important qualitative elements that could impact solar DE deployment in Arizona are the following:

- Clarification of social and institutional obstacles to full solar DE deployment.
- Identification of possible strategies or solutions that APS might take to address these obstacles.
- Non-economic considerations, such as customer conditions and perceptions regarding solar DE.

6.3 Methodology for Quantification of Savings

6.3.1 Quantitative Methodology Used to Value Solar DE Deployment

To estimate an annual economic savings in the target years of 2010, 2015, and 2025 for the APS distribution, transmission, and generation business sectors under the solar DE deployment scenarios, the first step was to separate capacity and energy savings. As previously discussed, this separation was made because capacity savings represent value in terms of either deferral or avoided investment costs by the utility, while energy savings represent both immediate and ongoing cumulative benefits associated with the reduction in energy requirements of the utility.

This methodology is consistent with the revenue requirement approach for capital investment economic evaluations developed by the EPRI more than 30 years ago and widely accepted in the utility industry[1]. The methodology recognizes all elements of a utility's cost to provide service, including energy components (fuel, purchased power, and operating and maintenance expenses and taxes) and capacity components (capital investment depreciation, interest expense and net income or return requirements). It measures reduced or avoided energy and capacity costs that APS will not incur if solar DE is successfully deployed.

Correspondingly, it measures the lower costs that future ratepayers of APS will see, and thus is the key quantifiable measure of value from solar DE deployment.

6.3.2 Value of Energy Savings

Future energy savings associated with solar DE deployment are readily identifiable through the simulation of APS's future costs to meet the energy needs in the target years of 2010, 2015, and 2025. As described in Section 5 of the Report, the operational cost savings for each business unit roll up to reduced fuel, purchased power, and losses associated with reduce production requirements on the APS system following solar DE deployment. Additional reductions in fixed O&M requirements for APS have been quantified and included as annual cost savings in this

[1] For a full description of this EPRI methodology, see the TAGTM Technical Assessment Guide, EPRI TR-100281, Volume 3: Rev. 6, December 1991, especially Section 8.

evaluation. These values were used to estimate annual energy savings and cost reductions for the total entire APS system at energy and operational levels.

As noted earlier, most solar DE savings are realized in terms of energy, as the capacity savings are limited by the time of day of APS's system peak demand, and to a lesser extent, by non-coincidental capacity demand reductions at the local distribution level. From a customer cost perspective, however, residential and commercial customers without demand changes will see the energy portion of their bill reduced as a direct offset for both energy and demand reduction in delivered energy from APS. As such, from an individual customer perspective it is the reduction in energy that is the primary factor in the establishment of value, rendered through reduced utility costs.

From the utility's perspective, however, the energy savings are not as important from a design of view, because the utility still has the responsibility to maintain a system capable of handling peak demand levels of its customers. Although the utility does realize system savings from reduced energy usage in terms of fuel reduction and lower line loses, it is the capacity costs associated with delivery of power at peak demand time periods that generally are of greatest concern to the utility.

The difference in costs and value reflected in these two perspectives – customer versus utility – that creates a considerable constraint on the fair evaluation of solar energy. This is inherently explored throughout this Report and addressed later in this section.

6.3.3 Value of Capacity Savings

The capacity savings associated with solar DE deployment requires a more complicated evaluation framework in order to calculate estimated savings for specific years. The identified reduction or deferral in total capacity investments in distribution, transmission, and power supply for the target years of 2010, 2015, and 2025 were presented in Sections 3, 4 and 5 of this Report. The corresponding annual reduction in APS's revenue requirements resulting from these capacity investment savings are estimated using carrying charges[2] calculated separately for each sector. Moreover, an appropriate carrying charge varies each year for a specific discrete investment made in a particular year. These carrying charges are primarily a function of the accumulated capital recovery or depreciation elements, as well as return on investment rate-base elements. These carrying charges generally decline over time as depreciation accumulates.

Because the specific year of avoided or deferred capital investment is both uncertain and difficult to clearly identify in the case of accumulated solar DE deployment savings, the Study used a levelized carrying charge for each utility sector to provide a reasonable estimate of annual capacity costs associated with capital investments. These levelized capacity carrying charges[3] for the APS distribution, transmission and generation systems are summarized in Table 6-1.

[2] The definition and calculation of the carrying charges for APS used in this study are discussed in Appendix N.
[3] The levelized carrying charge value represents approximately the same value as the 11th or 12th year carrying charge value for assets with 30- to 50-year lives such as most electric utility distribution, transmission, and generation investments entail.

Table 6-1
Levelized Carrying Charge by Functional Sector

	Distribution System	Transmission System	Generation System
All Years	12.06%	11.84%	11.79%

These carrying charges were used along with the capacity investment savings developed in the previous sections of the Report to estimate annual values associated with the avoided or deferred capital investment costs in the distribution, transmission, and generation sectors resulting from solar DE deployment. These annual capacity values were totaled for each sector and were then added to the annual energy and O&M savings for each target year in the Study.

It is possible that a reduction in capacity value can be particularly important in this analysis when the location can be defined and, thus, directly decrease the need for system improvement, removal of constraints or new construction. The ability and desirability of installing solar DE in strategic locations can potentially make a significant difference in the value of the solar DE deployment.

For example, under certain conditions, solar DE systems can affect savings both on energy and capacity value if located on a feeder with a known constraint. However, identifying specific feeders that have the ability to support the required amount of solar DE within APS's service territory could be challenging. This is because the characteristics of the customer types on the feeder typically vary from block to block. Targeting these customer types to install sufficient solar DE may be difficult.

In addition, storage capability had a notable impact on capacity value. SHW can be used to lower line losses and can defer some capacity generation needs, thus offering additional value to the utility. However, this value declines as the weather warms since the difference between incoming water temperature and the desired heated water temperature diminishes.

6.3.4 Total Annual Savings and Present Value of Savings

Annual energy, O&M and capacity savings values for all three sectors were calculated in the target years of 2010, 2015, and 2025. Each of these sector values were then added together to determine the total utility savings estimated to occur in these target years under the various solar DE deployment scenarios. These estimates are presented in both inflation-adjusted (2008 dollars) and nominal (escalated for inflation) terms. These tables provide ranges for the annual savings that would occur under various solar DE deployment scenarios.

The present value of these future energy and capacity savings as of the end of 2008 was calculated using APS's discount rate. This provides a range for the current economic values of the solar DE deployment options. More specifically, it represents a range of the estimated present value for the solar DE deployment scenarios that incorporates uncertainties associated with the various assumptions and time periods for solar DE deployment considered.

A more detailed technical discussion of the methodology and specific calculations used in the assessment of the value of solar DE deployment in provided in Appendix N.

6.4 Study Findings—Quantification of Solar DE Savings

6.4.1 Overview and Summary of Identified Savings

A number of key finding have been drawn during the course of this Study. For example, from a technical perspective, high density of solar DE deployment can allow greater numbers of residential customers to be on a single transformer, thereby representing some savings to the utility. Related to these findings, the Study found that the distribution system design cannot be fundamentally changed to reflect a significant amount of solar since it still needs to be sized to peak load conditions, but importantly that modern solar inverters do not create problems for the distribution system.

Some of the key findings identified in this Study include the following:

- Solar output is not coincident with peak demand for either the customer or the utility. This is critical when considering capacity considerations (either payments or incentives) as the impact is on the energy side of the equation, not capacity in any great measure.
- There is greater coincidence of solar and customer peak production for commercial class than residential class.
- There are diminishing returns as it relates to DE solar deployment (i.e., as the amount of solar DE increases, the incremental benefits decline, in terms of losses, capacity, and production costs).
- Since solar output peaks earlier than the load, steps that can shift solar output to later in the day increase capacity value.
- Single-axis tracking may also add significant value by shifting solar output to later in the day.
- Solar DE has a larger incremental value from losses than simply applying an average loss factor due to the exponential relationship of losses to current.
- Technology changes in solar DE energy storage could help extend solar output to meet APS's system peak.
- Energy storage can increase the capacity value, but at the expense of the capital costs and loss of efficiency associated with storage technologies.
- There is a limitation to the maximum capacity value for solar DE without storage. As the solar DE shifts the peak load hour from 5:00 PM to later, the solar output drops off quicker than the load (due to the setting sun). Therefore, while the peak load occurs later in the day, the contribution from solar DE generation is limited.
- For transmission system planning, there is a minimum amount of capacity that is needed to achieve significant value, which is roughly equivalent to one year's load growth for the area of study. The minimum would typically enable a one-year deferral of transmission related capital additions for that area of study. Dependable capacity below that threshold of one year's load growth has essentially zero capacity value.

6.4.2 Summary of Quantitative Findings

The analysis conducted for this section includes a review of the solar DE values from the previous sections for the distribution, transmission and generation functions. These findings include the value of the potential investment savings from capacity reductions along with fixed O&M savings from the generation system, the total annual energy savings from reduced fuel and purchased power costs due to reduced energy sales and reductions in losses, and the total annual savings (a combination of the two). These values are presented as discounted present value estimates for APS, as well as in nominal values. Analysis results are presented in total aggregate savings perspectives and also in related unit value ($/MWh) terms. The fixed and variable nature of the savings are also presented.

6.4.3 Capacity Cost Savings from Solar DE Deployment

Table 6-2 provides a summary of distribution system capital cost reductions associated with the deployment of solar DE. As noted in the table, no value was determined from the Market Adoption scenario (Low, Medium, and High Penetration Cases). In order to obtain capacity value for significant deferment of distribution investments, the distribution system requires that these solar installations be located on a specific feeder to reduce overloading, as discussed in Section 3. Table 6-2 also provides the marginal increased value associated with the single-axis tracking sensitivity. The first column in Table 6-2 represents the value of the distribution capacity cost reductions in the target years in which they occur. The second column is the carrying charge associated with the distribution functional sector for APS (see Table 6-1 above). The third column is the result of the capacity savings reduction times the carrying charge. As discussed in Section 3, these values are estimated from current capital costs in 2008 dollars associated with current distribution equipment costs.

Table 6-2
Capacity Reductions at Distribution Level (2008 $000)

	Distribution System	Carrying Charge (%)	Associated Annual Savings
Target Scenario			
2010	$345	12.06%	$42
2015	$3,335	12.06%	$402
2025	$64,860	12.06%	$7,822
Single-Axis Sensitivity			
2010	$345	12.06%	$42
2015	$3,450	12.06%	$416
2025	$67,045	12.06%	$8,086

Note: No quantified capacity value was identified for the Low, Medium and High Penetration Cases for the distribution system (see text for discussion).

Table 6-3 provides a summary of transmission system capital cost reductions associated with the deployment of solar DE. Unlike the distribution system, the specific location of the solar DE was not an impediment to obtaining value for the transmission system. However, due to the "lumpy" nature of improvements on the transmission system, as discussed in Section 4, a significant number of solar DE installations would be required to aggregate sufficient capacity demand reduction to avoid or defer transmission system costs. Therefore, the calculated transmission capacity savings values occur only in the last target year (2025) and for the High Penetration Case. As in Table 6-2, the first column represents the value of the transmission capacity savings in 2008 dollars, the second column is the transmission carrying charge, and the third column is the associated annual savings.

Table 6-3
Capacity Reductions at Transmission Level (2008 $000)

	Transmission System	Carrying Charge (%)	Associated Annual Savings
High Penetration Case			
2010	$0	11.84%	$0
2015	$0	11.84%	$0
2025	$110,000	11.84%	$13,024

Note: No quantified capacity value was identified for the Low and Medium Penetration Cases for the transmission system. Additionally, transmission capacity savings reductions are not dependent on specific location, so the Target scenario resulted in the same values as the High Penetration Case. Additionally, the single-axis sensitivity (not shown) did not increase the capacity value associated with transmission.

Table 6-4 provides a summary of generation system capital cost reductions associated with the deployment of solar DE. Similar to the transmission system capacity savings, the specific location of solar DE was not an impediment to determining value for the generation system. Additionally, similar to the transmission system, capacity cost reductions for the generation system require a significant aggregation of solar DE installations, which occur only in the later years of the Study period. Unlike the transmission system however, generation capital cost reductions were determined to exist for the Medium and High Penetration Cases. Similar to the previous tables, the first column represents the value of the generation capital cost reduction in 2008 dollars, the second column represents the generation system specific carrying charge, and the third column represents the resulting associated annual savings.

Table 6-4
Capital Cost Reductions at Generation Level (2008 $000)

	Generation System	Carrying Charge (%)	Associated Annual Savings
Medium Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$184,581	11.79%	$21,762
High Penetration Case			
2010	$0	11.79%	$0
2015	$0	11.79%	$0
2025	$299,002	11.79%	$35,252

Note: No avoided capital costs for generation were identified for the Low Penetration Case. Capital cost reductions for generation are not dependent on specific location, so the Target scenario (not shown) resulted in the same values as the Market Adoption scenario - High Penetration Case. Additionally, the single-axis tracking sensitivity (not shown) resulted in the same capital cost reductions as the High Penetration Case.

6.4.4 Annual Energy and Fixed O&M Savings

Table 6-5 provides a summary of the potential annual savings (in 2008 dollars) from a reduction in fuel and purchased power costs resulting from reduced energy requirements and associated reductions in line losses and annual fixed O&M costs. Generally, these savings were found to exist for all deployment cases, with the exception of reduction in fixed O&M costs for the Low Penetration Case. Additionally, the specific location of the deployment of solar DE was not a determinant for these value characteristics.

The values determined for the annual energy savings (including the reduction in losses discussed in Section 4 and the reduction in fuel and purchased power costs discussed in Section 5) are a direct result of the output from the solar DE installations. As more solar DE technologies are installed, the greater these values become. The reductions in fixed O&M costs are related to the reduction in demand for the dependable capacity for the generation analysis (discussed in Section 5). The Target scenario was not included below because the results are identical to the High Penetration Case (because the Target scenario is focused on specific locations of solar DE on the distribution system, which impacts the capacity savings, but not the energy savings). The single-axis sensitivity is included in the table below and results in slightly higher energy savings for all target years in the Study.

Table 6-5
Annual Energy and Fixed O&M Savings (2008 $000)

	Reduction in Losses	Reduction in Fuel/ Purchased Power	Reduction in Fixed O&M Costs	Total Energy Related and Fixed O&M Savings
Low Penetration Case				
2010	$102	$834	$0	$936
2015	$501	$5,105	$659	$6,266
2025	$701	$7,847	$3,728	$12,276
Medium Penetration Case				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$8,659	$87,936	$18,946	$115,542
High Penetration Case				
2010	$108	$872	$0	$980
2015	$1,034	$9,066	$1,351	$11,450
2025	$14,529	$167,480	$20,965	$202,974
Single-Axis Sensitivity				
2010	$114	$918	$0	$1,031
2015	$1,074	$9,504	$1,546	$12,124
2025	$14,925	$173,921	$21,444	$210,290

6.4.5 Total Annual Savings

Table 6-6 provides a summary of the total solar DE deployment savings by for the Market Adoption (Low, Medium, and High Penetration Cases), and the Target scenario (this is the sum of the values presented in Tables 6-2 through Table 6-5). The difference between the Market Adoption scenario and the Target scenario is that the later requires that the solar DE to be located at specific feeders.

These results indicate that there is more solar DE deployment savings (both terms of total energy and total value) with higher levels of deployment. The higher dollar savings in the Target scenario represents the incremental benefit to the distribution system related to the location specific installations (shown in Table 6-2). The estimated total energy savings (in MWh) are identical for the High Penetration Case and the Target scenario. The single-axis sensitivity includes marginally higher total savings, for both dollars and energy, which reflects the marginally higher output associated with those systems.

Table 6-6
Total Solar DE Savings (2008 $)

	Total Solar DE Savings (2008 $000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
Low Penetration Case			
2010	$936	17,301	$54.13
2015	$6,266	106,196	$59.00
2025	$12,276	176,009	$69.74
Medium Penetration Case			
2010	$980	18,099	$54.17
2015	$11,450	180,777	$63.34
2025	$137,304	1,788,610	$76.77
High Penetration Case			
2010	$980	18,099	$54.17
2015	$11,450	180,777	$63.34
2025	$251,250	3,862,585	$65.05
Target Scenario			
2010	$1,022	18,099	$56.47
2015	$11,853	180,777	$65.56
2025	$259,072	3,862,585	$67.07
Single-Axis Sensitivity			
2010	$1,073	19,061	$56.29
2015	$12,540	187,977	$66.71
2025	$266,652	4,045,697	$65.91

Note: The Target scenario recognizes the contribution to the dollar savings from the capacity cost reductions in the distribution system (which requires specific solar DE locations). However, the energy savings (in MWh) for this scenario is the same as for the High Penetration Case (see text for discussion).

APS presents much of its resource evaluation information in nominal dollar terms. Table 6-7 provides a summary of the same solar DE deployment savings presented in Table 6-6 but in nominal year dollar terms (i.e. including the effects of future inflation estimated at 2.5 percent per year).

Table 6-7
Total Solar DE Savings (nominal $)

	Total Solar DE Savings (nominal $000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
Low Penetration Case			
2010	$984	17,301	$56.87
2015	$7,448	106,196	$70.13
2025	$18,679	176,009	$106.12
Medium Penetration Case			
2010	$1,030	18,099	$56.91
2015	$13,611	180,777	$75.29
2025	$208,924	1,788,610	$116.81
High Penetration Case			
2010	$1,030	18,099	$56.91
2015	$13,611	180,777	$75.29
2025	$382,307	3,862,585	$98.98
Target Scenario			
2010	$1,074	18,099	$59.32
2015	$14,089	180,777	$77.94
2025	$394,209	3,862,585	$102.06
Single-Axis Sensitivity			
2010	$1,127	19,061	$59.14
2015	$14,906	187,977	$79.30
2025	$405,743	4,045,697	$100.29

Note: The Target scenario recognizes the contribution to the dollar savings from the capacity cost reductions in the distribution system (which requires specific solar DE locations). However, the energy savings (in MWh) for this scenario is the same as for the High Penetration Case (see text for discussion).

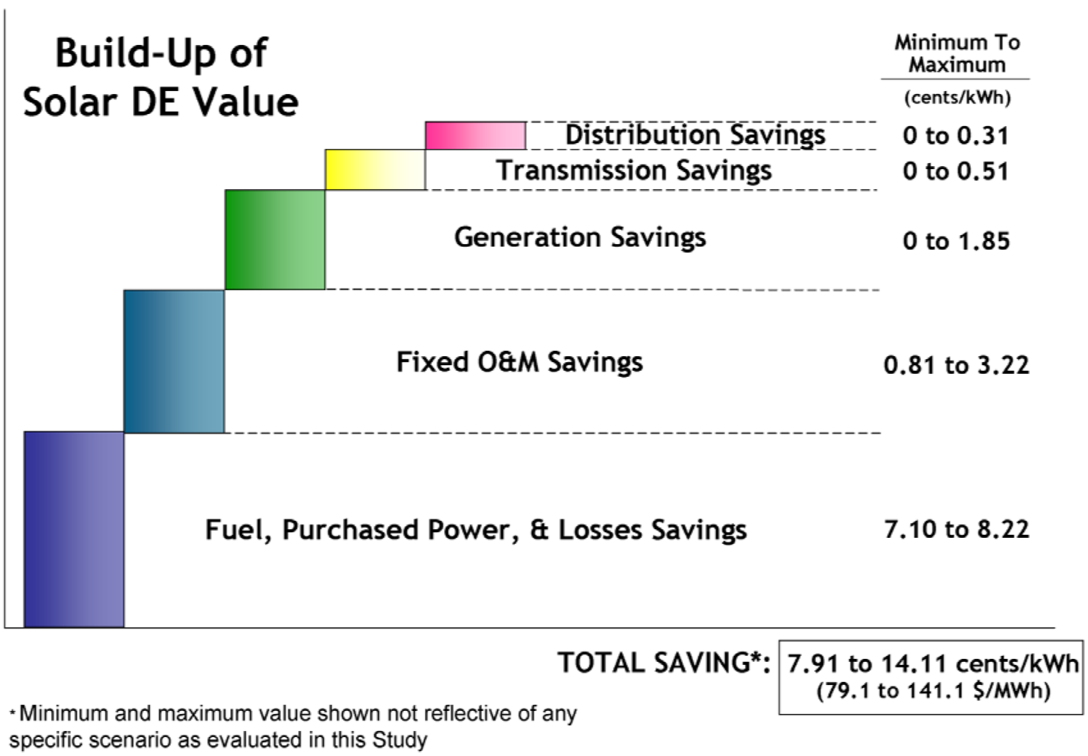
The results shown in Tables 6-6 (2008 dollars) and 6-7 (nominal dollars) demonstrate the reduction in marginal value as total energy from solar DE technology is increased (the "Law of Diminishing Returns" concept discussed in Section 4). As more solar DE technology is installed, the estimated total savings increases (both in the total dollars of savings and the total energy [MWh] savings). However, the increase is not linear and the unit savings ($/MWh) decrease with increased levels of solar DE deployment.

An example of this can be seen in a comparison between the Medium and High Penetration Cases for 2025. The total savings in dollars (both for 2008 dollars and for nominal dollars) is higher for the High Penetration Case, as are the total energy savings (MWh), however, the unit savings for the High Penetration Case is lower than the Medium Penetration Case ($98.98/MWh compared to $116.81/MWh for the nominal results).

The results also indicate that while there is a higher value associated with the Target scenario compared to the High Penetration Case (due to the capacity reduction for the distribution system), the increase on a unit basis is not significant (approximately 3 percent increase in value on a unit basis). Additionally, the results indicate that the single-axis tracking sensitivity provides marginally higher total solar value (for both dollars and energy) compared to the High Penetration Case; however, the unit savings are marginally lower than those for the Target scenario.

A build-up of the functional elements of the value from solar DE deployment developed in this Study for 2025 are represented graphically in Figure 6-2.

Figure 6-2: Elements of APS's Solar DE Savings in 2025



The build-up of value suggests that the relative magnitude of value varies tremendously, as indicated by the range of values shown in Figure 6-2. These results suggest that the value from the savings in fuel, purchased power and losses is the largest driver of value (ranging from about 90 percent of the total savings at the minimum and about 60 percent of the total savings at the maximum). It should be noted that the build-up of solar value presented above is not confined to any specific deployment, rather it represents the minimum and maximum values determined in year 2025 for all deployment scenarios across the functional areas identified in the Study.

6.4.6 Present Value Estimates

Table 6-8 provides a summary of the total solar DE deployment savings in present value terms. As indicated above, the results in the preceding tables were presented in both 2008 dollar and escalated nominal dollar terms for events that are projected to occur in future years. There is uncertainty related to both the many assumptions used in and necessary for preparing these analyses. To assess these values from a perspective addressing this uncertainty, the savings estimates were discounted using the APS specific discount rate. The present value savings are provided in total and unit cost ($/MWh) terms.

Table 6-8
Solar DE Savings (Present Value)

	Total Solar DE Savings Present Value ($000)	Estimated MWh Savings	Estimated Unit Savings ($/MWh)
Low Penetration Case			
2010	$846	17,301	$48.88
2015	$4,385	106,196	$41.29
2025	$5,160	176,009	$29.32
Medium Penetration Case			
2010	$885	18,099	$48.92
2015	$8,014	180,777	$44.33
2025	$57,718	1,788,610	$32.27
High Penetration Case			
2010	$885	18,099	$48.92
2015	$8,014	180,777	$44.33
2025	$105,617	3,862,585	$27.34
Target Scenario			
2010	$923	18,099	$50.99
2015	$8,295	180,777	$45.89
2025	$108,905	3,862,585	$28.19
Single-Axis Sensitivity			
2010	$969	19,099	$50.84
2015	$8,776	187,977	$46.69
2025	$112,091	4,045,697	$27.71

6.4.7 Fixed and Variable Savings Estimates

Table 6-9 provides an analysis of the fixed and variable nature of the estimated savings associated with solar DE deployment. It separates the variable savings from the total energy related savings (from Table 6-6), less the fixed O&M savings (if any), divided by the total solar DE savings. The fixed savings are then the remaining percentage (i.e. 1 minus the variable savings percent). Any capacity cost savings are included in the total solar DE savings, but not in the energy related savings, and therefore are part of fixed savings.

As indicated in the tables above, the primary driver of value for solar DE deployment is the reduction in fuel and purchased power (discussed in Section 5). While the capacity cost reductions do add value, they are highly dependent on the number of solar DE installations, as well as the specific location of these installations for the distribution system.

The results indicate that for the larger deployment cases (Medium and High Penetration Cases, as well as the Target scenario and single-axis sensitivity), the savings associated with solar DE deployment are overwhelmingly from variable energy savings rather than fixed capacity savings. For the Low Penetration Case, where there are less savings overall, the value is roughly one-third fixed and two-thirds variable (for 2025).

Table 6-9
Fixed and Variable Cost Savings of Solar DE Savings (%)

	Fixed Savings (%)	Variable Savings (%)
Low Penetration Case		
2010	0.0%	100.0%
2015	10.5%	89.5%
2025	30.4%	69.6%
Medium Penetration Case		
2010	0.0%	100.0%
2015	11.8%	88.2%
2025	29.6%	70.4%
High Penetration Case		
2010	0.0%	100.0%
2015	11.8%	88.2%
2025	27.6%	72.4%
Target Scenario		
2010	4.1%	95.9%
2015	14.8%	85.2%
2025	29.7%	70.3%
Single-Axis Sensitivity		
2010	3.9%	96.1%
2015	15.6%	84.4%
2025	29.2%	70.8%

6.5 Qualitative Findings—Factors Affecting Solar DE Deployment

6.5.1 Identified Potential Obstacles to Full Solar DE Deployment

The following are some of the potential obstacles identified during the course of this Study that might impede full solar DE solar deployment in the APS service territory.

- Solar DE capacity savings would increase from the values provided in this Study if efficient energy storage technology existed.
- Deployment must be concentrated in specific areas for there to be significant deferred distribution capacity savings, and possibly improved transmission capacity savings.
- The existing customer mix in specific areas may not be adequate to support solar DE deployment.
- Under current ratemaking practices, increased solar DE may increase power costs to non-solar DE customers because APS need to recover fixed costs over reduced energy sales. More of the fixed costs will be borne by non-solar DE customers.
- Zoning limitations, geography and customer preferences may also limit the optimal orientation of solar DE technology necessary to achieve adequate demand reduction sufficient for measurable distribution capacity savings.
- Current rate structures provide most solar DE customers (those without demand charges) with savings that are not necessarily consistent with APS's cost savings associated with solar DE deployment.
- There is considerable misunderstanding, mythology and opinion that affect the clarity of strategies and pathways forward for solar DE deployment. This condition complicates customer understanding of the APS's limitations for recognizing the value of solar DE technologies.
- Study results show that payback period is a key driver to solar DE adoption. In turn, payback is highly sensitive to numerous externalities (such as federal ITC policy, the pace of declining technology cost and the institution constraints) over which APS has little or no control.
- The current economic downturn in the housing market as well as the recent decline in world oil costs will impact solar DE deployment in new building developed for the 2010 and 2015 study periods, and may also influence the long term deployment of solar DE technology.
- The ability of maximize value of solar DE deployment in a greenfield development is diminished by many factors, including zoning, homeowner association covenants, ownership issues related to PV or other solar assets, developer versus builder relationships, etc. Solar development in a greenfield-opportunity areas will be most likely be driven by market "pull" factors rather than by home-builder or customer "push" factors.
- The requirements of the RES goals appear to outstrip the current capability of markets to supply or install solar DE resources. Current installation capacity may be in line with

current demand, but assuming increases from successful marketing programs, rebate opportunities and customer pull, additional resources will be required.

- Current research does not provide an adequate understanding of consumer behavior (for both residential and commercial customer classes) regarding the desire for solar DE systems or their willingness to pay for these solar systems.
- Alternative financing programs for provision of residential solar equipment (e.g., long-term leasing) have yet to receive widespread acceptance..

6.5.2 Possible Solutions to Alleviate Obstacles to Full Solar DE Deployment

The following are various possible changes or solutions that could occur in the near term, or that APS or other stakeholders in Arizona might consider to alleviate obstacles likely to hinder full solar DE deployment in the APS service territory.

- Improved solar DE storage technology could significantly increase the capacity reduction value of DE solar power and add dependability, especially in the distribution sector.
- Expanded use of AMI technology could provide proper indicators of customer value regarding solar DE technology. AMI could also increase load control options related to solar DE deployment, and improve understanding of usage that could in turn permit new standards to allow islanding for reliability purposes.
- Improved DSS modeling and analysis may provide planners better data on solar DE system impacts, and more precise understanding of the impacts at the local distribution level.
- Exploration of alternative rate structures to ensure revenue stability associated with reduced sales (through basic or customer charges, or the use of demand rates for residential and small general service customers).
- The concepts of increased strategic locations of solar DE (such as in the Yuma service territory) and teaming with builders need to be explored further.
- Public education on solar DE—its benefits, proper application, pitfalls, and cost impacts—should be a high priority for APS to help ensure more successful penetrations and customer acceptance.

6.6 Other Factors Impacting the Value of Solar DE Deployment

As with many markets, the successful implementation and expansion of solar DE requires the coincidence between the needs of customers, the provision of technology, and a financial model that supports the economic need. The absence of any of these three criteria can result in a lack of demand, undersupply of product or service, or the inability to obtain the funding necessary to sustain the market development.

The Study has focused primarily on the monetary values involved in solar DE deployment. This economic view is a cornerstone for any forward-looking opportunities to promote major gains in solar DE deployment in Arizona. However, a strictly financial perspective may be too limited. This perspective ignores customer conditions or perceptions that may change the market. Solar system prices, for example, may be too high on a purely economic basis until they reach a tipping point in terms of quantity which, in turn, drives costs lower. That tipping point may be achieved either through subsidies or market pull or a combination of both.

A winning business case needs to build upon broad scale solar energy deployment and market maturity to be successful. Achieving this success necessarily involves taking into account value factors beyond strict economics. The winning business case involves multiple benefits.

6.6.1 Customer Pull and Perception

The perceived value of solar DE can be as high, or higher, than the financial. As larger segments of the public become attuned to issues in the environment their willingness to pay a premium expands. This has been evidenced in multiple areas from green power premiums to hybrid vehicles.

Customers may also exhibit willingness for engagement in solar installations for reasons beyond the financial, since it directly impacts one of their largest investments: their homes, their businesses, or both. They must devote roof space, be accepting of the visual change in appearance (especially for residences), and be willing to take on an additional technology which over time requires servicing and repair.[4] In some areas, homes with solar DE may also have a higher value, either perceived or real. Empirical results from solar communities in California support this premise. Some developers are working on “net zero” communities which they hope will draw additional buyers willing to pay a upfront premium for the offsetting benefit of lower utility bills into the future, as well as supporting a more sustainable environmental lifestyle.

Similarly, in some communities financial institutions have offered energy efficient home buyers increased borrowing capacity based on the theory that reduced energy bills allow for better cash flow. There still needs to be additional work done in this regard, as well as in working with appraisers to capture the value of the solar system in the assessment of home prices.

6.6.2 Carbon Credit

There remains great uncertainty as to the outcome in assigning value to carbon, with an enormous disparity in assumptions about carbon prices and the method for capturing the value. Regardless of price, the assumption is that carbon will be monetized either through a carbon tax or a cap-and-trade program. Moving beyond the theoretical, there are unanswered questions as to who will capture the financial benefit: the customer (business or end user), utility, or a third party owner of the solar DE system.

Calculating the value of carbon will be important economic factor in the later years of the Study as the number of solar DE systems grows and begins to impact future generation planning. As can be seen in other sections of the Report, solar value is captured in reduced line losses, avoided system expansion and reduced purchases of thermal energy. While it may be the utility capturing the value of the reduced losses and avoided system costs and passing it through to the customers, it may be the customers themselves picking up the carbon reduction credits.

In today’s market, the value of carbon reduction through solar installations is still qualitative and difficult to capture, however, it is not a static situation. Currently, there is uncertainty in

[4] Some solar providers such as Sun Edison are offering turnkey, maintenance-included options.

legislation and regulation regarding carbon. However, in the future, there will likely be an assignable economic value to carbon which will accrue somewhere along the value chain. For the purpose of the analyses in the Study, carbon value was captured in Medium and High Penetration Cases in the parameter for APS Tariff projection.

6.6.3 Market Transformation

Several critical barriers exist for APS to meet its RES and to create a successful business case. The elimination of these barriers will require both long term fundamental changes in the market and the proper stimulation of conditions to encourage solar DE development. Most of these market transformation efforts are beyond sole control of APS, but can be encouraged with the right combination of economic, policy, political and business strategies. APS is clearly not the creator of these barriers; some are technological, others practical, and still others typical of nascent markets.

The optimum[5] potential for solar DE is hindered by a number of factors and the solutions need to reach across a wide collection of stakeholders. Some of these factors, such as in the area of energy storage, are broad issues which require massive amounts of investment. Timing, panel improvements and product availability are similarly global issues that impact the market and cannot be managed by APS.

There are, however, possibilities for market stimulation and transformation where APS and others can play a more direct role in building demand and availability for solar DE. The following are some general concepts that should be explored.

Codes and Standards

A powerful tool that has been successfully deployed at the state and federal level is the adoption of new building requirements. In California, for example, Title 24 changed the building codes to require energy efficiency in all new construction as well as in major retrofits. This helped drive the marketplace resulting in significant reductions in energy consumption. Similarly, Federal regulation around appliance standards has resulted in reduced energy and water use.

Arizona could consider making all new construction "solar ready," setting the baseline standard for residential and commercial buildings. This could also give special consideration to those communities that opt for a certain percentage of SHW and daylighting through tax incentives. The requirements could be phased in over a number of years allowing builders to move through their current stock of housing.

Commercial building codes could also be changed to require rooftops be built to specifications that allow for solar DE installations (particularly for multi-access tracking) and to require daylighting be considered as part of the permitting/plan process.

Current land use requirements could also be altered to facilitate harvesting greater benefit from greenfield areas. Dramatic future growth projections for new planned urban development offer Arizona a unique opportunity to promote and integrate solar DE in emerging communities. However, the opportunity is diminished by zoning, land use, and special exemption processes

[5] Optimum is from the utility perspective in that at some point the addition of solar DE does not bring value to the utility or ratepayers, although this is potentially far off from the current projections.

that offer no advantage in solar DE promotion, and may actually diminish acceptance. Policy transition and resulting changes in zoning and permitting could benefit or hinder the winning business case.

Institutional Support

In some jurisdictions, homes with superior energy efficiency are awarded lower mortgage rates because the homeowner will be paying lower utility bills and, therefore, will theoretically have additional cash flow to make mortgage payments. Facilitating this change in Arizona will require working with banks and other lenders in proving the efficiency of the solar DE systems.

Concurrently, the current appraisal community needs to be educated as to the value of a solar DE system in order to be able to conduct accurate assessments of a home or business value. There is a need to ensure that the appraisers understand solar DE systems are a positive, not negative, improvement to the home. Increased home values due to the inclusion of solar PV or SHW will tie to the banking community's understanding and willingness to support larger, and/or lower cost, loans.

New Business Model

During the course of the Study, the stakeholders confirmed many market changes underway in business models and approaches. For example, third party equipment leasing and ownership is becoming more common for commercial installations and may become the norm. This change in business model may be replicated in an effort to address any of the three prerequisites for the winning business case, namely the market, the technology, and the financing. By way of example, Southern California Edison developed a new business model to meet its distribution transformer needs. Instead of relying on traditional market purchases, it entered into the international transformer supply chain to facilitate the raw materials acquisition and fabrication of over one million distribution transformers to meet its system rehabilitation efforts.

APS may consider a new business model in which it directly provides services that help promote solar DE market development. These could include such services as financial programs, technology development, and supply partnerships, as well as design, billing and field support for the installation of solar DE rooftop units in conjunction with the marketplace.

6.6.4 Installation Challenges and Opportunities

Alignment of solar deployment with a winning business case and successful market drivers will require a significant expansion of solar installation capabilities. Current installation capacity may be in line with current demand, but assuming increases from successful marketing programs, rebate opportunities and customer pull, additional resources will be required.

Hitting the RES goals will require the installation of between approximately 18,000 and 400,000 solar DE systems between 2009 and 2025. This represents a large increase in the number of installers in order to take advantage of the demand. In turn, this will require significant investments in training and education. Currently, the installation community in the APS territory is between 10 and 40 installers, each with a maximum capacity of 1 to 2 systems per day. This will undoubtedly grow over time as demand rises, but the challenge is to pace the demand and the addition of new installation resources.

The expansion of "green jobs" such as these will be a net positive for the economy and a cornerstone of a winning business case. This is another example of an alignment between the needs of the market and a range of potential benefits, from economic to environmental.

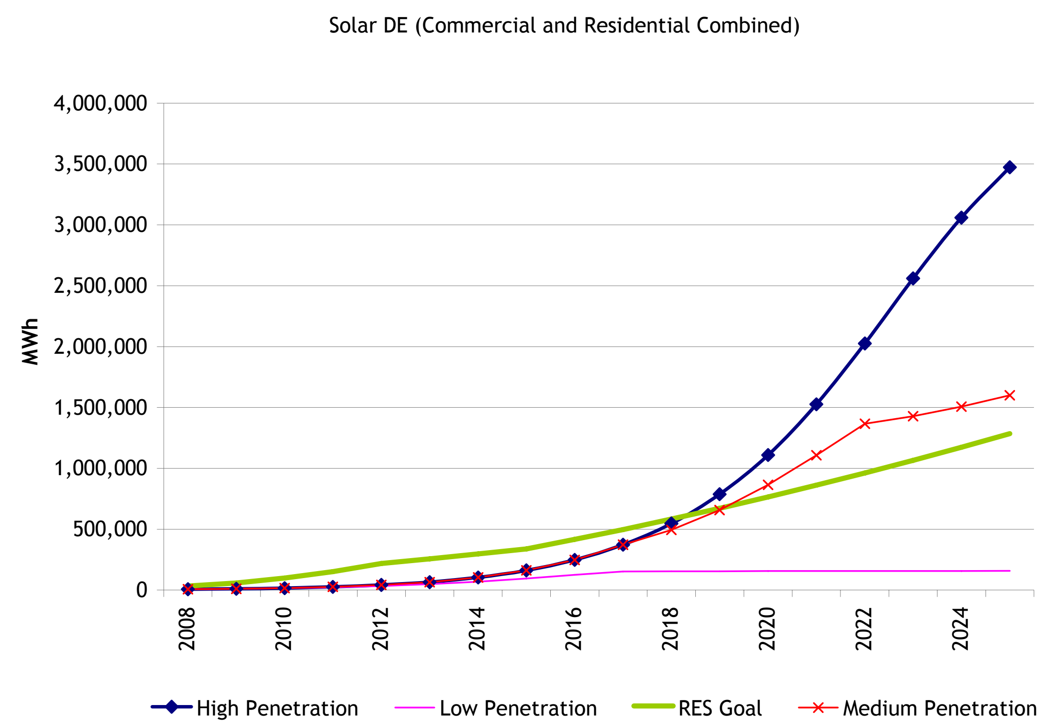
6.7 Semi-Strategic Scenario Options

At the beginning of the Study, there was an expectation that a subset of the targeted, or strategic opportunities might become apparent for APS to pursue. As the market deployment cases expanded to encompass essentially the full range of market uptake, the results diminished the opportunities for intermediate value targets. The results clearly indicate that broad market adoption under the most favorable conditions, would offer high value without the necessity to strategically site solar DE. Almost all (about 96 percent) of monetary value in distribution, transmission and power supply comes from system-wide solar DE deployment.

Importantly, under even the best solar DE deployment forecast, there is a shortfall in achieving the RES solar DE goals in the early years. As a result, the semi-strategic scenario focused on exploring options for improving the market response, thus accelerating deployment and reducing the gap between RES solar DE goals and anticipated solar DE penetration.

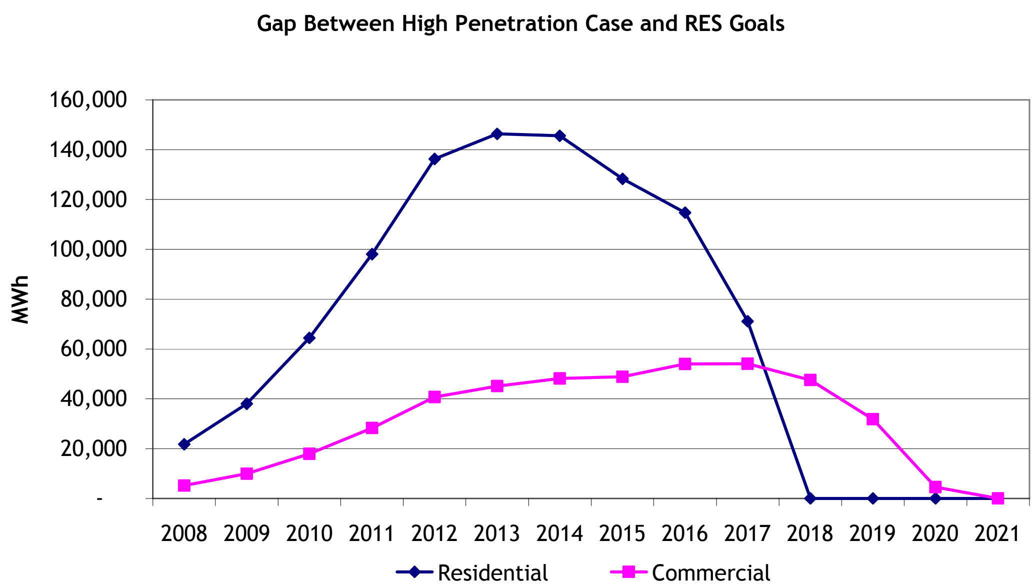
The gap in achieving the RES goal is primarily one of timing. As Figure 6-3 shows, total solar DE forecast will likely exceed the RES goals beginning around 2018 (for the High Penetration Case). Since the forecast total market adoption achieves – and surpasses – the RES goals, options must focus on ways to affect market behavior and accelerate adoption between the present and 2018.

Figure 6-3: Total Solar DE MWh Production Compared to RES Goal



More importantly, the adoption curve shows an inflection point in about 2012 at which point the increase in the annual gap begins to close. To visualize how the deployment "ramps up," the annual values are shown in Figure 6-4. Though the RES goals are stated in terms of total MWh production as a percent of total customer load, APS drives, maintains, and tracks separate internal goals for commercial and residential customer classes. All analyses in this Study have maintained this important distinction between residential and commercial goals consistent with APS.

Figure 6-4: Annual Residential and Commercial Gap against RES Goal



6.7.1 Types of Strategies

The options for accelerating solar DE production fall into two categories. Technical options focus on alternate technologies and on ways to increase the number of installations, or the output capacity of a single unit. Alternatively, there are numerous financial strategies. Influencing the financial attractiveness of solar DE reduces payback to customers and results in greater deployment. These strategies tend to focus more on affecting consumer behavior, and thus adoptions.

6.7.2 Technical Strategies

Community Development

Residential systems are individually small and each requires a full sales cycle. The residential curve in Figure 6-4 shows that the residential sector has a much more noticeable gap when measured against the RES goal. The natural pace of the residential market adoption falls far short of the RES goals. One strategy to accelerate adoption would be to concentrate on community solar DE development over individual premises, where a single sale and installation can yield greater results more quickly and controllably.

Discussions with stakeholders suggest developers and homebuilders would be interested in opportunities to promote community solar DE projects on common parcels or on less desirable sites. Single-axis tracking provides higher energy output than fixed plate arrays and installations are efficient and cost effective. Issues of ownership and incentive payments would need to be worked out with developers and homeowner associations (HOAs). Perhaps most importantly, the current economic downturn and slowed housing market needs to improve.

However, in a robust housing market, community development can have a notable impact in accelerating residential production against the RES goals. APS designs its substations for approximately 60 MW of load, and about 12 MW of load per feeder. In addition, the current design limits solar DE to approximately 15 percent of a feeder load. Thus, in a new planned urban development in a greenfield area, a development of 25,000 homes could support up to approximately 14 MW of community solar generation. This could generate up to 55,000 MWh of solar production annually, which is a substantial percentage of the RES goal shortfall.

Single-Axis Tracking

Single-axis tracking extends the hours that a PV panel can harness solar radiance. The increase in capital for both technology and installation is recovered by the increased energy production over fixed panels. Notably, new technologies are rapidly extending the application to flat elevated structures such as parking lots and increasingly, rooftops.

Energy production of tracking units shows an increase of 32 to 40 percent over fixed panels at 10 and zero percent tilt, respectively[6]. In addition to added energy output, the ability to extend production further into the late day offers capacity value to APS. The Study team calculated in Section 1 of this Report that there are about 3.2 million MWh of technical PV potential, calculated for 10 degree tilt commercial PV installations. Though it is certainly not feasible to completely substitute single-axis tracking units for flat plate collectors, the output difference at technical potential exceeds 1 million MWh. This is 20 times the gap between current commercial output and the commercial RES goal set by APS. Approaches that enhance the attractiveness of single-axis tracking over flat plate collectors could materially impact RES goal achievement.

6.7.3 Market Transformation Strategies

The charts shown below in Figure 6-5 were presented earlier but warrant revisiting. They show the adoption curves for residential and commercial customer segments under the three deployment cases. In all instances, the customer adoption shows the "S" curve that typifies consumer adoption for virtually all technologies. Options to influence this adoption curve result from moving the curve left (straight acceleration) or steepening the rate of rise for the early portion of the adoption curve. Both can be achieved by reducing the payback period for the consumer and thus accelerating the market development. Accelerating market adoption could include the following:

[6] Nominal results. Actual increase is diminished by a shading factor when individual panels block adjacent ones in early and late hours. Actual net MWh reduction requires additional analysis but does not materially affect the justification herein.

Address Greenfield Opportunities

As discussed previously, the greenfield potential for the developing areas in and around the APS service territory provides a unique opportunity to accelerate solar DE deployment above and beyond normal adoption rates. These developments, some planned for tens of thousands of homes, can promote solar or partially solar (and "green") communities by driving deployment through design standards, community marketing and shared benefits with homeowners. The scale of these developments and the opportunity to preempt adoption by "building in" some, or many, solar DE technologies holds tremendous opportunities for accelerating residential production goals. In reality, the current housing market downturn will likely diminish the near-term opportunities. However, this market segment will likely become more pronounced in the 2015 Study time frame.

Reward Early Adopters

As previously discussed, the "Law of Diminishing Returns" shows that the first unit of energy (MWh) of solar production is more valuable to APS than the last. There is an argument that an incentive structure that reflects this economic reality would incentivize early adoption. This is analogous to initiating a land grab, which would accelerate market deployment.

Another variation would be to consider rewarding larger systems. Encouraging larger sized systems, thus moving customers from a purely economic decision to a practical limitation based on roof space, would decrease the administrative cost per MWh while boosting net incremental production. This increasing incentive structure has been successfully employed in California.

APS as a Market Entrant

The adoption gap for both residential and commercial customers stems from the Study finding that payback period is longer in the early years. The market behavior also has less momentum given the lower cumulative installations of solar DE. Both of these issues can be addressed if APS becomes a market entrant. APS could stimulate the market in several ways, such as the following:

- Ease consumer adoption – Easy, streamlined, one-stop shopping will help move customers to early adoption. This is particularly focused on the residential market. Automobile leasing created a robust market by making leases easy and allowing customers to walk in and drive out. A similar approach that streamlines financing, contacting, installation and operation/maintenance could attract customers and build market momentum.
- Partner for the greenfield – The areas north and west of Phoenix shows significant growth projections in housing. APS could partner with home builders and developers to establish solar programs, such as 100 percent SHW heating and optional-sized PV systems.
- Partner with solar installation community – This is particularly suited to the commercial market segment. Even under the best conditions, the installation segment may face limitations in reaching all aspects of the market, accommodating installations, etc. APS may consider partnering opportunities that benefit the commercial installation sector and protect APS resources yet accelerate market adoption.

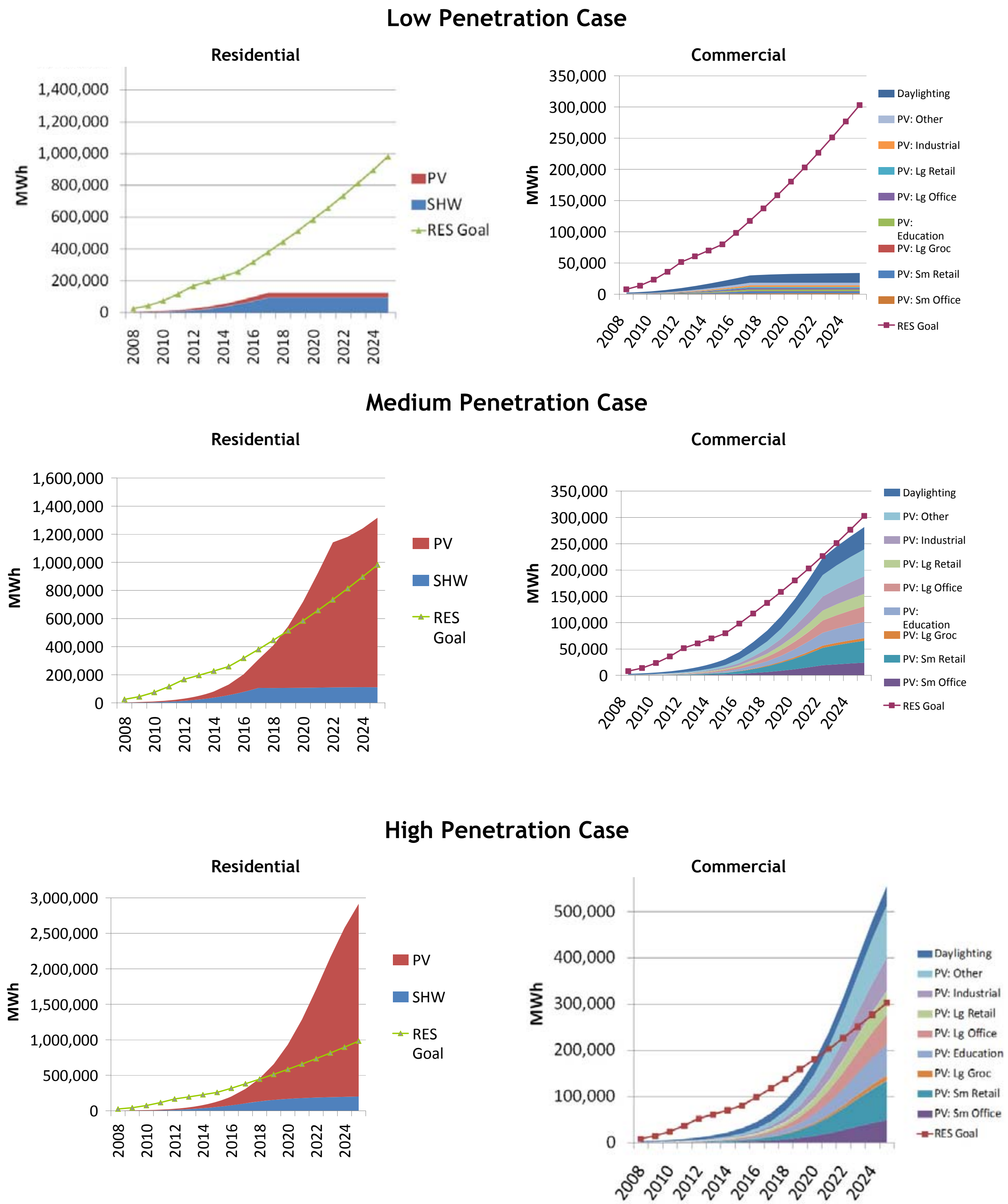
- Provide financing – Making technology procurement easy and transparent to the end customer will drive the market and increase uptake. Dell computers was hugely successful in increasing sales by making the purchasing experience fast and easy for millions of customers.
- Consider a creative business model – A broad option would be to consider development of a new business model in which APS provides the financing, billing and field support for the installation of solar rooftop units in conjunction with the marketplace. Based on numerous successful programs in SHW and other appliance provision models, APS could work with the local installation, supply and manufacturing community to provide its customers, particularly residential, with "no up-front cost" units.

  APS could be the provider of capital (allowed a rate of return on the investment), manage the installation field force (using local contractors) and offer billing as well as an ongoing service contract. The customers would benefit from having a no-hassle process for obtaining SHW and solar PV, ensuring the systems were operating properly, and offsetting the cost of the system with the monthly savings.

  After the systems were fully depreciated, the customers could have the option of buying the system along with a maintenance contract, or they could opt to continue paying a monthly fee for guaranteed service. The system would transfer with the sale of the house with the new owners either buying the solar DE out from the lease or continuing with the program.

  In addition to creating an easy way for systems to be deployed, the local contractor and vendor community would be supported, creating jobs and the potential for a constant stream of business.

Figure 6-5: Market Adoption Curves for Solar DE Technologies



6.8 Conclusions

The winning business case for solar DE in Arizona is a combination of hard, quantitative economic facts, such as the reduction of line losses, energy savings for customers, and reduced or deferred capital expenditures. But it also includes softer, qualitative benefits such as increased job opportunities for installers, a more sustainable environment, and as yet unquantifiable benefits that will likely become economic in the future, such as the value of carbon. The broader economic benefits would include improved worker productivity and a more robust solar DE manufacturing industry.

To capture the benefits of a winning business case it will be important to regularly monitor and report on the progress being made, and to look for opportunities to remove barriers to the successful expansion of solar in the state. It is the removal of those barriers and the movement toward the tipping point – where solar is the norm – that will prove the programs have become mainstream and part of a new energy future. The state of Arizona has a particularly important role to play in the future of solar energy.

APPENDIX A — GLOSSARY AND ABBREVIATIONS

Glossary of Terms

balance-of-system:	The remainder of the photovoltaic system, aside from the photovoltaic modules.
distributed energy:	Generation of electricity from many small energy sources, typically located near where it is used, perhaps even in the same building. Reduces the amount of power that needs to be generated in large centralized facilities, and reduces the size and number of power lines that must be constructed.
energy factor:	A measure of a water heater's overall energy efficiency based on the amount of hot water produced per unit of fuel consumed over a typical day.
greenfield solar project:	A solar project which is not constrained by prior work. It is constructed on unused land where there is no need to remodel or demolish an existing structure.
photovoltaic:	Using solar cells to convert sunlight directly into electricity.
power density:	Ratio of kW_{AC}/kW_{DC}.
solar energy factor (SEF):	The energy delivered by the system divided by the electrical or gas energy put into the system.
solar fraction:	The fraction of a building's water heating energy demand met by the SWH system.
Solar Heat Gain Coefficient (SHGC):	The fraction of the heat from the sun that enters through a window; expressed as a number between 0 and 1. The lower a window's SHGC, the less solar heat it transmits.

solar incidence:	The arrival of sunlight at a surface.
solar transmittance:	The amount of solar energy that passes through a glazing material, expressed as a percentage.
U-value:	A measure of how well heat is transferred by a window either into or out of the building. The lower the U-value number, the better the window will keep heat inside a building on a cold day. (Also called U-factor.)

Abbreviations

AC	alternating current
ACC	Arizona Corporation Commission
ACEEE	American Council for an Energy-Efficient Economy
ADOT	Arizona Department of Transportation
AMI	advanced metering infrastructure
APS	Arizona Public Service
ASHRAE	American Society of Heating, Refrigerating and Air-Conditioning Engineers
capex	capital expenditures
CBECS	Commercial Buildings Energy Consumption Survey
CC	combined cycle
CO_2	carbon dioxide
CT	combustion turbine
DC	direct current
DCT	dependable capacity for transmission
DE	distributed energy
DR	distributed renewable
DSS	Distribution System Simulator
EERE	U.S. Department of Energy's Office of Energy Efficiency and Renewable Energy
EF	energy factor
EPRI	Electric Power Research Institute
ES	Energized Solutions
EUDAP	End-Use Data Acquisition Project
GHG	greenhouse gas
GIS	geographic information system

GW	gigawatt
GWh	gigawatt-hour
IOU	investor-owned utility
kW	kilowatt
LOLE	loss of load expectation
LOLH	loss of load hours
LOLP	loss of load probability
MMBtu	million British thermal units
MVAR	mega-var (volt-ampere reactive)
MW	megawatt
MWh	megawatt-hour
NERC	North American Electric Reliability Corp.
NREL	National Renewable Energy Laboratory
O&M	operation and maintenance
PG&E	Pacific Gas and Electric
PTC	PVUSA Test Conditions
PV	photovoltaic
REC	renewable energy credit
RES	Renewable Energy Standards
RFP	request for proposal
SEF	solar energy factor
SEIA	Solar Energy Industries Association
SHGC	solar heat gain coefficient
SHW	solar hot water
SME	subject matter expert
SRCC	Solar Rating and Certification Corporation
STAR	APS Solar Test and Research Facility
T&D	transmission and distribution
TMY	Typical Meteorologic Year

APPENDIX B — CALIFORNIA PV PROGRAM

The analysis of trends associated with PV programs in the state of California focuses primarily on the incentive programs that have been administered by the three investor-owned utilities (Pacific Gas and Electric, Southern California Edison, and San Diego Gas and Electric). This data has been analyzed to determine if it provides insight into PV programs and PV installation characteristics such as number of systems installed by year, system sizes, and system costs. Ideally, the data will provide insight into the PV market based on system applications such as residential, office buildings, schools, etc.

Since 1998, the incentives that have been available for customers of the three investor-owned utilities have transitioned through several programs. From 1998 through 2007 incentives were available through the Emerging Renewable Program (ERP). In 2002 a new program that focuses on generation technologies for commercial customers was established and was known as the Self Generation Incentive Program (SGIP). In 2006, the state established the California Solar Initiative (CSI) and the New Solar Home Partnership (NSHP). Both the ERP and SGIP discontinued accepting new applications for PV projects starting on December 31, 2006.

Data sets available on the programs provide data on system locations (city and zip code), utility program administrator, system capacity, installed system cost, level of incentive, collector manufacture, inverter manufacturer, date the application was received, and the date that the incentive was paid. The data sets do not provide any information on customer class (i.e. residential, commercial, industrial). As a result, the data is useful for looking at trends in the number of installations, system sizes and installed system costs on a program level basis. The data is not useful to look at the characteristics of the target PV customer or the trends associated with various applications or building types where PV is being installed.

There is no intention to compare direct numbers of system installations or total installed capacity to the potential for Arizona as the two markets have significant differences in number of customers, overall demand, and electric consumption patterns.

Note that information in this appendix is provided for the purposes described above. There is no intention to compare direct numbers of system installations or total installed capacity to the potential for Arizona as the two markets have significant differences in number of customers, overall demand, and electric consumption patterns.

B.1 Number of Systems Installed

The following table presents an overview of the number of systems installed in California from 1998 through 2007. The data shows that the number of installations increases in nearly every year (there was a slight decrease in 2005). In 2007, more than 8,000 PV systems were installed and at the end of 2007 the total number of systems installed was 30,121. Note this data does not represent the total for the state as it only focuses on the programs administered by the investor-owned utilities. The shape of the cumulative installation curve indicates that the PV market is still in the early stages of market penetration and is growing.

Table B-1
Number of PV System Installations

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Energy Renewable Program (ERP):										
Pacific Gas and Electric	27	127	125	650	1,309	1,693	2,977	2,582	3,893	3,389
Southern California Edison	14	47	59	311	584	711	985	714	1,213	1,277
San Diego Gas and Electric	0	6	31	275	332	456	605	584	1,005	637
Total ERP	***41***	***180***	***215***	***1,236***	***2,225***	***2,860***	***4,567***	***3,880***	***6,111***	***5,303***
New Solar Homes Partnership (NSHP):										
Pacific Gas and Electric										2
Southern California Edison										
San Diego Gas and Electric										
Total NSHP	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***2***
Self Generation Incentive Program (SGIP):										
Pacific Gas and Electric	0	0	0	0	9	47	87	61	76	102
Southern California Edison	0	0	0	0	3	23	41	69	53	31
San Diego Gas and Electric	0	0	0	0	2	6	17	36	84	19
Southern California Gas Company	0	0	0	0	3	17	9	6	8	8
Total SGIP	***0***	***0***	***0***	***0***	***17***	***93***	***154***	***172***	***221***	***160***
California Solar Initiative (CSI):										
Pacific Gas and Electric										1,664
Southern California Edison										746
San Diego Gas and Electric										274
Southern California Gas Company										0
Total CSI	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***2,684***
Grand Total	**41**	**180**	**215**	**1,236**	**2,242**	**2,953**	**4,721**	**4,052**	**6,332**	**8,149**
Cumulative Number of Installations	**41**	**221**	**436**	**1,672**	**3,914**	**6,867**	**11,588**	**15,640**	**21,972**	**30,121**

Figure B-1. Annual Number of PV Installations in California

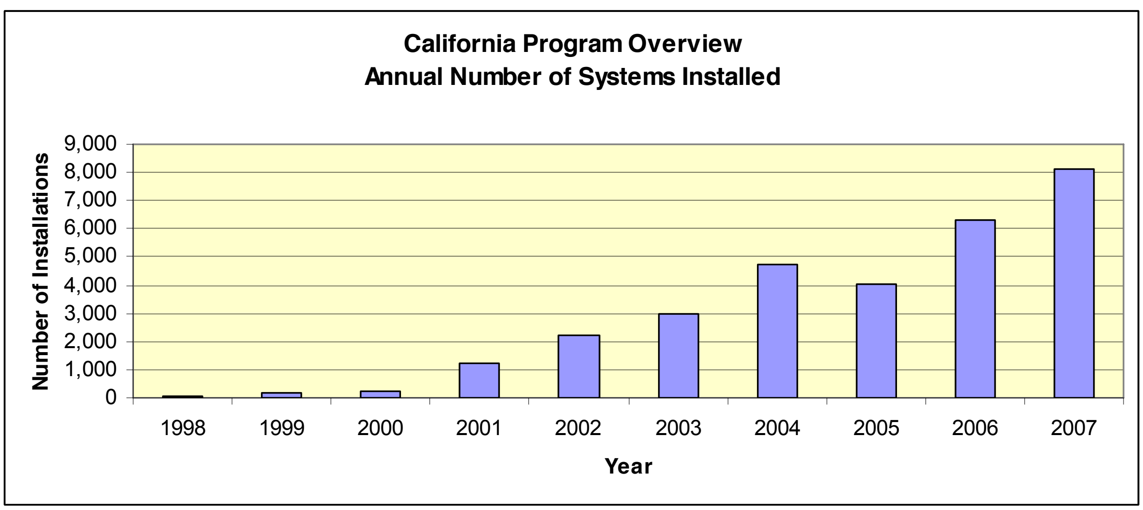
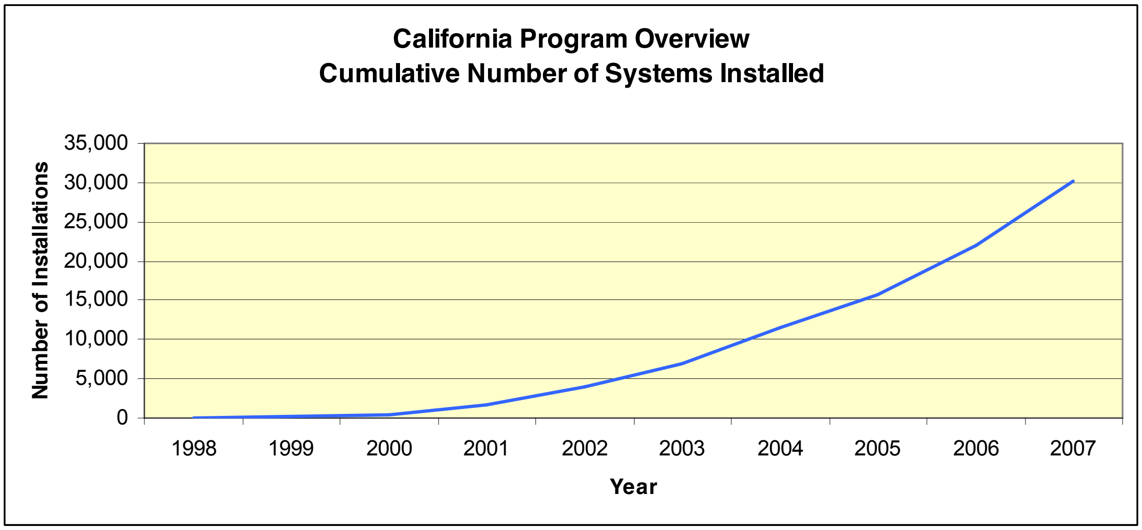


Figure B-2. Cumulative Number of PV Systems Installed in California



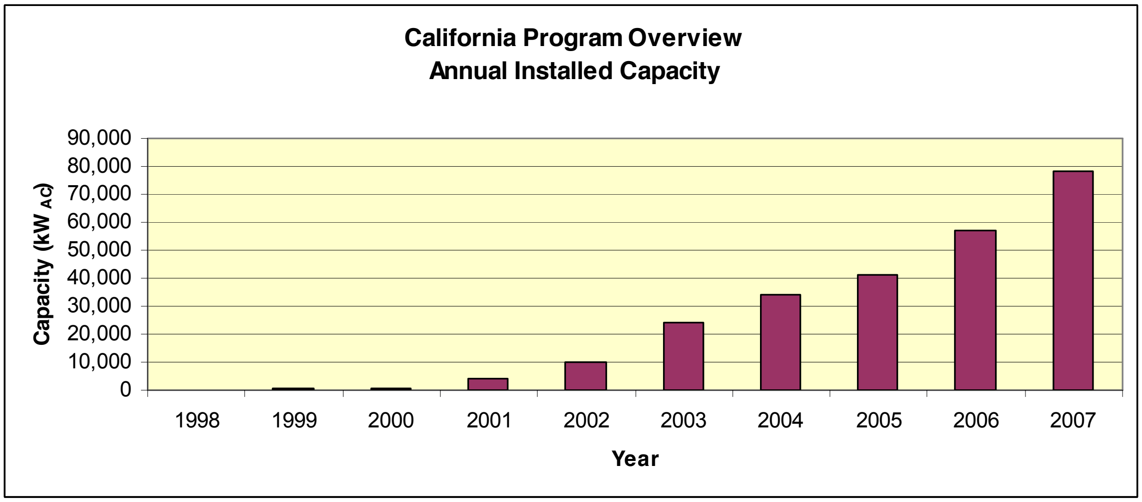
B.2 Installed Capacity

The data in the following table presents the installed capacity of the systems installed by the three investor-owned utilities. The data shows that the installed capacity has increased significantly year over year. The PV systems that were installed in 2000 represented a capacity of 726 kW and the systems that were installed in 2007 represented a capacity of 78,270 kW. That is to say that the rate of installed capacity in the state of California was 100 times more in 2007 than it was in 2000.

Table B-1
Installed Capacity of PV (kW)

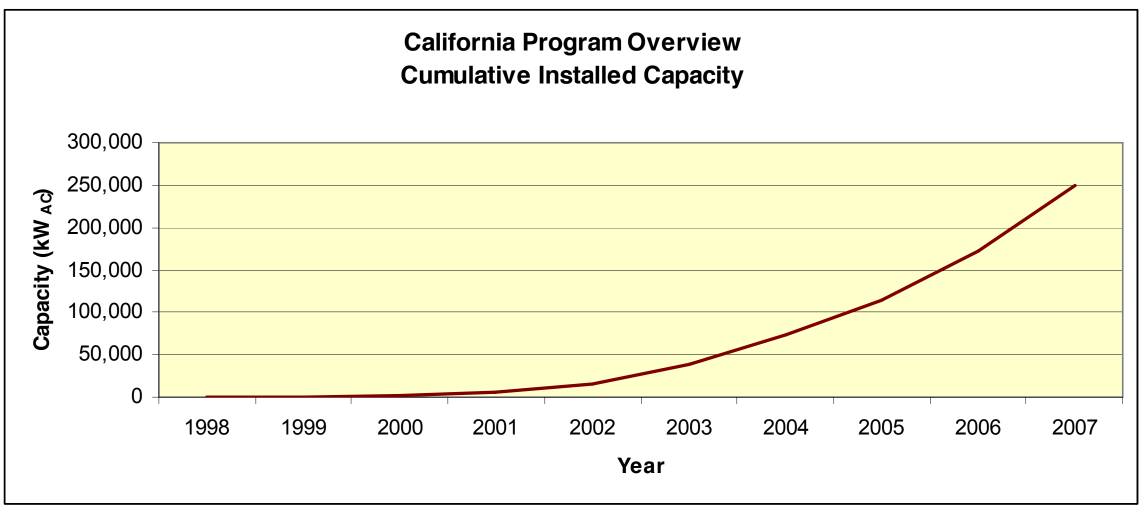
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Energy Renewable Program (ERP):										
Pacific Gas and Electric	61	360	487	2,041	4,951	7,418	11,909	11,643	19,365	16,909
Southern California Edison	120	250	133	1,118	2,108	3,156	4,617	3,521	6,277	6,496
San Diego Gas and Electric	0	10	106	866	1,042	1,675	2,319	2,044	3,393	2,657
Total ERP	***181***	***619***	***726***	***4,025***	***8,102***	***12,249***	***18,846***	***17,208***	***29,035***	***26,062***
New Solar Homes Partnership (NSHP):										
Pacific Gas and Electric										8
Southern California Edison										
San Diego Gas and Electric										
Total NSHP	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***8***
Self Generation Incentive Program (SGIP):										
Pacific Gas and Electric	0	0	0	0	1,671	4,208	10,178	12,950	14,535	16,921
Southern California Edison	0	0	0	0	114	2,649	3,149	6,306	6,290	10,560
San Diego Gas and Electric	0	0	0	0	74	1,971	947	4,028	6,404	3,989
Southern California Gas Company	0	0	0	0	132	2,790	802	716	577	1,530
Total SGIP	***0***	***0***	***0***	***0***	***1,990***	***11,618***	***15,076***	***24,000***	***27,806***	***33,000***
California Solar Initiative (CSI):										
Pacific Gas and Electric										8,334
Southern California Edison										9,411
San Diego Gas and Electric										1,455
Southern California Gas Company										
Total CSI	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***0***	***19,199***
Grand Total	**181**	**619**	**726**	**4,025**	**10,092**	**23,867**	**33,922**	**41,208**	**56,841**	**78,270**
Cumulative Installed Capacity	**181**	**800**	**1,526**	**5,551**	**15,643**	**39,510**	**73,432**	**114,640**	**171,481**	**249,750**

Figure B-1. Annual Installed Capacity of PV Systems in California



The following figure shows the cumulative installed capacity for PV under programs administered by the three investor-owned utilities. In 2007, these installations represented an electrical capacity of nearly 250,000 kW or 250 MW. The total for the entire state in 2007, including PV programs administered by municipal utilities, was 280 MW.

Figure B-2. Cumulative Installed Capacity of PV in California



B.3 Average System Size

Utilizing the data from the previous two tables, the average system size was calculated. The results are presented in the following table. The data shows that the typical size of systems installed under the ERP program were less than 5 kW and that the average size of system was getting larger. The data also shows that systems installed under the SGIP program were larger systems. The lowest annual average capacity systems were 36.9 kW (SDG&E in 2002) and the largest average capacity systems were 340.7 kW (SCE in 2007). In all but one year (2004), the average system size was greater than 100 kW. In 2007, the average system size of systems receiving an incentive was greater than 200 kW.

Table B-1
Average System Size (kW_{AC})

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Energy Renewable Program (ERP):										
Pacific Gas and Electric	2.3	2.8	3.9	3.1	3.8	4.4	4.0	4.5	5.0	5.0
Southern California Edison	8.6	5.3	2.2	3.6	3.6	4.4	4.7	4.9	5.2	5.1
San Diego Gas and Electric		1.7	3.4	3.1	3.1	3.7	3.8	3.5	3.4	4.2
Total ERP	***4.4***	***3.4***	***3.4***	***3.3***	***3.6***	***4.3***	***4.1***	***4.4***	***4.8***	***4.9***
New Solar Homes Partnership (NSHP):										
Pacific Gas and Electric										4.0
Southern California Edison										
San Diego Gas and Electric										
Total NSHP	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***4.0***
Self Generation Incentive Program (SGIP):										
Pacific Gas and Electric					185.7	89.5	117.0	212.3	191.3	165.9
Southern California Edison					38.0	115.2	76.8	91.4	118.7	340.7
San Diego Gas and Electric					36.9	328.6	55.7	111.9	76.2	209.9
Southern California Gas Company					43.8	164.1	89.1	119.3	72.2	191.3
Total SGIP	***0.0***	***0.0***	***0.0***	***0.0***	***117.1***	***124.9***	***97.9***	***139.5***	***125.8***	***206.3***
California Solar Initiative (CSI):										
Pacific Gas and Electric										5.0
Southern California Edison										12.6
San Diego Gas and Electric										5.3
Southern California Gas Company										
Total CSI	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***0.0***	***7.2***

Figure B-1. Average Installed PV System Size Under the ERP Program

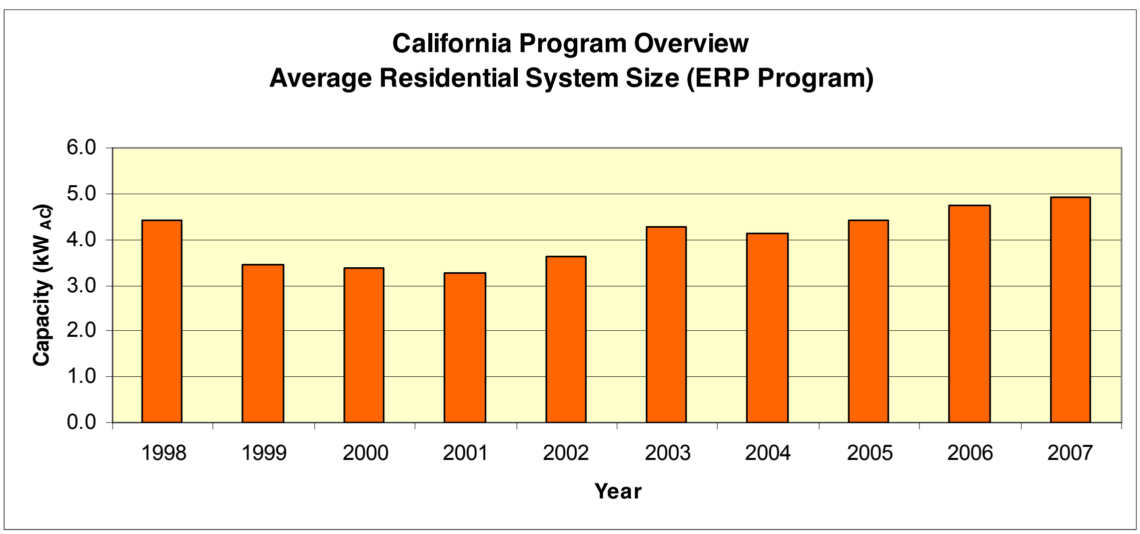
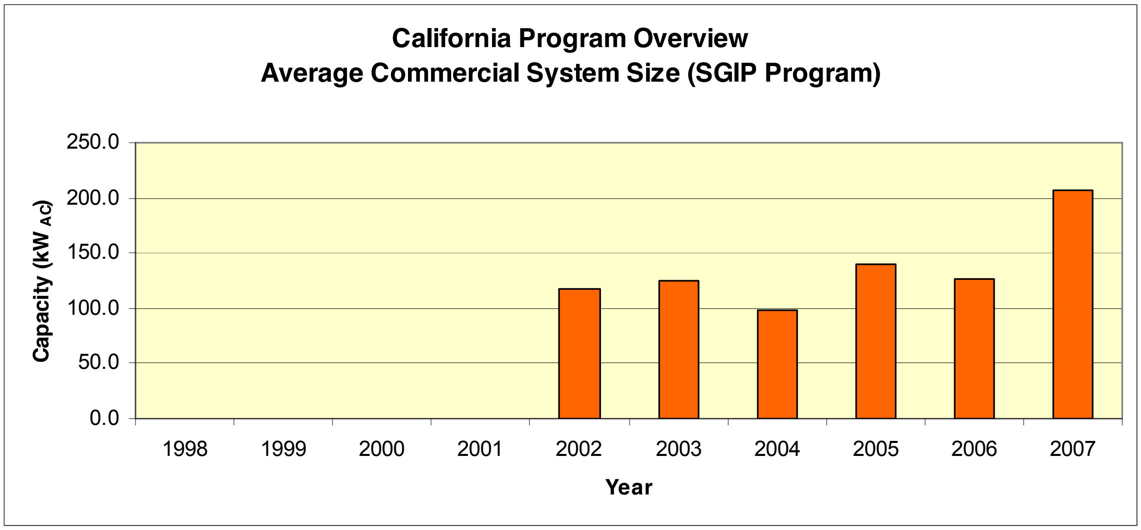


Figure B-2. Average Installed PV System Size Under the SGIP Program



B.4 System Cost

An analysis of the individual records was conducted to gain insight into the installed cost of systems and cost trends under the PV programs. The data sets for the ERP and SGIP were analyzed.

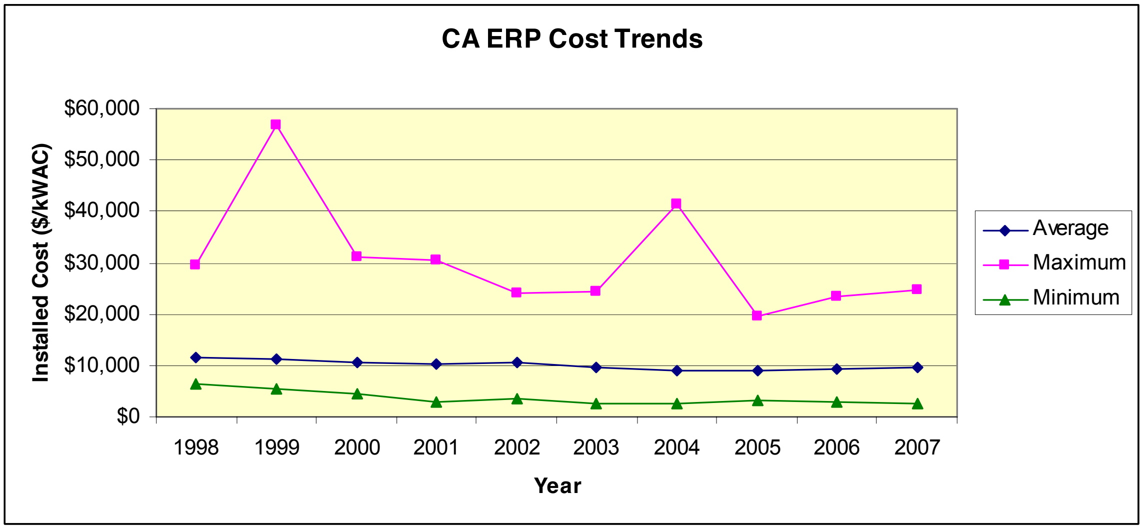
The ERP program has data going back to 1998 and the systems installed under the program were fairly small. As presented above, the average system size was less than 5 kW. The data shows that there a small number of systems receiving incentives that were greater than 50 kW. The following table shows the installed system cost statics for the ERP program.

Table B-1
Annual PV Installed Cost in ERP Program

	Installed System Cost ($/kW$_{AC}$)		
Year	Average	Maximum	Minimum
1998	$11,644	$29,670	$6,269
1999	$11,070	$56,680	$5,573
2000	$10,572	$31,256	$4,530
2001	$10,362	$30,408	$2,732
2002	$10,476	$24,047	$3,563
2003	$9,564	$24,260	$2,470
2004	$9,049	$41,345	$2,541
2005	$8,861	$19,674	$3,200
2006	$9,237	$23,337	$2,800
2007	$9,532	$24,751	$2,600

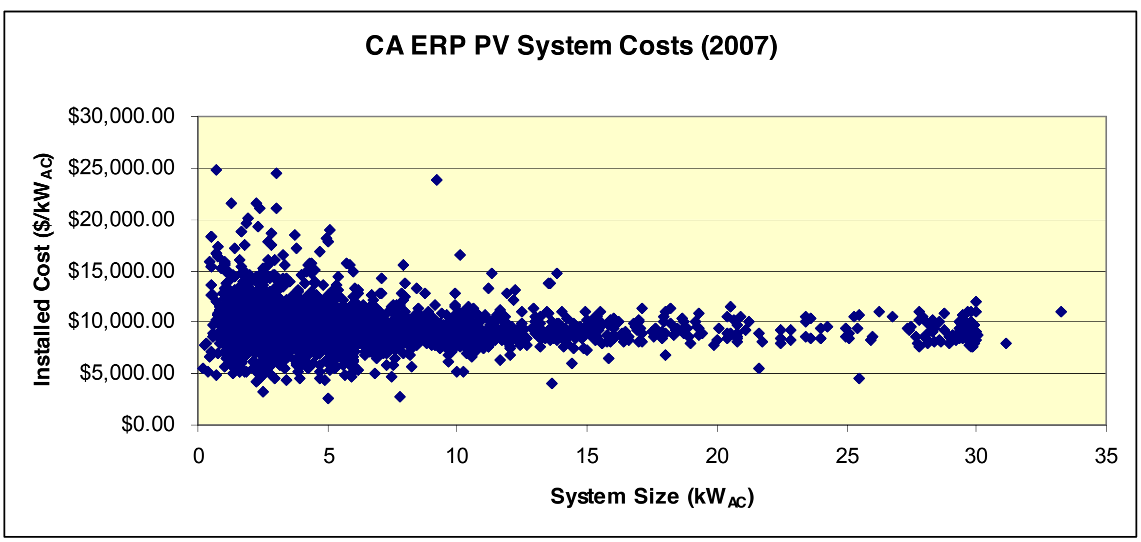
The data shows wide fluctuation in the maximum installed costs from one year to the next. The average system cost trend shows some fluctuation with a slight downward trend. The installed system cost for small systems (~ 5 kW) is approximately $9,000/kWAC.

Figure B-1. Installed Cost Trends in the ERP Program



The following figure presents the installed system cost by size of system for systems receiving an incentive from the ERP program during the year of 2007. The data shows a high level of variability for the smaller systems and less cost variability for larger systems (i.e. greater than 15 kW).

Figure B-2. Installed Cost by System Size in the ERP Program for 2007



The remainder of this section looks at trends of installed cost based on selected system sizes. The sizes of systems that are evaluated are 5, 50, 100, and 200 kWAC. The 5 kW system data has been extracted from the data sets for the ERP program and the data for the other systems has been extracted from the SGIP program.

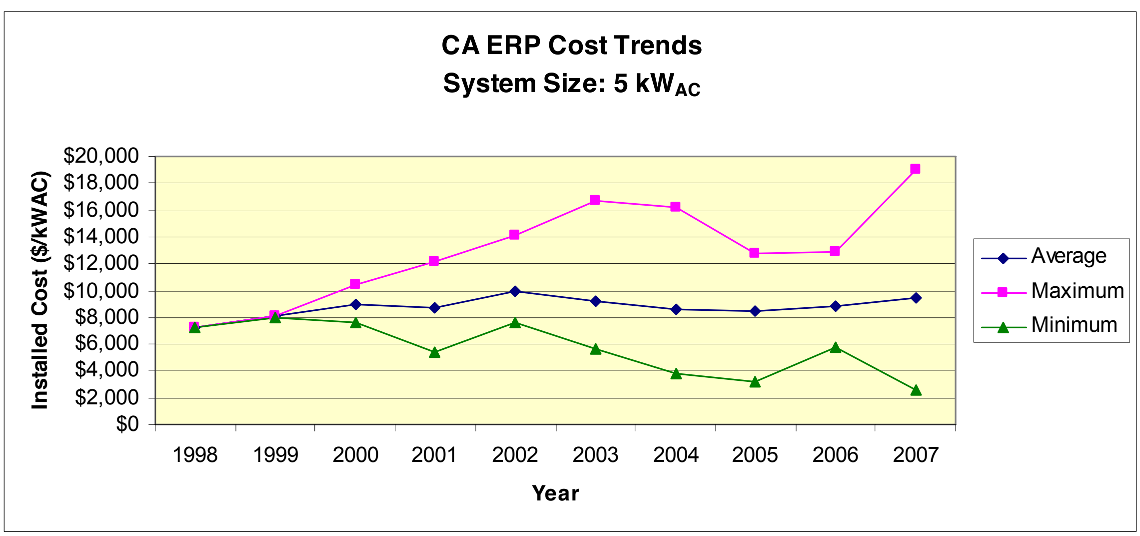
The following table presents the analysis of the cost trends for a 5 kWAC system. The data represents systems that have a stated capacity of 4.9 to 5.1 kWAC. The annual average installed system cost has varied between $7,235/kWAC to $9,892/kWAC and has averaged $8,748/kWAC across all years.

Table B-2
Installed Costs of 5 kW Systems in ERP Program

Year	Number of Systems	Installed System Cost ($/kW$_{AC}$) Average	Maximum	Minimum
1998	1	$7,235	$7,235	$7,235
1999	2	$8,070	$8,124	$8,016
2000	2	$9,013	$10,456	$7,569
2001	9	$8,716	$12,185	$5,420
2002	87	$9,893	$14,108	$7,605
2003	258	$9,199	$16,634	$5,647
2004	535	$8,563	$16,191	$3,800
2005	297	$8,482	$12,779	$3,200
2006	273	$8,857	$12,873	$5,748
2007	233	$9,454	$19,026	$2,600

The trend of the cost data is presented in the following figure. The trend shows that the average installed costs have remained fairly constant over the duration of the program.

Figure B-3. Historical Installed Cost of 5 kWAC System in the ERP Program

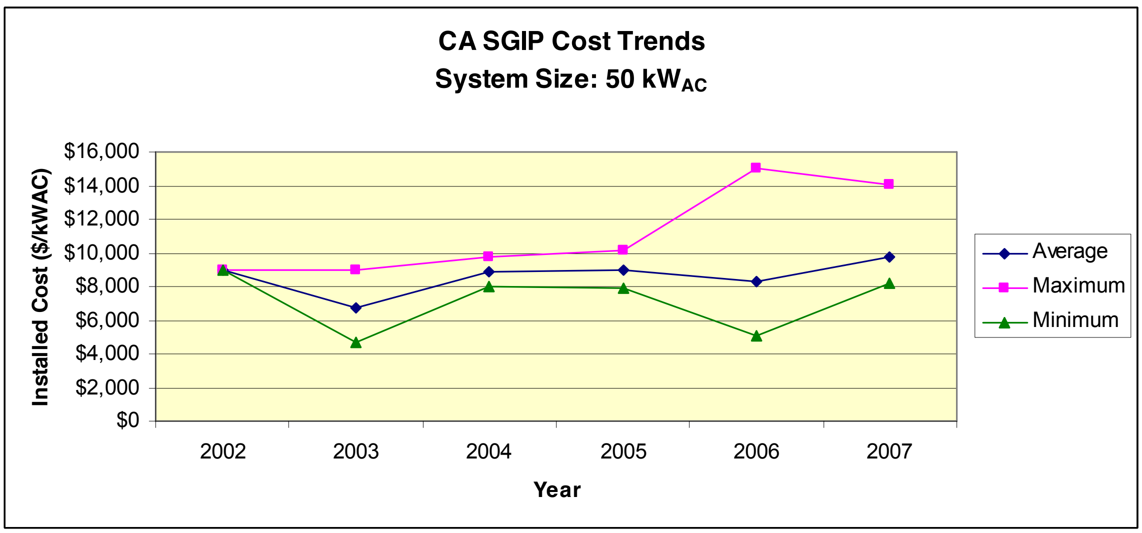


The following table presents the summary of installed cost for 50 kW PV systems that have received an incentive through the SGIP program. The annual average installed system cost has varied between $6,740/kWAC to $9,710/kWAC and has averaged $8,581/kWAC across all years.

Table B-3
Installed Costs of 50 kW_{AC} Systems in SGIP Program

Year	Number of Systems	Installed System Cost ($/$kW_{AC}$) Average	Maximum	Minimum
2002	1	$8,950	$8,950	$8,950
2003	7	$6,740	$8,981	$4,710
2004	11	$8,846	$9,740	$8,020
2005	9	$8,966	$10,188	$7,856
2006	13	$8,275	$15,037	$5,111
2007	9	$9,710	$14,006	$8,149

Figure B-4. Historical Installed Cost of 50 kWAC System in the SGIP Program

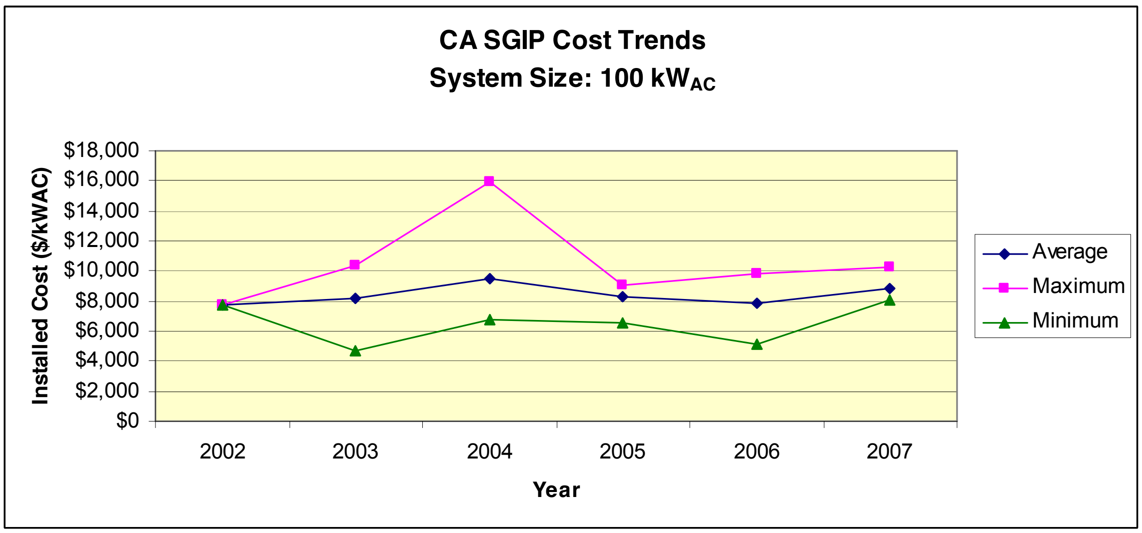


The following table presents the summary of installed cost for 100 kW PV systems that have received an incentive through the SGIP program. The annual average installed system cost has varied between $7,710/kWAC to $9,511/kWAC and has averaged $8,424/kWAC across all years.

Table B-4
Installed Costs of 100 kWAC Systems in SGIP Program

Year	Number of Systems	Installed System Cost ($/kW$_{AC}$) Average	Maximum	Minimum
2002	1	$7,710	$7,710	$7,710
2003	8	$8,232	$10,400	$4,730
2004	8	$9,511	$15,900	$6,794
2005	10	$8,341	$9,039	$6,563
2006	15	$7,899	$9,818	$5,170
2007	14	$8,849	$10,288	$8,060

Figure B-5. Historical Installed Cost of 100 kWAC System in the SGIP Program

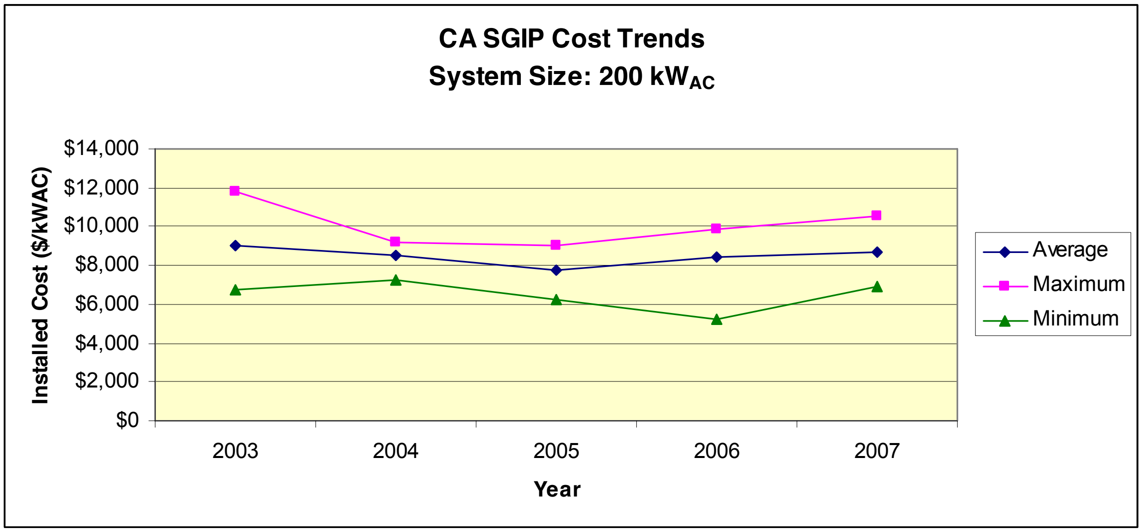


The following table presents the summary of installed cost for 200 kW PV systems that have received an incentive through the SGIP program. The annual average installed system cost has varied between $7,732/kWAC to $9,993/kWAC and has averaged $8,482/kWAC across all years.

Table B-5
Installed Costs of 200 kWAC Systems in SGIP Program

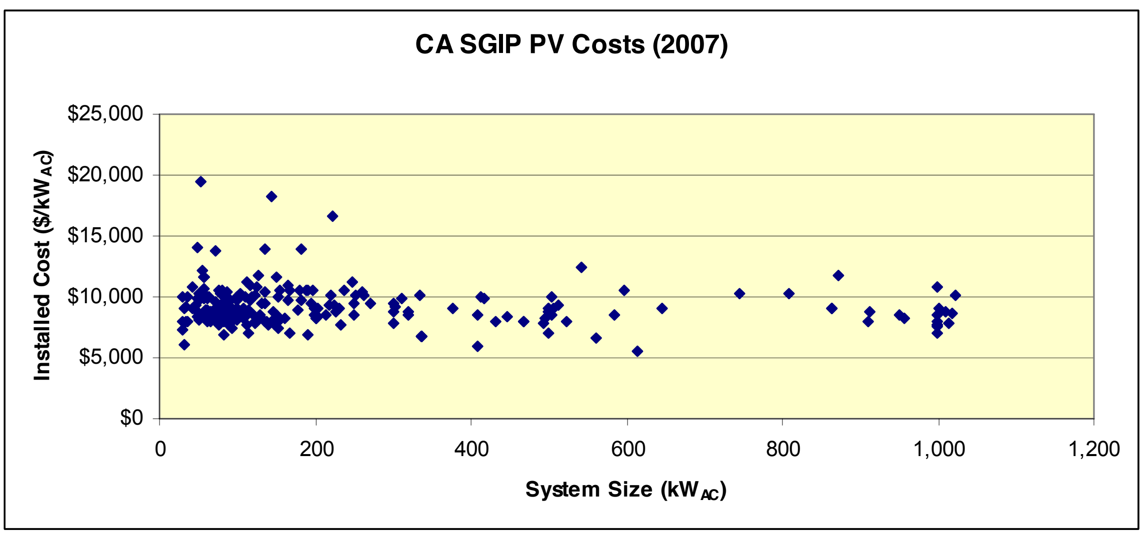
Year	Number of Systems	Installed System Cost ($/kW$_{AC}$) Average	Maximum	Minimum
2002	0	N/A	N/A	N/A
2003	9	$8,993	$11,824	$6,730
2004	7	$8,500	$9,193	$7,250
2005	8	$7,732	$9,042	$6,250
2006	21	$8,399	$9,883	$5,190
2007	10	$8,687	$10,526	$6,890

Figure B-6. Historical Installed Cost of 100 kWAC System in the SGIP Program



The following figure presents the installed system cost by size of system for systems receiving an incentive from the SGIP program during the year of 2007. The data shows some level of variability for the smaller systems (i.e. less than 300 kWAC) and less cost variability for larger systems (i.e. greater than 300 kWAC).

Figure B-7. Installed Cost by System Size in the SGIP Program for 2007



APPENDIX C — NEW JERSEY PV PROGRAM

The New Jersey program data provides the same data as the California program described in Appendix B, but also includes a classification of the customer (i.e., residential, school, government, municipal, and commercial). In addition, the New Jersey data includes information on the commercial customers that allows the further segregation of the data down to the type of commercial customer (i.e., hotel, grocery, retail, medical, etc.). This analysis is not intended to compare direct numbers of system installations or total installed capacity to the potential for Arizona, as the two markets have significant differences in number of customers, overall demand, and electric consumption patterns. However, the New Jersey program does provide insight into the types of commercial customers who purchase and install PV systems, the typical sizes of these systems by customer type, and the average installed system costs.

C.1 Program Overview

New Jersey's program is currently under transition. Historically, New Jersey's solar financing program has relied heavily on up-front rebates to provide up to 70 percent of the installation cost. From May 2001 through November 2007, 45 MW of solar capacity was installed at a cost of $178 million in rebates, or about $4,200 per kW. Under the program, customers receive direct rebates for systems less than 10 kW. For systems over 10 kW, a rebate formula applies with three categories: 10 kW to 40 kW, 40 kW to 100 kW, and greater than 100 kW. In addition, PV systems are not subject to state sales tax. A 30 percent federal investment tax credit (ITC) of up to $2,000 also applies to residential systems.

Rebates have averaged $20,000 for residential projects and more than $1 million for large commercial installations. The state plans to phase out rebates over the next four years. To foster the program, the proposed focus is to require utilities, such as PSE&G, to purchase Solar Renewable Energy Certificates (SRECs) to offset carbon emissions from their power plants and to help meet renewable-energy targets. By purchasing credits, the utilities do not actually generate solar power, but they offset the cost of installing and operating solar equipment.

New Jersey's Renewable Energy Portfolio Standard (RPS) requires 2.12 percent solar by 2021, or an estimated 1,500 to 2,300 MW of solar capacity, depending on the level of 2021 retail sales. To meet this goal, New Jersey will have to substantially grow and expand the state's solar capacity from 90 MW in 2008 to 2,300 MW by 2021.

On September 12, 2007, the state adopted a market-based financing program that relies primarily on the use of Solar Renewable Energy Certificates with provisions to continue rebates for small solar systems less than 10 kW. To support this approach, the Solar Alternative Compliance Payment (SACP) program was developed and provides a mechanism for utilities to reach their RPS goals through the purchase of SRECs to avoid a penalty.

The price of an SREC is determined by a number of factors including supply and demand for SRECs in any given year and the cost of the SACP that utilities are required to pay if they do not meet their RPS goals. SRECs have been trading in the range of 50 to 75 percent of the SACP level for the past two years.

The following table presents the state-approved SACP schedule for the next eight years. The schedule reflects a three percent annual decrease to account for an expected decrease in the cost of PV systems going forward along with improved project economics.

Table C-1
New Jersey Approved 8-Year Schedule for Solar Alternative Compliance Payments

Approved 8 Year SACP Schedule

Energy Year	2009	2010	2011	2012	2013	2014	2015	2016
SACP	$711	$693	$675	$658	$641	$625	$609	$594

The SREC is issued once a solar facility has generated 1,000 kWh through either estimated or actual metered production, and represents all the clean energy benefits of electricity generated from a solar electric system. SRECs can be sold or traded separately from the electricity, which provides solar system owners a source of revenue to help offset the cost of installation.

C.2 Summary of Non-Residential PV Installations in New Jersey Since 2003

The following graphs provide a summary of the non-residential PV systems installed under the New Jersey program since 2003. Data are presented for the following types of customers:

- Universities
- Schools: K-12
- Non-Profit Agencies
- Municipal Facilities
- Government Facilities
- Commercial Buildings

For each customer category, data is presented for the number of installations by year, the average installed capacity for each year, and the average installed cost of the systems.

C.2.1 Universities

In 2006, there were four PV installations at universities, with an average capacity of 145.9 kW_{DC} and a cost of $6,364 per kW_{DC}. There are currently six PV installations scheduled for completion in 2007/2008 with an average capacity of 43.4 kW_{DC} and a cost of $7,545 per kW_{DC}.

Figure C-1. Number of New Jersey PV Installations at Universities by Year

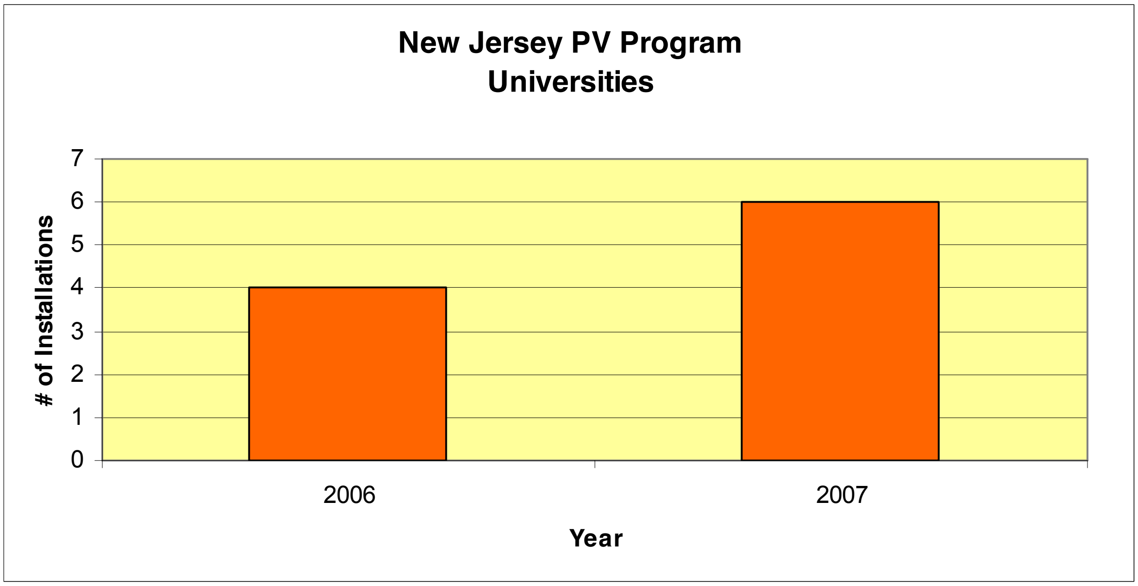


Figure C-2. Average Capacity of New Jersey PV Installations at Universities by Year

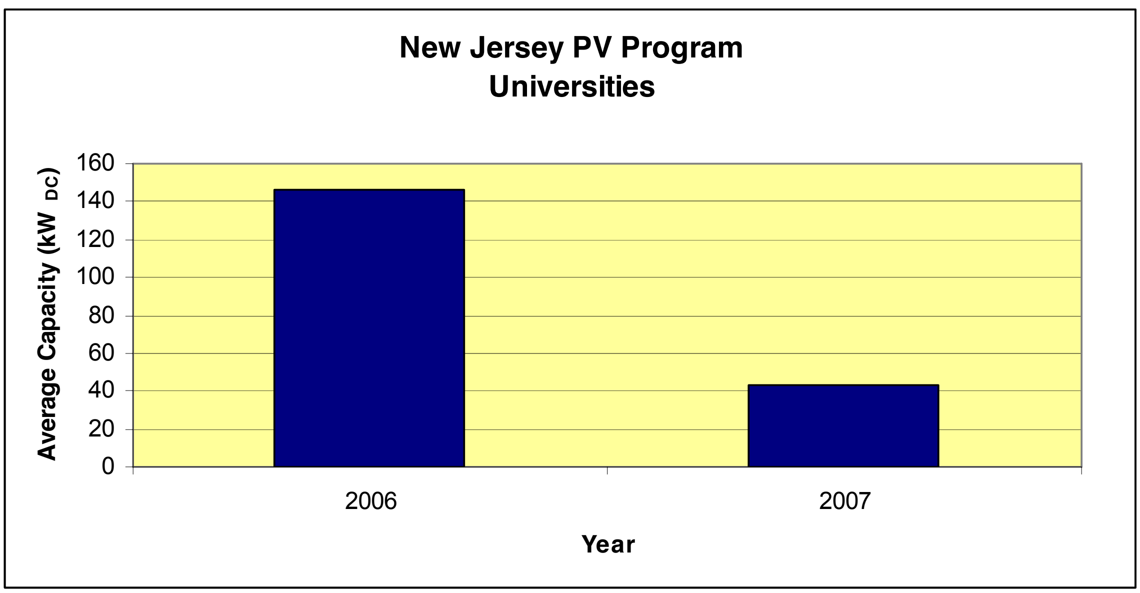
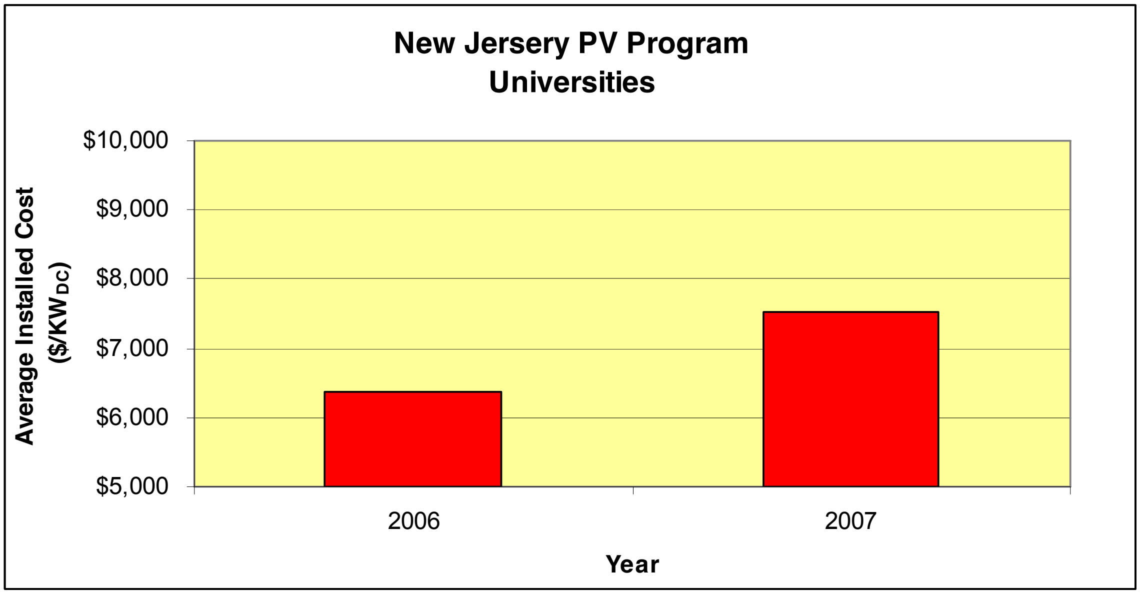


Figure C-3. Average Cost of New Jersey PV Installations at Universities by Year



C.2.2 Schools (K-12)

In 2003 there were two school PV installations with an average capacity of 50.4 kW$_{DC}$ and an average cost of $8,383 per kW$_{DC}$. In 2004 there was only one PV installation with capacity of 12.6 kW$_{DC}$ and a cost of $9,343 per kW$_{DC}$. For 2005, there were nine PV installations with an average capacity of 169.8 kW$_{DC}$ at a cost of $6,980 per kW$_{DC}$. Installations rose to 19 in 2006 with an average capacity of 158.4 kW$_{DC}$ at a cost of $7,207 per kW$_{DC}$. There are currently 50 PV installations scheduled for completion in 2007/2008 with an average capacity of 227.3 kW$_{DC}$ at a cost of $6,644 per kW$_{DC}$.

The data show a trend of an increasing number of installations year over year as well as an increasing average system capacity per installation. The data also show a trend of lower installed system cost, which has been approximately $7,000 per kW$_{DC}$ from 2005 to present.

Figure C-4. Number of New Jersey PV Installations at Schools (K-12) by Year

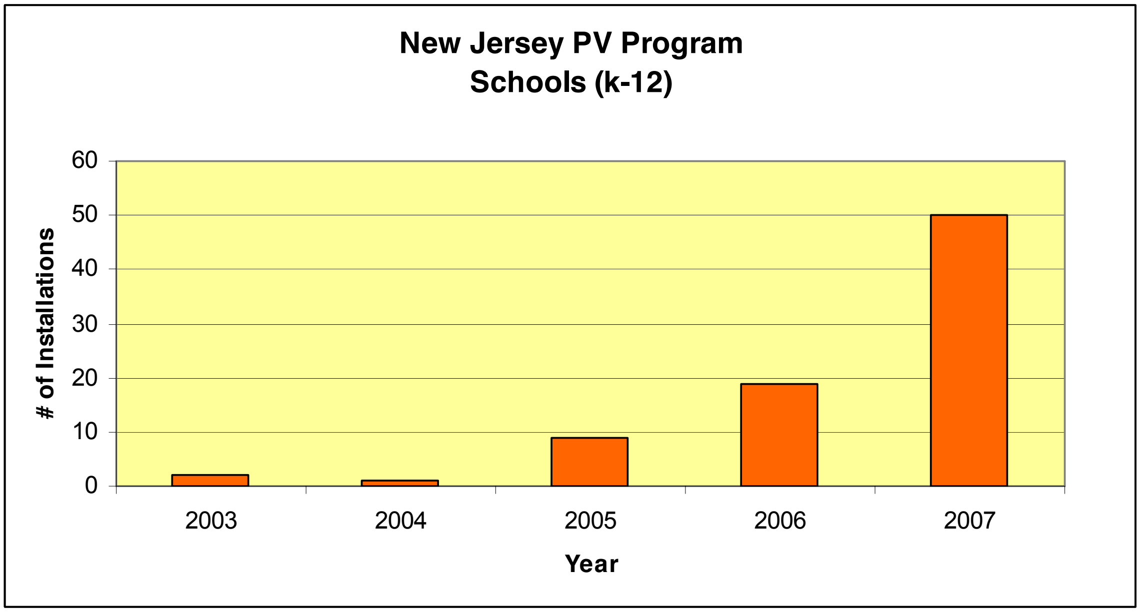


Figure C-5. Average Capacity of New Jersey PV Installations at Schools (K-12) by Year

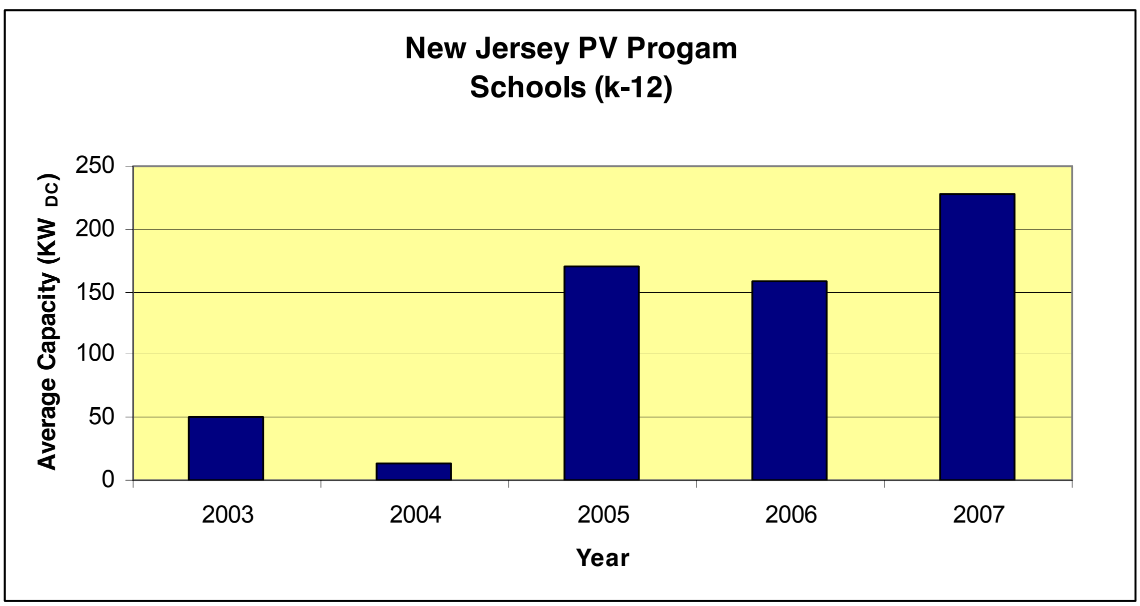
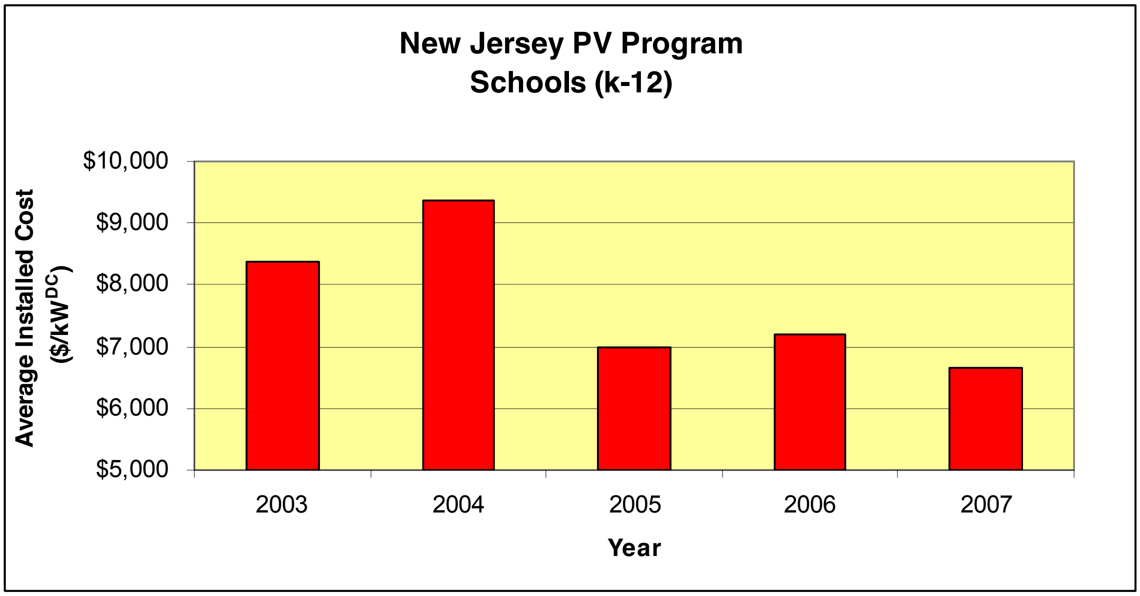


Figure C-6. Average Cost of New Jersey PV Installations at Schools (K-12) by Year



C.2.3 Non-Profit Agencies

In 2003, there was one PV installation at a non-profit agency in the state of New Jersey. That system had a capacity of 8.4 kW_{DC} and had an installed cost of \$8,526 per kW_{DC}. The number of installations per year for this customer segment has increased every year with the average system size also increasing to more than 50 kW. The cost of systems for this customer class has a decreasing trend, which is likely attributed to the larger system sizes. There are currently 25 PV installations scheduled for completion in 2007/2008 with an average capacity of 55.8 kW_{DC} at a cost of \$7,448 per kW_{DC}.

Figure C-7. Number of New Jersey PV Installations at Non-Profit Agencies by Year

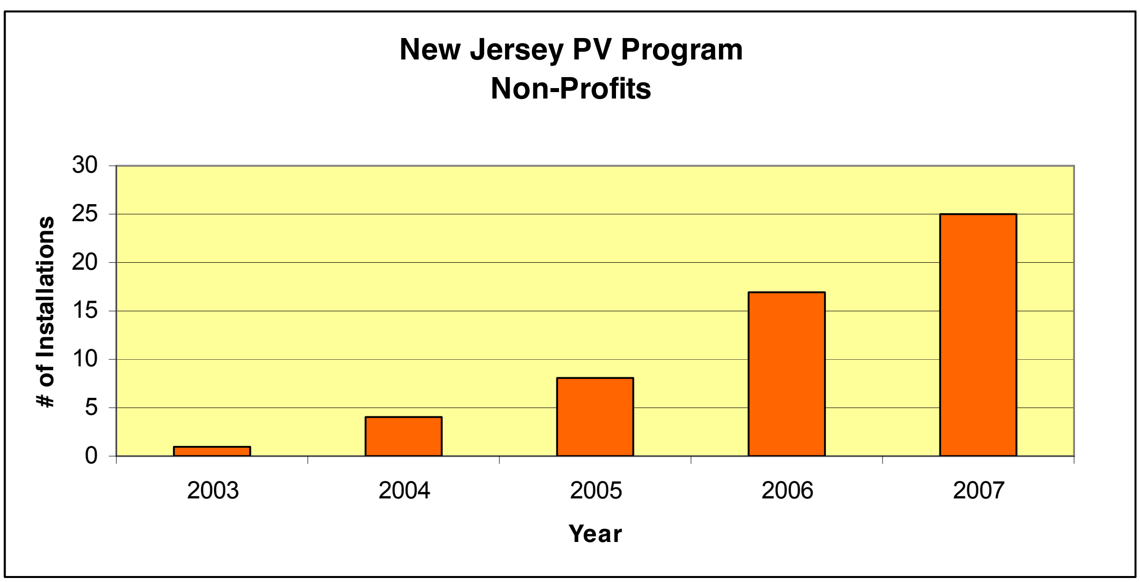


Figure C-8. Average Capacity of New Jersey PV Installations at Non-Profit Agencies by Year

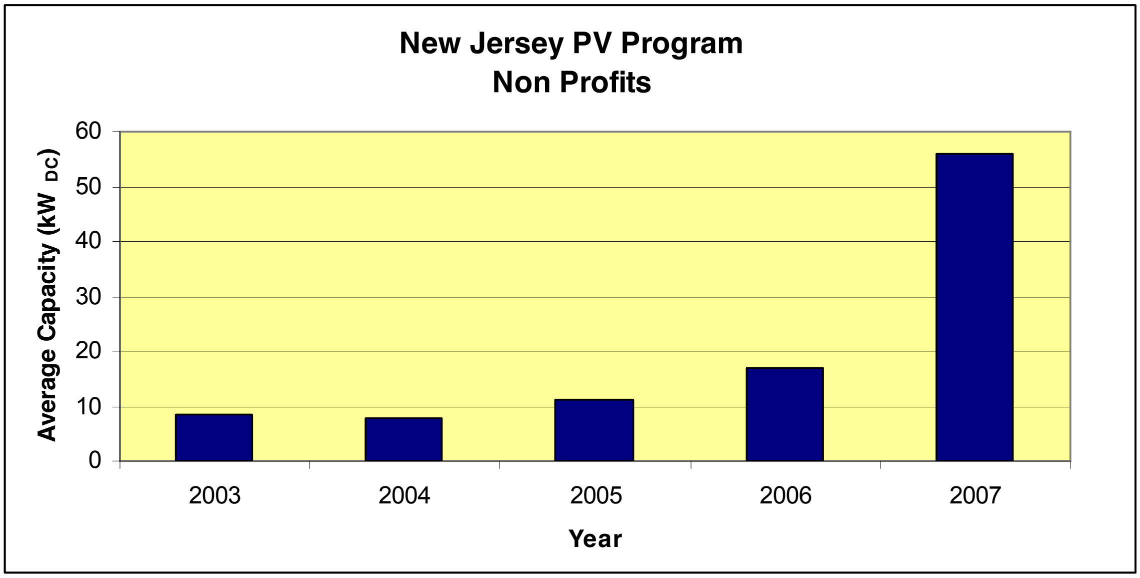
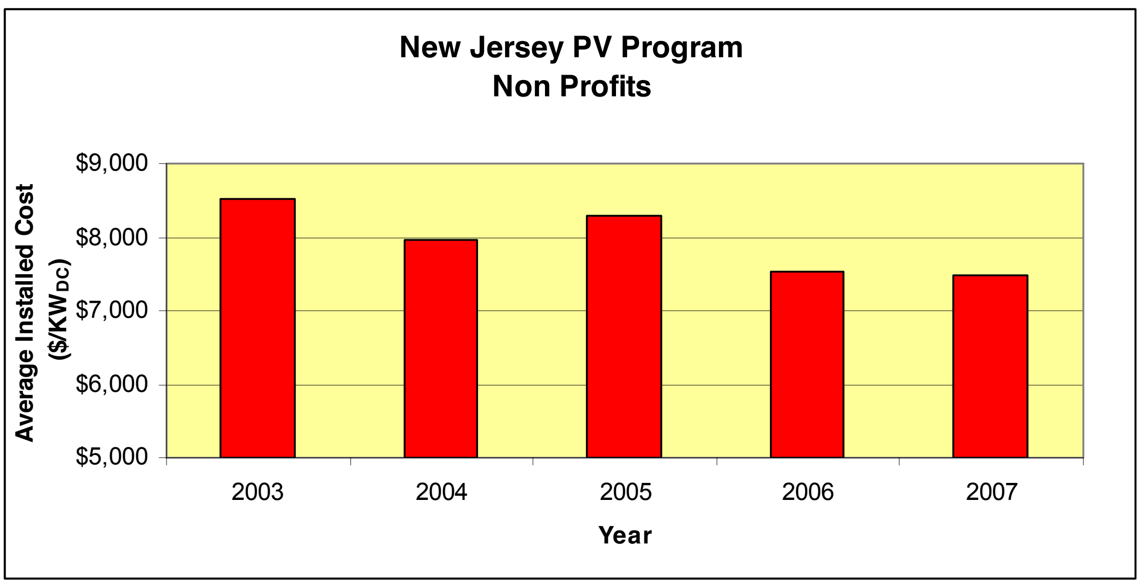


Figure C-9. Average Cost of New Jersey PV Installations at Non-Profit Agencies by Year



C.2.4 Municipal Facilities

There have been no municipal PV installations in the state of New Jersey prior to 2007/2008. There are currently 13 installations scheduled for completion in 2007/2008, with an average capacity of 179.2 kW_{DC} at a cost of $9,731 per kW_{DC}.

C.2.5 Government Facilities

From 2003 through 2006, there were very few PV installations at government facilities. In 2007 the number of installations increased significantly. There are currently 52 PV installations scheduled for completion in 2007/2008 with an average capacity of 166 kW_{DC} at a cost of $6,725 per kW_{DC}.

Figure C-10. Number of New Jersey PV Installations at Government Facilities by Year

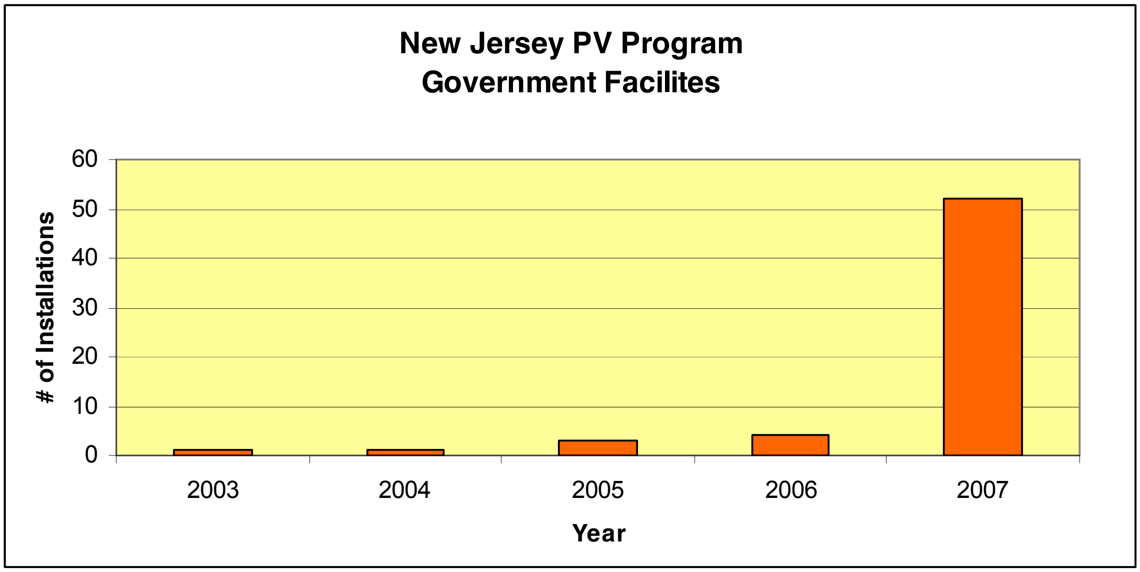


Figure C-11. Average Capacity of New Jersey PV Installations at Government Facilities by Year

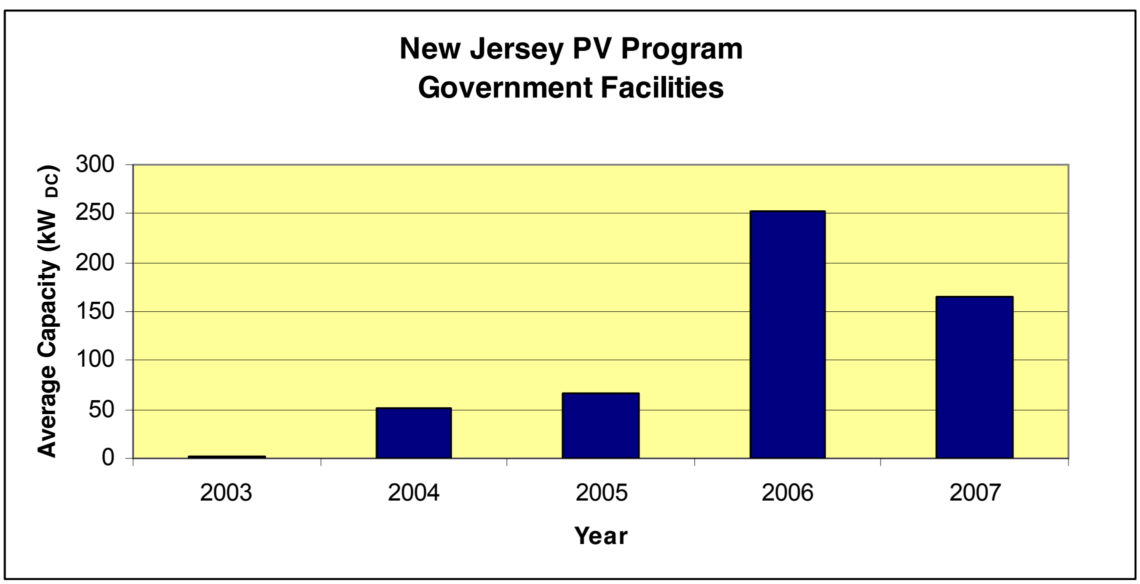
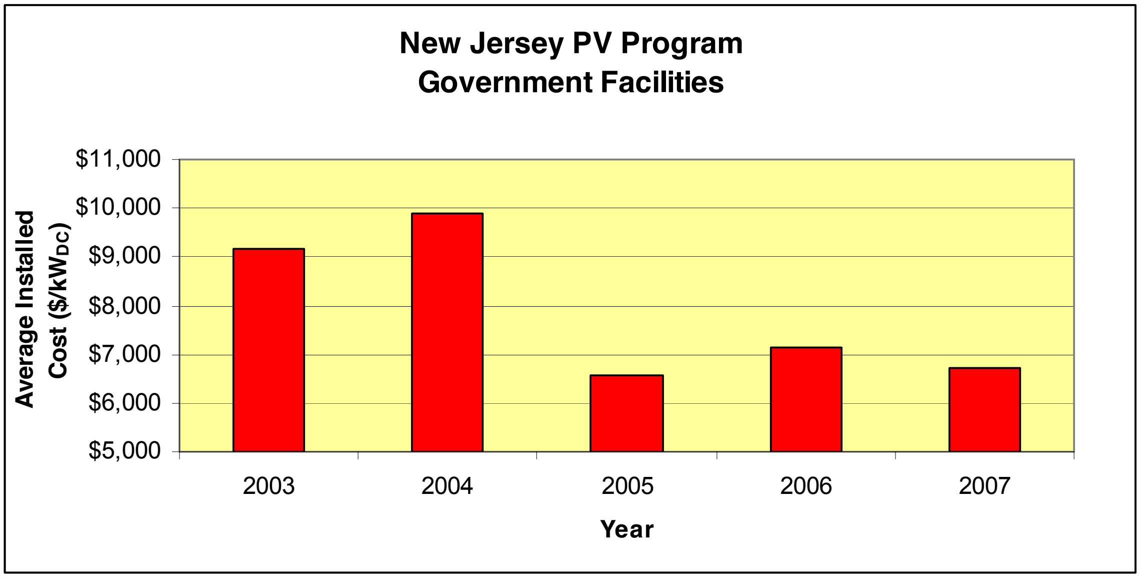


Figure C-12. Average Cost of New Jersey PV Installations at Government Facilities by Year



C.2.6 Commercial

The category of commercial customer is very broad and includes applications such as grocery stores, hotels, retail stores, churches, storage facilities, and distribution facilities. The annual number of installations of commercial PV systems was less than 100 per year between 2003 and 2006. In 2007, the number of commercial installations jumped to nearly 500 systems. In addition, the size of systems installed has increased steadily over the years and averaged more than 160 kW_{DC} in 2007.

Figure C-13. Number of New Jersey PV Installations at Commercial Buildings by Year

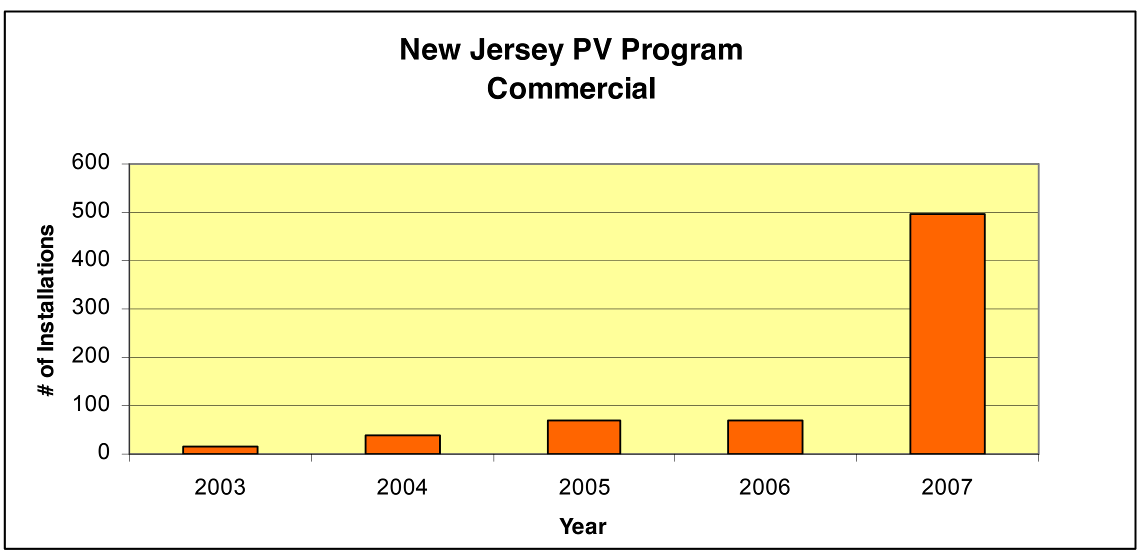


Figure C-14. Average Capacity of New Jersey PV Installations at Commercial Buildings by Year

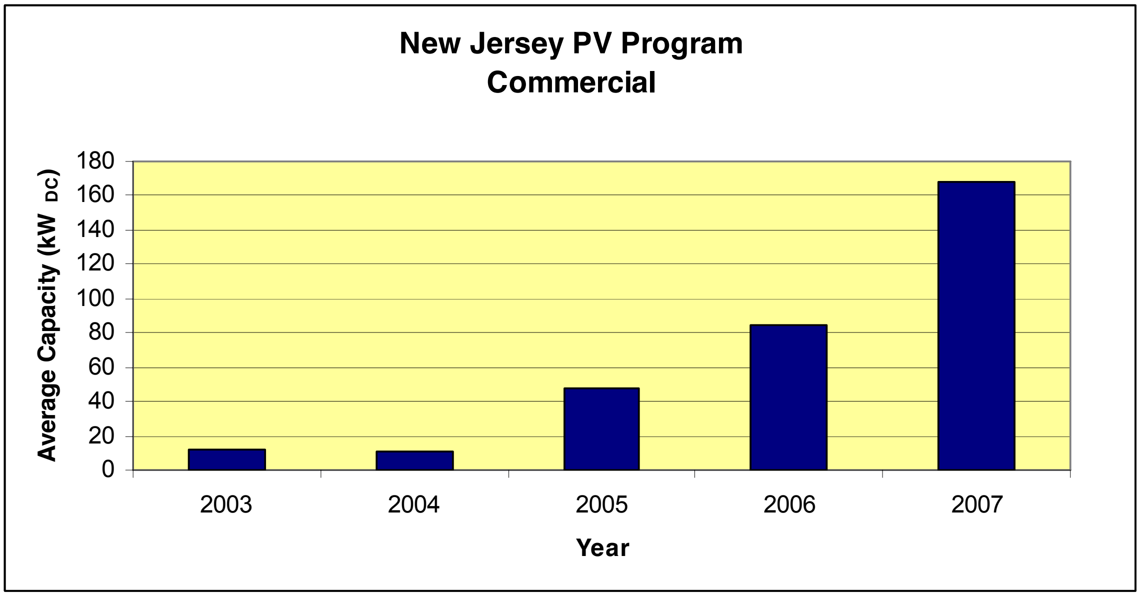
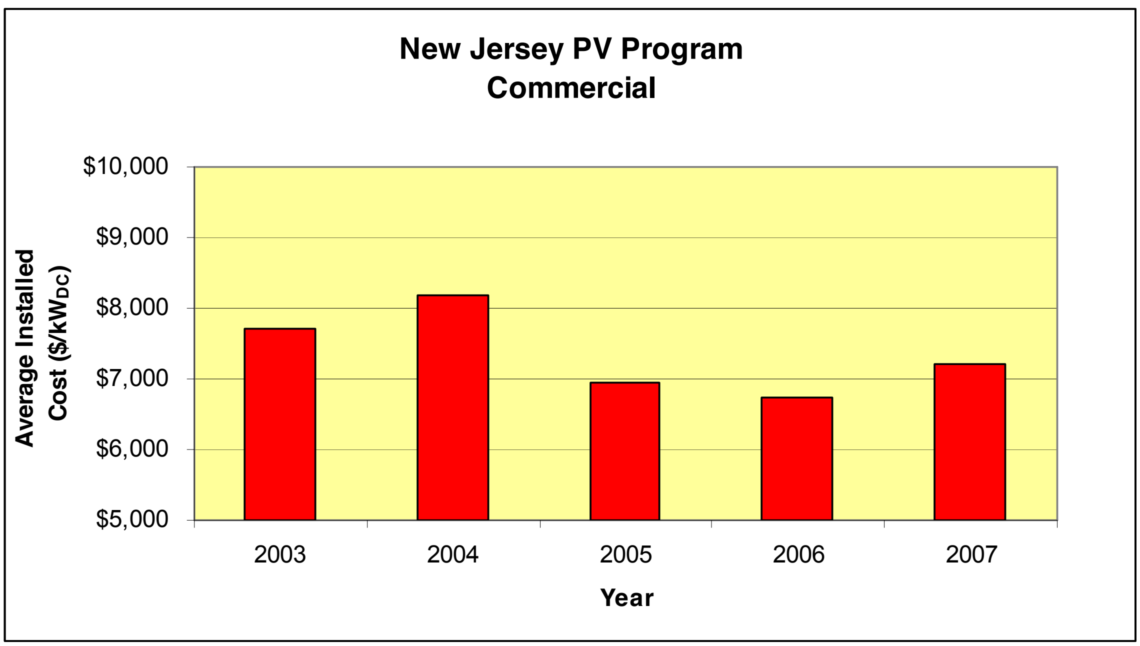


Figure C-15. Average Cost of New Jersey PV Installations at Commercial Buildings by Year



To provide more insight into the commercial PV market, the installed system data has been broken down into business types. A summary of the commercial market by type of business is presented in the following table.

Table C-1
New Jersey PV Program Commercial Installations by Business Type

Business Type	# of Intallations	Avg. Capacity (kW_{DC})	Avg. Installed Cost ($/$kW_{DC}$)
Banking	6	79.3	$7,280
Church	12	34.9	$7,787
Construction	27	92.8	$6,825
Distribution	17	409.9	$6,796
Environmental	5	56.1	$8,876
Farm	42	27.0	$8,689
Funeral	4	14.3	$8,269
Grocery	17	184.0	$6,963
Hotel	2	406.0	$7,500
Manufacturing	13	410.6	$6,589
Medical	18	52.5	$6,775
Other	312	108.6	$7,080
Real Estate	73	46.9	$7,491
Retail (Large)	64	363.5	$6,913
Retail (Medium)	45	158.4	$9,444
Services	13	133.7	$6,991
Storage	13	86.8	$7,240
Utility	2	262.1	$6,779
Vineyard	4	14.6	$8,560

The data show that the larger systems (greater than 300 kW_{DC}) have been installed at hotels, manufacturing facilities, distribution facilities, and large retail stores. Medium retail store applications have an average size of 158 kW_{DC} but have the highest installed costs of the commercial business types at more than $9,000 per kW_{DC}.

Figure C-16. Total Number of New Jersey PV Installations at Commercial Buildings by Business Type

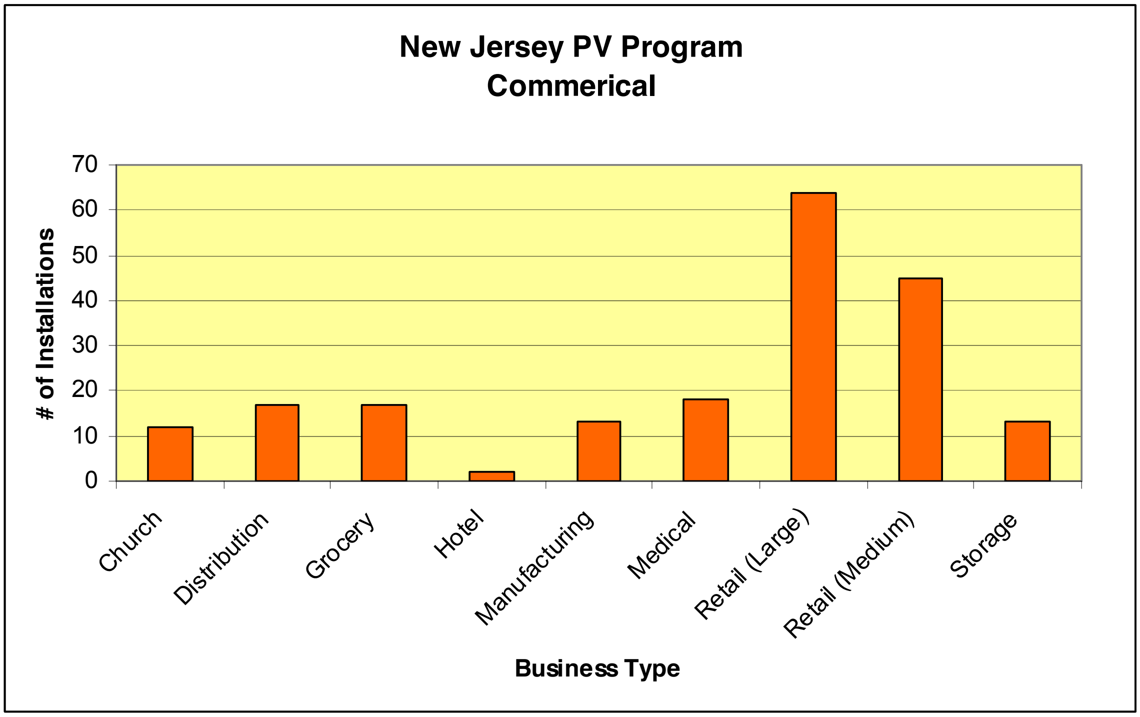


Figure C-17. Average Capacity of New Jersey PV Installations at Commercial Buildings by Business Type

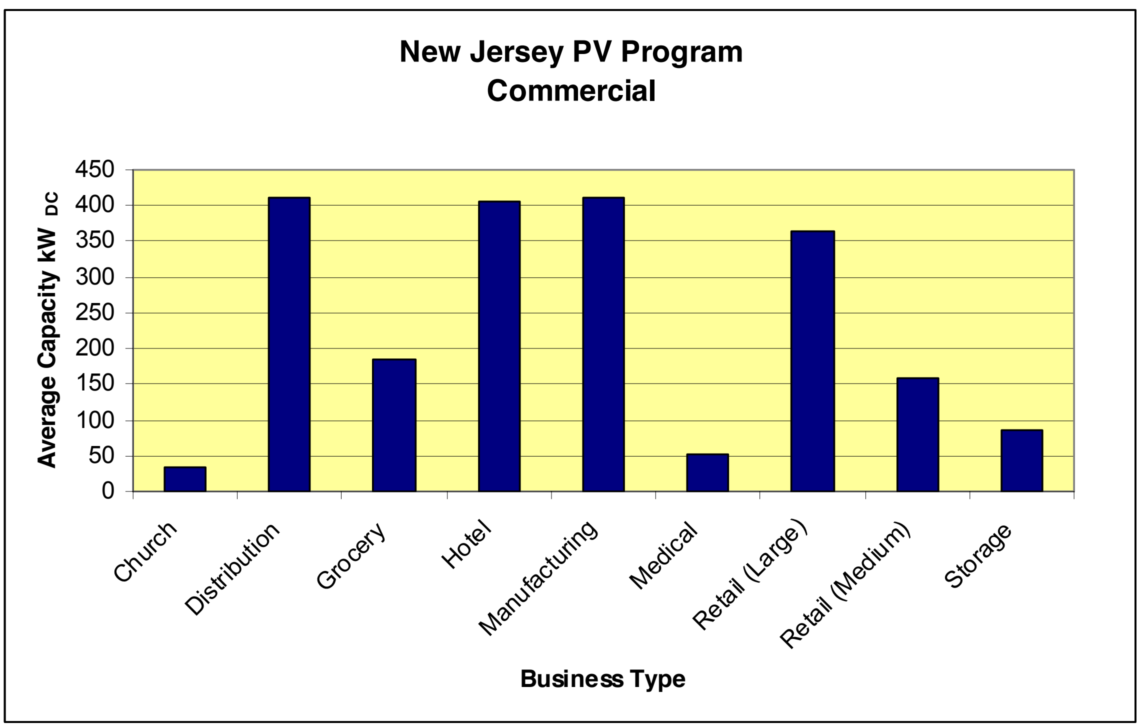
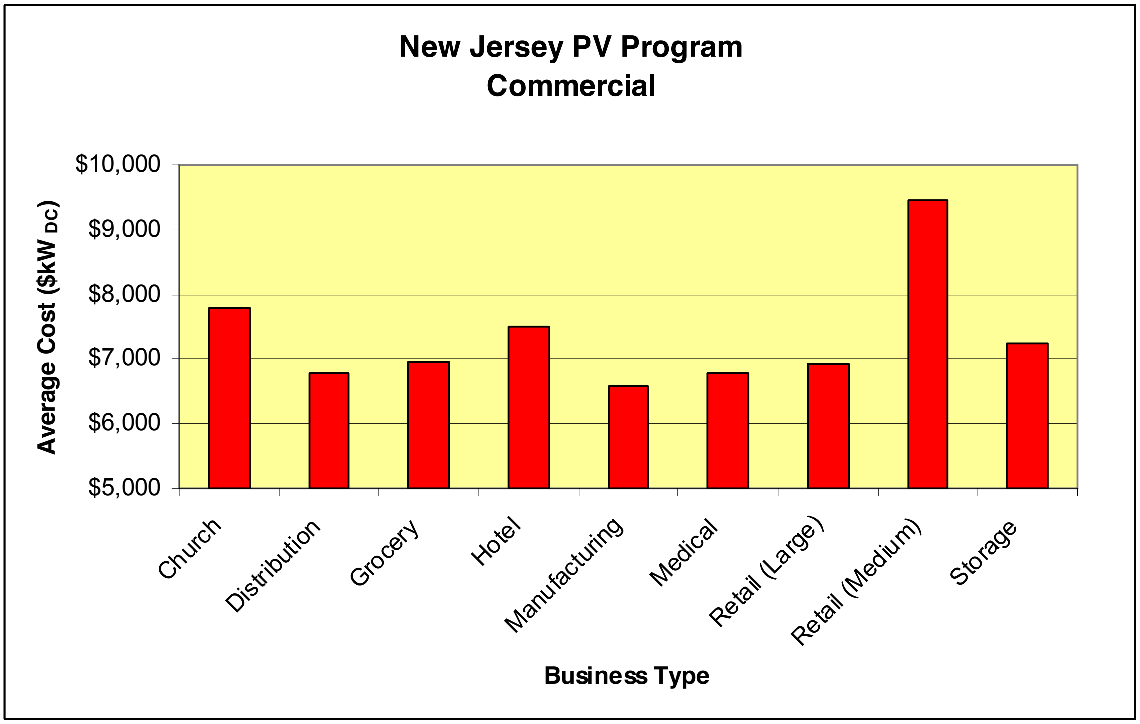


Figure C-18. Average Cost of New Jersey PV Installations at Commercial Buildings by Business Type



APPENDIX D — CUSTOMER USE CHARACTERISTICS BY SELECTED APS RATE GROUP

D.1 Residential E12 Characteristics

The average residential customer under the E12 tariff has an annual electric consumption of 8,676 kWh and peak demand of 2.6 kW that occurs in August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-1. E12 Residential Energy Consumption

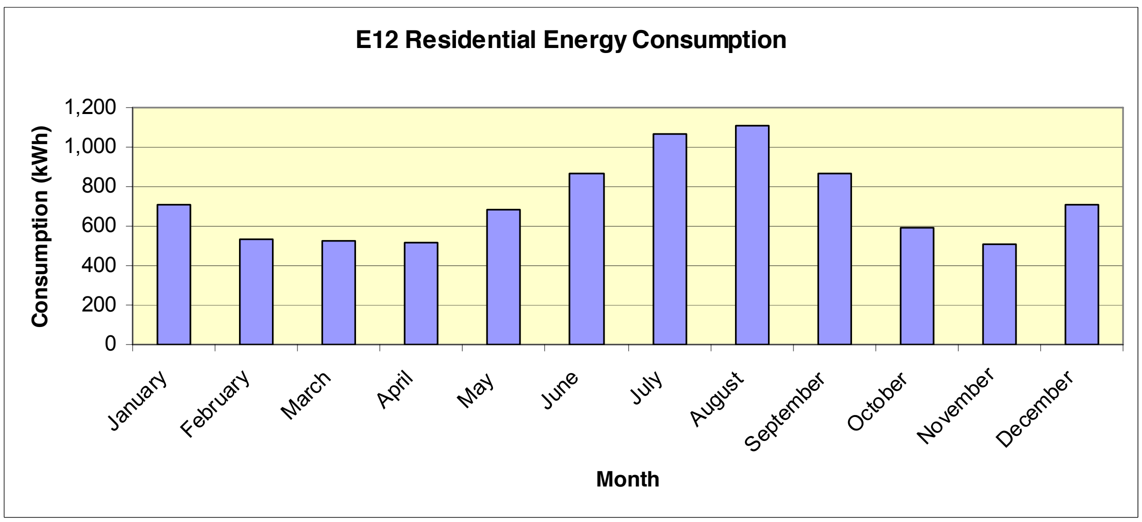


Figure D-2. E12 Residential Maximum Demand

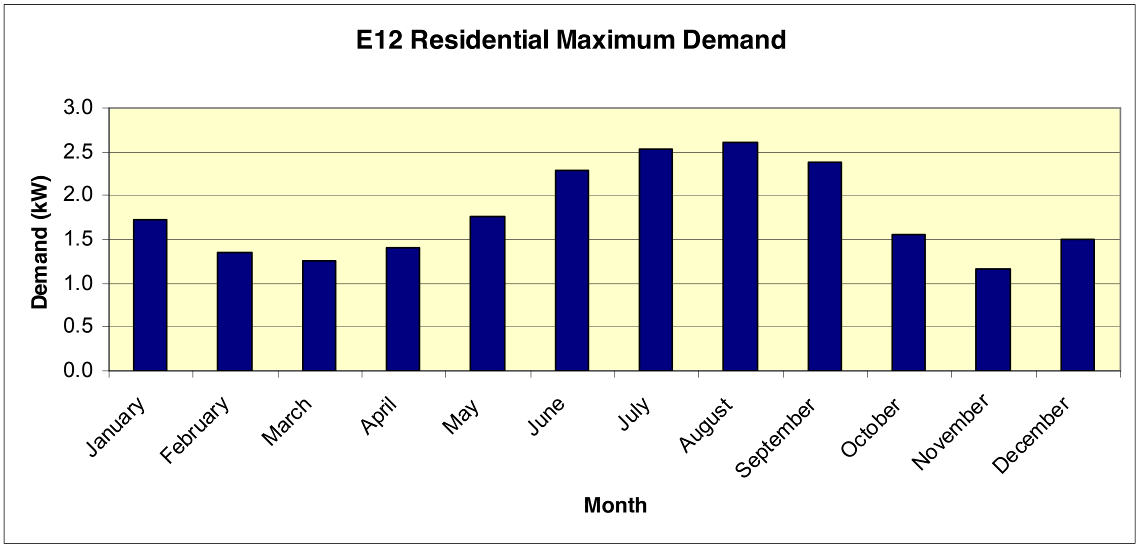
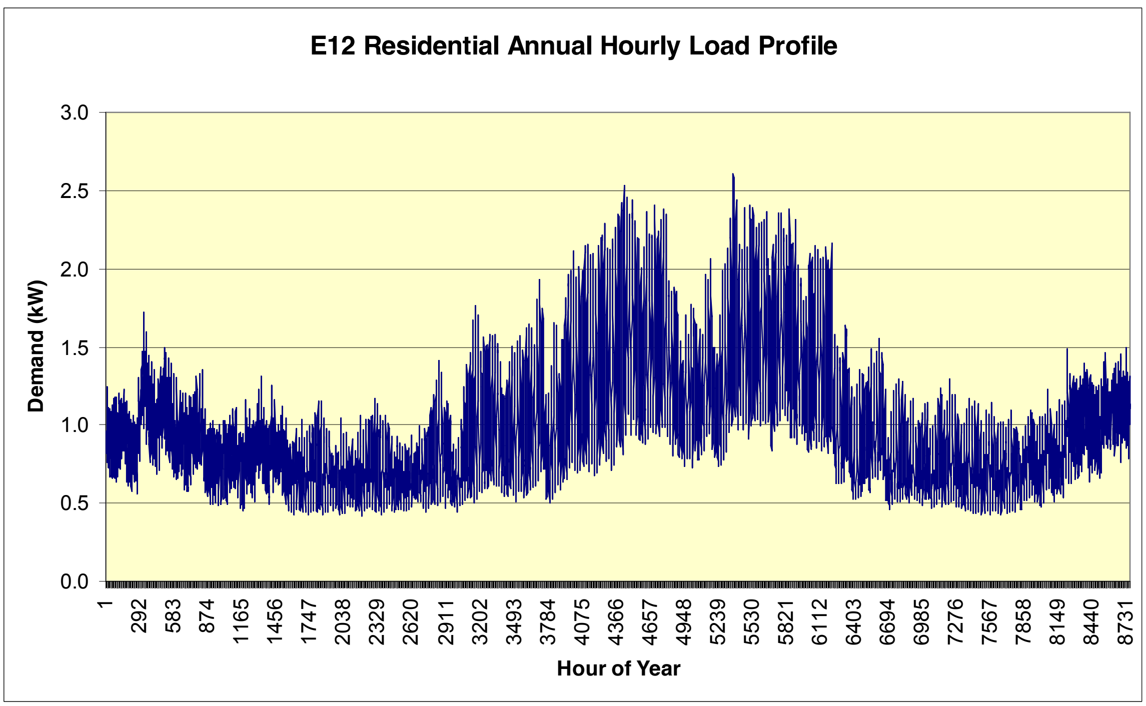


Figure D-3. Residential Annual Hourly Load Profile



Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

D.2 Residential ET-1 Characteristics

The average residential customer under the ET-1 tariff has an annual electric consumption of 17,546 kWh and a peak demand of 5.6 kW that occurs in August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-4. ET-1 Residential Energy Consumption

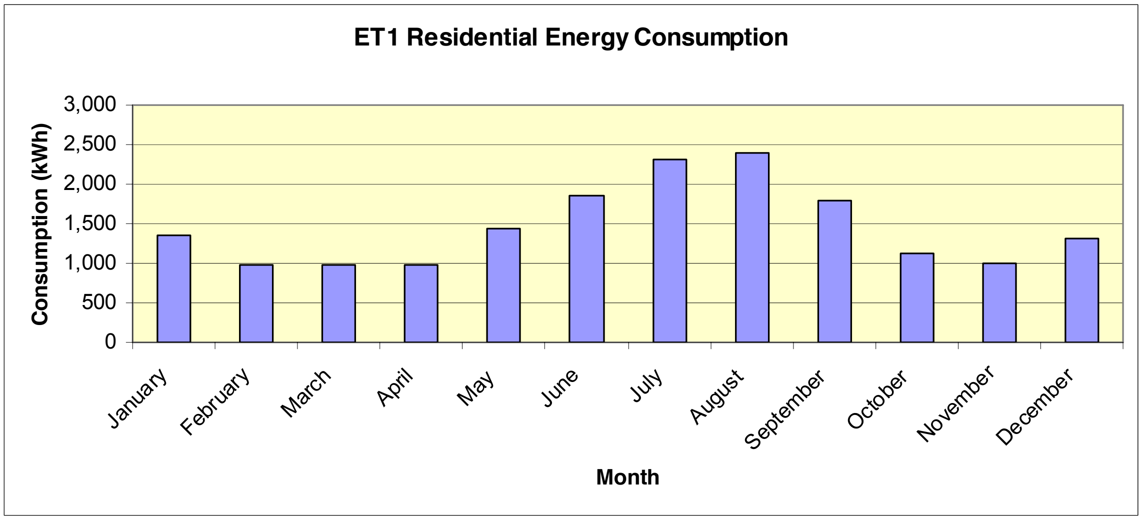


Figure D-5. ET-1 Residential Maximum Demand

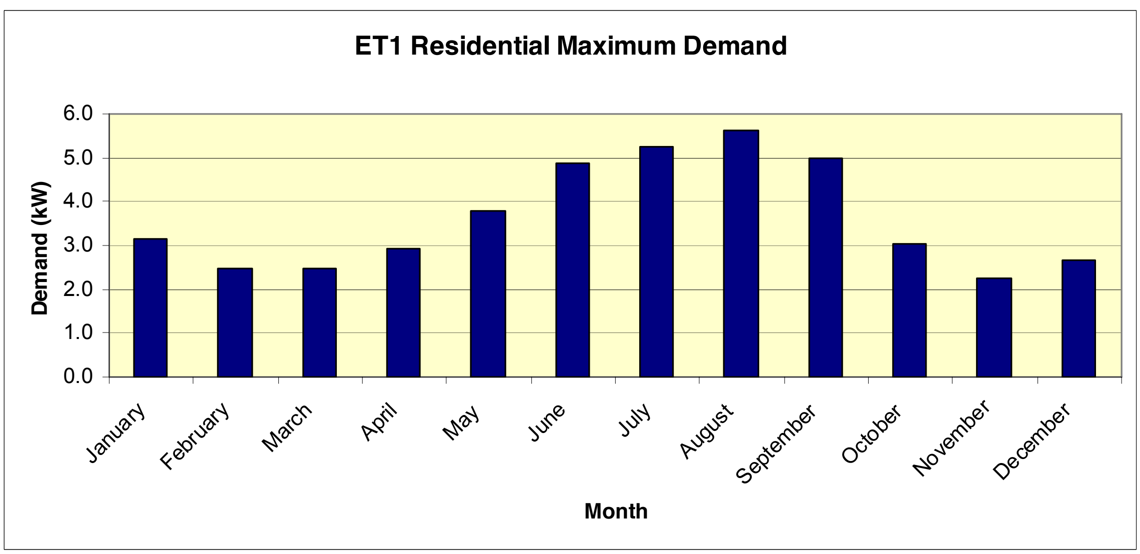
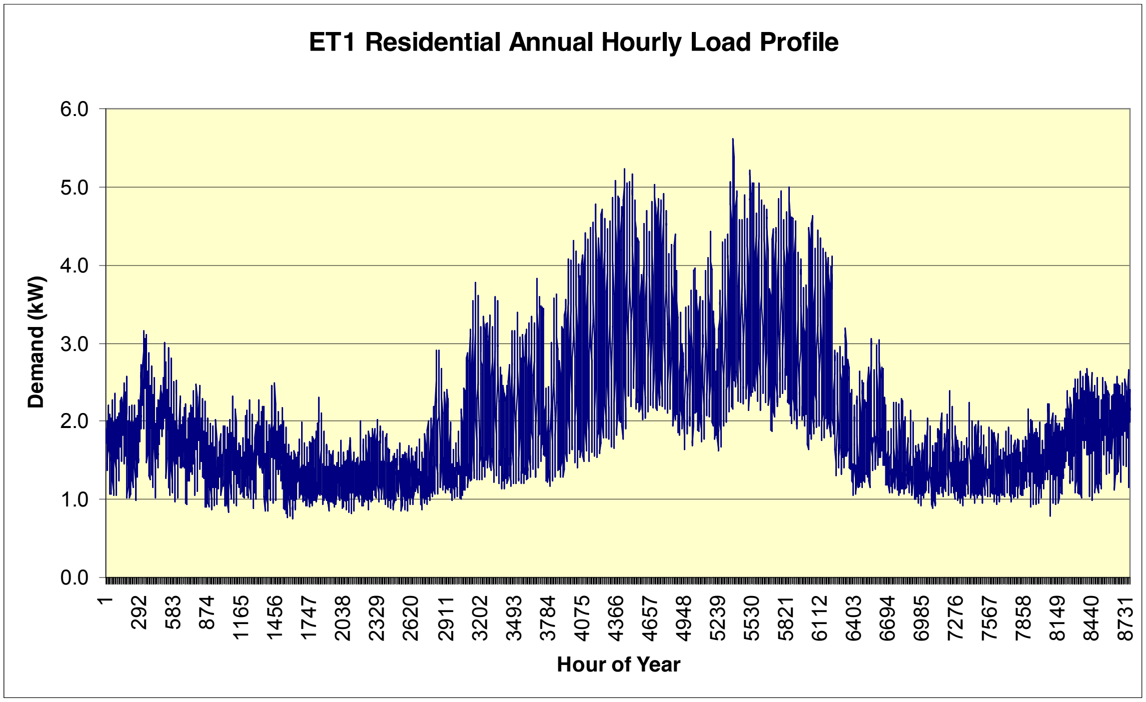


Figure D-6. ET-1 Residential Annual Hourly Load Profile



Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

D.3 Commercial E32 Extra Small Characteristics

The average commercial customer under the E32 tariff has a peak demand of less than 20 kW has an annual electric consumption of 26,103 kWh and peak demand of 7.2 kW that occurs in July and August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-7. E32 Extra Small Commercial Energy Consumption

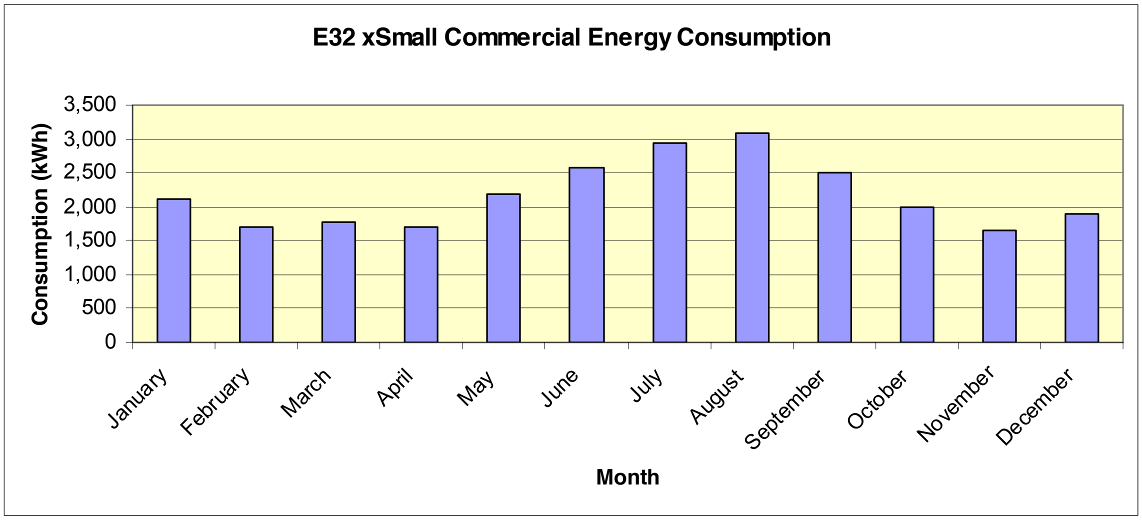


Figure D-8. E32 Extra Small Commercial Maximum Demand

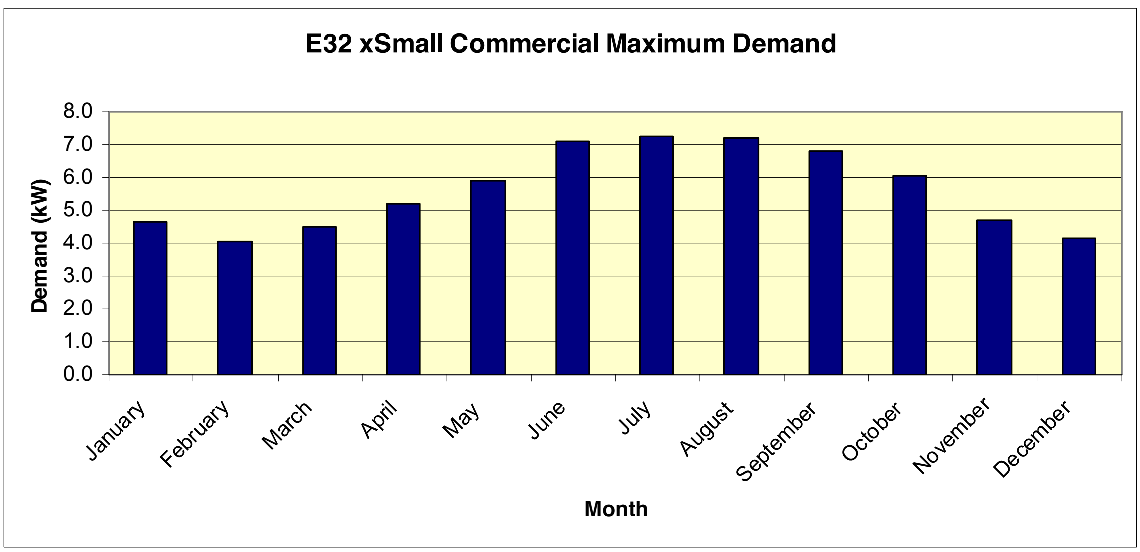
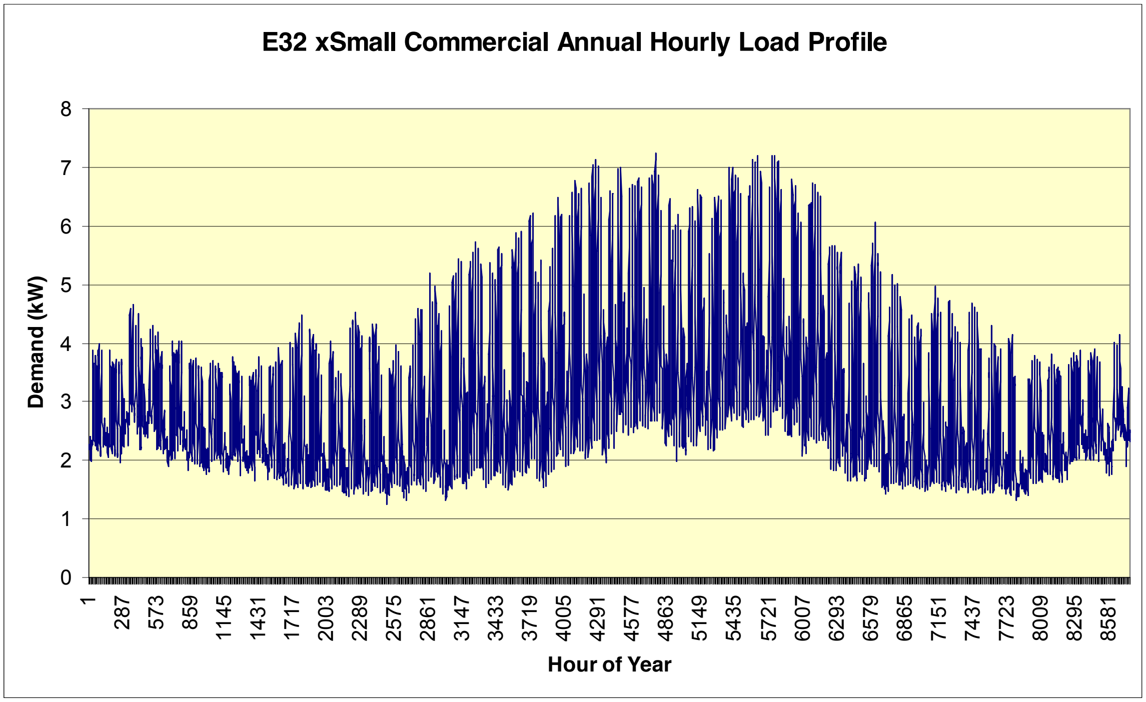


Figure D-9. E32 Extra Small Commercial Annual Hourly Load Profile



Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

D.4 Commercial E32 Small Characteristics

The average commercial customer under the E32 tariff with a peak demand in the range of 20 kW to 100 kW has an annual electric consumption of 189,058 kWh and a peak demand of 43.3 kW that occurs in August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-10. E32 Small Commercial Energy Consumption

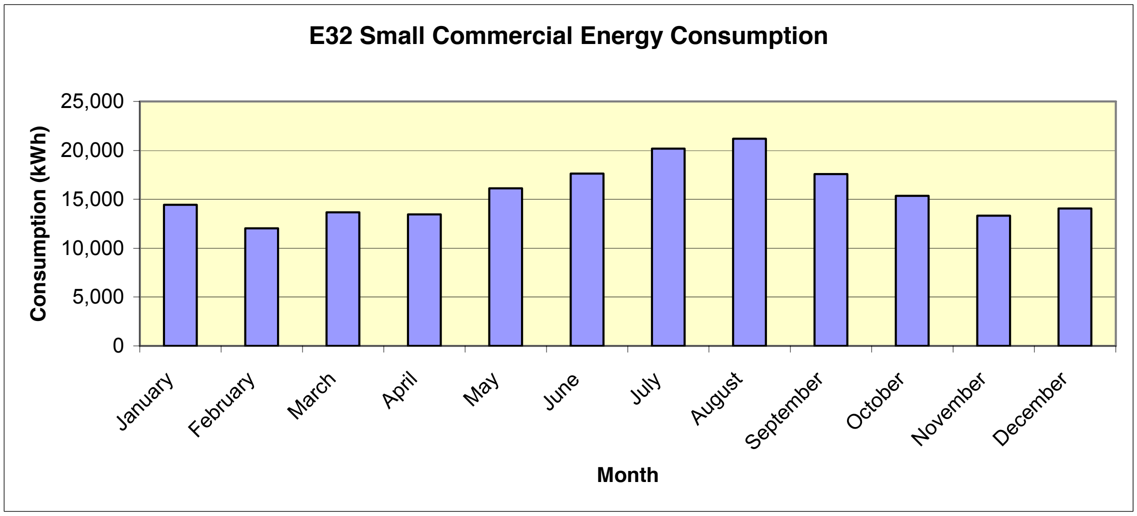


Figure D-11. E32 Small Commercial Maximum Demand

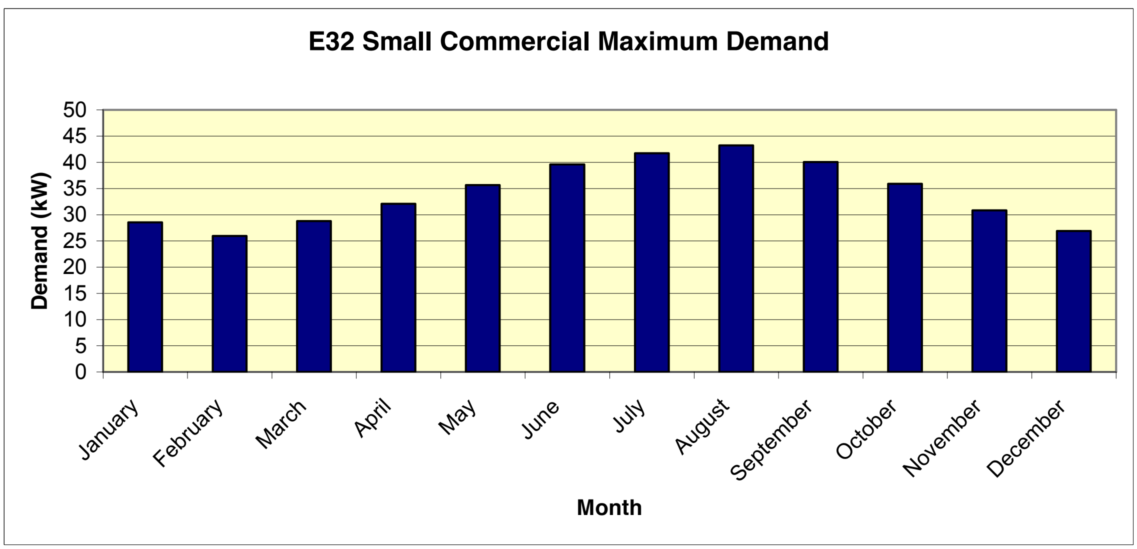
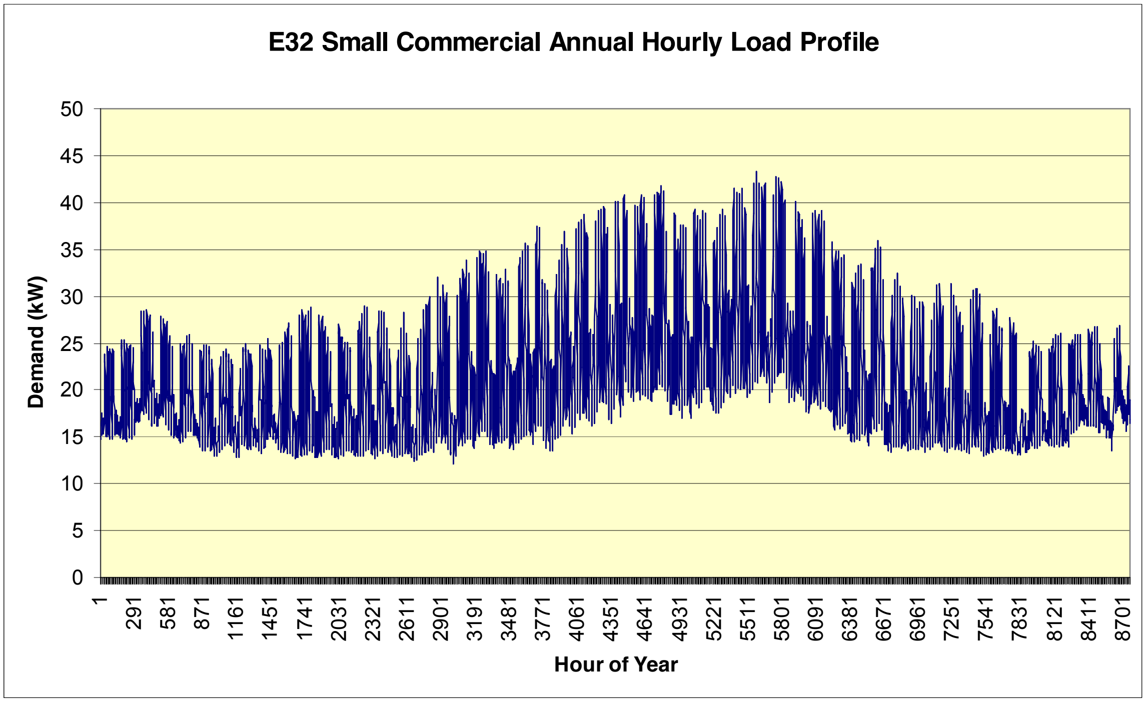


Figure D-12. E32 Small Commercial Annual Hourly Load Profile



Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

D.5 Commercial E32 Medium Characteristics

The average commercial customer under the E32 tariff with a peak demand in the range of 101 kW to 400 kW has an annual electric consumption of 928,847 kWh and a peak demand of 193.7 kW that occurs in August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-13. E32 Medium Commercial Energy Consumption

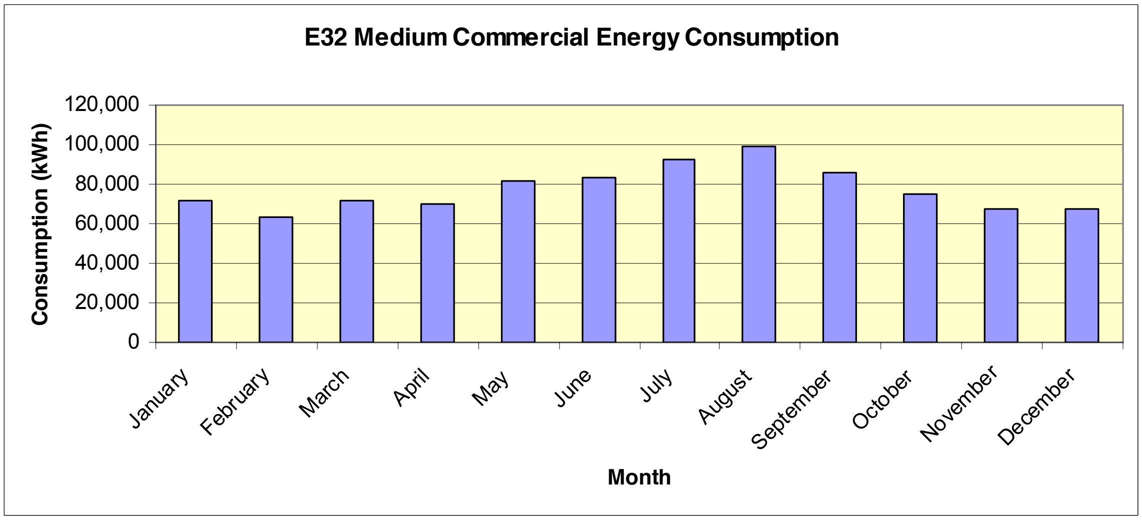


Figure D-14. E32 Medium Commercial Maximum Demand

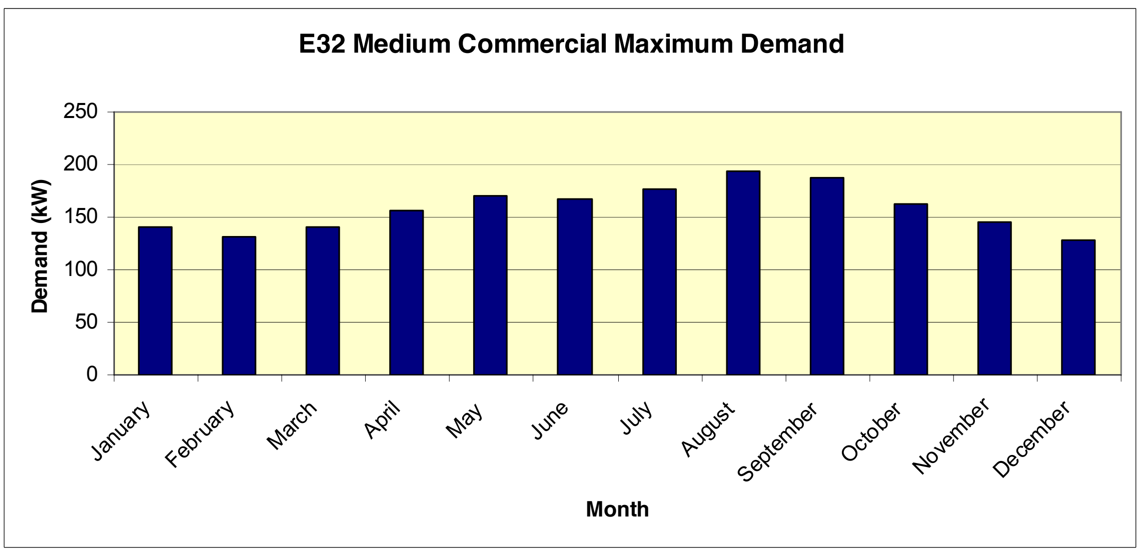
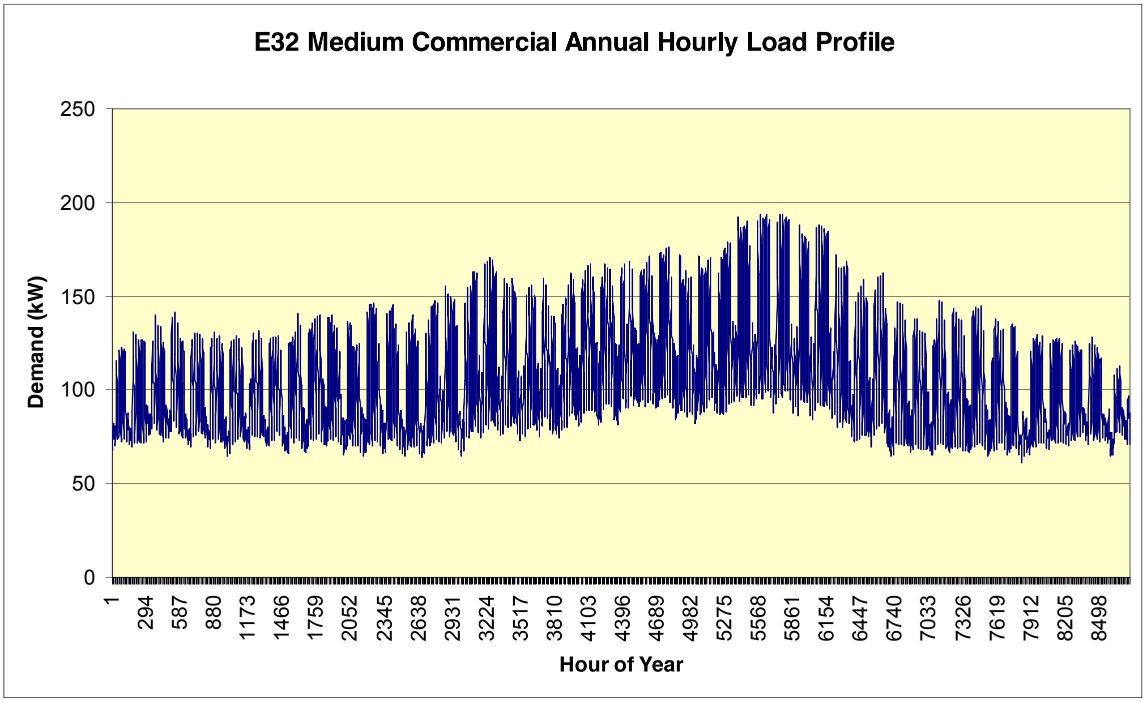


Figure D-15. E32 Medium Commercial Annual Hourly Load Profile



Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

D.6 Commercial E32 Large Characteristics

The average commercial customer under the E32 tariff with a peak demand greater than 400 kW has an annual electric consumption of 3,379,799 kWh and a peak demand of 597.8 kW that occurs in August. A summary of the electric consumption characteristics is provided in the following table and graphs.

Figure D-16. E32 Large Commercial Energy Consumption

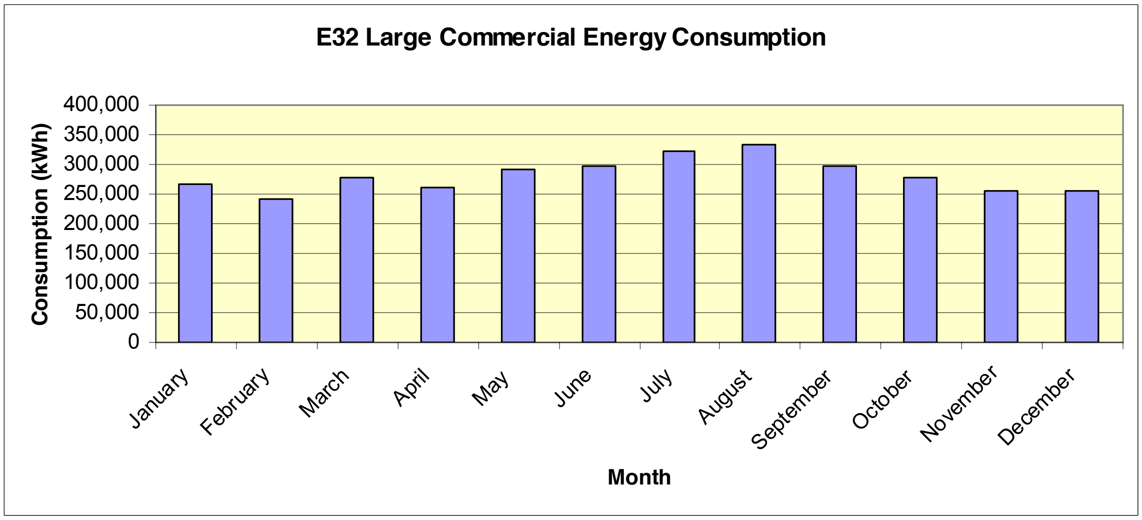


Figure D-17. E32 Large Commercial Maximum Demand

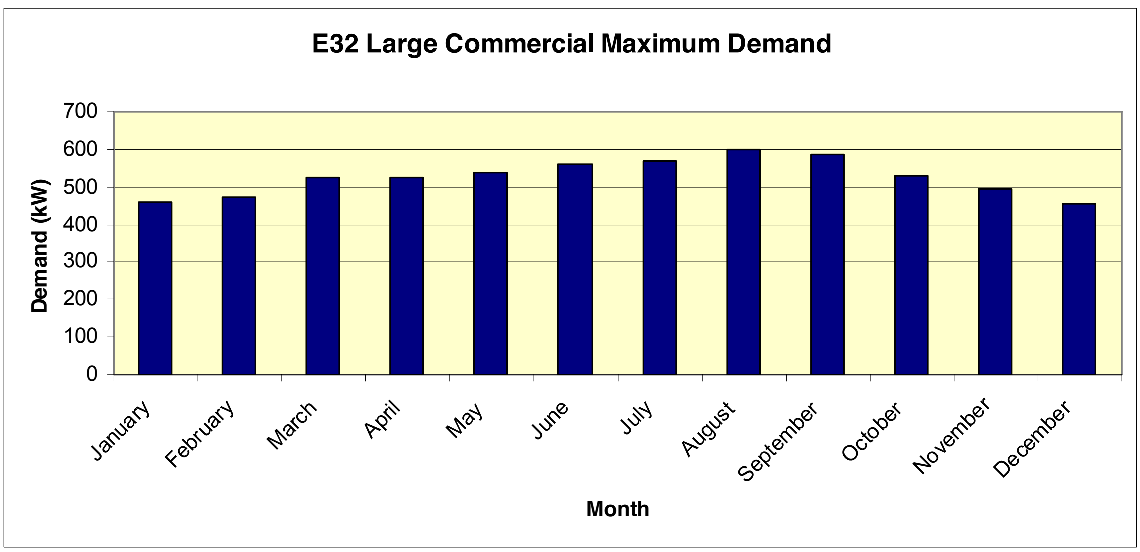
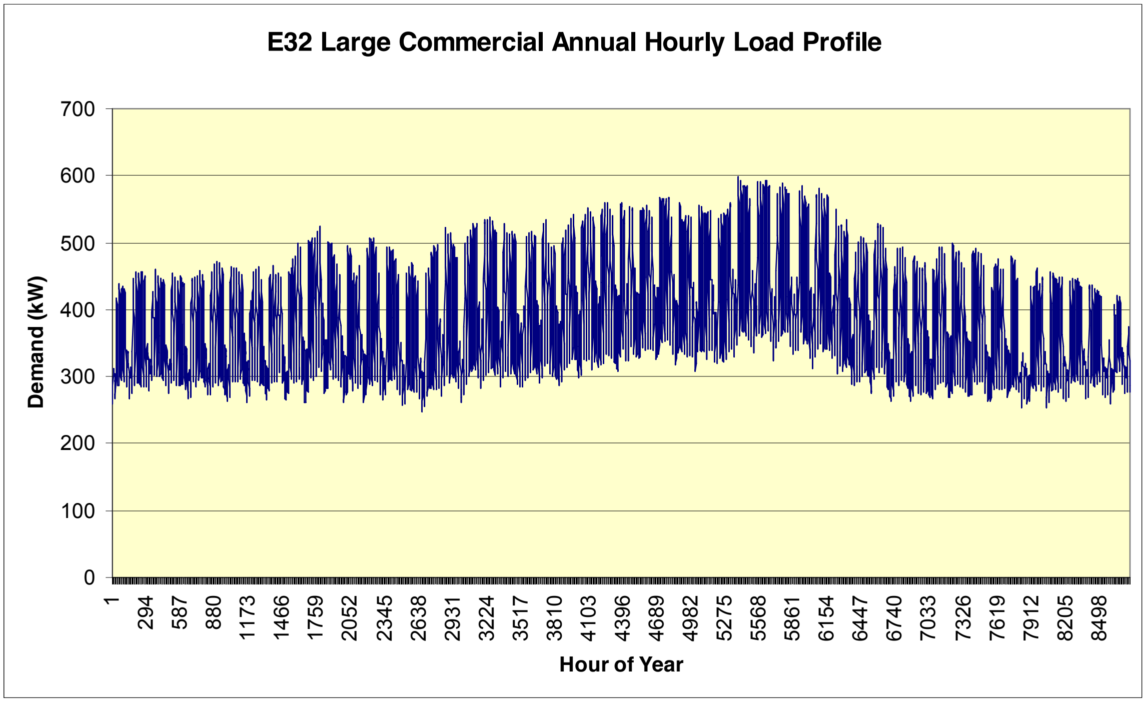


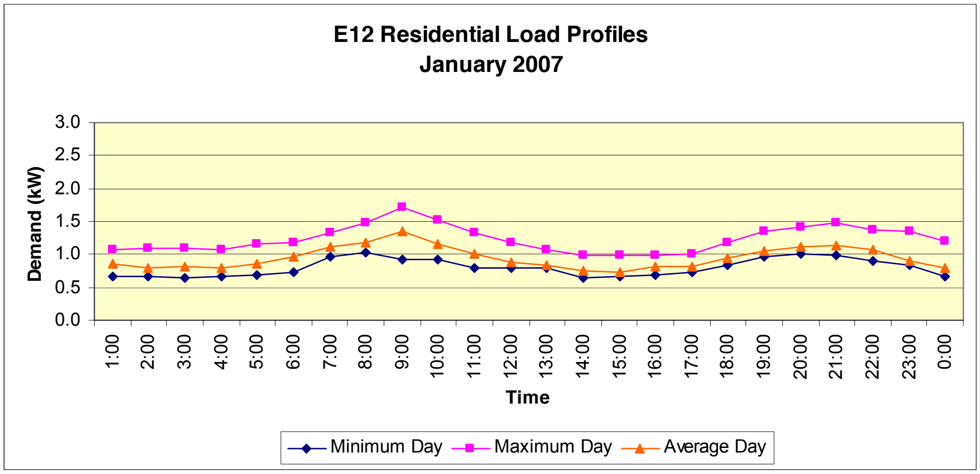
Figure D-18. E32 Large Commercial Annual Hourly Load Profile

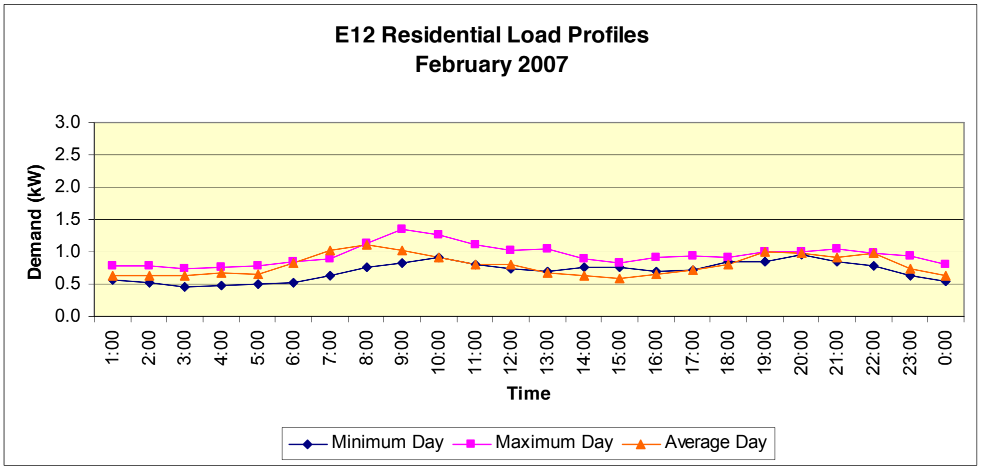


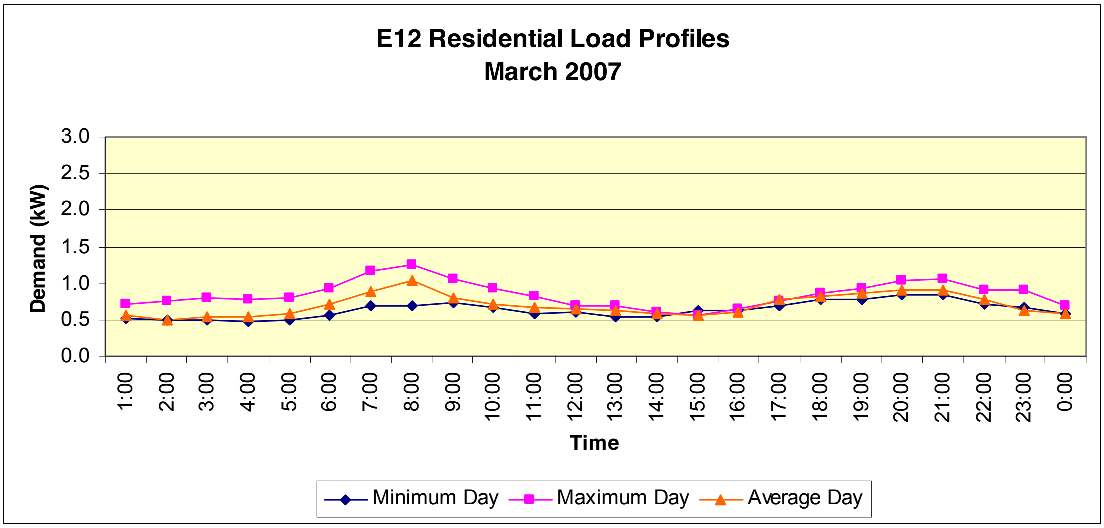
Appendix E presents hourly load data that occurred in 2007. The profiles presented for each month consist of the maximum consumption day, the minimum consumption day, and the average consumption day.

APPENDIX E — MONTHLY LOAD PROFILES BY SELECTED APS RATE GROUP FOR 2007

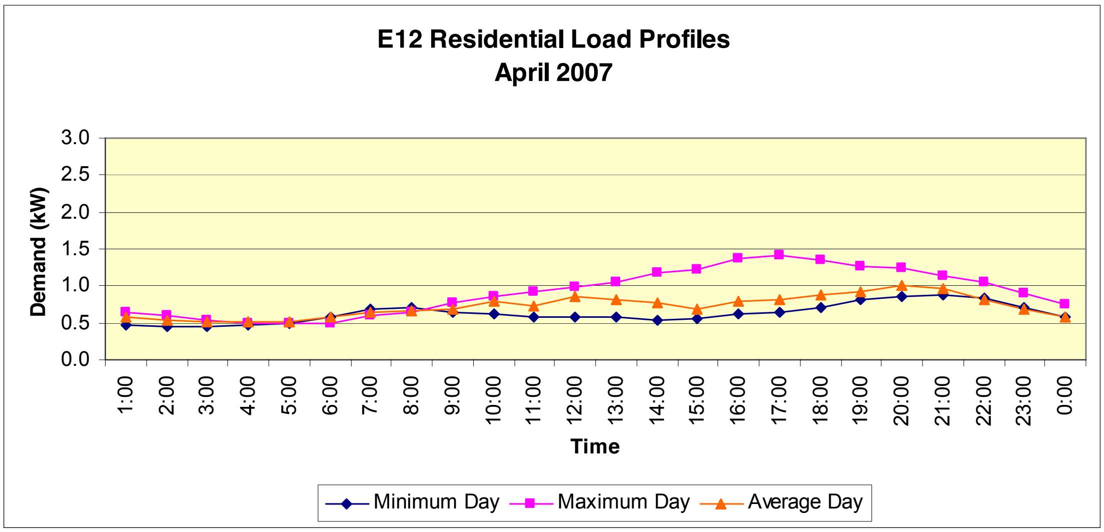
E.1 E12 Residential Load Profiles by Month



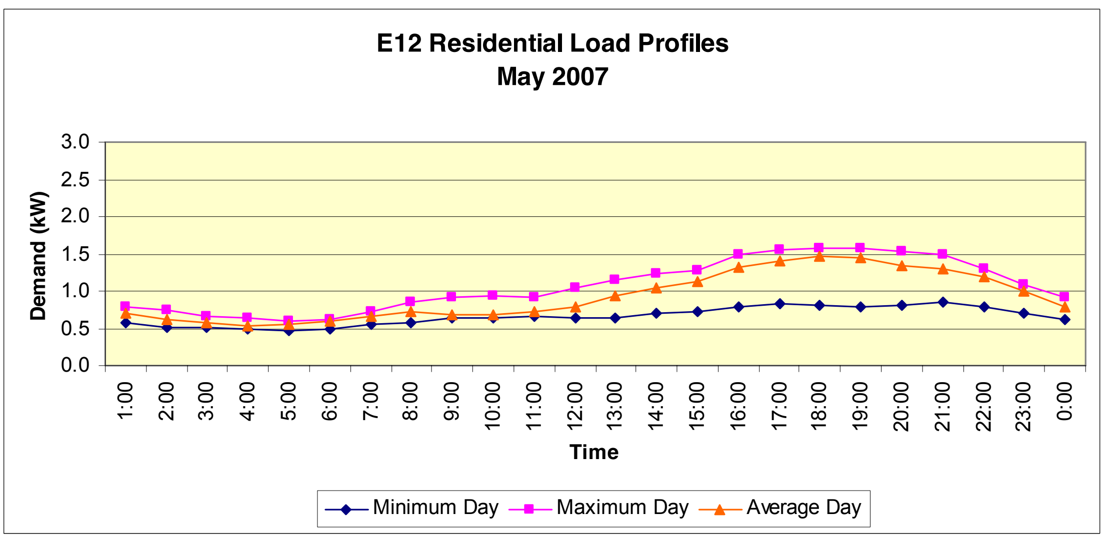




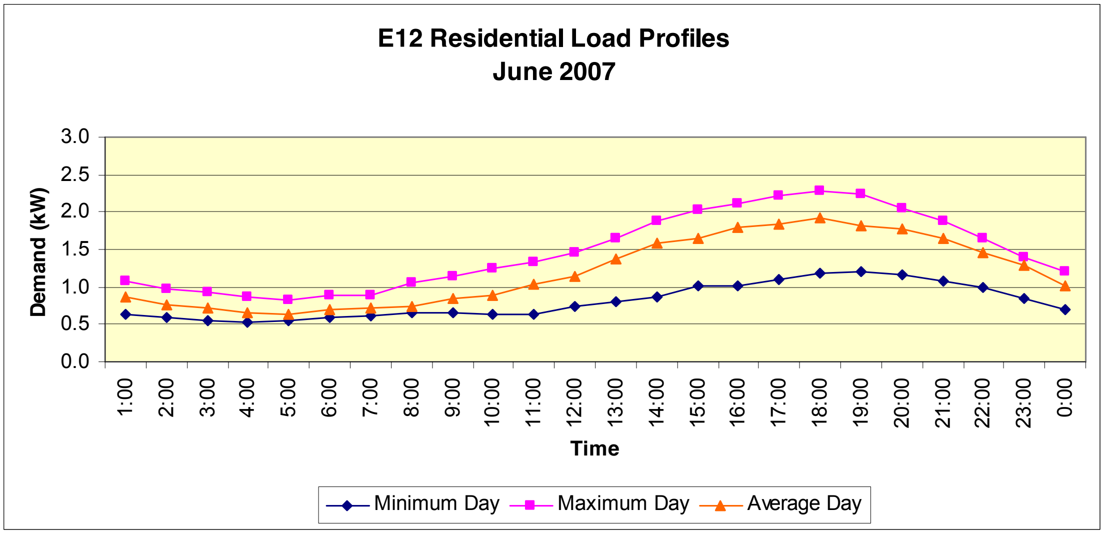
E12 Residential Load Profiles
March 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

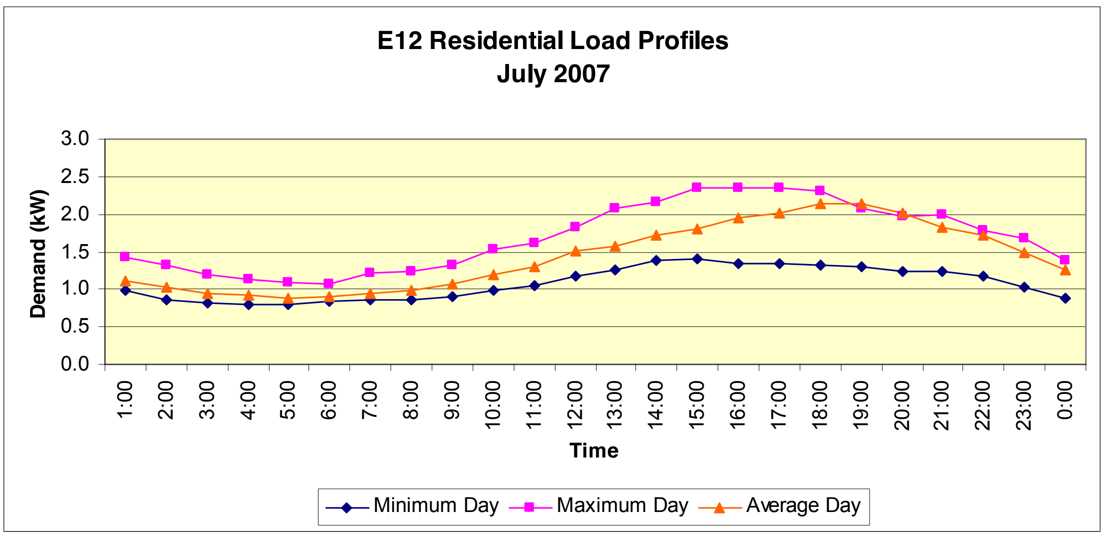


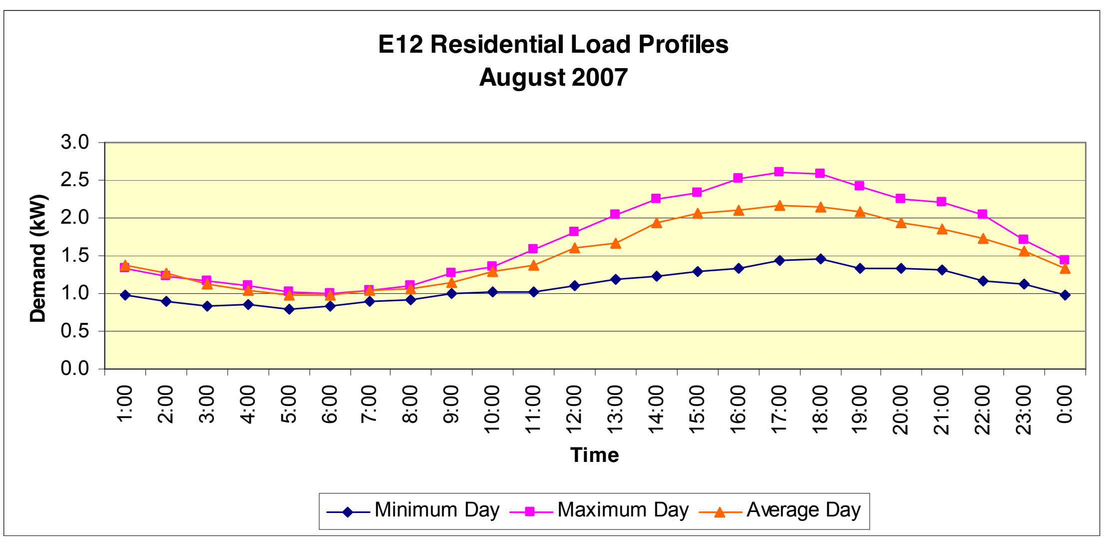
E12 Residential Load Profiles
April 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

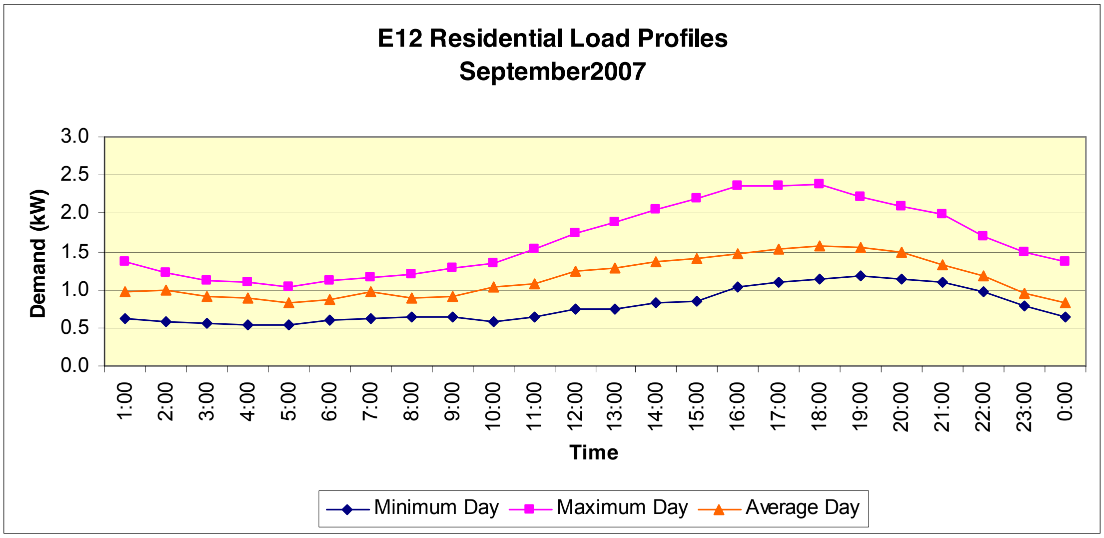


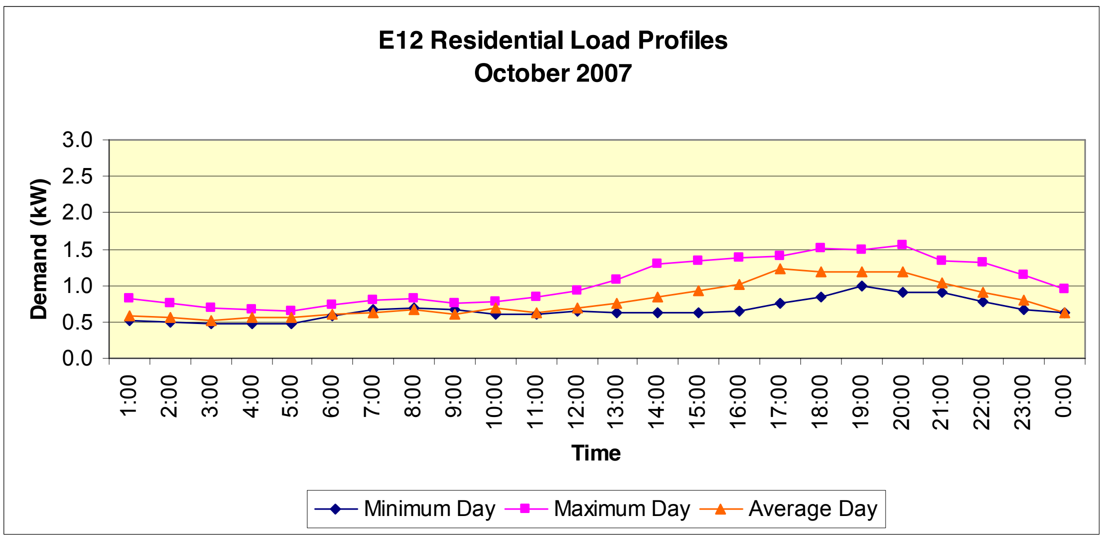
E12 Residential Load Profiles
May 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

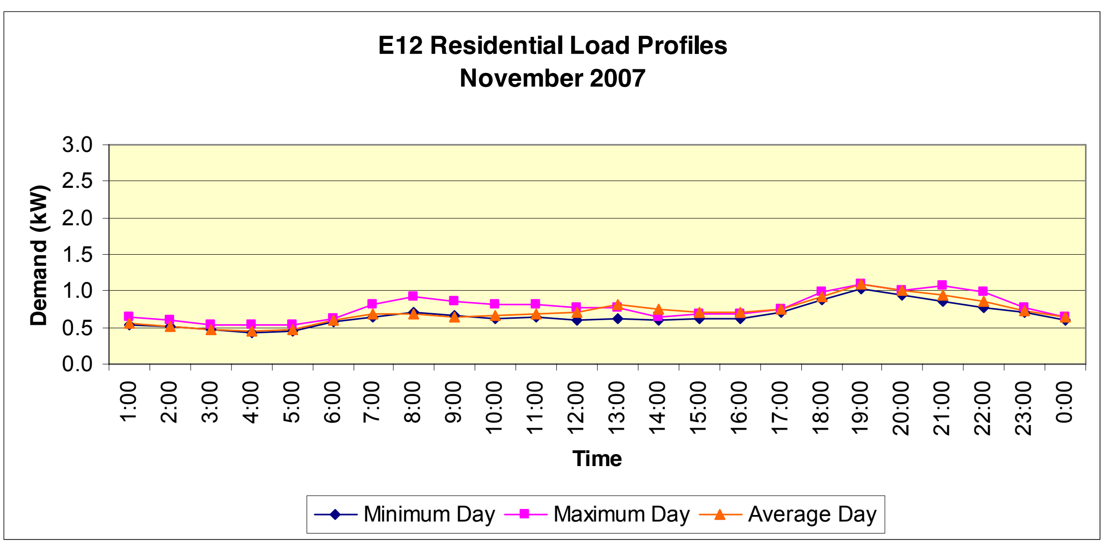

E12 Residential Load Profiles
June 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

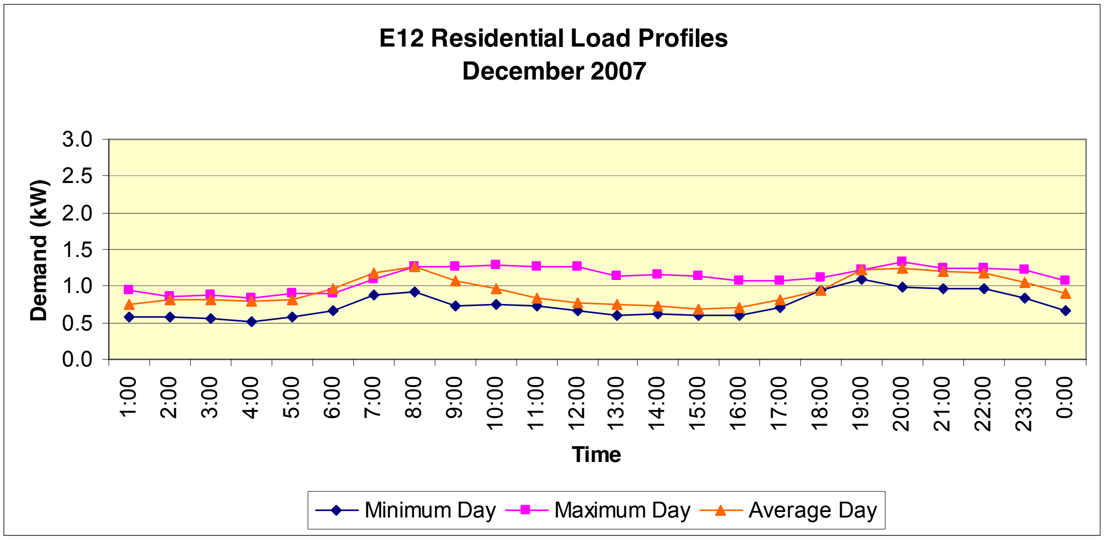

E12 Residential Load Profiles
July 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E12 Residential Load Profiles
August 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

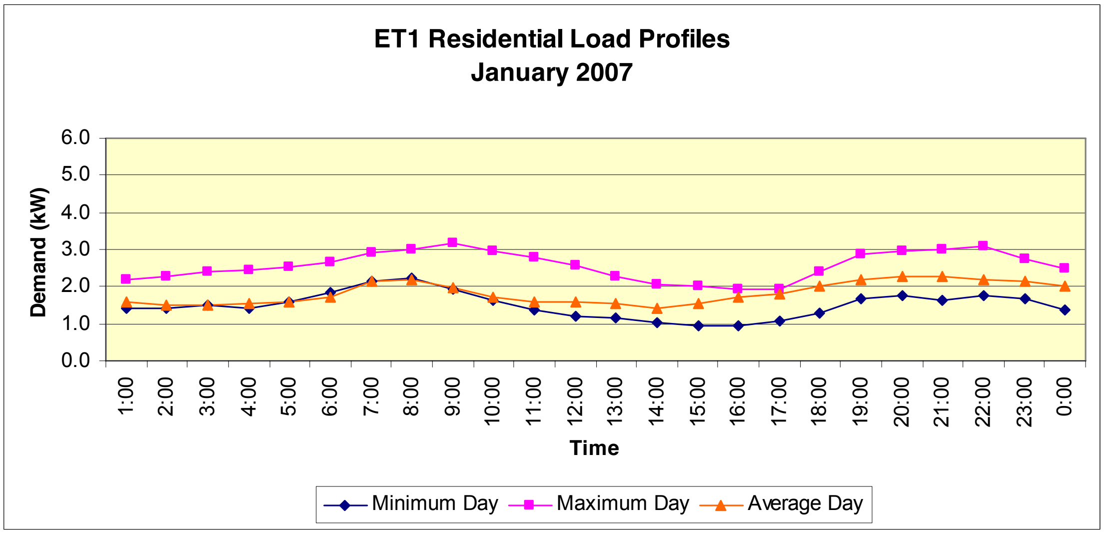

E12 Residential Load Profiles
September2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

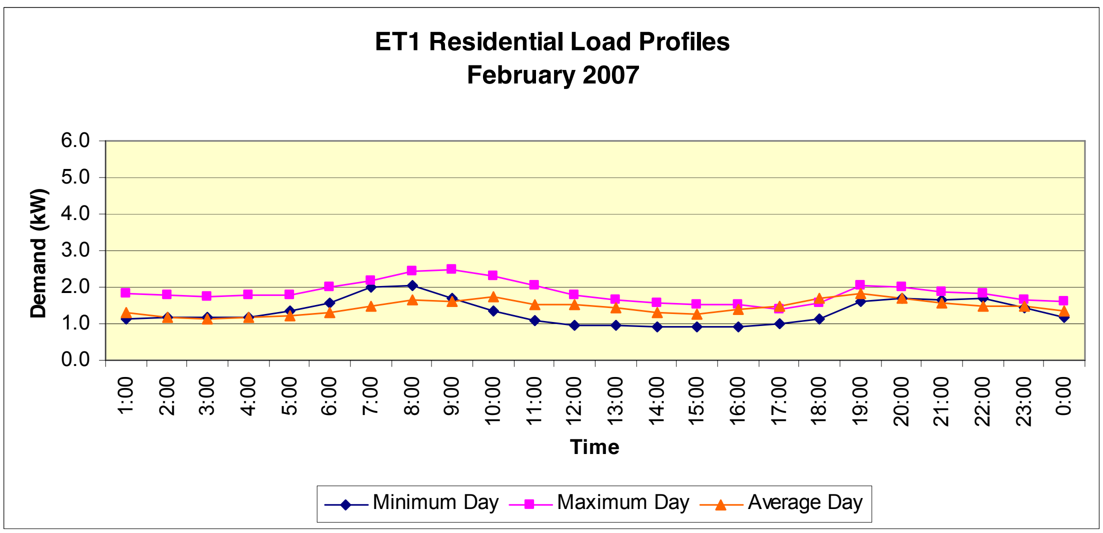

E12 Residential Load Profiles
October 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

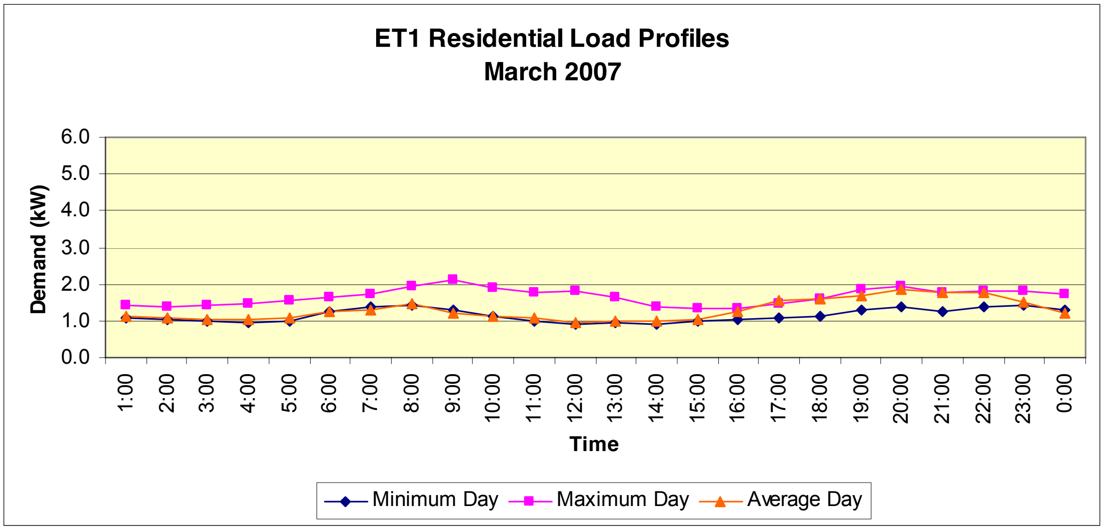

E12 Residential Load Profiles
November 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

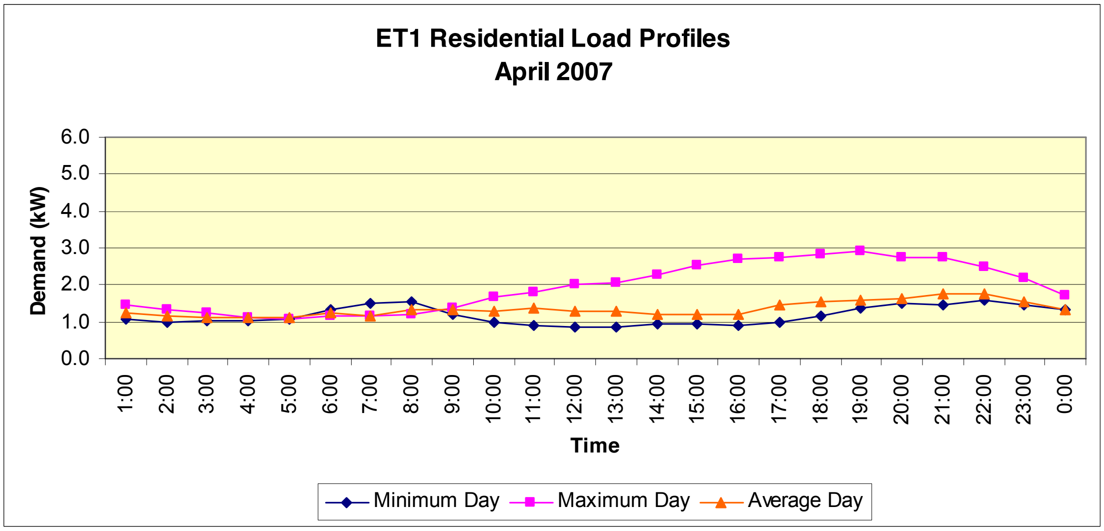

E12 Residential Load Profiles
December 2007
Demand (kW)
3.0
2.5
2.0
1.5
1.0
0.5
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

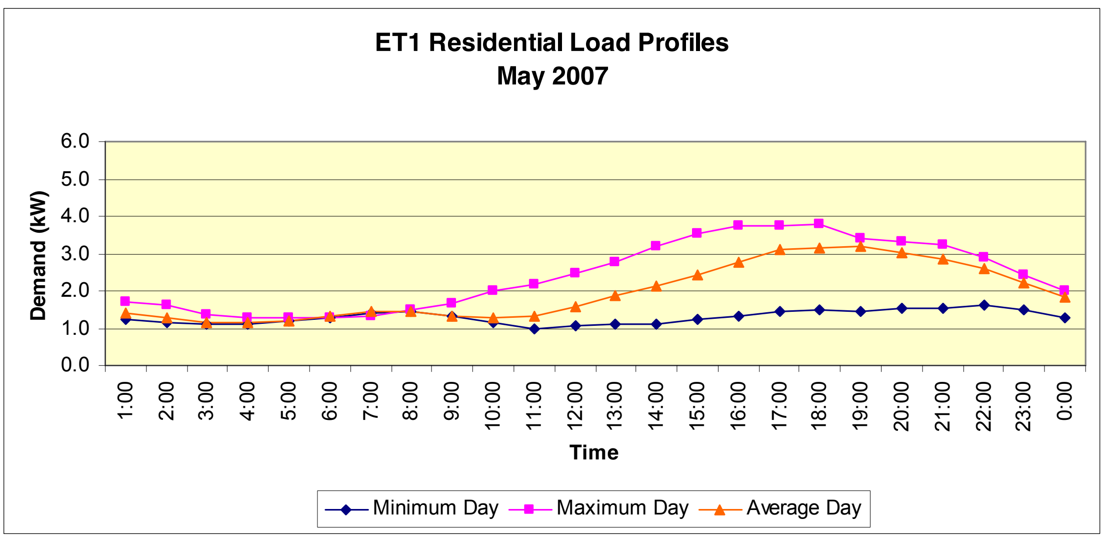
E.2 ET-1 Residential Load Profiles by Month

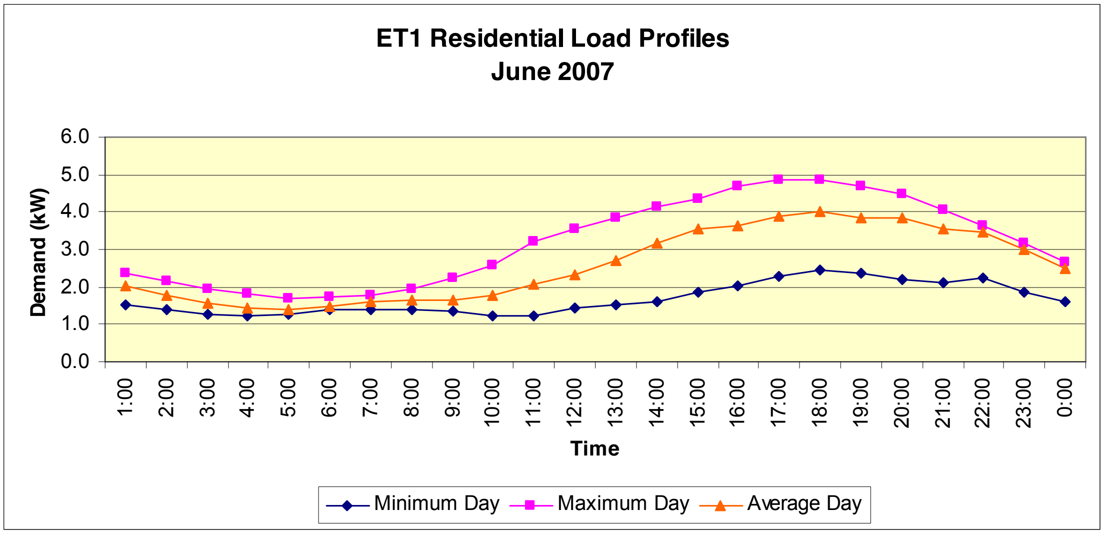


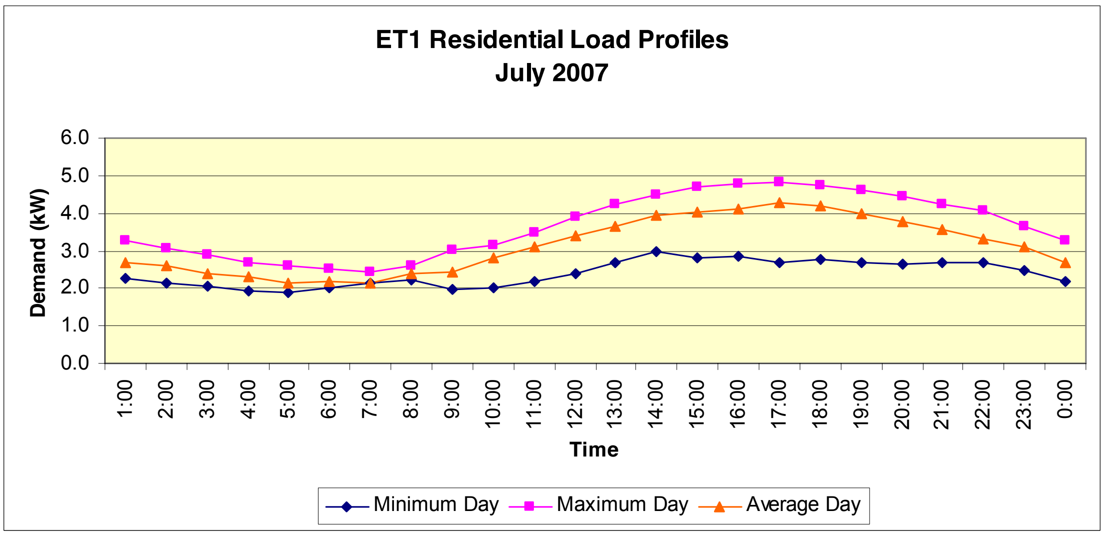


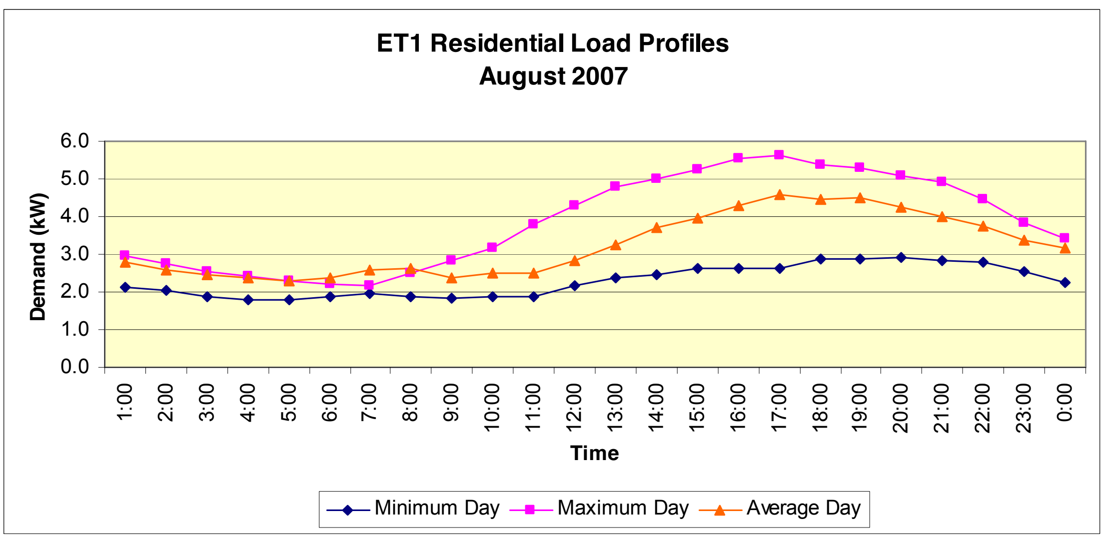

ET1 Residential Load Profiles
March 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

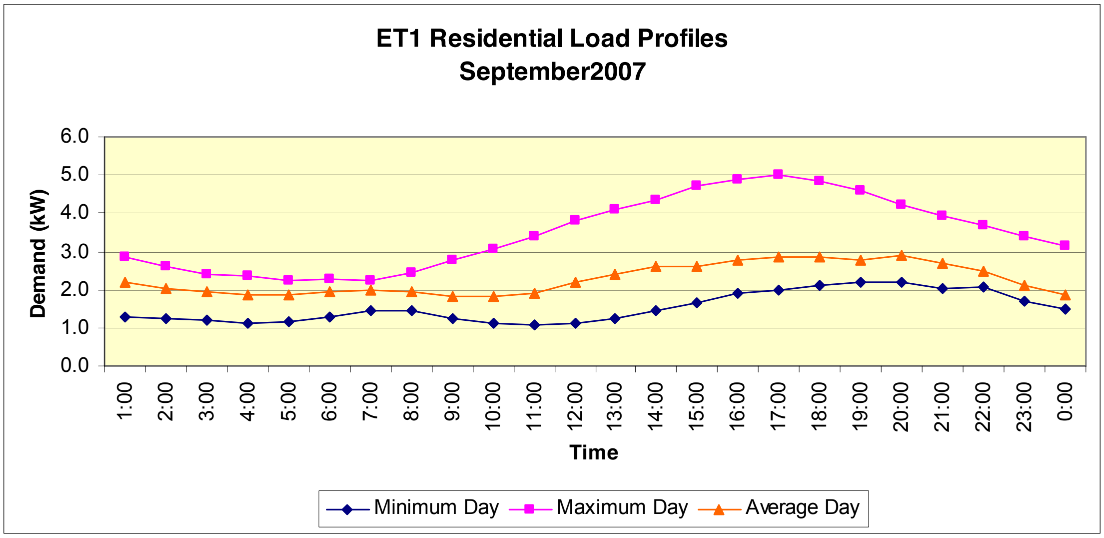

ET1 Residential Load Profiles
April 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

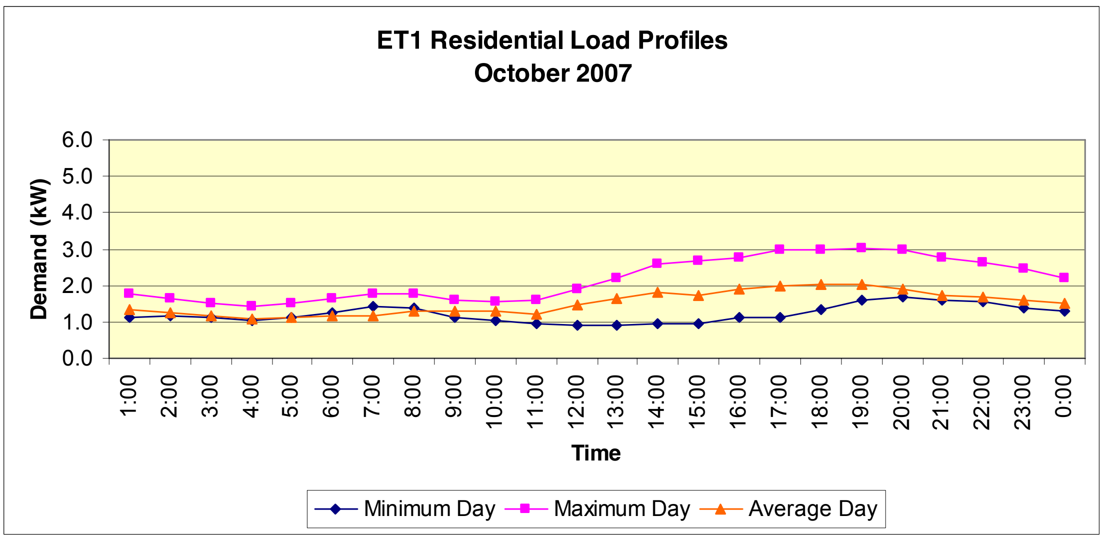

ET1 Residential Load Profiles
May 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

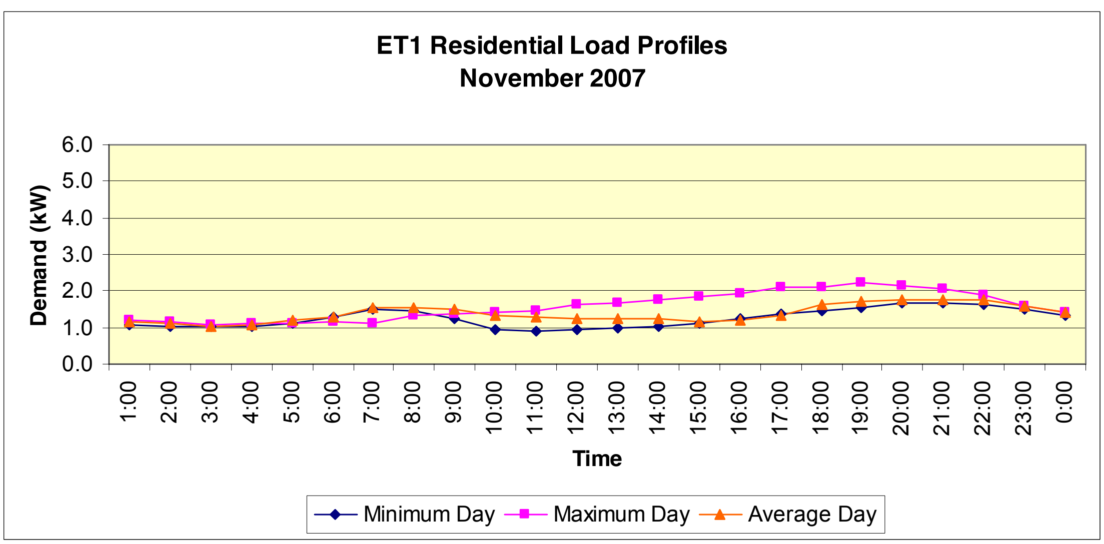

ET1 Residential Load Profiles
June 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

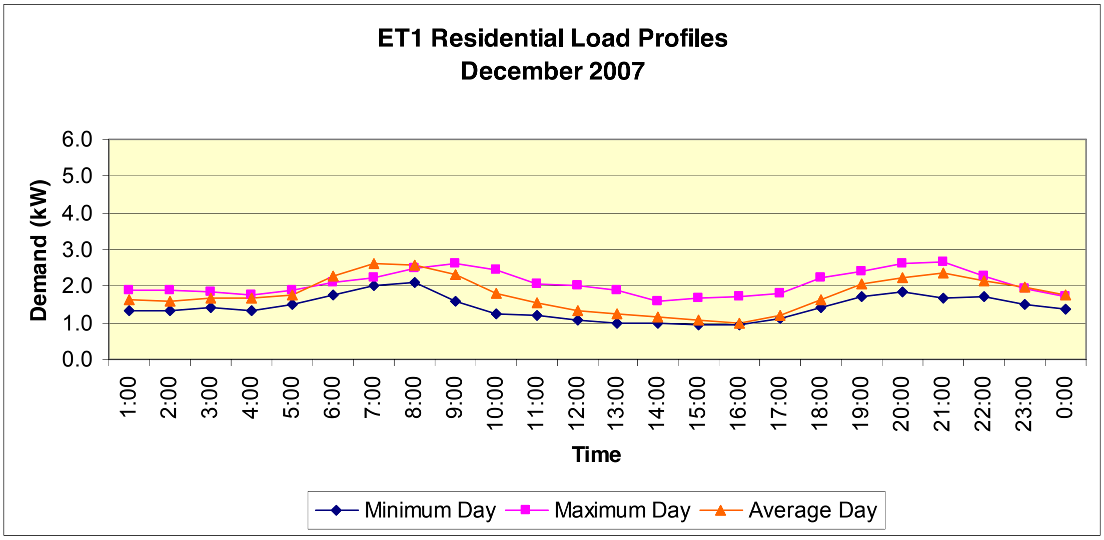

ET1 Residential Load Profiles
July 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


ET1 Residential Load Profiles
August 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

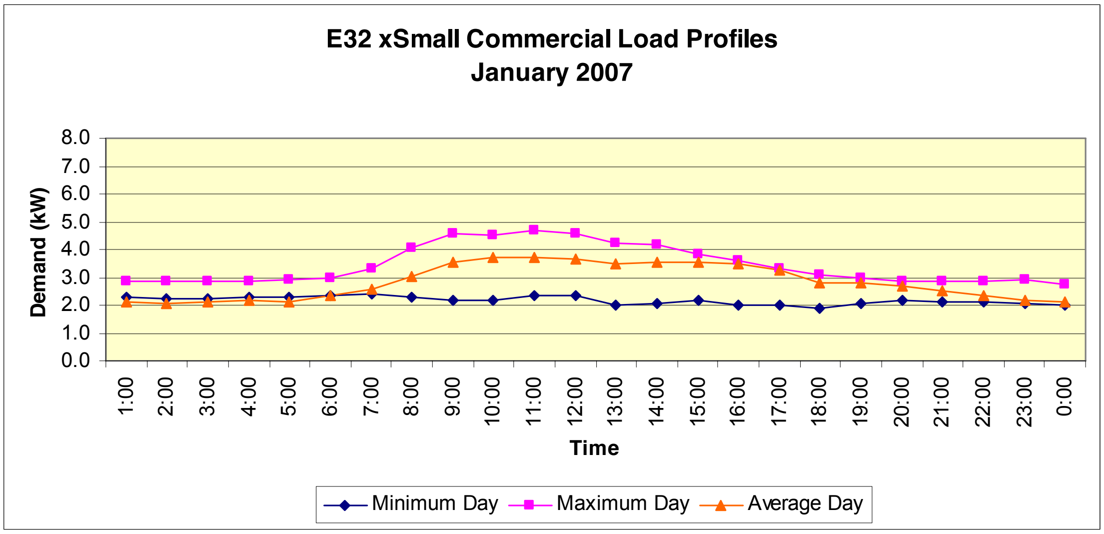

ET1 Residential Load Profiles
September2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

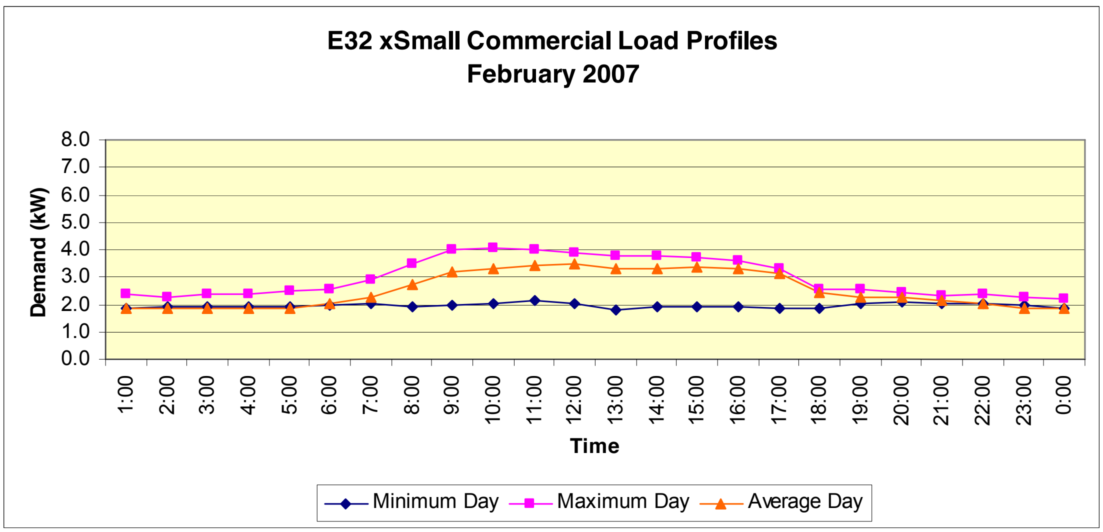

ET1 Residential Load Profiles
October 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

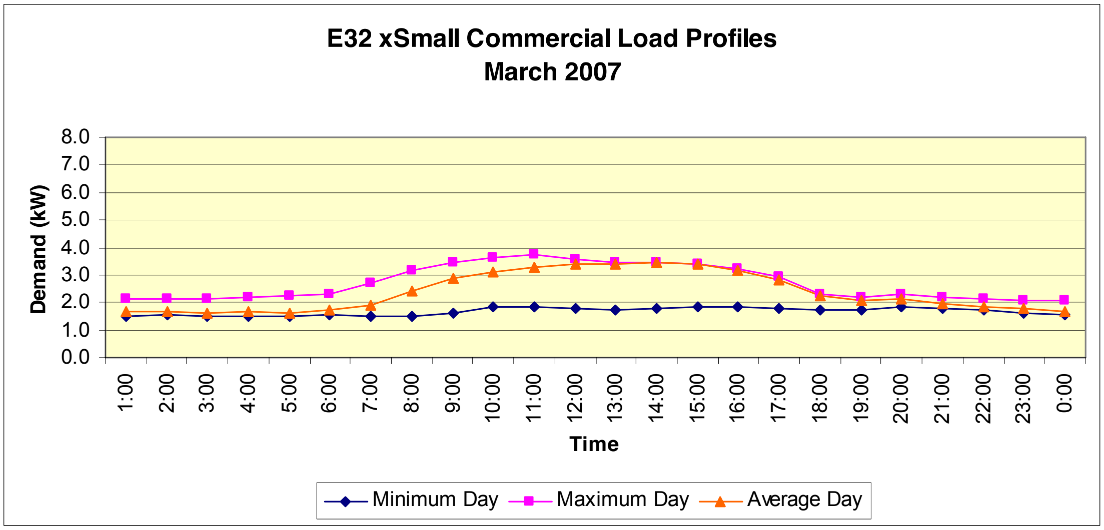

ET1 Residential Load Profiles
November 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

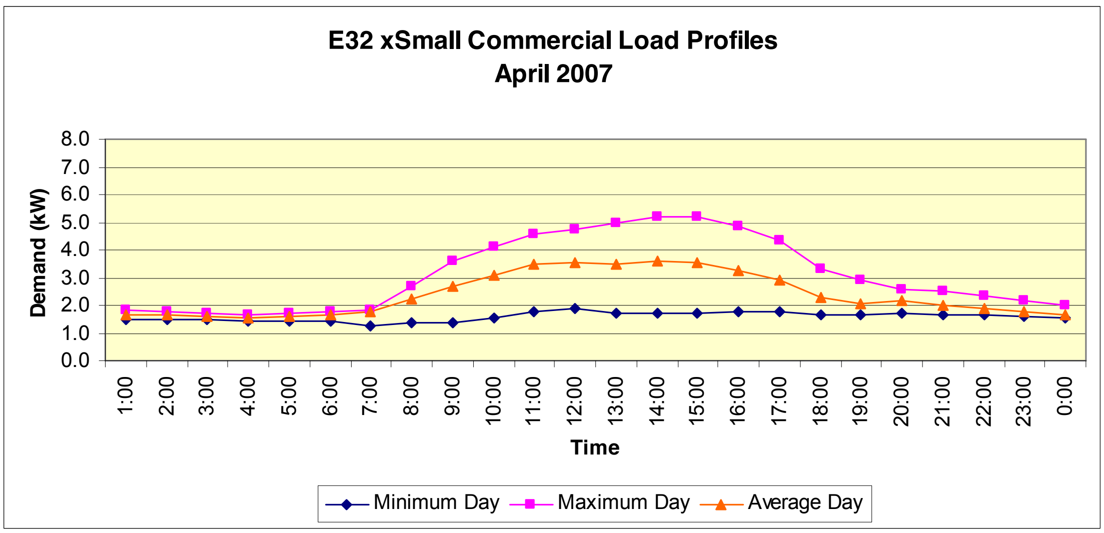

ET1 Residential Load Profiles
December 2007
Demand (kW)
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

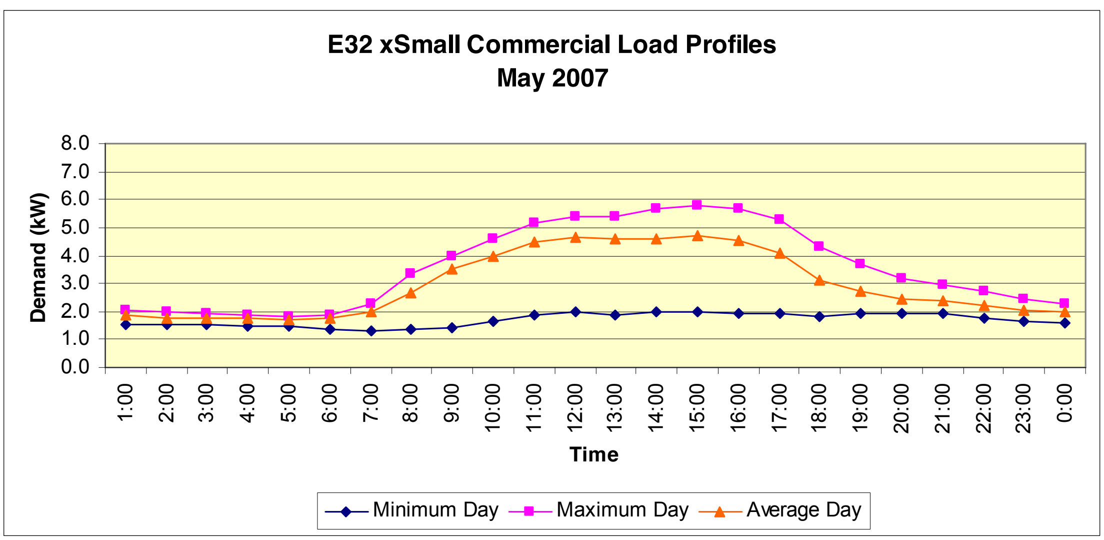
E.3 E32 Extra Small Commercial Load Profiles by Month

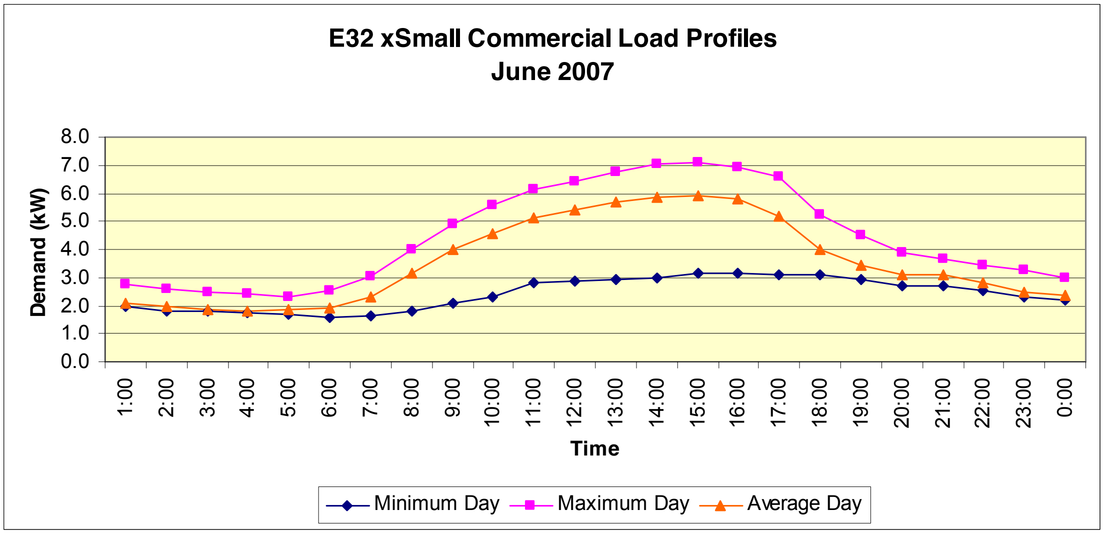


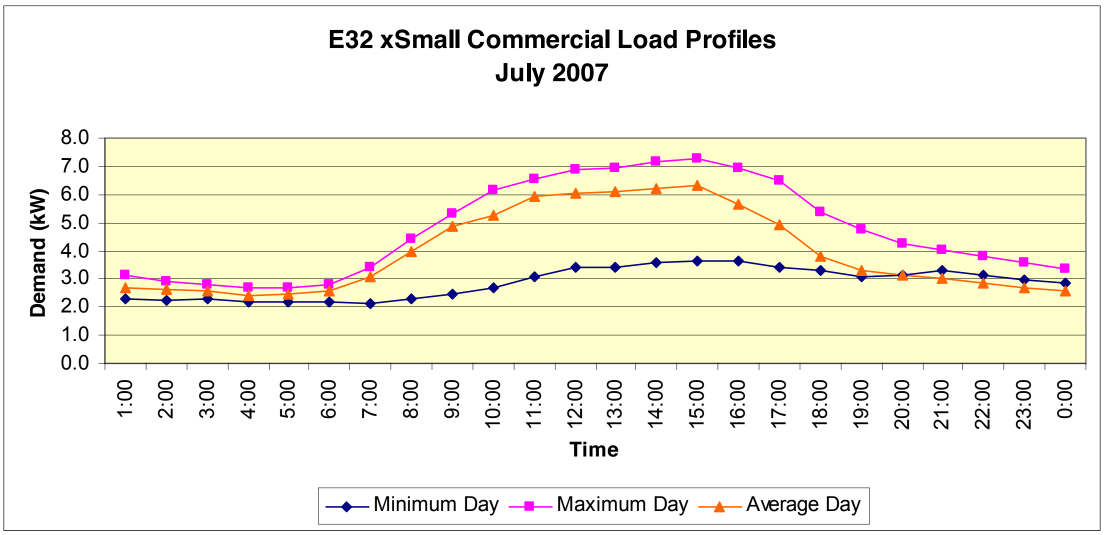


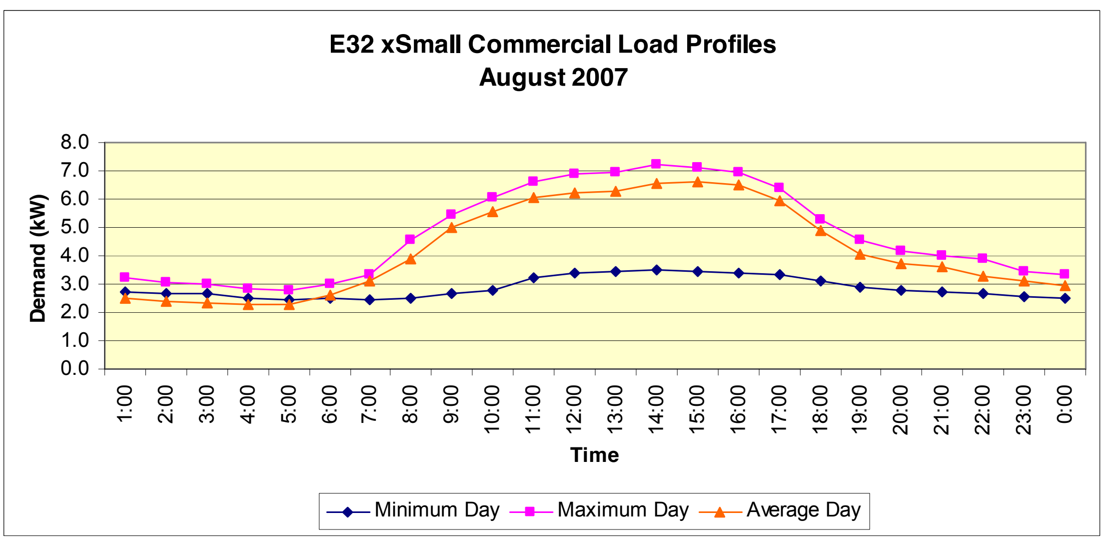

E32 xSmall Commercial Load Profiles
March 2007
Demand (kW)
Time
Minimum Day
Maximum Day
Average Day

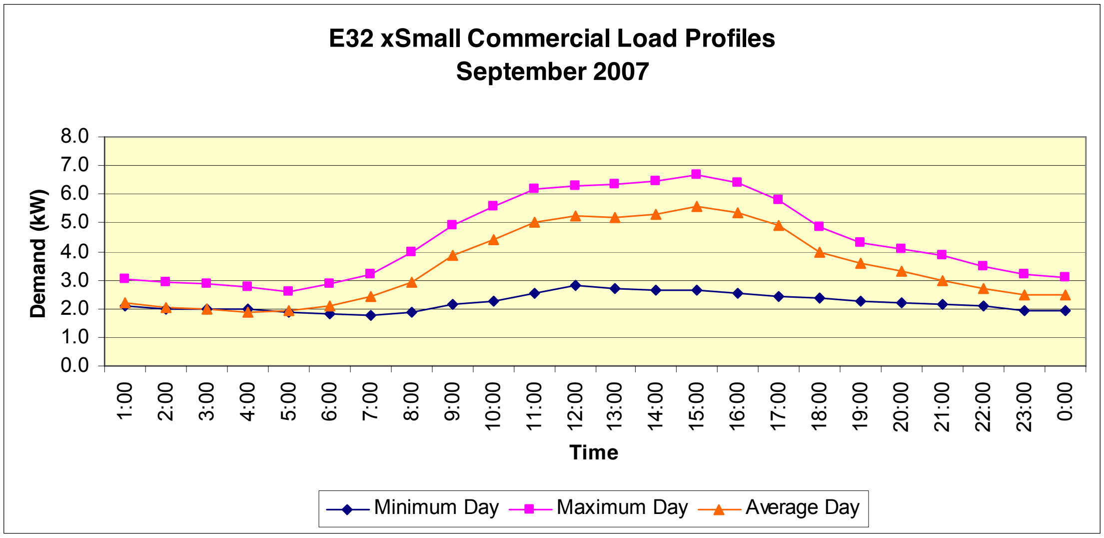

E32 xSmall Commercial Load Profiles
April 2007
Demand (kW)
Time
Minimum Day
Maximum Day
Average Day

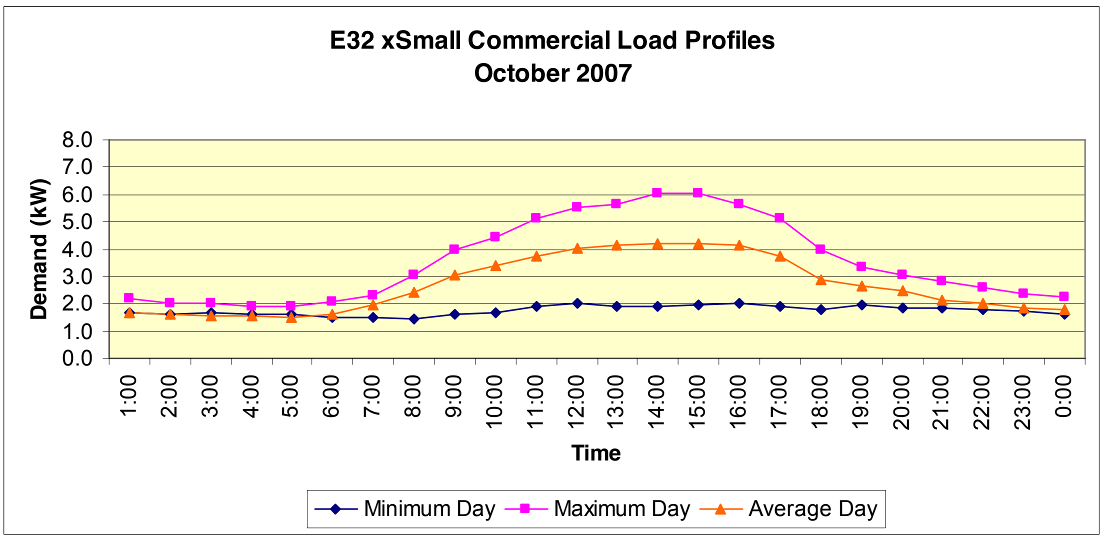

E32 xSmall Commercial Load Profiles
May 2007
Demand (kW)
Time
Minimum Day
Maximum Day
Average Day

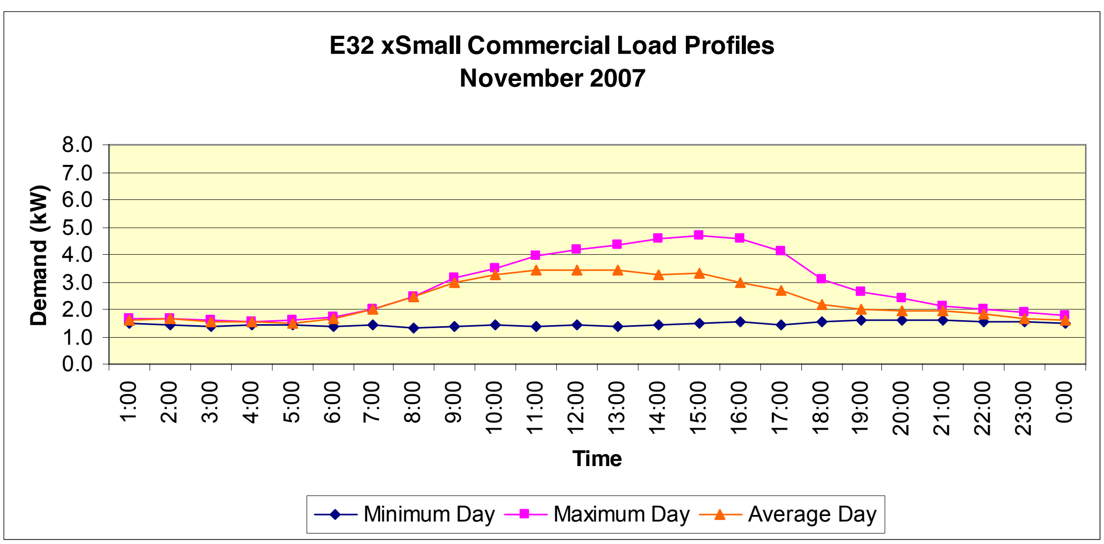

E32 xSmall Commercial Load Profiles
June 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

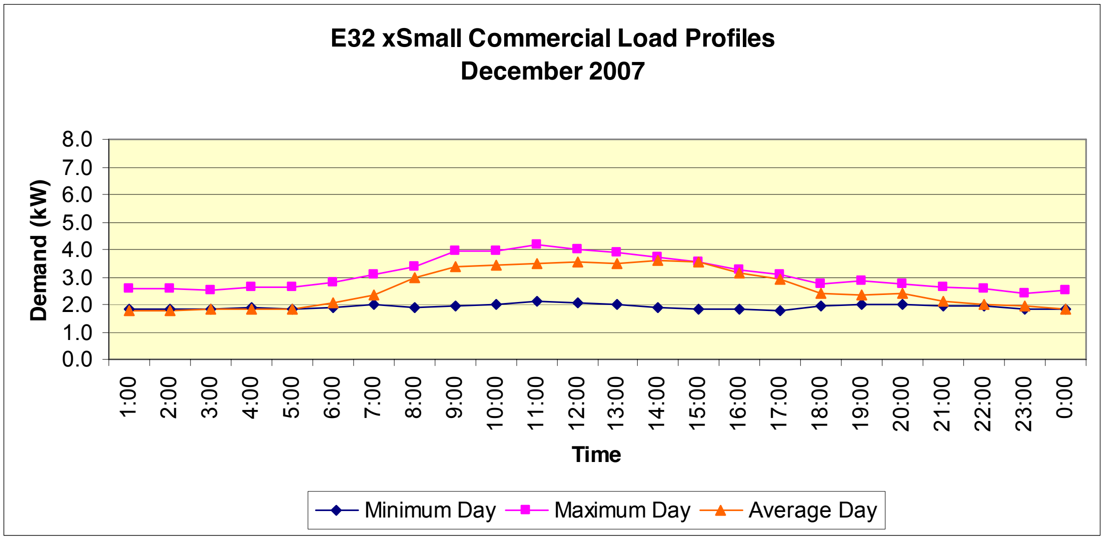

E32 xSmall Commercial Load Profiles
July 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day


E32 xSmall Commercial Load Profiles
August 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

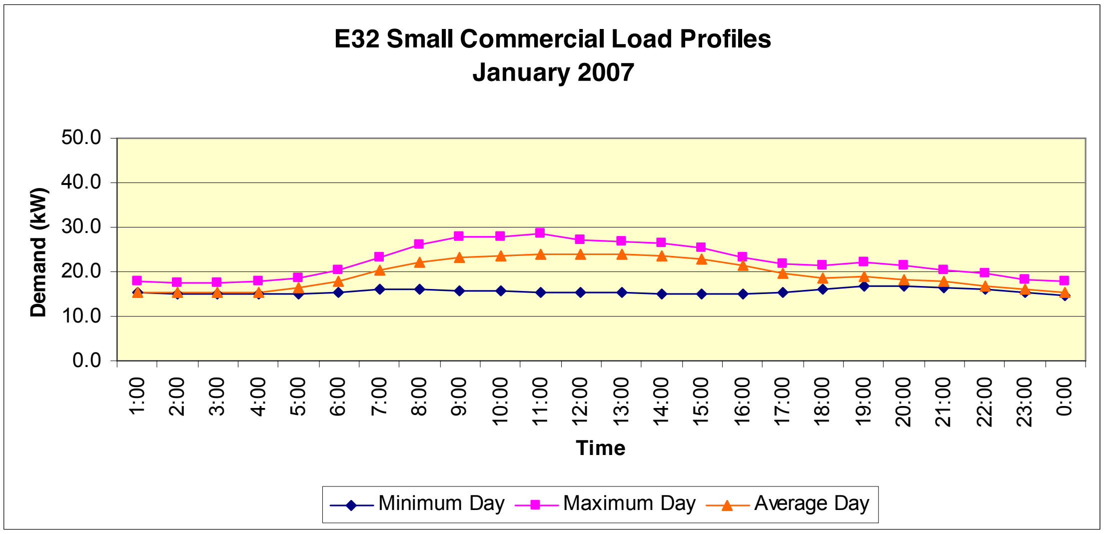

E32 xSmall Commercial Load Profiles
September 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

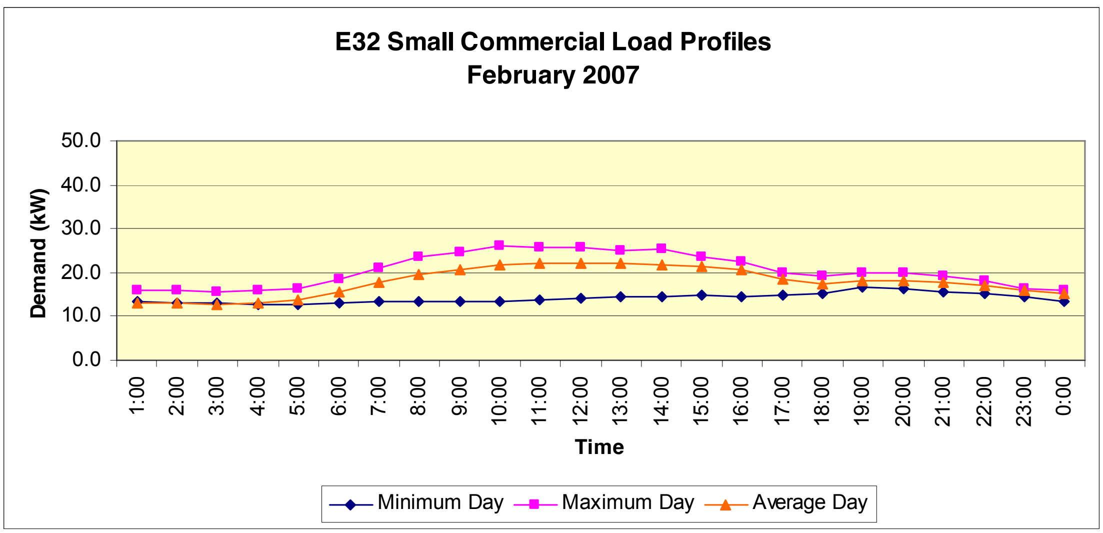

E32 xSmall Commercial Load Profiles
October 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

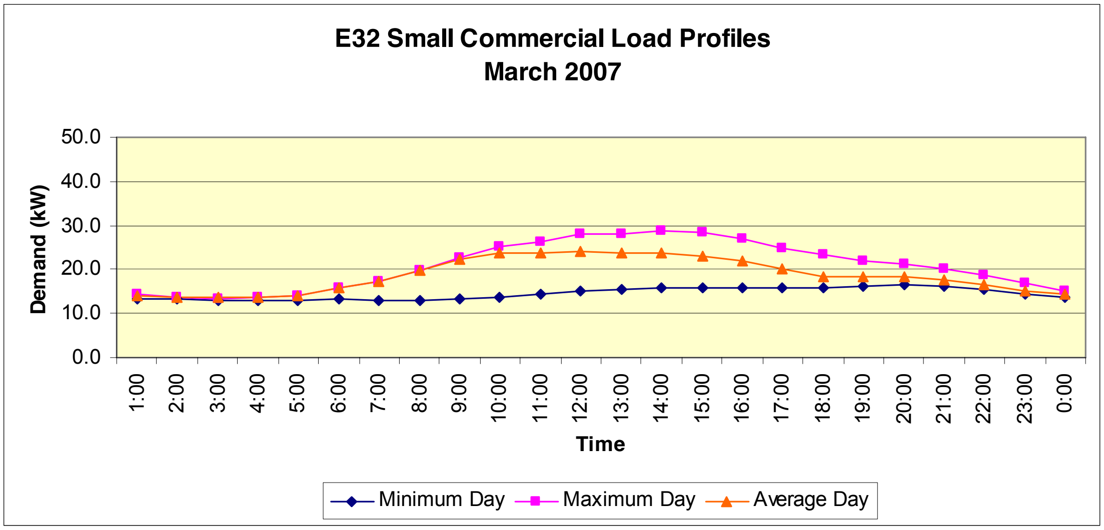

E32 xSmall Commercial Load Profiles
November 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

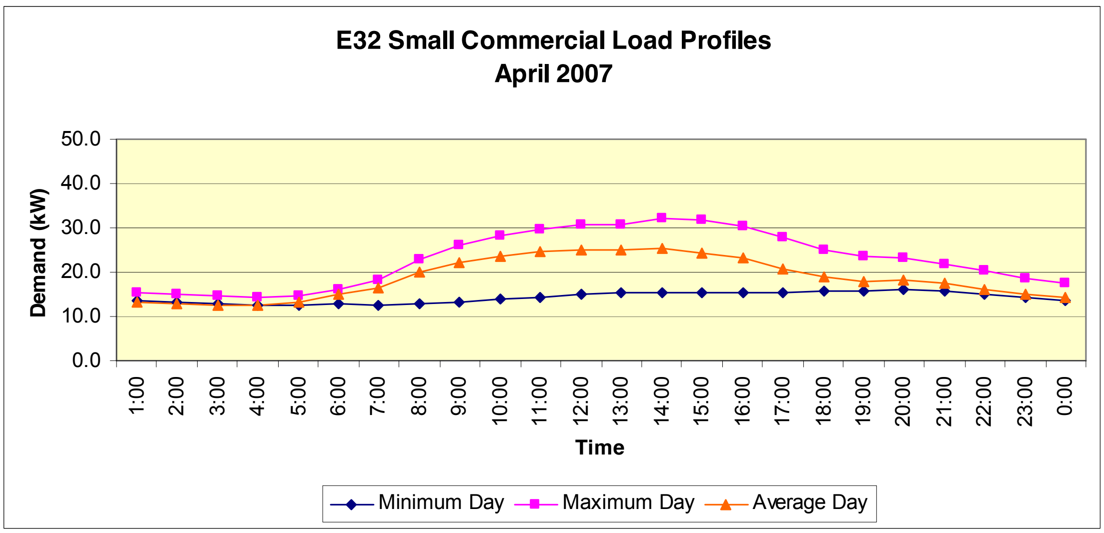

E32 xSmall Commercial Load Profiles
December 2007
Demand (kW)
8.0
7.0
6.0
5.0
4.0
3.0
2.0
1.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

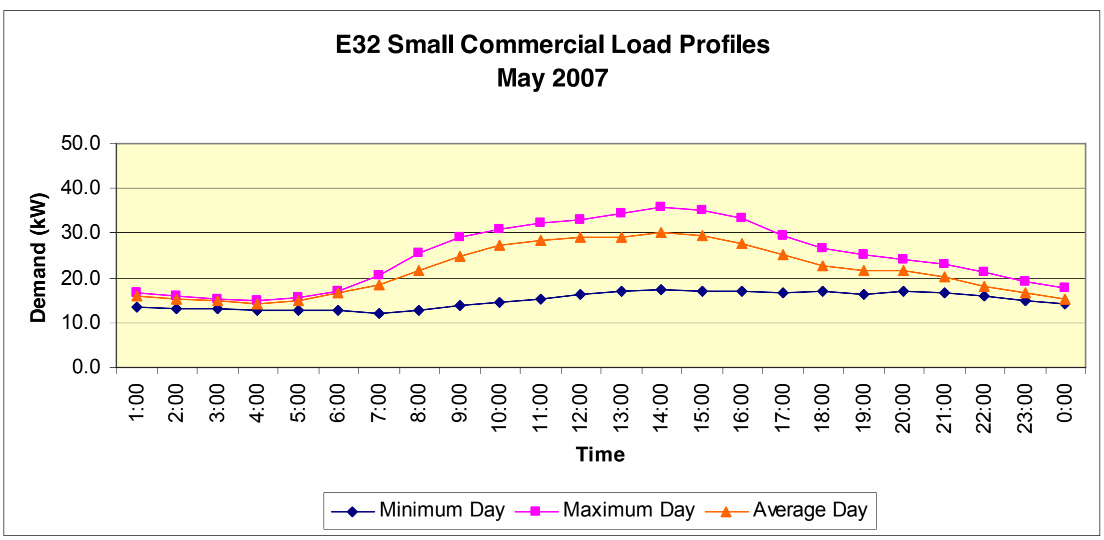
E.4 E32 Small Load Profiles by Month

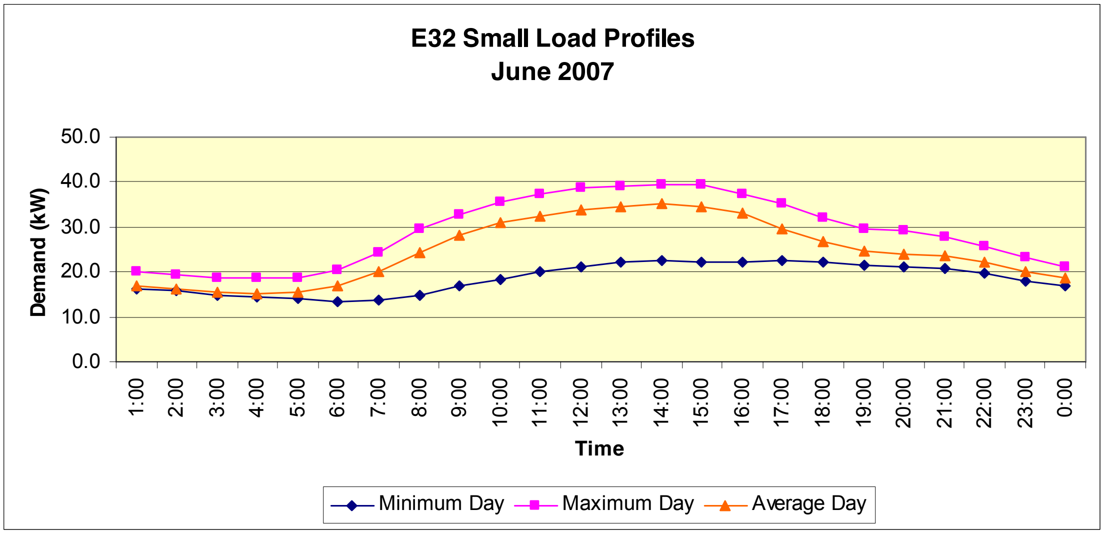


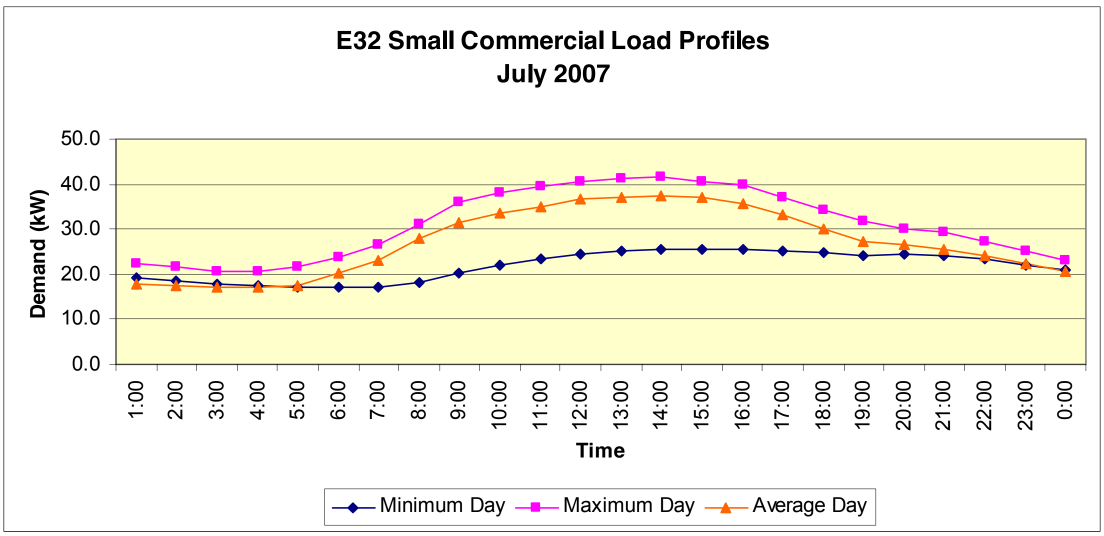


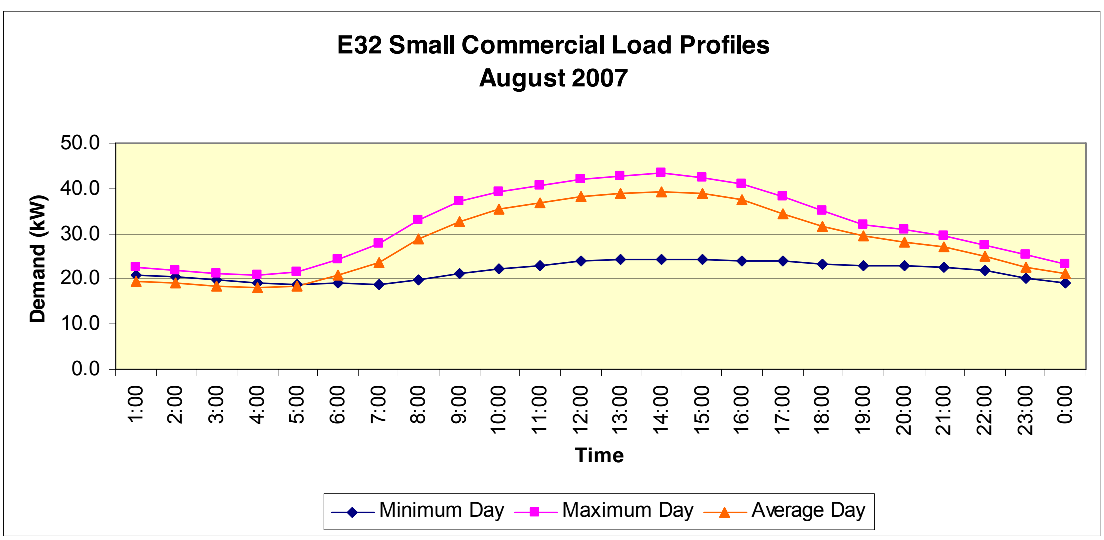

E32 Small Commercial Load Profiles
March 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

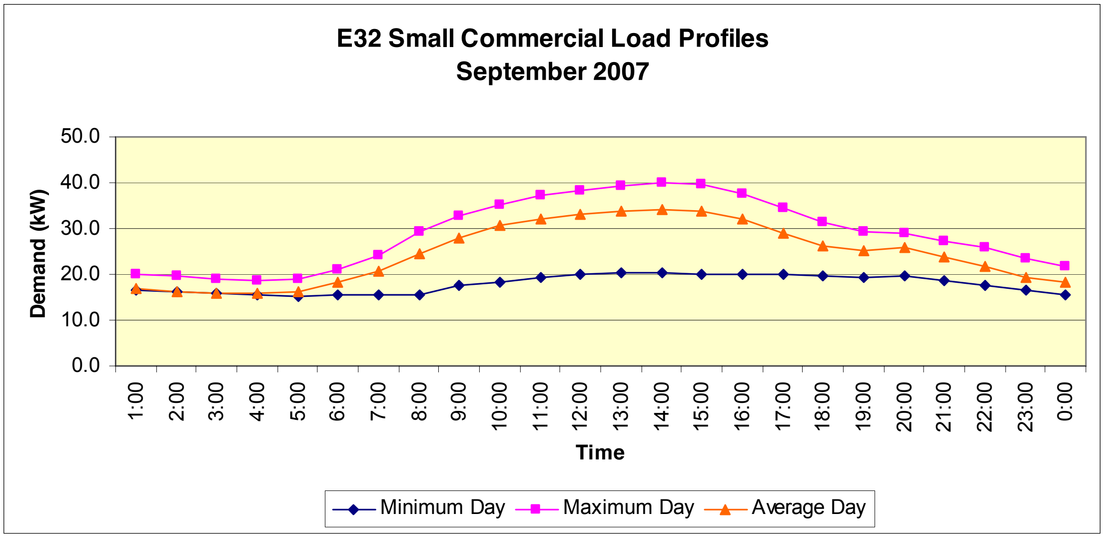

E32 Small Commercial Load Profiles
April 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

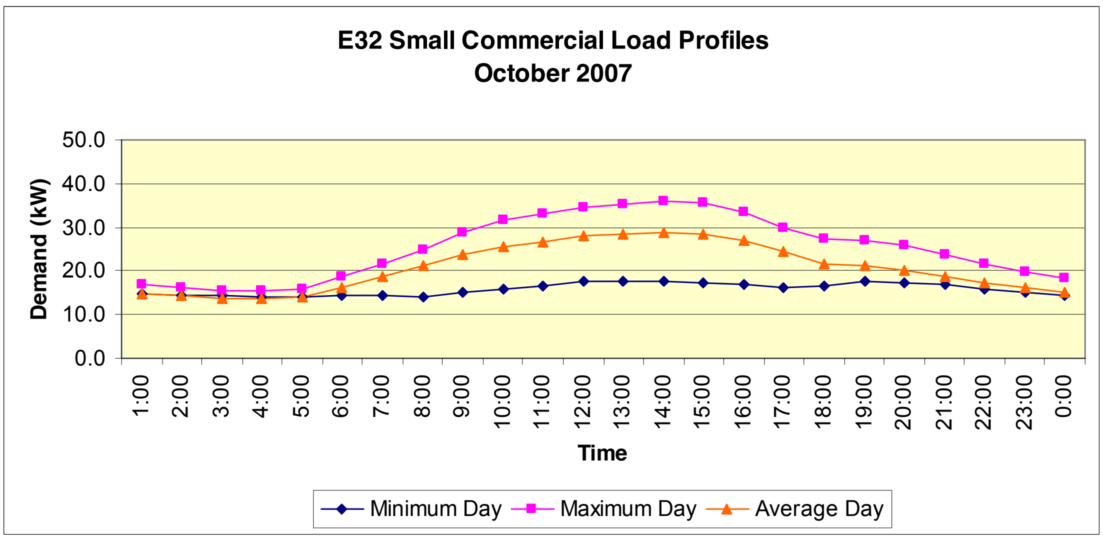

E32 Small Commercial Load Profiles
May 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

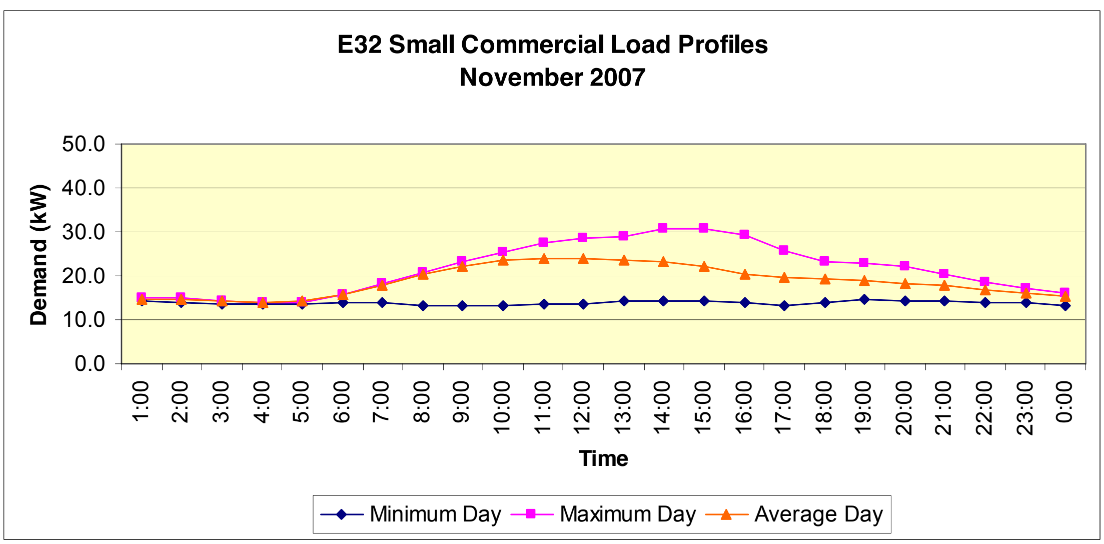

E32 Small Load Profiles
June 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

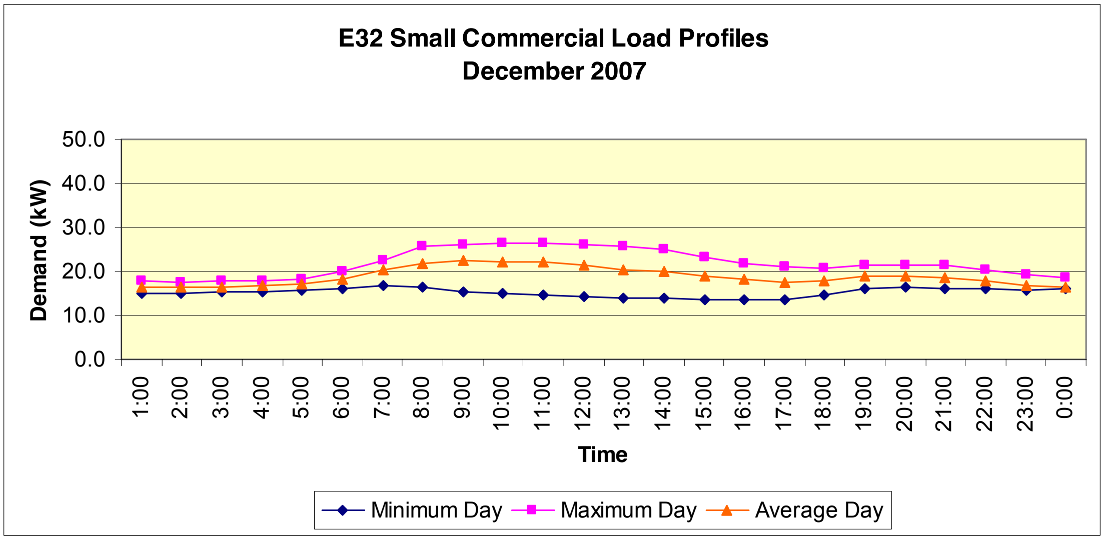

E32 Small Commercial Load Profiles
July 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Small Commercial Load Profiles
August 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

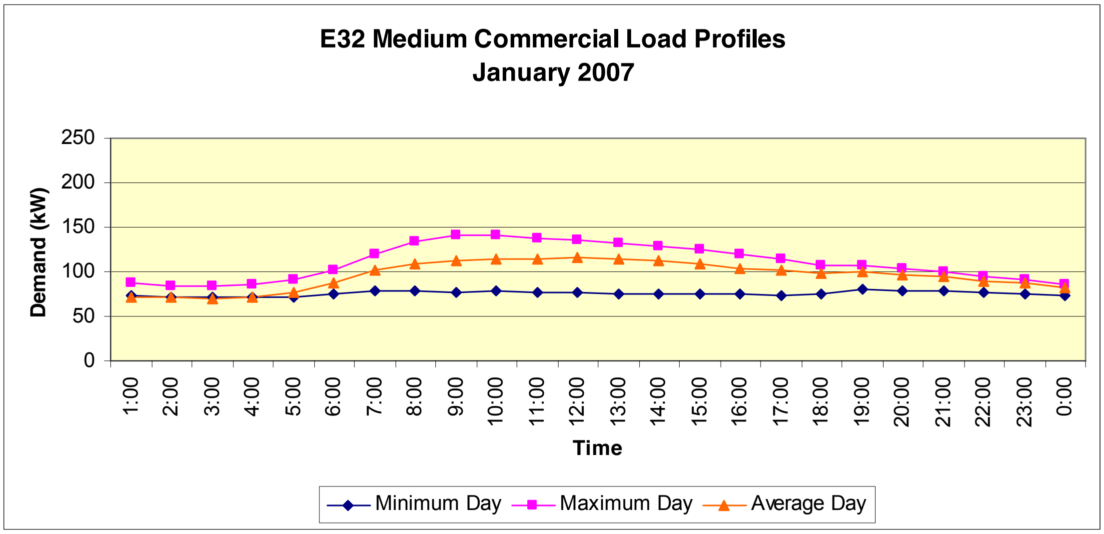

E32 Small Commercial Load Profiles
September 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

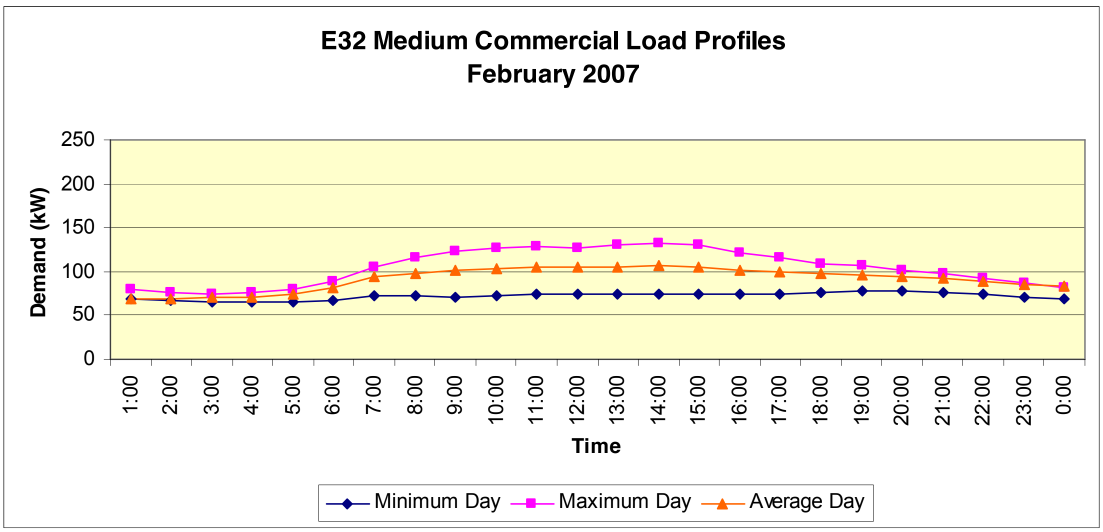

E32 Small Commercial Load Profiles
October 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

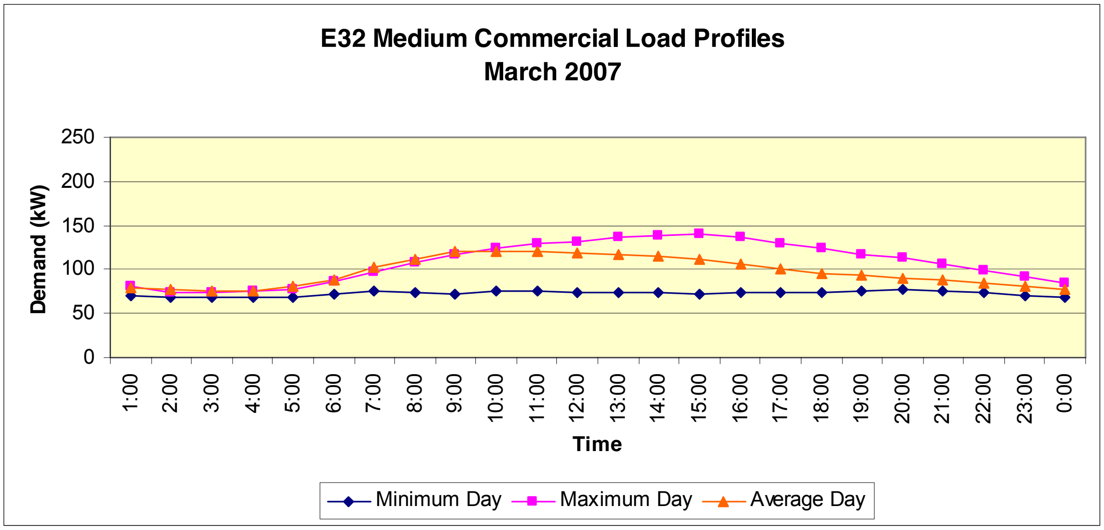

E32 Small Commercial Load Profiles
November 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

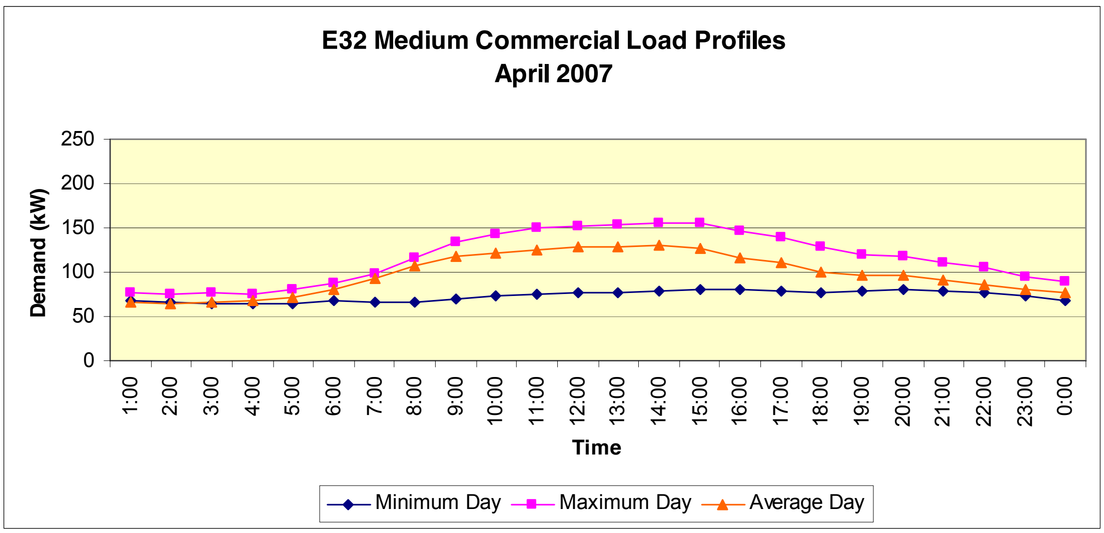

E32 Small Commercial Load Profiles
December 2007
Demand (kW)
50.0
40.0
30.0
20.0
10.0
0.0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

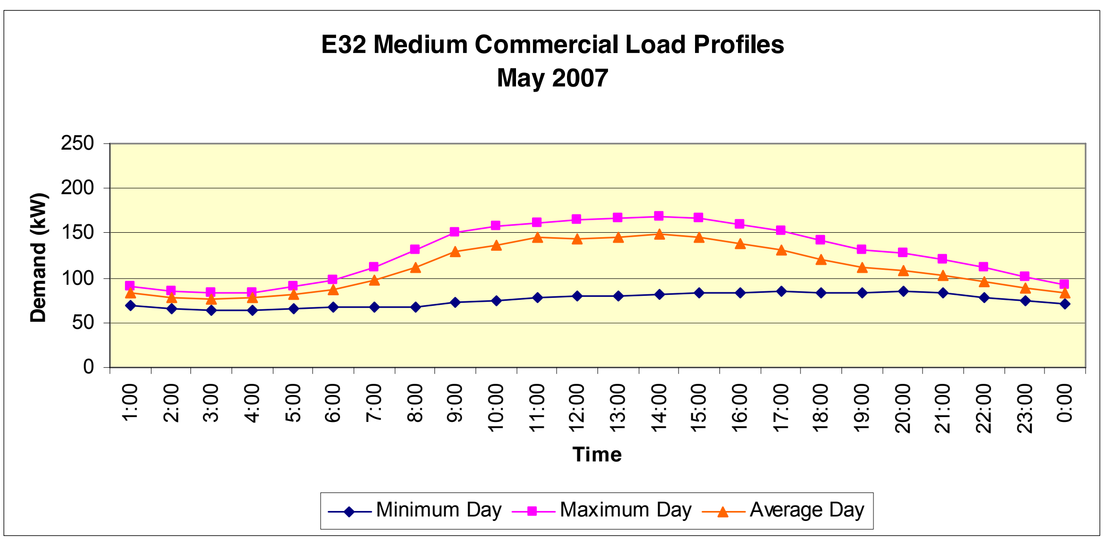
E.5 E32 Medium Commercial Load Profiles by Month

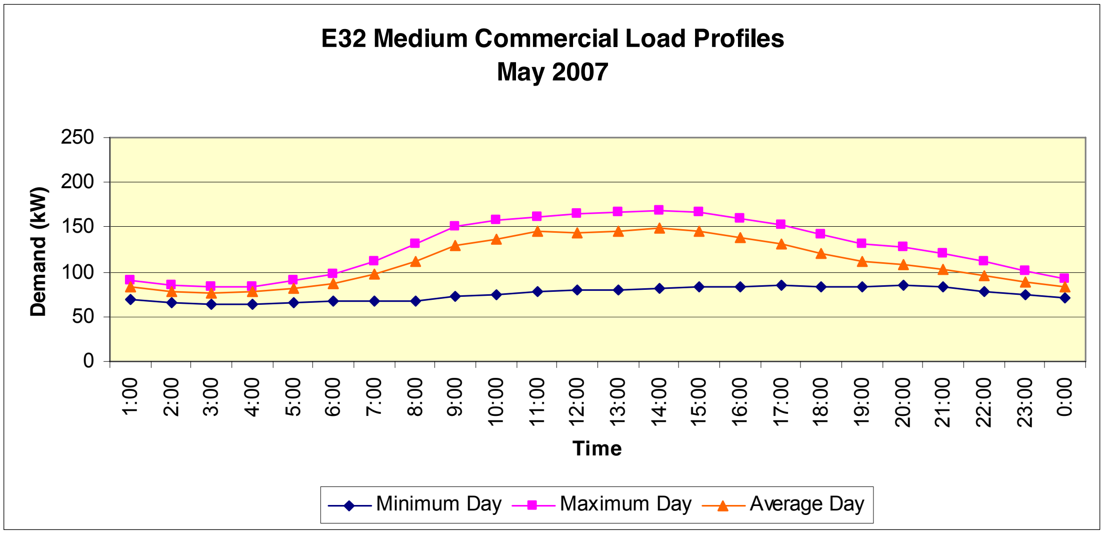


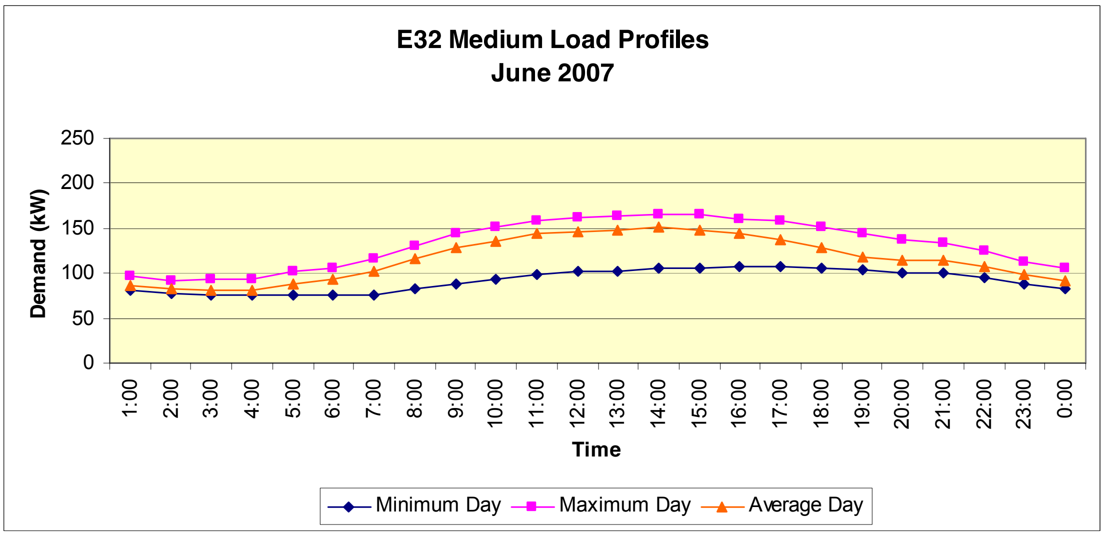


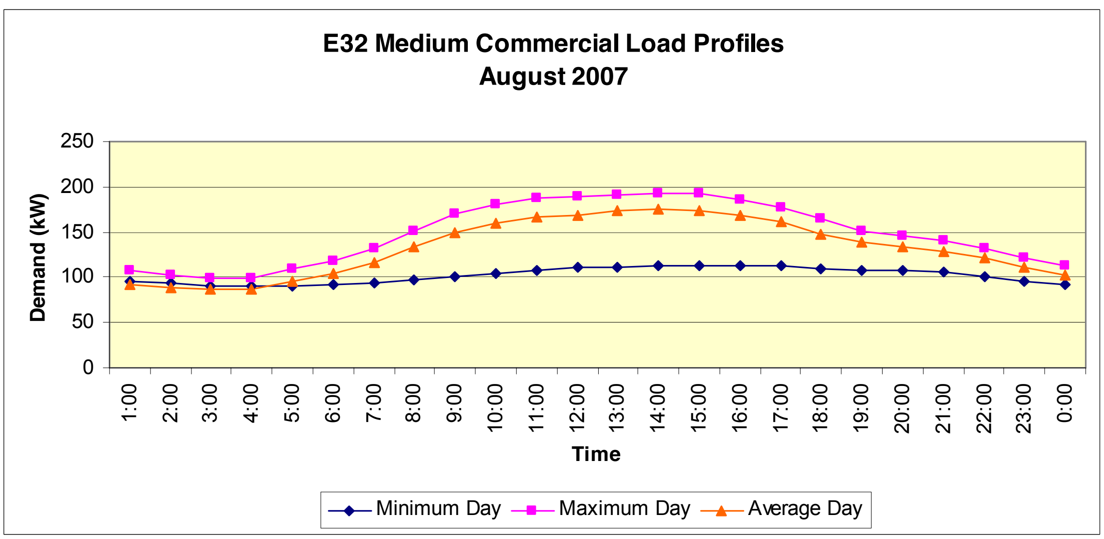

E32 Medium Commercial Load Profiles
March 2007
Demand (kW)
250
200
150
100
50
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

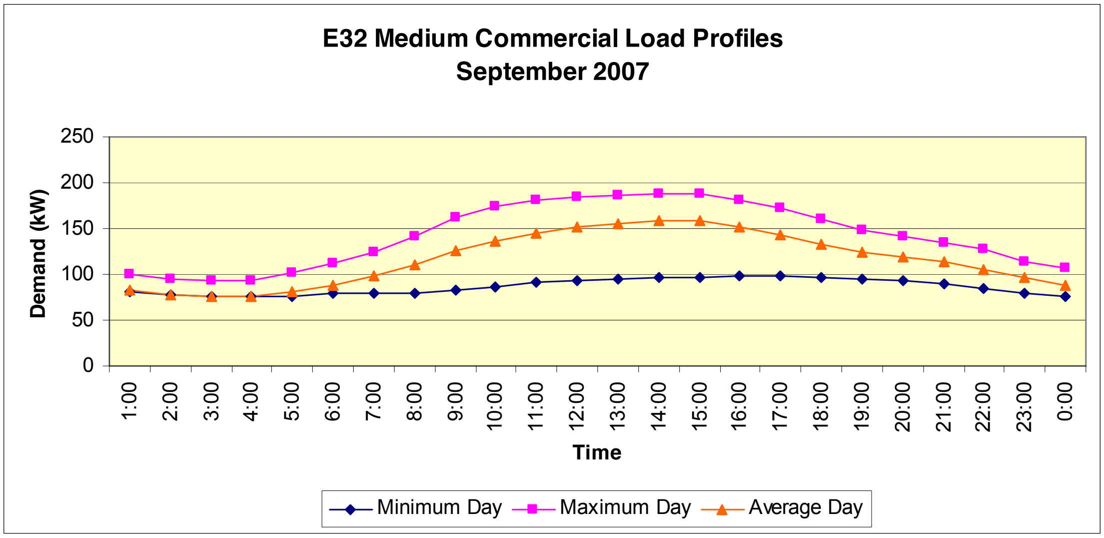

E32 Medium Commercial Load Profiles
April 2007
Demand (kW)
250
200
150
100
50
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

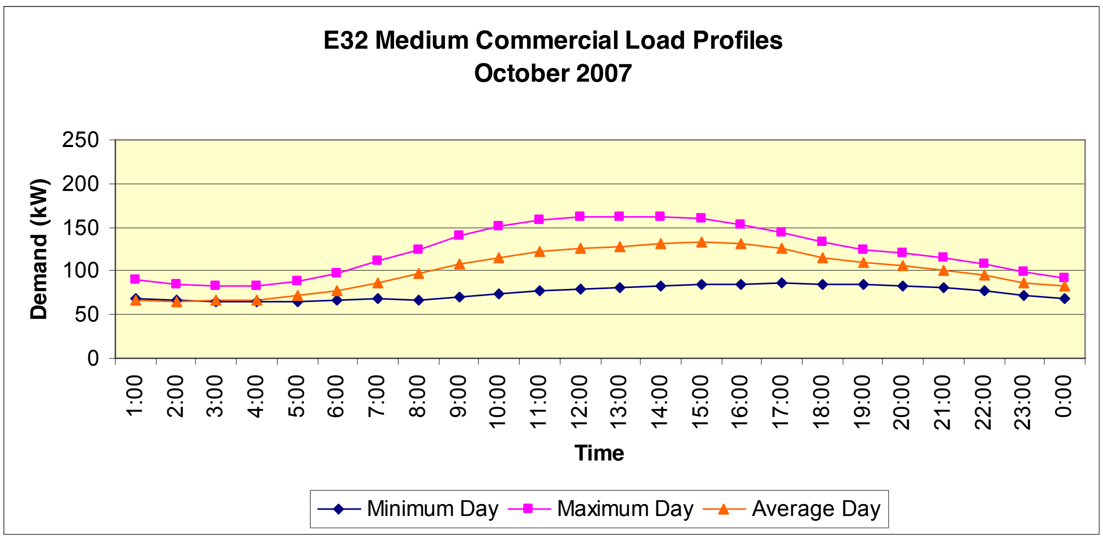

E32 Medium Commercial Load Profiles
May 2007
Demand (kW)
250
200
150
100
50
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

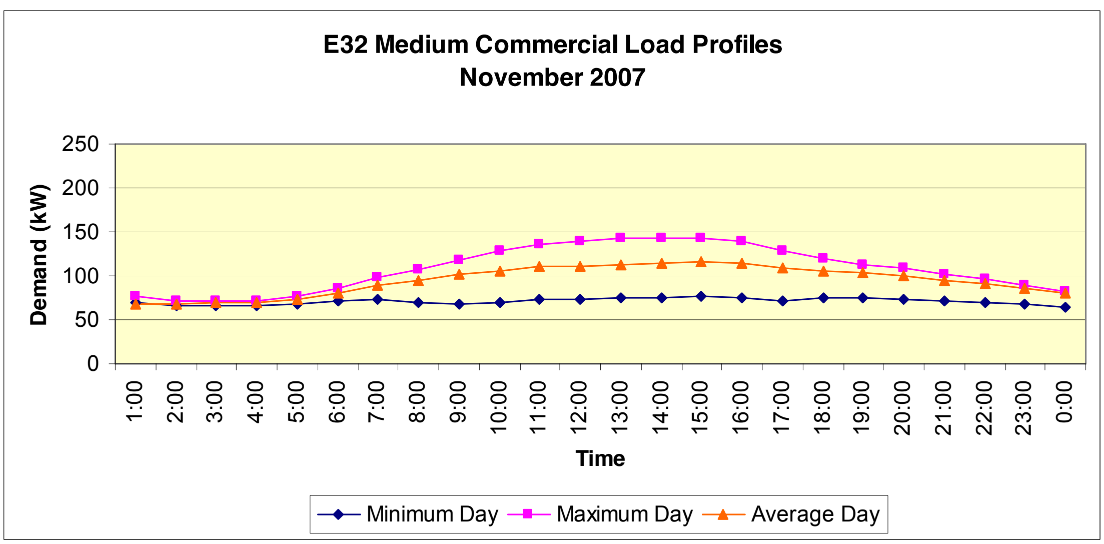

E32 Medium Commercial Load Profiles
May 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

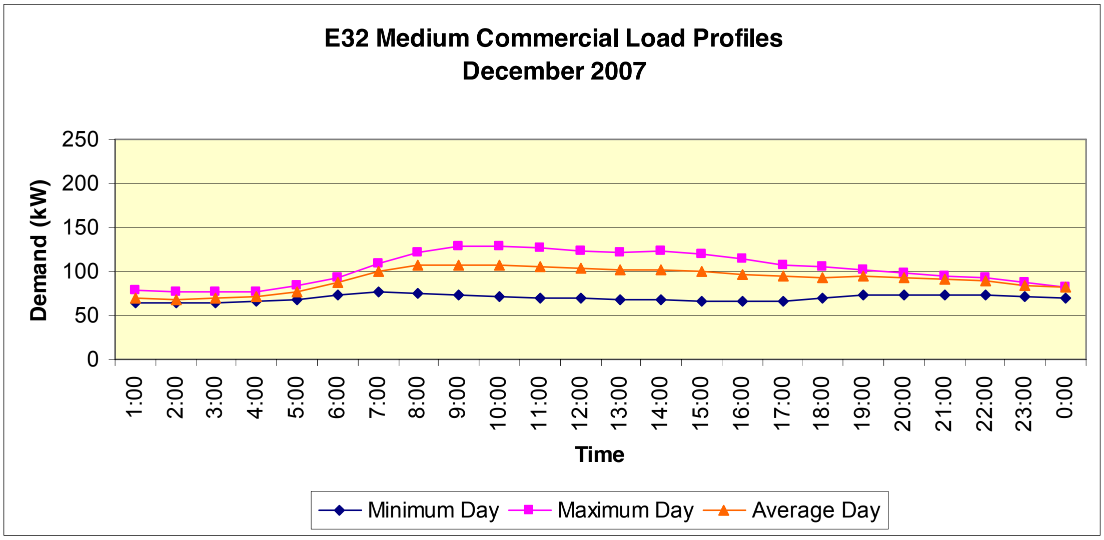

E32 Medium Load Profiles
June 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Medium Commercial Load Profiles
August 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

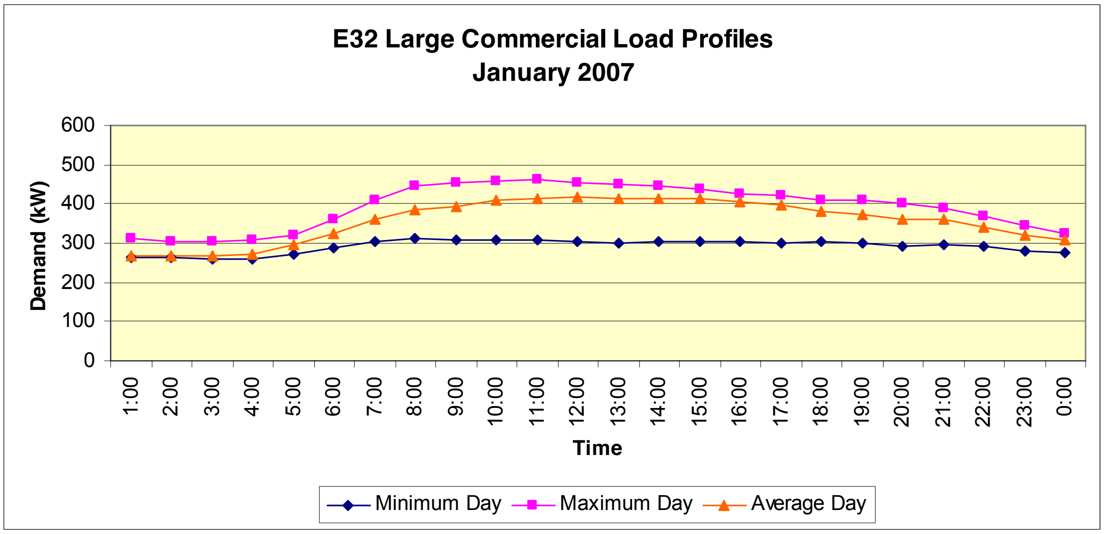

E32 Medium Commercial Load Profiles
September 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

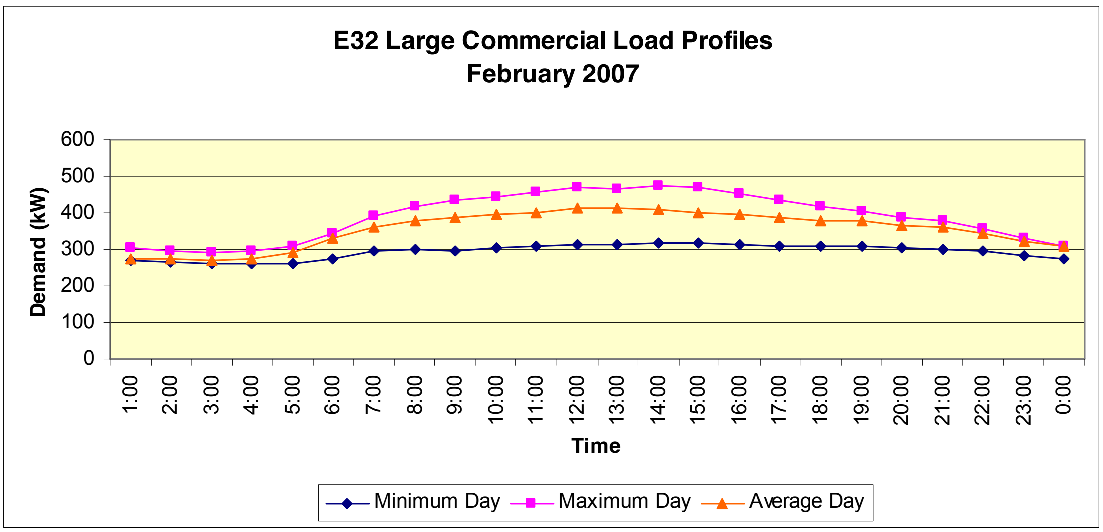

E32 Medium Commercial Load Profiles
October 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

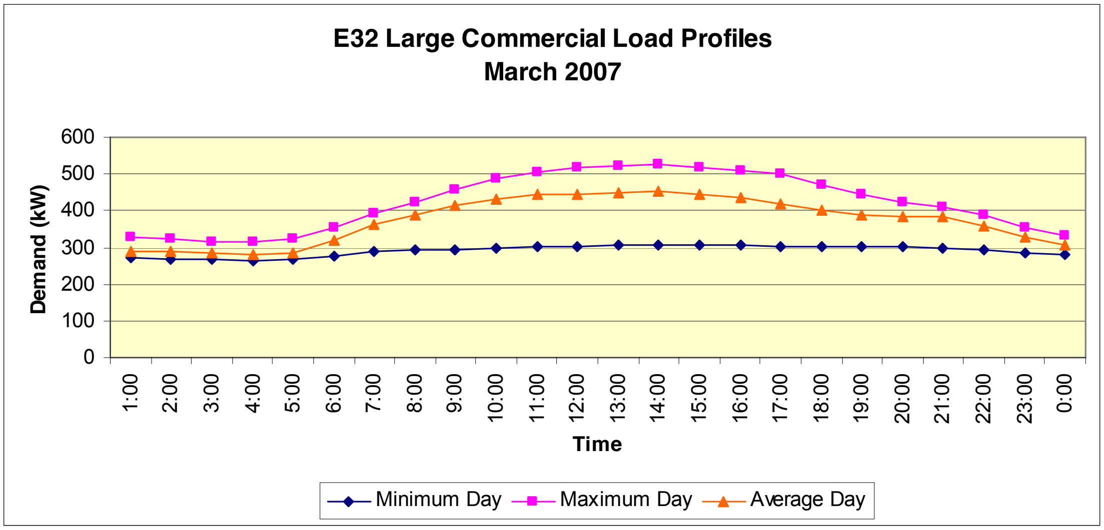

E32 Medium Commercial Load Profiles
November 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

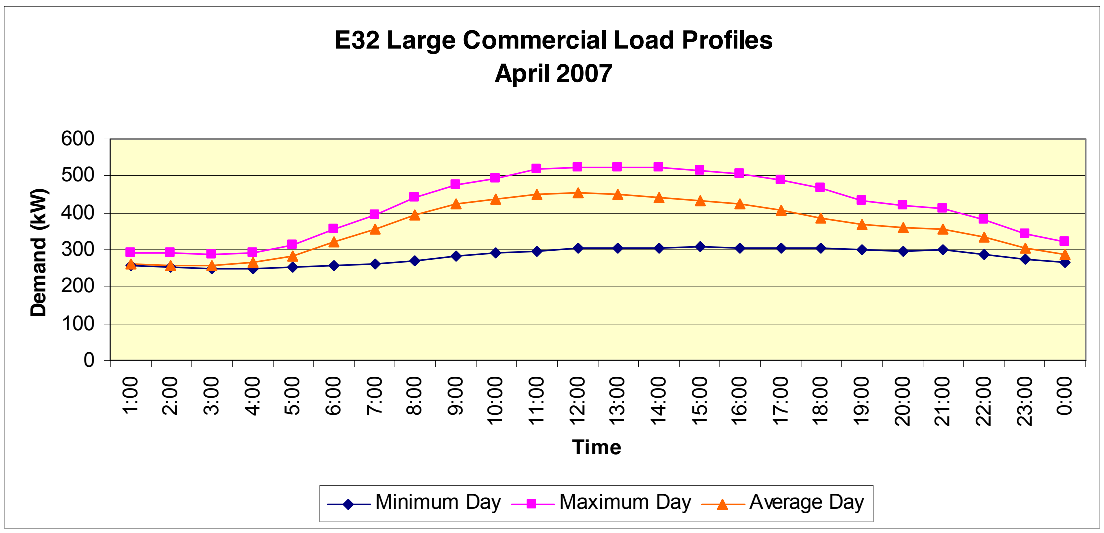

E32 Medium Commercial Load Profiles
December 2007
Demand (kW)
250
200
150
100
50
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

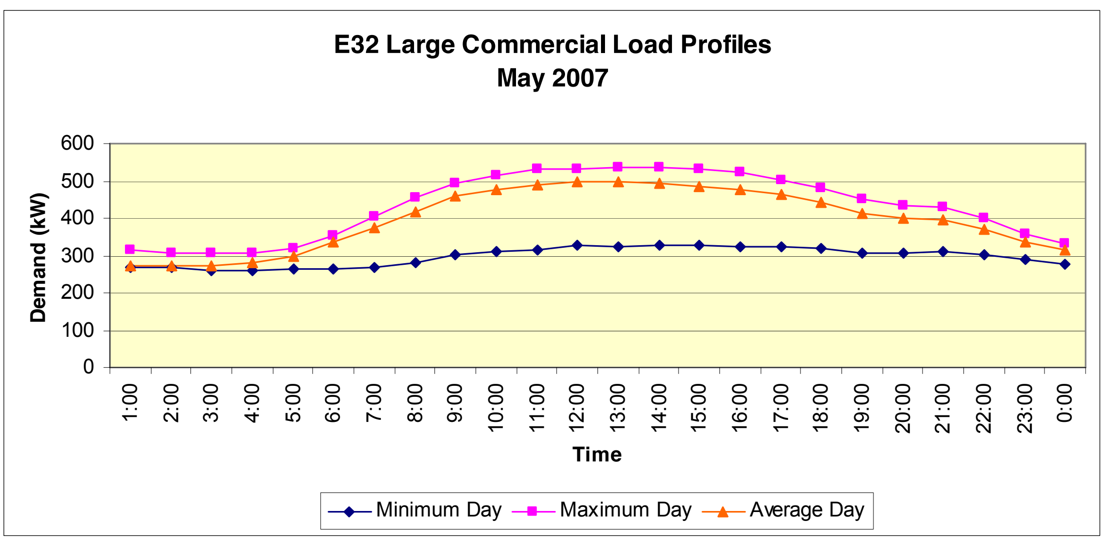
E.6 E32 Large Commercial Load Profiles by Month

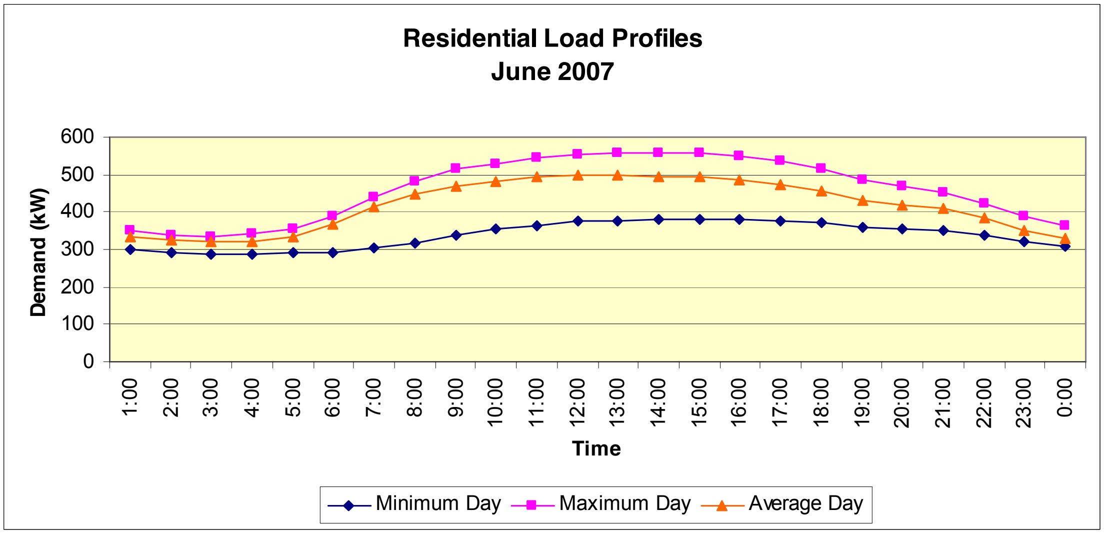




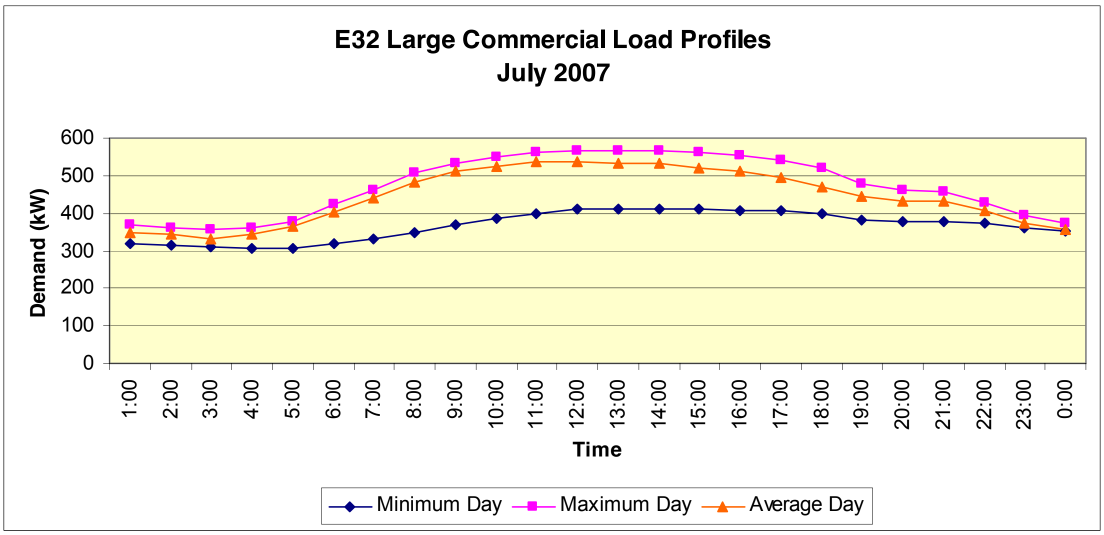

E32 Large Commercial Load Profiles
March 2007
Demand (kW)
600
500
400
300
200
100
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Large Commercial Load Profiles
April 2007
Demand (kW)
600
500
400
300
200
100
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day

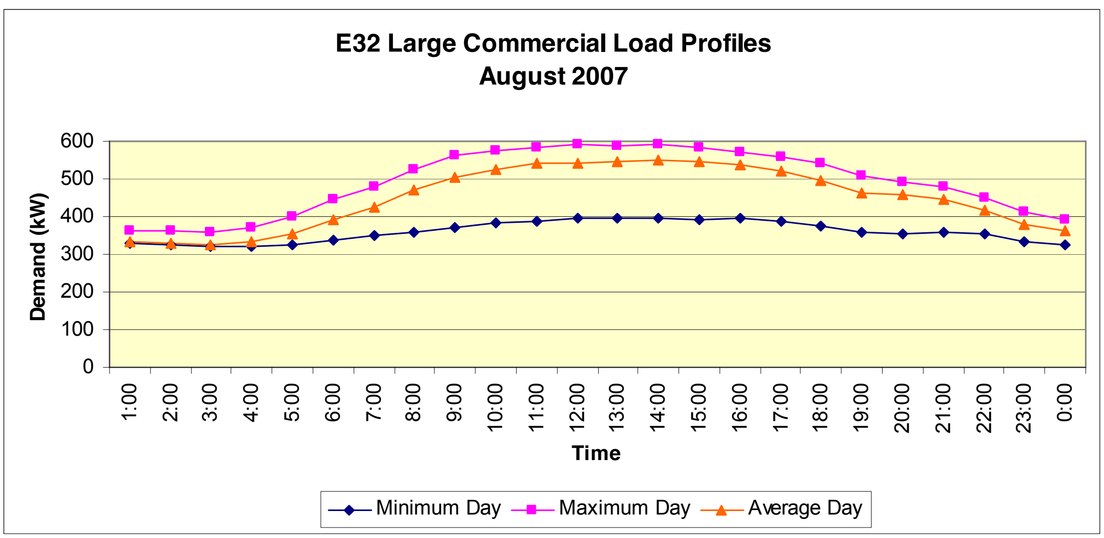

E32 Large Commercial Load Profiles
May 2007
Demand (kW)
600
500
400
300
200
100
0
1:00 2:00 3:00 4:00 5:00 6:00 7:00 8:00 9:00 10:00 11:00 12:00 13:00 14:00 15:00 16:00 17:00 18:00 19:00 20:00 21:00 22:00 23:00 0:00
Time
Minimum Day
Maximum Day
Average Day



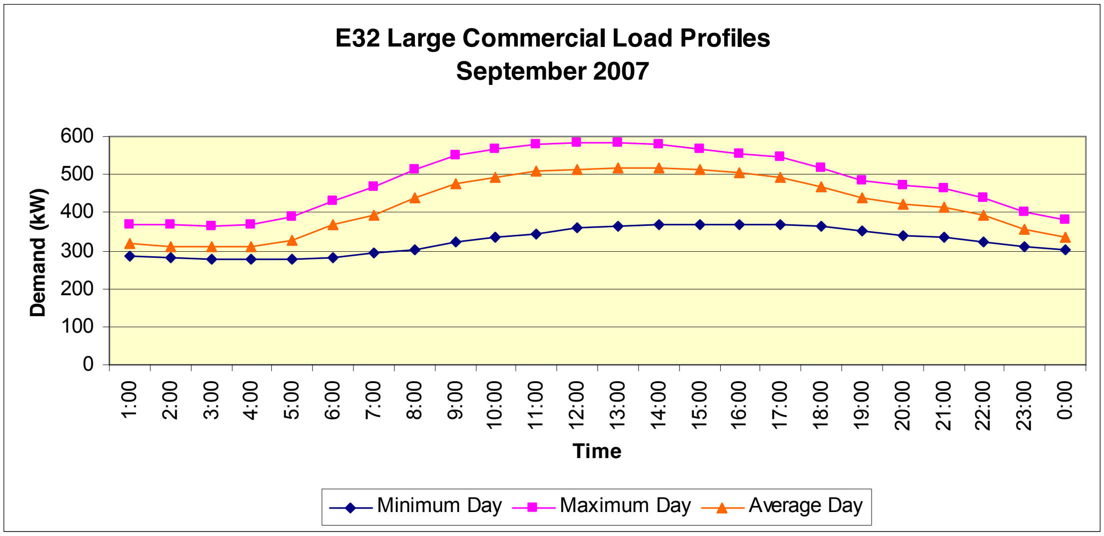
Residential Load Profiles
June 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

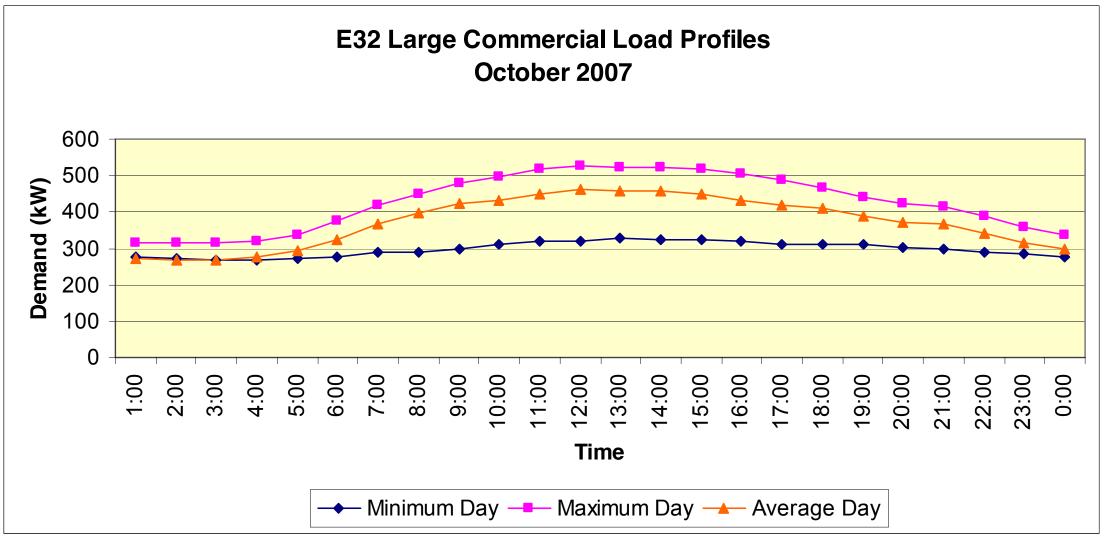


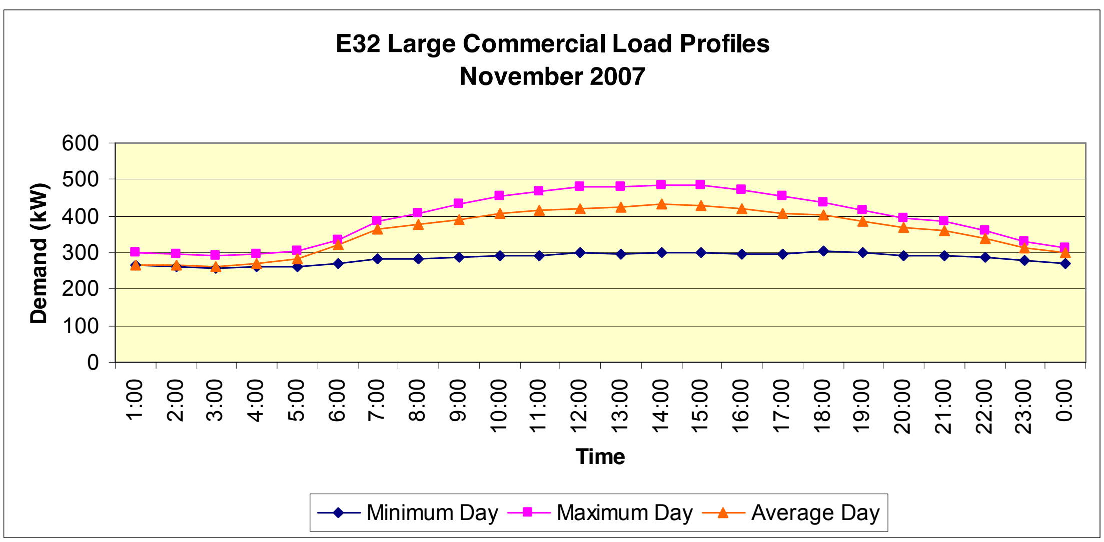
E32 Large Commercial Load Profiles
July 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

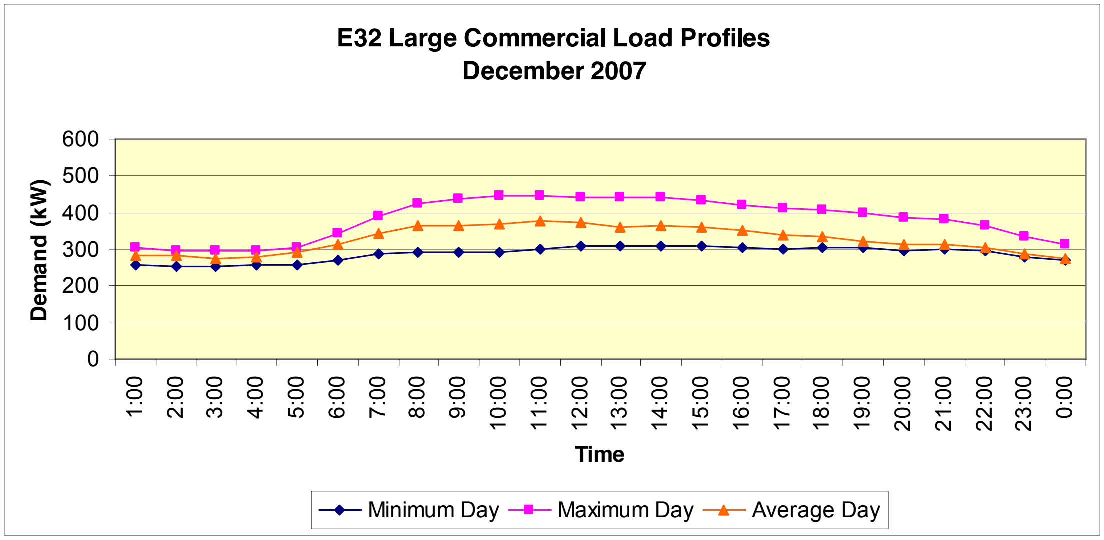


E32 Large Commercial Load Profiles
August 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Large Commercial Load Profiles
September 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Large Commercial Load Profiles
October 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Large Commercial Load Profiles
November 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day


E32 Large Commercial Load Profiles
December 2007
Demand (kW)
600
500
400
300
200
100
0
1:00
2:00
3:00
4:00
5:00
6:00
7:00
8:00
9:00
10:00
11:00
12:00
13:00
14:00
15:00
16:00
17:00
18:00
19:00
20:00
21:00
22:00
23:00
0:00
Time
Minimum Day
Maximum Day
Average Day

APPENDIX F — PHOTOVOLTAIC SYSTEM MODELING

F.1 Model Selection

A number of photovoltaic performance models were considered for this study. Most of the models provide comparable results, as shown in the following table. This evaluation was performed by Sandia National Laboratories, and compares simulation results from each model, along with actual data from a photovoltaic system in Phoenix.

Table F-1

Model	Annual Energy Production (kWhac)	Final Annual Yield (kWhac/kWdc)
PV Watts	3683	1615
PV Watts Ver2	3522	1545
Maui (PV Design Pro)	4140	1816
PV Mod	3311	1562
RETScreen	3834	1682
SAM (Solar Advisor Model)	3609	1583
Measured Data (4-year average)	3529	1548

Source: Sandia National Laboratories, "Larry More and Chris Cameron, DOE Solar Energy Technologies Program presentation, April 17-19, 2007, Denver, CO

The Solar Advisor Model (SAM) was selected for this study. Following are the key factors used in making this decision:

- The model provides good correlation with actual PV production
- It uses state-of-the-art modeling of the PV modules (an I-V curve based on actual module data) and inverters (an efficiency versus load curve based on actual inverter performance)
- SAM produces hourly data strips of PV system power/energy production
- APS uses this model for solar thermal studies
- It is free from National Renewable Energy Laboratory (NREL)

SAM Version 2.0 was released during the APS study, and this version was used for all final results.

F.2 Input Assumptions

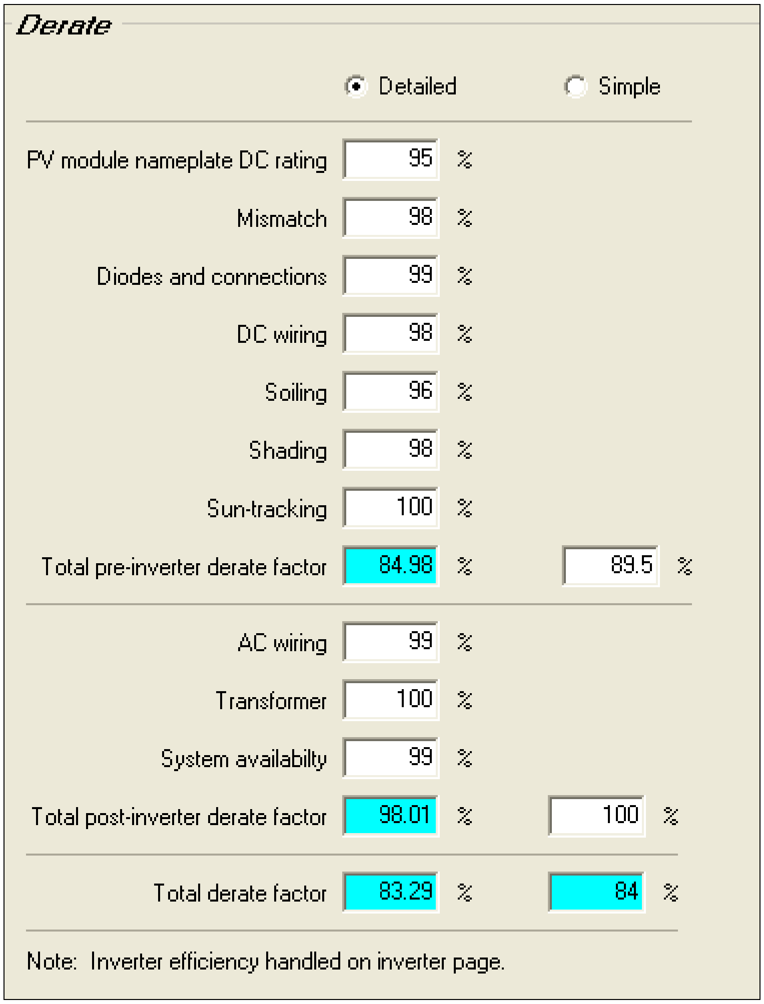
Two baseline PV systems were simulated, one residential and one commercial system. The PV technologies were selected as typical PV systems currently being installed in the Phoenix area. Detailed modeling data on the PV modules and inverters was included in the SAM database provided with the program.

The various loss factors were selected to calibrate the model. That is, the loss factors were adjusted so that the model results were slightly over 1600 kWh per DC kilowatt per year for a tilted residential PV system in Phoenix. See discussion below on how and why this value was selected.

F.3 Residential PV System Baseline

- PV Module: Sharp ND187U1, with Sandia PV array performance model
- PV array: 15 modules per string, 2 strings in parallel
- Baseline orientation: 18.4 deg tilt, 0 deg azimuth
- Inverter SB5000US 240, using Sandia performance model
- Derate factors: refer to the following screenshot from the SAM input screen

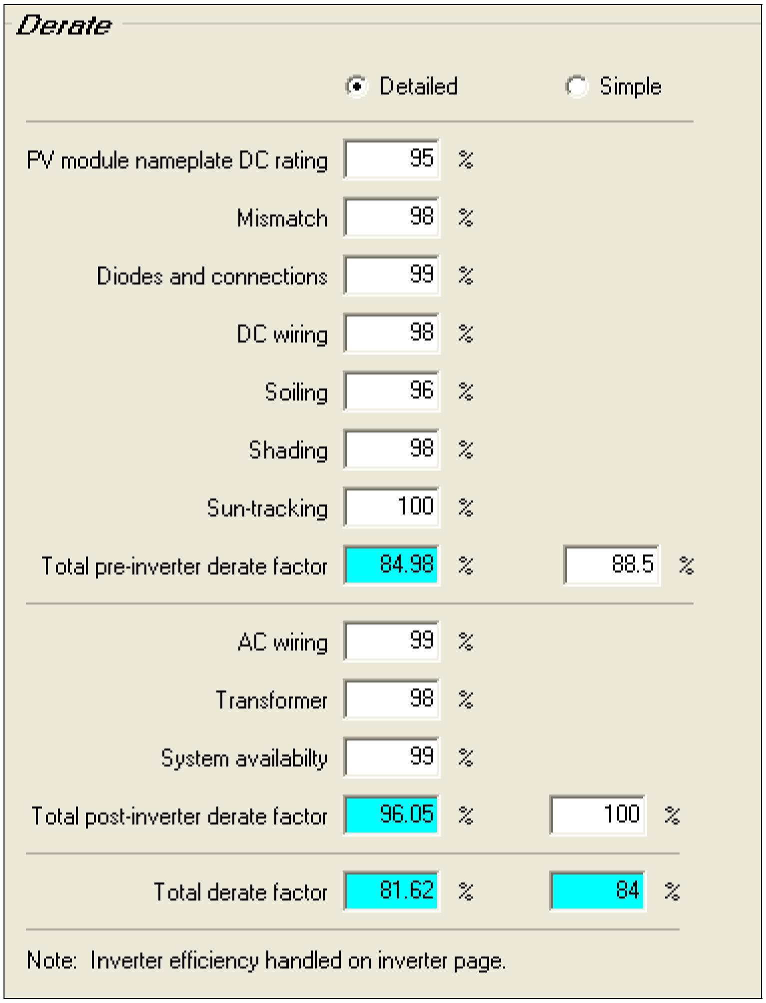
Figure F-1. SAM Input Screen – Residential



F.4 Commercial PV System Baseline

- PV Module: Sharp ND216U2, with Sandia PV array performance model
- PV array: 14 modules per string, 35 strings in parallel
- Baseline orientation: 10 deg tilt, 0 deg azimuth
- Inverter: Satcon AE-100-60-PV-A-HE 480V (CEC), using Sandia performance model
- Derate factors: refer to the following screenshot from the SAM input screen

Figure F-2. SAM Input Screen - Commercial



F.5 Typical Photovoltaic System Performance in the Phoenix Area

Photovoltaic systems in the Phoenix area have a wide range of performance. Based on various reports, the annual performance in kilowatt-hours per DC kilowatt per year vary from about 1300 to 1800 kWh per kW_{DC}. (This ratio is sometimes called Final Annual Yield or FAY.)

Results from APS's customer-installed PV systems were not available, so a number of other sources were consulted. For example:

1. A letter report from Sandia National Laboratories implies about 1300 kWh/kW_{DC} per year.
2. An APS/Sandia paper showing data from 1998 through 2003 on APS-owned and operated PV systems lists the following Final Annual Yields:
   - Fixed Horizontal 1324 kWh/kW_{DC}
   - Fixed Latitude Tilt 1479 kWh/kW_{DC}

- One-Axis NS Tracking Horizontal 1813 kWh/kW_{DC}
- One-Axis NS Tracking Tilt 2032 kWh/kW_{DC}

3. A report by Arizona State University's Photovoltaic Testing Laboratory for Salt River Project lists annual production for three "well-behaved" systems as 1520, 1400 and 1690 kWh/kW_{DC}, and concludes that the primary difference is due to array tilt angle. The closer the tilt is to the local latitude angle of 33.4 degrees, the more energy is produced.

Based on these reports and other information, many factors come into play in the energy production of a PV system. For example, a few of these factors are:

- Orientation and tracking. A fixed array will have better performance if south-facing and tilted at the latitude angle. Tracking systems have better performance than fixed arrays. Note, however, that optimized orientation is not always feasible for many PV projects.
- PV technology. Some technologies have better temperature coefficients than others. Their performance under hot conditions does not degrade as much, and they have higher annual energy production.
- Shading. Some customer-sited systems have partial shading due to trees, chimneys, etc.
- Age of the system. A typical assumption is 1 percent per year degradation in output, so older systems produce less energy than newer systems.
- Wiring losses. Some systems have longer conductor runs, and may have greater wiring loss.
- Soiling loss. Some systems may have greater dirt buildup than others, resulting in relatively poorer performance.
- Relative inverter loading. This factor is still not well quantified, but a lightly loaded inverter may have lower conversion losses than heavily-loaded inverters.

Based on all of these factors, the expected annual performance for a "typical" tilted, residential system was estimated at about 1630 kWh per kW_{DC} for this study. The input loss assumptions for SAM were adjusted (calibrated) to reflect this output. Other PV model results were then calculated by SAM using different solar data, different orientations, etc., but with the same loss factor input assumptions.

APPENDIX G — CERTIFICATION FOR SOLAR WATER HEATERS

The Solar Rating and Certification Corporation (SRCC) currently administer a certification, rating, and labeling program for complete solar water heating systems. SRCC's certification program operating guidelines, test methods and minimum standards, and rating methodologies require the performance of nationally accepted equipment tests on solar equipment by independent laboratories which are accredited by SRCC. The test results and product data are evaluated by SRCC to determine the product's compliance with the minimum standards for certification and to calculate the performance ratings.

Equipment which has been certified and rated by SRCC is required to bear the SRCC certification label which shows the performance rating for that product. In addition, each certified product is published by SRCC in a directory. Each product's directory listing contains information on the product's material and specifications as well as the certified thermal performance rating.

G.1 SRCC OG-300 System Standard

The objective of Task 1 is to characterize the targeted renewable distributed energy (DE) technologies as they would typically be applied in the Arizona Public Service (APS) service territory and develop a framework for their deployment. The products of Task 1 are the building blocks to support the analysis of the potential impacts of these technologies on the distribution system, transmission system and other generation resources related to the APS system.

The OG-300 rating and certification program for solar water heating systems integrates results of collector tests with a performance model for the entire systems and determines whether systems meet minimum standards for system durability, reliability, safety and operation. The thermal performance rating is based on the system design and performance projections derived from testing of the collector components used in the system, or from testing and evaluation of the system as a whole.

SRCC uses the solar energy factor (SEF) as its performance rating for solar domestic water heating systems. The SEF is defined as:

> The energy delivered by the system divided by the electrical or gas energy put into the system.

The SEF is presented as a number similar to the energy factor (EF) given to conventional water heaters by the Gas Appliance Manufacturers Association (GAMA). Because the hot water load assumed for calculating the SEF for all systems is the same, regardless of system size, large systems might be able to provide all of the hot water without consuming any auxiliary energy. This will cause the SEF to become very large. In those cases, the SEF is listed as 99.9 or 999.9.

The SRCC provides estimates of annual solar water heater performance in the Phoenix area. SRCC uses a computer model to estimate the thermal performance of solar water heating systems under specified conditions. A separate computer model for each system is developed from test data on some of the system components, manufacturer's literature on the others, and theoretical calculations. These ratings are based on conditions similar to the ones defined by the DOE for testing conventional water heaters. These conditions describe hot water usage for a single day. These ratings are only estimates based on an assumed set of operating conditions and actual performance will vary depending on hot water usage pattern and actual weather conditions.[1]

G.2 Operating Conditions

The estimated annual performances given by the SRCC are based on the following conditions:

- Hot water load: 64.3 gallons (243 liters) per day drawn throughout the day with the maximum loads occurring at 8:00 AM and 8:00 PM
- Water mains temperature: Varied monthly using Phoenix, AZ values
- Collector orientation: Facing south at a tilt of 23 degrees
- Distance from collector to tank: 25 feet pipe length (each way), 16 feet vertical rise
- Backup heater set point: 125°F
- Weather conditions: TMY2 data for Phoenix, AZ
- Air temperature around indoor tanks: Tair + [(72-Tair)/3], this estimates the temperature in a garage

[1] Source: *Annual Performance of OG-300 Certified Systems in Phoenix, Arizona*, March 2008, Solar Rating and Certification Corporation

APPENDIX H — DAYLIGHTING PROGRAM AND MODEL PARAMETERS

Equipment Qualifications (APS Renewable Energy Incentive Program)	eQuest Building Simulation Method (version 3-61)
A roof mounted skylight assembly with a dome having a minimum of 70% solar transmittance	“Skylight Glazing Type” the “Domed” box is checked See “Skylight Glazing Type” specifications to meet the 70% solar transmittance requirement
A reflective light well to the interior ceiling or a minimum of 12" below roof deck in open bay areas	“Skylight Light Well”- specify % inside reflectance (70% default) and depth
An interior diffusion lens	“Skylight Glazing Type” the “Skylight is diffusing” box is checked
A minimum of one thermal break/dead air space in the system between the skylight dome and the interior diffuser	Specified in the “Frame Type” within the “Skylight Glazing Type”
If artificial lighting systems remain part of the installation, the system shall include automated lighting control(s) that are programmed to keep electric lights off during daylight hours	Lighting control inputs defined below.
The system must provide a minimum of 70% of the light output of the artificial lighting system that would otherwise be used for all of the claimed period of energy savings, as measured in foot-candles	This qualification was assumed to hold true for the building models; however, it was not tested on all models.
Other Simulation Inputs	
Skylit Rooftop Zones	All zones
Amount of skylights (% coverage)	3.5% (default)
Typical skylight dimensions (width 1, width 2)	4 feet x 4 feet (Source: Natural Lighting Co., Inc. Model NL-SM 5252)
Skylight Glazing Type	User specified skylight properties **Conductance:** U-value **Solar transmit:** Shading coefficient **Product Type:** Acrylic/Polycarbonate w/ curb (Source: Natural Lighting Co., Passive Daylighting TM System) **Number of Panes:** Single (Source: Natural Lighting Co. products) **Frame Type:** Aluminum w/ thermal break (Source: Natural Lighting Co. products; based on APS’s requirement for a thermal break) **Glass Tint:** Clear (Source: Natural Lighting Co. products) **U-Value:** 0.43 Btu/h*ft2*°F (Source: Stein, B., J.S. Reynolds, W.T. Grondzik, and A.G. Kwok, Mechanical and Electrical Equipment for Buildings, 10th edition, Appendix E, Table E.17, 2006)

Equipment Qualifications (APS Renewable Energy Incentive Program)	eQuest Building Simulation Method (version 3-61)
Skylight Glazing Type (continued)	**Shading coefficient:** 0.58 (Source: Stein, B., J.S. Reynolds, W.T. Grondzik, and A.G. Kwok, Mechanical and Electrical Equipment for Buildings, 10th edition, Appendix E, Table E.17, 2006) (Note: SHGC = SC x 0.86) **Visible light transmittance:** 0.65 (Source: Stein, B., J.S. Reynolds, W.T. Grondzik, and A.G. Kwok, Mechanical and Electrical Equipment for Buildings, 10th edition, Appendix E, Table E.18, 2006 and need for 70% solar transmittance)
Skylight light well (depth and inside reflectance)	1 foot (based on APS's requirements); 70% inside reflectance (default)
Daylit from	Toplighting
Number of photosensors per zone	1 (default)
Percent of lights controlled (%)	100% (default)
Design light level	50 foot-candles (default)
Photosensor location (height above floor)	2.5 feet, desktop height (default)
Lighting control method (by photosensor)	Dimming 30% Light (default)

Note: The qualifications defined by APS are not in the National Fenestration Rating Council (NFRC) terminology: including U-value, solar heat gain coefficient (SHGC), and visible light transmittance. Therefore, these values were estimated based on the APS requirements.

APPENDIX I — SUMMARY USE CHARACTERISTICS AND TARIFFS BY SELECTED APS RATE GROUP

Table I-1

Residential Customer Counts, and Energy and Demand Use

Tariff	Customer Count	% of Customers	% of Total Residential Demand	% of Total Residential Energy
E10	69,731	7%	5.4%	5.5%
E12	437,213	46%	28.2%	29.9%
ET-1	339,594	36%	47.2%	47.0%
ET-2	36,083	4%	5.7%	3.9%
ECT-1	54,789	6%	11.3%	12.3%
ECT-2	8,566	1%	2.1%	1.4%

Table I-2

Residential Energy Use Summary by Tariff

	E10	E12	ET-1	ET2	ECT1	ECT2
Winter peak	2.00	2.14	3.16	5.95	4.63	9.40
Summer peak	3.12	2.74	5.26	6.37	7.63	10.04
Summer on-peak kWh	2,591	2,232	4,497	3,179	6,972	4,730
Summer off-peak kWh	3,340	2,959	6,665	5,279	10,676	7,724
Winter on-peak kWh	1,453	1,222	1,862	3,480	2,612	4,685
Winter off-peak kWh	2,520	2,065	3,738	5,310	5,393	7,305

Table I-3
Residential Charges by Tariff

Tariff	Summer Charges						Winter Charges			
	1st 400 kWh	2nd 400 kWh	Additional kWh	On-peak kWh	Off-peak kWh	On-peak Demand	All kWh	On-peak kWh	Off-peak kWh	On-peak Demand
E10	0.0874	0.1243	0.1474				0.0850			
E12	0.0857	0.1218	0.1443				0.0833			
ET-1				0.1581	0.0511			0.1285	0.0493	
ET-2				0.2160	0.0541			0.1752	0.0541	
ECT-1				0.0659	0.0369	11.86		0.0498	0.0353	8.15
ECT-2				0.0783	0.0386	11.87		0.0515	0.0378	8.15

Table I-4
Commercial Customer Counts, and Energy and Demand Use

Tariff	Customer Count	% of Customers	% of Total Commercial Demand	% of Total Commercial Energy
E32 xsmall	90,811	77.52%	20.1%	15.3%
E32 small	20,496	17.50%	26.7%	25.4%
E32 medium	4,535	3.87%	26.4%	27.2%
E32 large	893	0.76%	16.1%	20.1%
E32 xlarge	196	0.17%	7.3%	9.5%
E32 TOU xsmall	52	0.04%	0.0%	0.0%
E32 TOU small	91	0.08%	0.1%	0.1%
E32 TOU medium	47	0.04%	0.2%	0.3%
E32 TOU large	20	0.02%	0.4%	0.6%
E32 TOU xlarge	8	0.01%	2.6%	1.5%

Table I-5
Commercial Energy Use by Tariff

	xsmall	Small	medium	large	Xlarge
winter peak	5	28	140	485	1,018
summer peak	7	43	193	614	1,231
summer on-peak kWh	7,124	49,165	225,633	804,103	1,619,787
summer off-peak kWh	7,862	62,941	300,563	1,144,344	2,401,893
winter on-peak kWh	4,789	32,441	147,537	544,047	1,041,858
winter off-peak kWh	6,397	45,612	205,617	812,164	1,598,870

Table I-6
Commercial Charges by Tariff

	Summer Charges						Winter Charges			
Tariff	1st 5000 kWh	Additional kWh	1st 200 kWh	Additional kWh	1st 100 kW	Rest of kW	1st 5000 kWh	Additional kWh	1st 200 kWh	Additional kWh
E32 xsmall	0.1116	0.0598					0.0965	0.0447		
E32 small			0.0912	0.0533	7.8650	4.509			0.0761	0.0383
E32 medium			0.0912	0.0533	7.8650	4.509			0.0761	0.0383
E32 large			0.0912	0.0533	7.8650	4.509			0.0761	0.0383
E32 xlarge			0.0912	0.0533	7.8650	4.509			0.0761	0.0383

Appendix J

APS Incentive Schedules

DISTRIBUTED ENERGY ADMINISTRATION PLAN CONFORMING PROJECT UP-FRONT INCENTIVES

UFI Matrix

			1	2	3	4	5
	Residential or Non-Residential	**Resource Type**	**Year Beginning**				
			2009	**2010**	**2011**	**2012**	**2013**
Residential [1]							
SMALL WIND Residential (off-grid)	Residential	Wind	$2.00/Watt	$2.00/Watt	$1.80/Watt	$1.80/Watt	$1.53/Watt
SMALL WIND Residential (grid-tied)	Residential	Wind	$2.50/Watt	$2.50/Watt	$2.25/Watt	$2.25/Watt	$1.91/Watt
PV RESIDENTIAL (grid-tied) [2]	Residential	Solar PV	$3.00/Watt	$3.00/Watt	$2.70/Watt	$2.70/Watt	$2.30/Watt
PV RESIDENTIAL (off-grid) [2]	Residential	Solar PV	$2.00/Watt	$2.00/Watt	$1.80/Watt	$1.80/Watt	$1.53/Watt
SOLAR THERMAL [3,4]	Residential	Solar - All Other	$0.50/kWh	$0.50/kWh	$0.45/kWh	$0.45/kWh	$0.38/kWh
SMALL SOLAR WATER HEATING [4, 5]	Residential	Solar - All Other	$0.75/kWh	$0.75/kWh	$0.68/kWh	$0.68/kWh	$0.57/kWh
Non-Residential [6]							
BIOMASS/BIOGAS (electric)	Non-Residential	Biomass/Biogas	-	-	-	-	-
BIOGAS/BIOMASS - CHP (electric) [7]	Non-Residential	Biomass/Biogas	-	-	-	-	-
BIOGAS/BIOMASS - CHP (thermal) [7]	Non-Residential	Biomass/Biogas	-	-	-	-	-
BIOMASS/BIOGAS (thermal)	Non-Residential	Biomass/Biogas	-	-	-	-	-
BIOMASS/BIOGAS (cooling)	Non-Residential	Biomass/Biogas	-	-	-	-	-
NON-RESIDENTIAL DAYLIGHTING [4]	Non-Residential	Other	$0.20/kWh	$0.20/kWh	$0.18/kWh	$0.18/kWh	$0.15/kWh
GEOTHERMAL - (electric)	Non-Residential	Geothermal	$0.50/Watt	$0.50/Watt	$0.45/Watt	$0.45/Watt	$0.38/Watt
GEOTHERMAL - (thermal)	Non-Residential	Geothermal	$1.00/Watt	$1.00/Watt	$0.90/Watt	$0.90/Watt	$0.77/Watt
PV NON-RESIDENTIAL - small [2]	Non-Residential	Solar PV	$2.50/Watt	$2.50/Watt	$2.25/Watt	$2.25/Watt	$1.91/Watt
PV NON-RESIDENTIAL (grid-tied) [2]	Non-Residential	Solar PV	$2.50/Watt	$2.50/Watt	$2.25/Watt	$2.25/Watt	$1.91/Watt
PV NON-RESIDENTIAL (off-grid) [2]	Non-Residential	Solar PV	$1.50/Watt	$1.50/Watt	$1.35/Watt	$1.35/Watt	$1.15/Watt
SMALL WIND Non-Residential (grid-tied) [8]	Non-Residential	Wind	$2.50/Watt	$2.50/Watt	$2.25/Watt	$2.25/Watt	$1.91/Watt
SMALL WIND Non-Residential (off-grid) [8]	Non-Residential	Wind	$2.00/Watt	$2.00/Watt	$1.80/Watt	$1.80/Watt	$1.53/Watt
SOLAR SPACE COOLING [4,9]	Non-Residential	Solar - All Other	$1.00/kWh	$1.00/kWh	$0.90/kWh	$0.90/kWh	$0.77/kWh
SOLAR WATER HEATING / SPACE HEATING [4,9]	Non-Residential	Solar - All Other	$0.45/kWh	$0.45/kWh	$0.41/kWh	$0.41/kWh	$0.34/kWh
NON-RESIDENTIAL POOL HEATING [4]	Non-Residential	Solar - All Other	$0.10/kWh	$0.10/kWh	$0.09/kWh	$0.09/kWh	$0.08/kWh

DISTRIBUTED ENERGY ADMINISTRATION PLAN CONFORMING PROJECT PRODUCTION BASE INCENTIVES

PBI Matrix 1	Contract Years	10	PBI Years 10				
			1	2	3	4	5
	Residential or Non-Residential	Resource Type	Year Beginning				
			2009	2010	2011	2012	2013
Non-Residential[6]							
BIOMASS/BIOGAS (electric)	Non-Residential	Biomass/Biogas	$0.060/kWh	$0.060/kWh	$0.054/kWh	$0.054/kWh	$0.046/kWh
BIOGAS/BIOMASS - CHP (electric)[7]	Non-Residential	Biomass/Biogas	$0.035/kWh	$0.035/kWh	$0.032/kWh	$0.032/kWh	$0.027/kWh
BIOGAS/BIOMASS - CHP (thermal)[7]	Non-Residential	Biomass/Biogas	$0.018/kWh	$0.018/kWh	$0.016/kWh	$0.016/kWh	$0.014/kWh
BIOMASS/BIOGAS (thermal)	Non-Residential	Biomass/Biogas	$0.015/kWh	$0.015/kWh	$0.014/kWh	$0.014/kWh	$0.011/kWh
BIOMASS/BIOGAS (cooling)	Non-Residential	Biomass/Biogas	$0.032/kWh	$0.032/kWh	$0.029/kWh	$0.029/kWh	$0.025/kWh
NON-RESIDENTIAL DAYLIGHTING	Non-Residential	Other	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh
GEOTHERMAL - (electric)	Non-Residential	Geothermal	$0.024/kWh	$0.024/kWh	$0.022/kWh	$0.022/kWh	$0.019/kWh
GEOTHERMAL - (thermal)	Non-Residential	Geothermal	$0.048/kWh	$0.048/kWh	$0.044/kWh	$0.044/kWh	$0.037/kWh
PV NON-RESIDENTIAL - small[2]	Non-Residential	Solar PV					
PV NON-RESIDENTIAL (grid-tied)[2]	Non-Residential	Solar PV	$0.202/kWh	$0.202/kWh	$0.182/kWh	$0.182/kWh	$0.154/kWh
PV NON-RESIDENTIAL (off-grid)[2]	Non-Residential	Solar PV	$0.121/kWh	$0.121/kWh	$0.109/kWh	$0.109/kWh	$0.093/kWh
SMALL WIND Non-Residential (grid-tied)[8]	Non-Residential	Wind	$0.145/kWh	$0.145/kWh	$0.131/kWh	$0.131/kWh	$0.111/kWh
SMALL WIND Non-Residential (off-grid)[8]	Non-Residential	Wind	$0.116/kWh	$0.116/kWh	$0.105/kWh	$0.105/kWh	$0.089/kWh
SOLAR SPACE COOLING[9]	Non-Residential	Solar - All Other	$0.129/kWh	$0.129/kWh	$0.116/kWh	$0.116/kWh	$0.099/kWh
SOLAR WATER HEATING / SPACE HEATING[9]	Non-Residential	Solar - All Other	$0.057/kWh	$0.057/kWh	$0.051/kWh	$0.051/kWh	$0.043/kWh
NON-RESIDENTIAL POOL HEATING	Non-Residential	Solar - All Other	$0.012/kWh	$0.012/kWh	$0.011/kWh	$0.011/kWh	$0.009/kWh

DISTRIBUTED ENERGY ADMINISTRATION PLAN CONFORMING PROJECT PRODUCTION BASE INCENTIVES

PBI Matrix 2	**Contract Years**	**15**	**PBI Years 15**				
	Residential or Non-Residential	**Resource Type**	**1** Year Beginning	**2**	**3**	**4**	**5**
			2009	**2010**	**2011**	**2012**	**2013**
Non-Residential[6]							
BIOMASS/BIOGAS (electric)	Non-Residential	Biomass/Biogas	$0.056/kWh	$0.056/kWh	$0.050/kWh	$0.050/kWh	$0.043/kWh
BIOGAS/BIOMASS - CHP (electric)[7]	Non-Residential	Biomass/Biogas	$0.032/kWh	$0.032/kWh	$0.029/kWh	$0.029/kWh	$0.025/kWh
BIOGAS/BIOMASS - CHP (thermal)[7]	Non-Residential	Biomass/Biogas	$0.017/kWh	$0.017/kWh	$0.015/kWh	$0.015/kWh	$0.013/kWh
BIOMASS/BIOGAS (thermal)	Non-Residential	Biomass/Biogas	$0.014/kWh	$0.014/kWh	$0.013/kWh	$0.013/kWh	$0.011/kWh
BIOMASS/BIOGAS (cooling)	Non-Residential	Biomass/Biogas	$0.030/kWh	$0.030/kWh	$0.027/kWh	$0.027/kWh	$0.023/kWh
NON-RESIDENTIAL DAYLIGHTING	Non-Residential	Other	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh
GEOTHERMAL - (electric)	Non-Residential	Geothermal	$0.022/kWh	$0.022/kWh	$0.020/kWh	$0.020/kWh	$0.017/kWh
GEOTHERMAL - (thermal)	Non-Residential	Geothermal	$0.045/kWh	$0.045/kWh	$0.040/kWh	$0.040/kWh	$0.034/kWh
PV NON-RESIDENTIAL - small[2]	Non-Residential	Solar PV					
PV NON-RESIDENTIAL (grid-tied)[2]	Non-Residential	Solar PV	$0.187/kWh	$0.187/kWh	$0.168/kWh	$0.168/kWh	$0.143/kWh
PV NON-RESIDENTIAL (off-grid)[2]	Non-Residential	Solar PV	$0.112/kWh	$0.112/kWh	$0.101/kWh	$0.101/kWh	$0.086/kWh
SMALL WIND Non-Residential (grid-tied)[8]	Non-Residential	Wind	$0.135/kWh	$0.135/kWh	$0.121/kWh	$0.121/kWh	$0.103/kWh
SMALL WIND Non-Residential (off-grid)[8]	Non-Residential	Wind	$0.108/kWh	$0.108/kWh	$0.097/kWh	$0.097/kWh	$0.082/kWh
SOLAR SPACE COOLING[9]	Non-Residential	Solar - All Other	$0.120/kWh	$0.120/kWh	$0.108/kWh	$0.108/kWh	$0.092/kWh
SOLAR WATER HEATING / SPACE HEATING[9]	Non-Residential	Solar - All Other	$0.052/kWh	$0.052/kWh	$0.047/kWh	$0.047/kWh	$0.040/kWh
NON-RESIDENTIAL POOL HEATING	Non-Residential	Solar - All Other	$0.011/kWh	$0.011/kWh	$0.010/kWh	$0.010/kWh	$0.009/kWh

PBI Matrix 3	Contract Years	20	PBI Years 20				
	Residential or Non-Residential	Resource Type	1 Year Beginning	2	3	4	5
			2009	2010	2011	2012	2013
Non-Residential[6]							
BIOMASS/BIOGAS (electric)	Non-Residential	Biomass/Biogas	$0.054/kWh	$0.054/kWh	$0.048/kWh	$0.048/kWh	$0.041/kWh
BIOGAS/BIOMASS - CHP (electric)[7]	Non-Residential	Biomass/Biogas	$0.031/kWh	$0.031/kWh	$0.028/kWh	$0.028/kWh	$0.024/kWh
BIOGAS/BIOMASS - CHP (thermal)[7]	Non-Residential	Biomass/Biogas	$0.016/kWh	$0.016/kWh	$0.014/kWh	$0.014/kWh	$0.012/kWh
BIOMASS/BIOGAS (thermal)	Non-Residential	Biomass/Biogas	$0.013/kWh	$0.013/kWh	$0.012/kWh	$0.012/kWh	$0.010/kWh
BIOMASS/BIOGAS (cooling)	Non-Residential	Biomass/Biogas	$0.029/kWh	$0.029/kWh	$0.026/kWh	$0.026/kWh	$0.022/kWh
NON-RESIDENTIAL DAYLIGHTING	Non-Residential	Other	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh	$0.000/kWh
GEOTHERMAL - (electric)	Non-Residential	Geothermal	$0.022/kWh	$0.022/kWh	$0.019/kWh	$0.019/kWh	$0.017/kWh
GEOTHERMAL - (thermal)	Non-Residential	Geothermal	$0.043/kWh	$0.043/kWh	$0.039/kWh	$0.039/kWh	$0.033/kWh
PV NON-RESIDENTIAL - small[2]	Non-Residential	Solar PV					
PV NON-RESIDENTIAL (grid-tied)[2]	Non-Residential	Solar PV	$0.180/kWh	$0.180/kWh	$0.162/kWh	$0.162/kWh	$0.138/kWh
PV NON-RESIDENTIAL (off-grid)[2]	Non-Residential	Solar PV	$0.108/kWh	$0.108/kWh	$0.065/kWh	$0.065/kWh	$0.083/kWh
SMALL WIND Non-Residential (grid-tied)[8]	Non-Residential	Wind	$0.130/kWh	$0.130/kWh	$0.117/kWh	$0.117/kWh	$0.099/kWh
SMALL WIND Non-Residential (off-grid)[8]	Non-Residential	Wind	$0.104/kWh	$0.104/kWh	$0.094/kWh	$0.094/kWh	$0.080/kWh
SOLAR SPACE COOLING[9]	Non-Residential	Solar - All Other	$0.115/kWh	$0.115/kWh	$0.104/kWh	$0.104/kWh	$0.088/kWh
SOLAR WATER HEATING / SPACE HEATING[9]	Non-Residential	Solar - All Other	$0.051/kWh	$0.051/kWh	$0.045/kWh	$0.045/kWh	$0.039/kWh
NON-RESIDENTIAL POOL HEATING	Non-Residential	Solar - All Other	$0.011/kWh	$0.011/kWh	$0.010/kWh	$0.010/kWh	$0.008/kWh

DISTRIBUTED ENERGY ADMINISTRATION PLAN CONFORMING PROJECT INCENTIVES- NOTES TO UFI AND PBI MATRICES:

1) Residential projects are only eligible for up-front incentives (UFI). UFI payments, whether residential or non-residential, can not exceed 50% of the system cost.
2) Some installations will require an adjustment of the incentive as detailed in the PV Incentive Adjustment Chart.
3) Residential Solar Thermal is a single system design that produces both space heating and water heating for residential use. These applications require a report detailing energy savings for the complete system.
4) Rate applies to rated first year energy savings only.
5) Energy savings rating is based on the SRCC OG-300 published rating. The customer contribution must be a minimum of 15% of the project cost after accounting for and applying all available Federal and State incentives.
6) Non-residential projects with a total incentive of less than or equal to $75,000 are only eligible for a UFI. Non-residential projects with a total incentive of greater than $75,000 are only eligible for a production-based incentive. The total payments under a PBI can not exceed 60% of the Project Costs.
7) The CHP incentives may be used in combination for the appropriate components of one system.
8) The small wind PBI applies to a maximum sytem size of 100 kW. A larger wind system may apply for an incentive as a non-conforming project.
9) The solar space heating and cooling incentives may be used in combination for the appropriate components of one system.

Appendix K

DSS Study – Distribution System Impacts of Distributed Solar Technology

Distribution System Impacts of Distributed Solar Technology

Submitted to R.W. Beck
12/18/08

EPRI PDU System Studies Group

Overview

- EPRI was contracted by R.W. Beck to evaluate potential distribution system impacts of distributed solar technologies on an Arizona Public Service Company (APS) distribution feeder
- Project specifically addresses
  – Loss impacts
  – Voltage regulation
- Solar technologies considered include
  – Residential and commercial PV
  – Residential solar water heaters (SWH)
  – Commercial lighting

Scenarios Considered

- Base case
  - No Solar
- Business as Usual
  - 52% of residential customers with PV
  - 11% of residential customers with SWH
  - 100% Commercial w/ Solar PV and/or lighting
- Greenfield
  - 100% of residential customers with PV
  - 100% of residential customers with SWH
  - 100% Commercial w/ Solar PV and/or lighting

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Circuit Model

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Circuit Modeling

- Develop working electrical model in OpenDSS format of Deadman 04 (DM04) feeder
- GIS data of feeder provided to EPRI
  - Not a true electrical model
  - Considerable number of line segments used to represent primary and secondary circuits
- Custom GIS-OpenDSS converter developed
  - Not all circuits are represented similarly in GIS
  - Transformers not linked to primary circuit, modified converter to estimate connection point based on proximity
  - “missing” data had to be filled in where appropriate

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Modeling Assumptions

- Distribution Transformers
  - 50% of distribution transformers did not have kVA size designation
  - Estimated size based on number of customers connected and 10 kVA/customer
  - Standard transformer sizes used
- Distribution Transformer Loss Data
  - No test data available for transformers in circuit
  - used typical loss data provided by APS for xfmrs they had purchased within the past 8 years to assign load and no-load losses per transformer
  - Loss data based on kVA size of transformer (~ 1% for load losses, ~0.22% for no-load losses)
- Feeder capacitor control
  - No formal control algorithm provided
  - Assumed capacitor bank switched on during peak period (June – September)
- Load Data
  - Size of individual loads were unknown
  - Maximum feeder loading per-phase was used to allocate load levels throughout the feeder
  - Power factor: Residential – 0.9, Commercial – 0.87
- Annual load shapes
  - Historical 8760 currents per phase for feeder at substation utilized as load shape applied to loads on each phase

Working Electrical Model

- 2007 peak demand of 10.3 MW
- 295 service transformers
- 17,619 primary line segments
- 17,890 secondary line segments
- 1,429 customers
  - Only 2, three-phase customers
  - Unable to identify the 30+ commercial customers on feeder, assumed remaining 1-phase services were residential
- 3, 1200 kvar feeder capacitor banks
- Circuit miles (all underground)
  - Primary: 26 mi.
  - Secondary: 30 mi.

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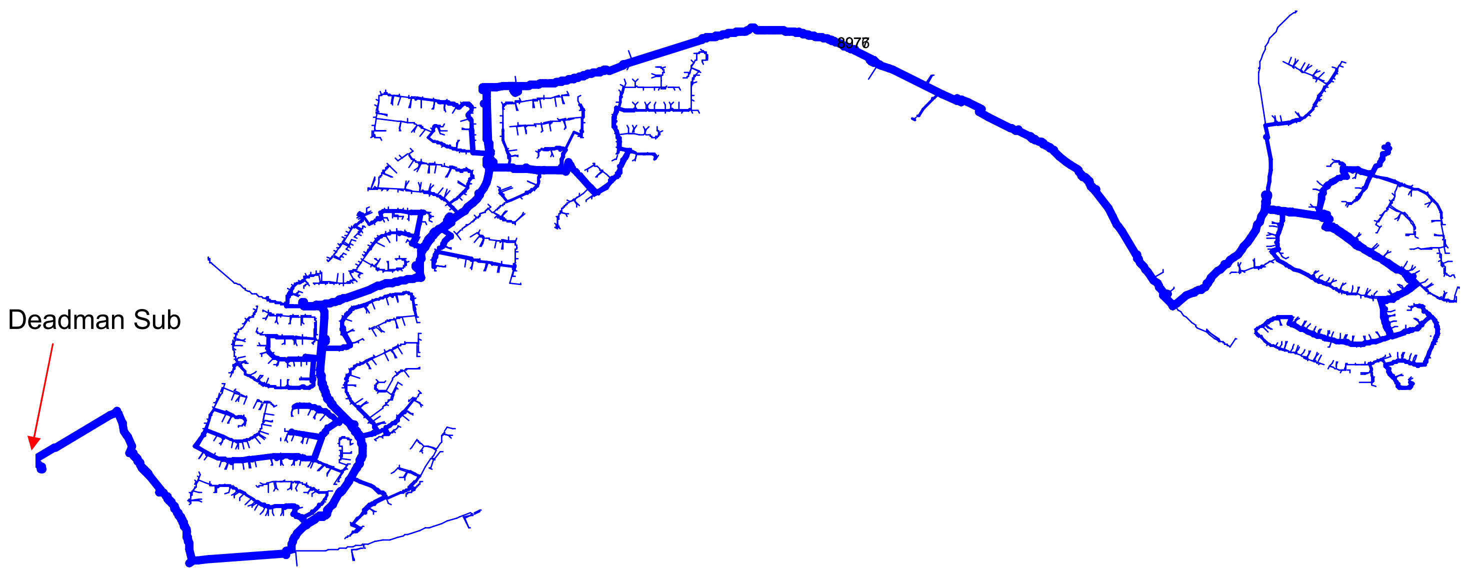
Procedures After Model Conversion

- With the current version of the GIS-OpenDSS converter customized with the DM04 data, the following procedures should be manually performed to verify a working model has been produced
  - Update model with missing data from GIS
    - Transformer kVA
    - Transformer impedances
    - Transformer no-load data
    - Load kVA size
    - Load voltage
    - Missing conductor information
    - Substation transformer
    - Transmission equivalent
    - Capacitor controls
    - Feeder regulator and controls (if any)
  - Allocate loads
  - Deploy solar PV/SWH/Lighting loads
  - Update master file to include load and PV 8760 curves

Circuit Diagram as Modeled in OpenDSS



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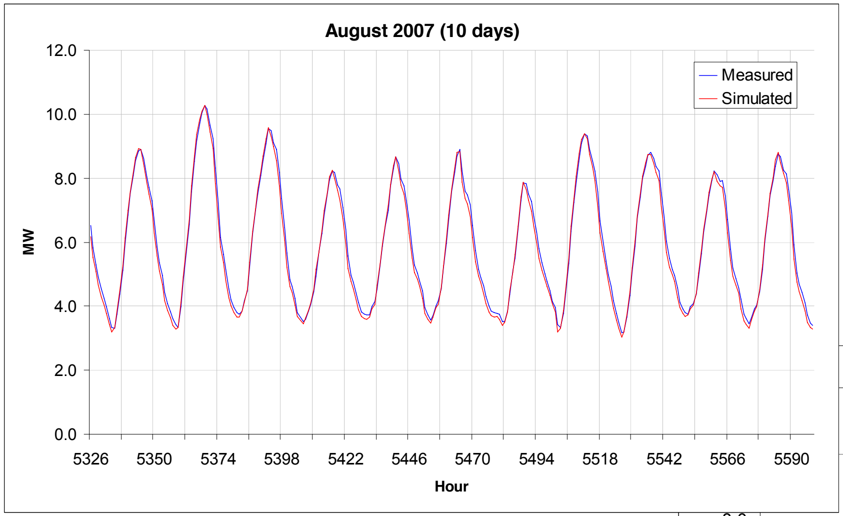
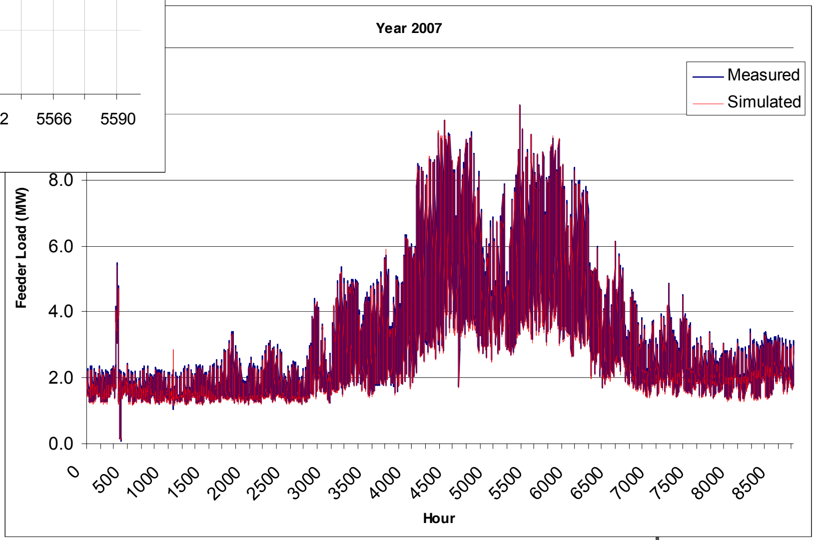
Load Models

- Individual customer load data is unknown
- Loads allocated using peak current levels measured on each phase
  - Phase A: 483A
  - Phase B: 489A
  - Phase C: 460A
- Hourly feeder current measured at substation used to scale load throughout the year (each phase individually)
- Represents calendar year 2007
- All loads modeled as constant P,Q

Basecase Measured vs Simulated Results





	Measured	Simulated	% Error
Total kWH	26,590,234	25,986,366	-2.3%
Average kWH	3,035	2,966	-2.3%
Max kWH	10,265	10,276	0.1%
Load Factor	30%	29%	-2.4%

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Loss Impact Analysis

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Solar Deployment

- 8760 solar technology curves provided by RW Beck
- Two Solar Scenarios
  - Case 1: Business as Usual
    - 52% of residential customers with PV
      - Blended PV curve
    - 11% of residential customers with SWH
      - Residential SWH curve
    - 100% Commercial w/ Solar PV
      - Commercial, large retail PV curve
      - Industrial PV curve
      - Commercial retail lighting (lrg retail only)
    - Customers with PV and SWH randomly chosen
  - Case 2: Greenfield
    - 100% of residential customers with PV
      - Residential, west-facing PV curve (N. Scottsdale)
    - 100% of residential customers with SWH
      - Residential SWH curve
    - 100% Commercial w/ Solar PV and/or lighting
      - 1-axis tracking PV curve on both (N. Scottsdale)
      - Commercial retail lighting (lrg retail only

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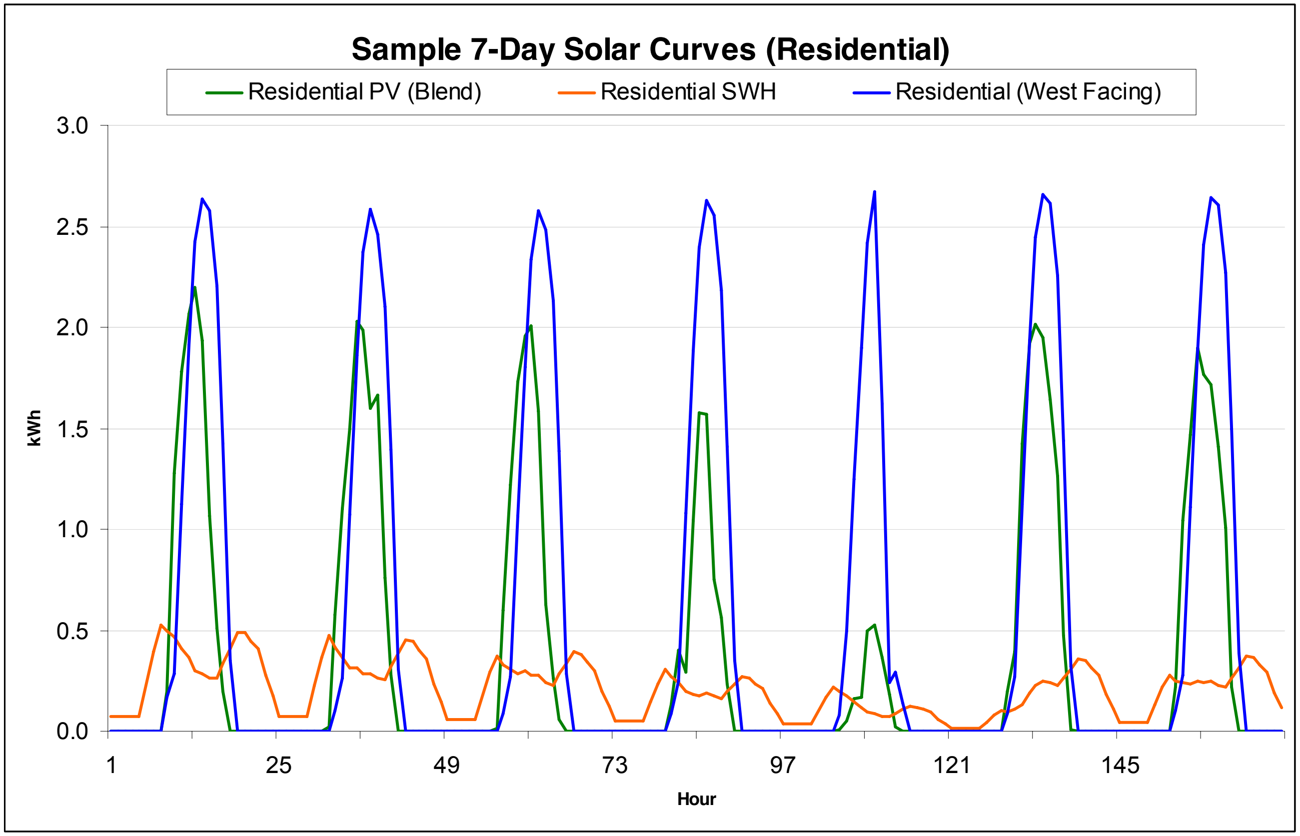
Sample Residential Solar Curves



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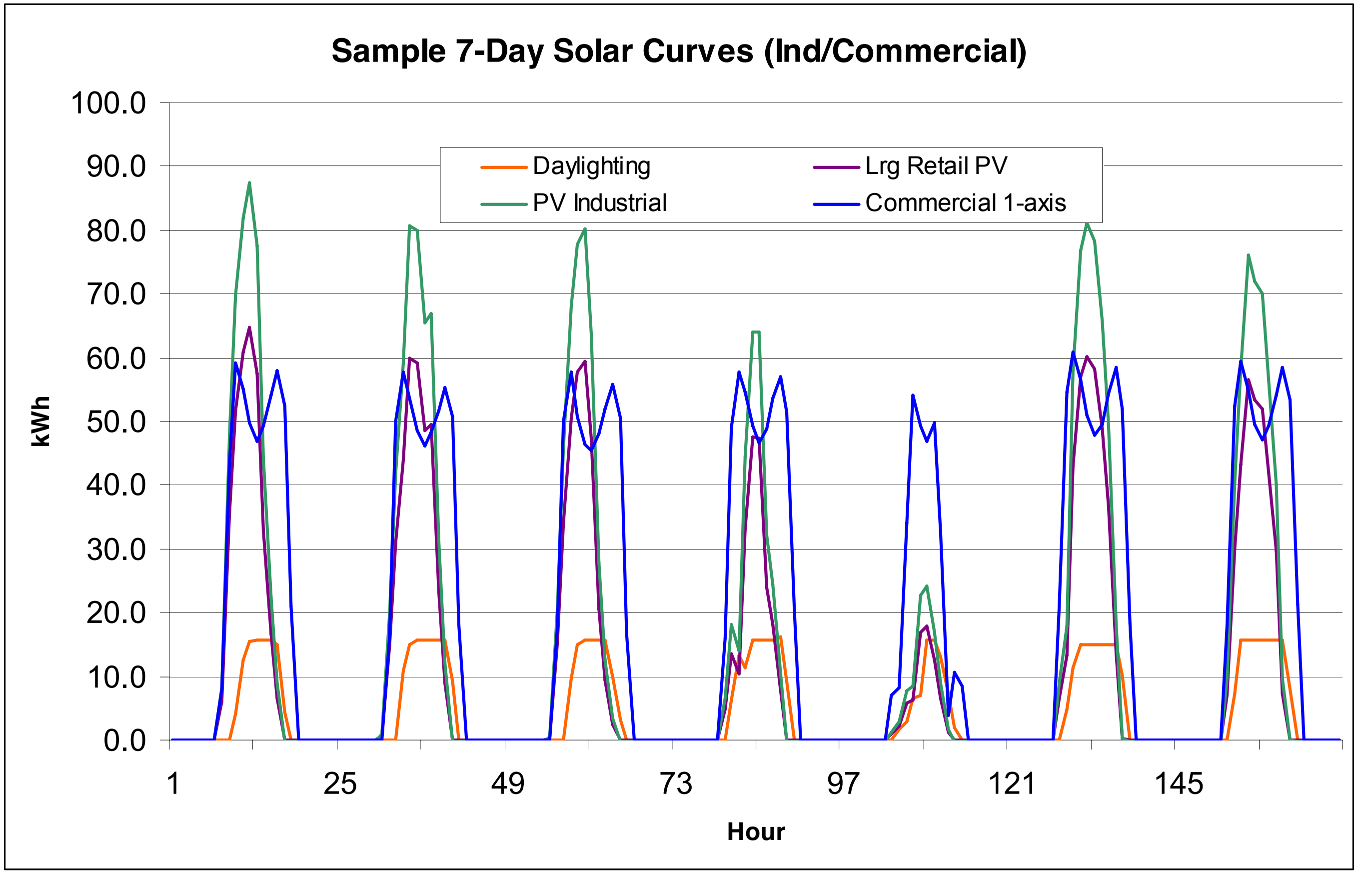
Sample Commercial/Industrial Solar Curves



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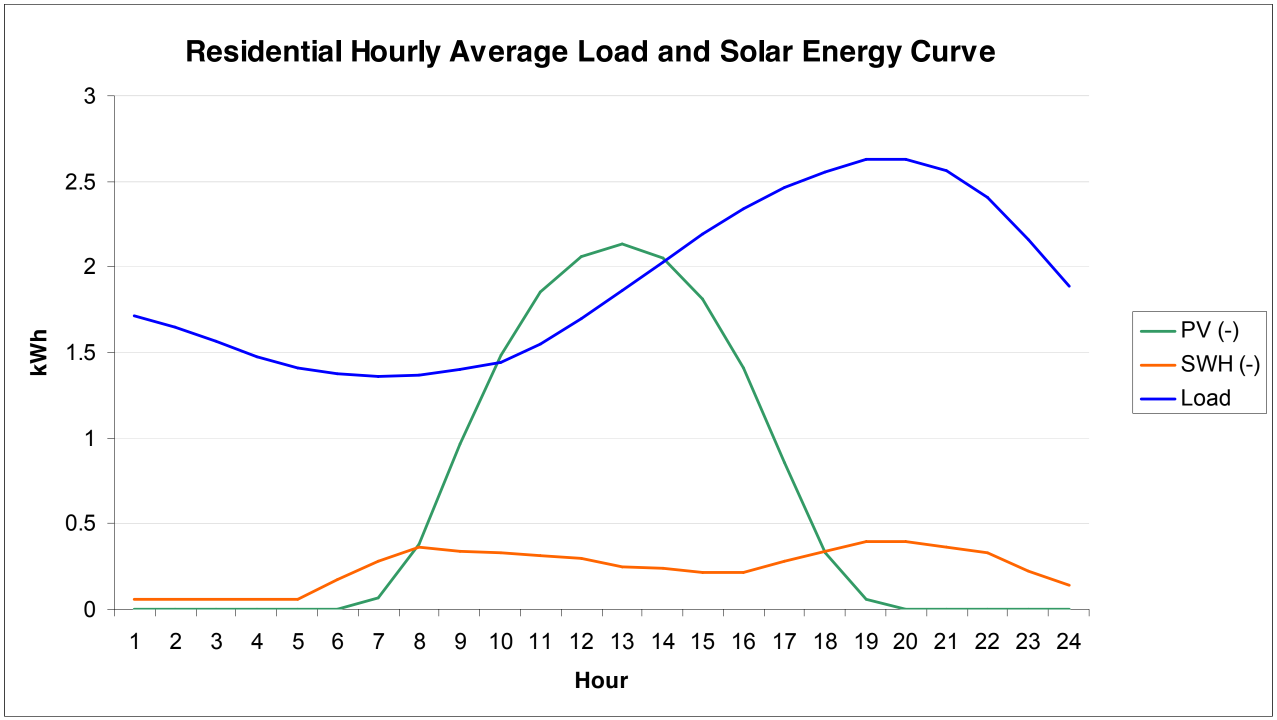
Hourly Average Load and Solar Curves for One Residential Customer



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Loss Categorization

- **Total losses:** total feeder losses measured on secondary side of substation transformer*. Total losses are subdivided into the following three inclusive groups

- **Load losses:** total resistive losses of all lines and xfmrs
- **No-load losses:** total transformer no-load losses

- **Line losses:** primary and secondary circuits
- **Transformer losses:** transformer load and no-load losses

- **12kV losses:** primary line and transformer losses
- ****Secondary losses:** secondary line losses only

*Loss calculations do not consider substation transformer

**Note that historically losses calculated on the secondary level have included all or a portion of the service transformer losses, but for this analysis all line transformer losses are included in the 12 kV losses reported.

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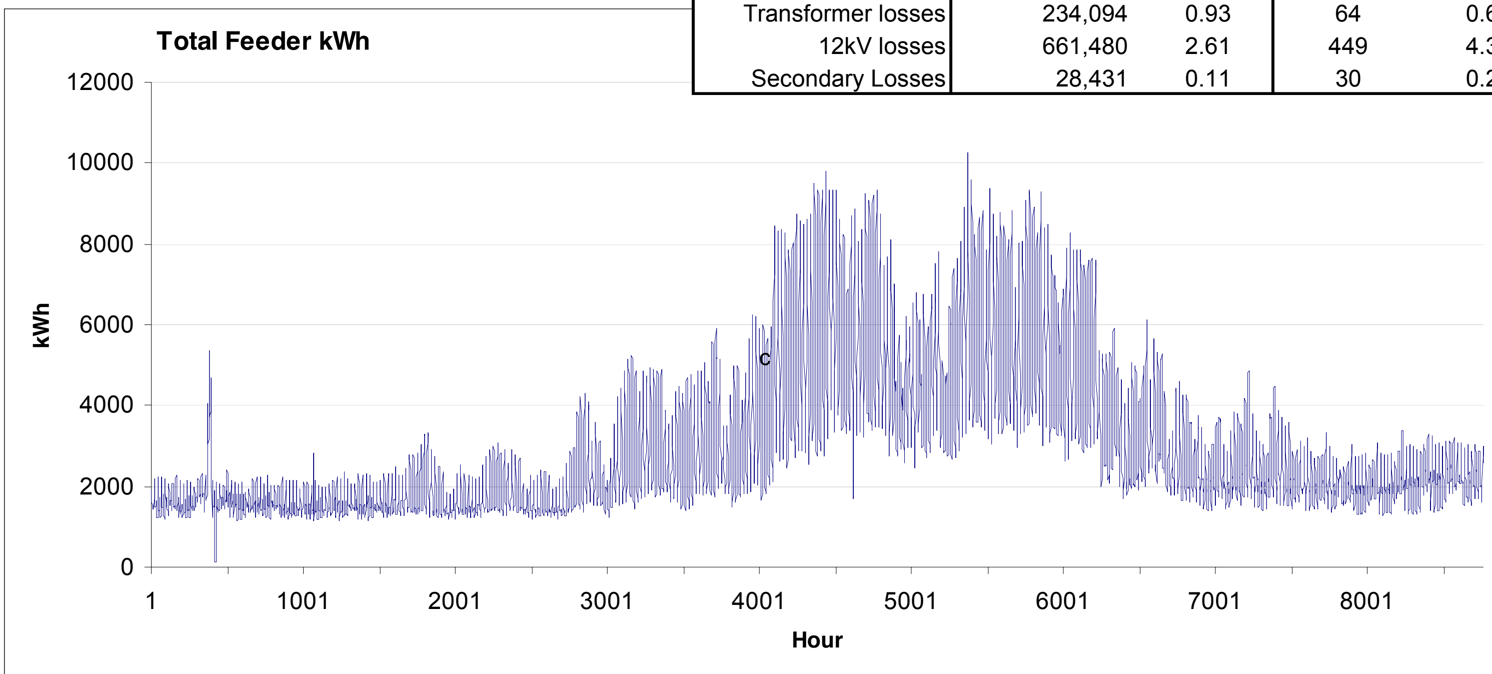
Base Case Results: No Solar

	Total kWh 25,296,330	% of Total	Peak kWh 10,276	% of of Peak
Total Losses	689,911	2.73	479	4.66
No Load Losses	191,170	0.76	20	0.19
Load Losses	498,741	1.97	459	4.47
Line Losses	455,817	1.80	415	4.04
Transformer losses	234,094	0.93	64	0.62
12kV losses	661,480	2.61	449	4.37
Secondary Losses	28,431	0.11	30	0.29



Base Case Results: No Solar (Lower Efficiency Transformers)

- Snapshot load flow at peak load levels
- Lower efficiency transformers assumed
  - No-load losses: 0.5% (0.217% - 0.22% assumed for rest of study)
  - Load Losses: 1.0% (0.96% - 1.16% assumed for rest of study

	High Efficiency		Lower Efficiency	
	Peak kWh 10,276	**% of of Peak**	**Peak kWh** 10379	**% of** of Peak
Total Losses	479	4.66	586	5.64
No Load Losses	20	0.19	78	0.75
Load Losses	459	4.47	508	4.89
Line Losses	415	4.04	423	4.08
Transformer losses	64	0.62	162	1.56
12kV losses	449	4.37	556	5.35
Secondary Losses	30	0.29	30	0.29

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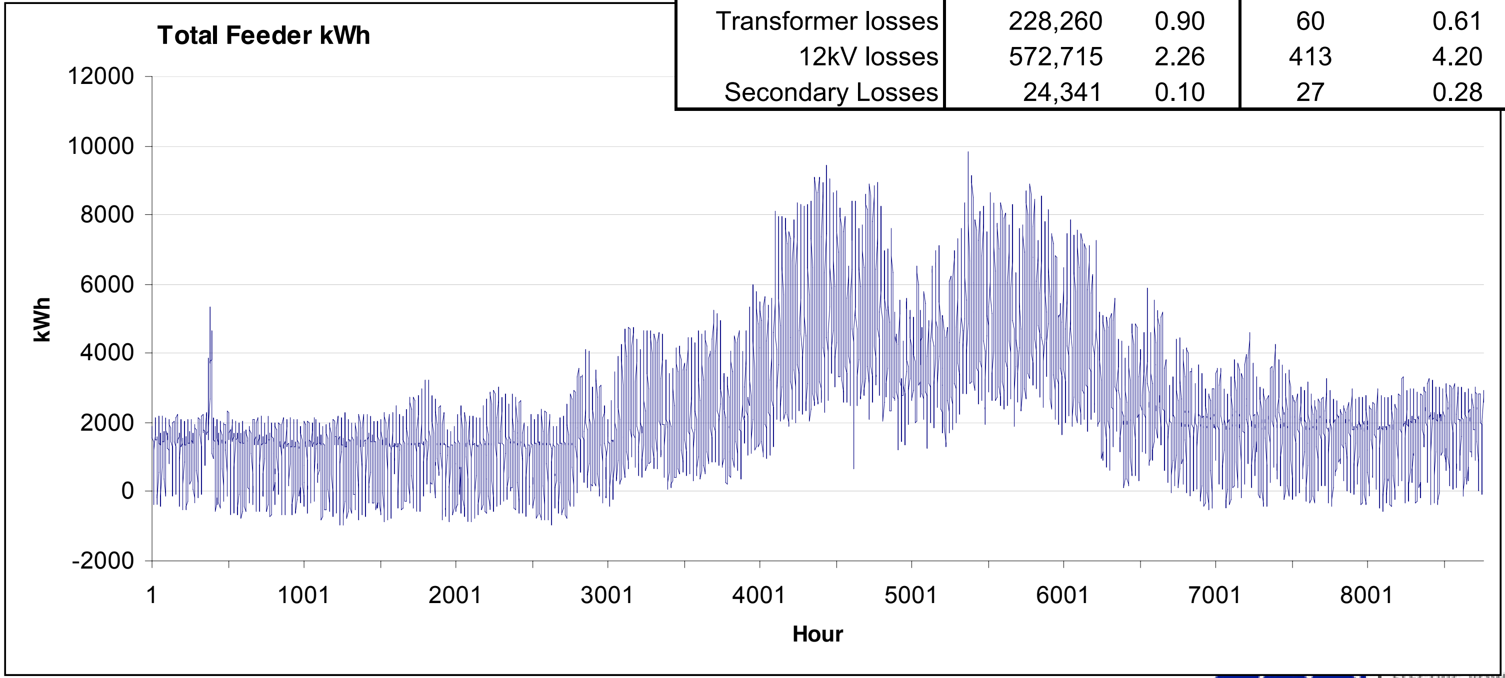
Case 1 Results: Business as Usual

	Total kWh 20,359,873	% of Base	Peak kWh 9,835	% of of Peak
Total Losses	597,056	2.36	440	4.47
No Load Losses	192,706	0.76	20	0.20
Load Losses	404,350	1.60	420	4.27
Line Losses	368,796	1.46	380	3.86
Transformer losses	228,260	0.90	60	0.61
12kV losses	572,715	2.26	413	4.20
Secondary Losses	24,341	0.10	27	0.28



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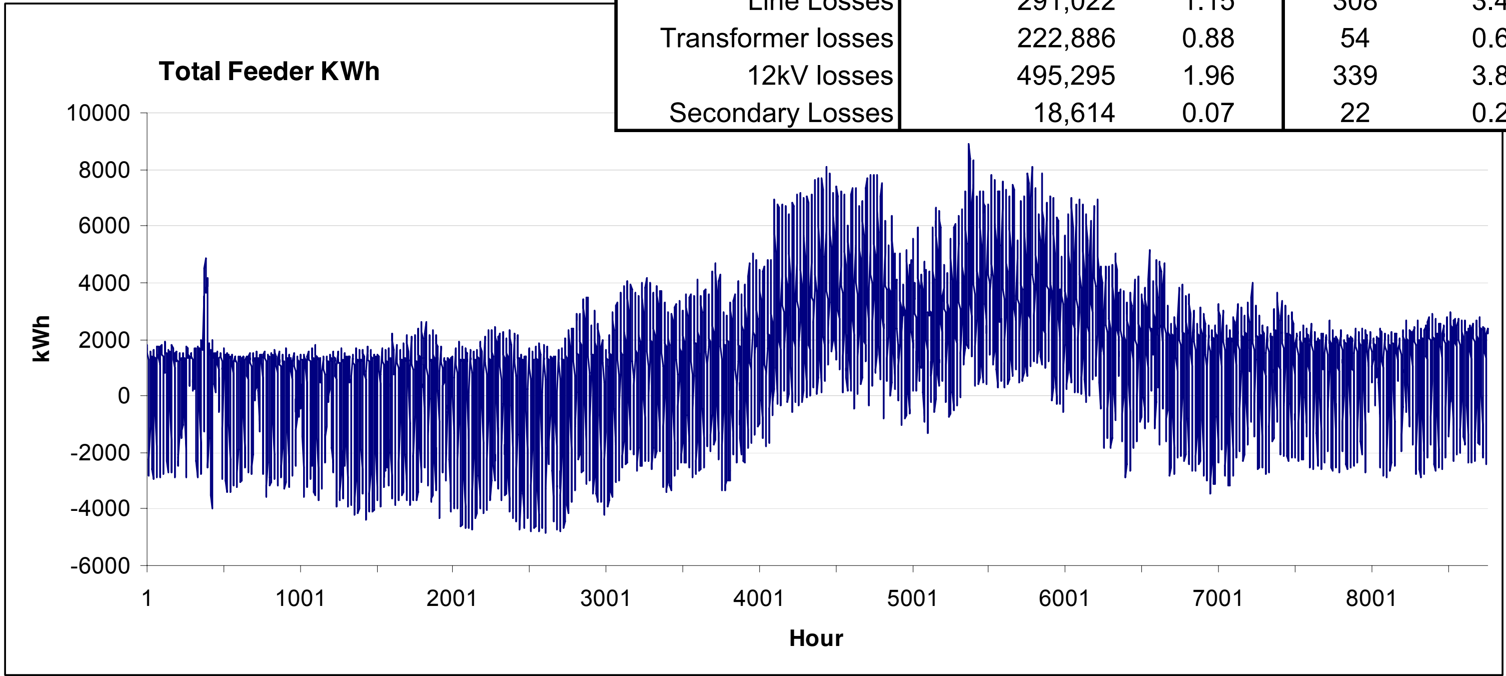
Case 2 Results: Greenfield

	Total kWh 10,606,393	% of Base	Peak kWh 8,876	% of of Peak
Total Losses	513,908	2.03	362	4.08
No Load Losses	195,024	0.77	20	0.23
Load Losses	318,884	1.26	342	3.85
Line Losses	291,022	1.15	308	3.47
Transformer losses	222,886	0.88	54	0.61
12kV losses	495,295	1.96	339	3.82
Secondary Losses	18,614	0.07	22	0.25



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Loss Analysis Results Summary

	Base	Business as Usual		Greenfield	
	Total kWh	Total kWh	Diff	Total kWh	Diff
	25,296,330	20,359,873	4,936,457	10,606,393	14,689,937
Total Losses	689,911	597,056	92,855	513,908	176,003
No Load Losses	191,170	192,706	1,536	195,024	3,855
Load Losses	498,741	404,350	94,391	318,884	179,857
Line Losses	455,817	368,796	87,021	291,022	164,794
Transformer losses	234,094	228,260	5,834	222,886	11,208
12kV losses	661,480	572,715	88,765	495,295	166,185
Secondary Losses	28,431	24,341	4,090	18,614	9,817

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Loss Analysis Results Summary, cont.

	Base	Business as Usual		Greenfield	
	Total kWh	Total kWh	Diff	Total kWh	Diff
Total kWh	25,296,330	20,359,873	19.51%	10,606,393	58.07%
Total Losses	2.73%	2.36%	0.37%	2.03%	0.70%
No Load Losses	0.76%	0.76%	0.01%	0.77%	0.02%
Load Losses	1.97%	1.60%	0.37%	1.26%	0.71%
Line Losses	1.80%	1.46%	0.34%	1.15%	0.65%
Transformer losses	0.93%	0.90%	0.02%	0.88%	0.04%
12kV losses	2.61%	2.26%	0.35%	1.96%	0.66%
Secondary Losses	0.11%	0.10%	0.02%	0.07%	0.04%

Note: Loss values on % of Total Base Case Demand

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Reduction in 2007 Peak Load

	2007 Peak kWh	
	Business as Usual	Greenfield
Base Case	10,276	10,276
With PV	9,889	7,320
With Lighting	10,258	10,256
With SWH	10,230	9,820

Loss Analysis Conclusions

- Business as Usual Case
  - Total energy offset of 4,936 MWh
  - Peak reduction in demand of 441 kW
  - Reduction in losses of 93 MWh
  - 0.37% reduction in total losses
- Greenfield Case
  - Total energy offset of 14,689 MWh
  - Peak reduction in demand of 1,400 kW
  - Reduction in losses of 176 MWh
  - 0.7% reduction in total losses

- Circuit load factor is low (~29%)
- Slight increase in no-load losses due to higher voltages in circuit
- High-efficiency transformers
- PV peak does not coincide with load peak, therefore during light load customers are back-feeding into grid
- Losses are considered regardless of current direction, if backfeeding were not allowed the loss reduction would be greater

Voltage Regulation

Summary

- This study was conducted to determine what effects a system level PV power profile has on overall voltage regulation of DM04
  - Study used residential based PV profile (discussed below)
  - Study conducted in the Greenfield configuration (every customer has PV installed)
  - No SWH or day lighting modeled due to lack of information
  - Study concluded no adverse effects on voltage regulation were experienced due to PV operation (based on 10-min solar data provided)
- Additional study conducted to show the effects on voltage regulation if the system would sporadically lose all PV supply
  - This study concluded that no adverse effects on voltage regulation were experienced due to the PV operation

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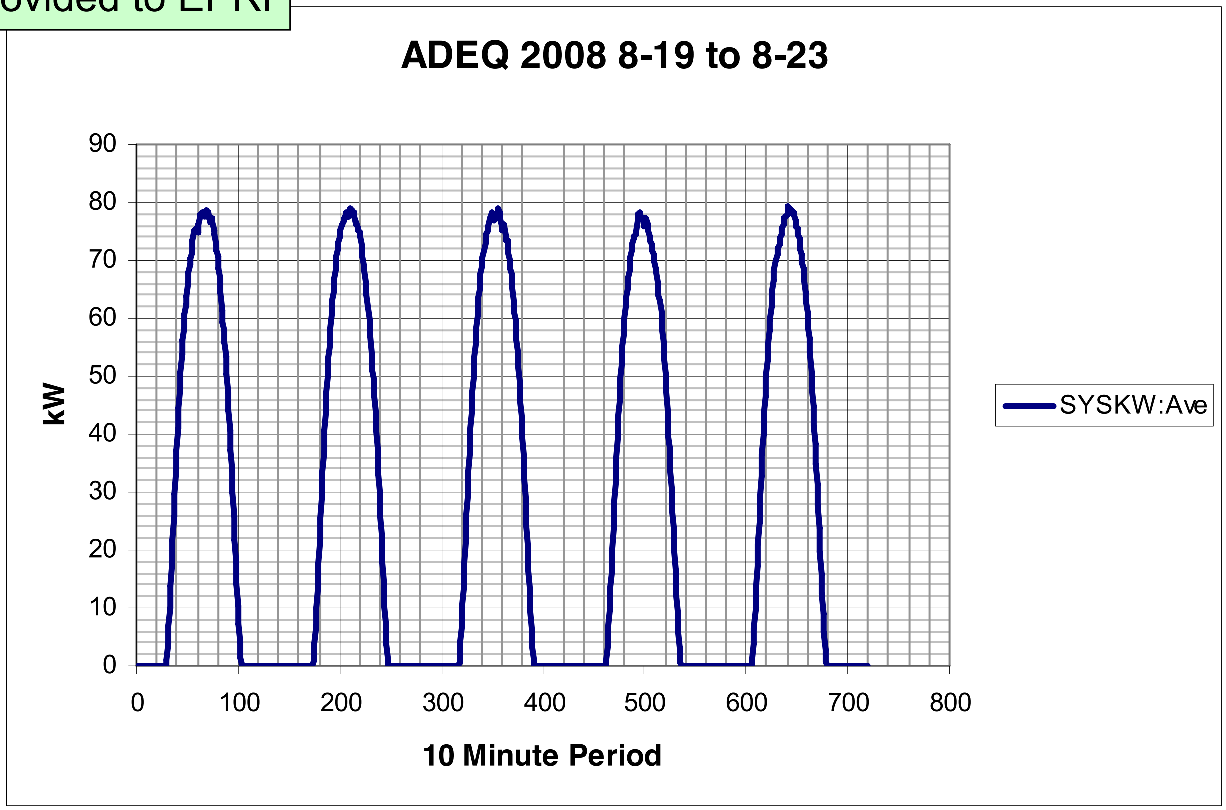
ADEQ: Fixed Horizontal commercial PV system in Phoenix 2008-8-19 to 2008-8-23

Data Provided to EPRI



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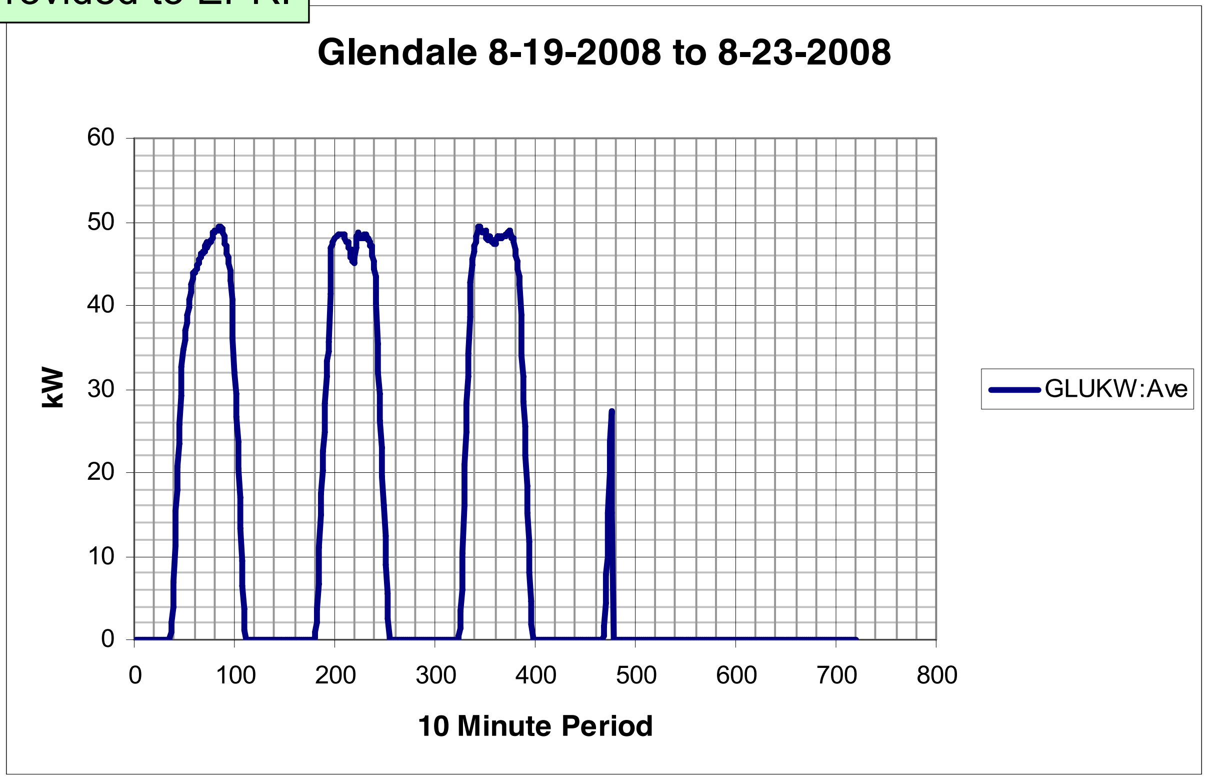
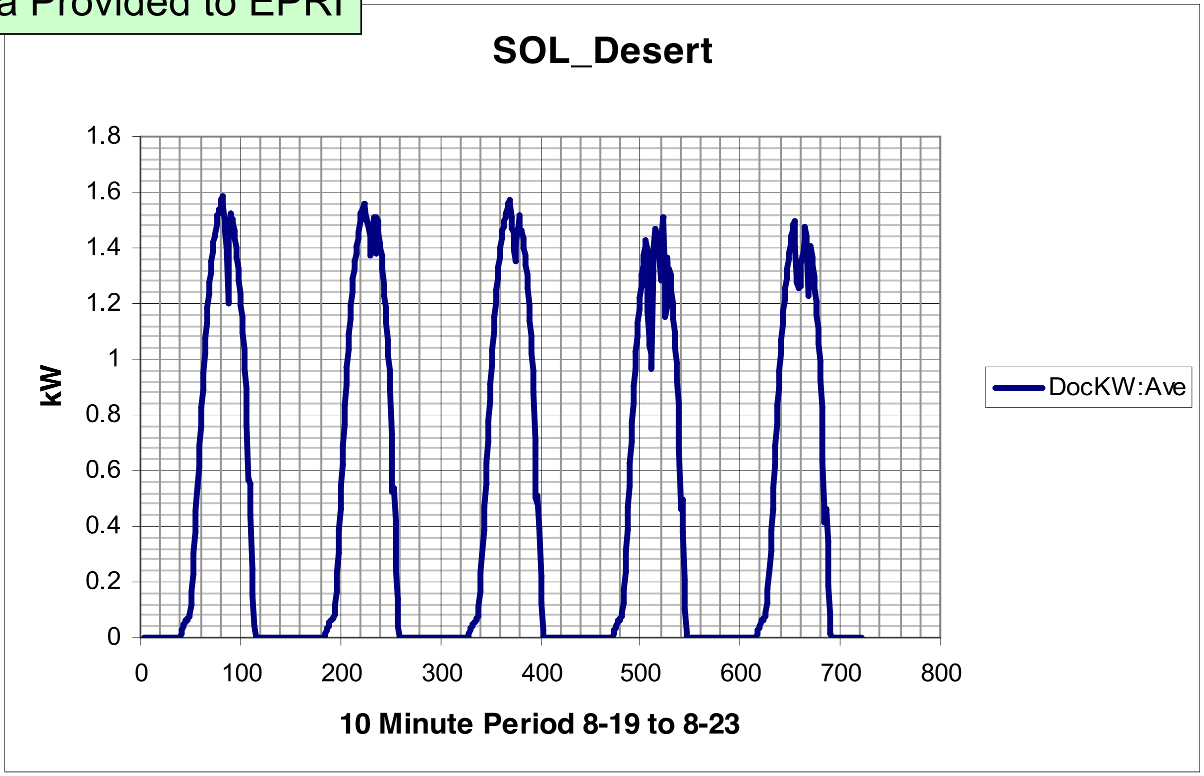
Glendale_SAT: 1 Axis tracking PV system in Glendale 2008-8-19 to 2008-8-23

Data Provided to EPRI



SOL_Desert: Fixed Latitude (residential size) PV system at Lake Pleasant 2008-8-19 to 2008-8-23

Data Provided to EPRI



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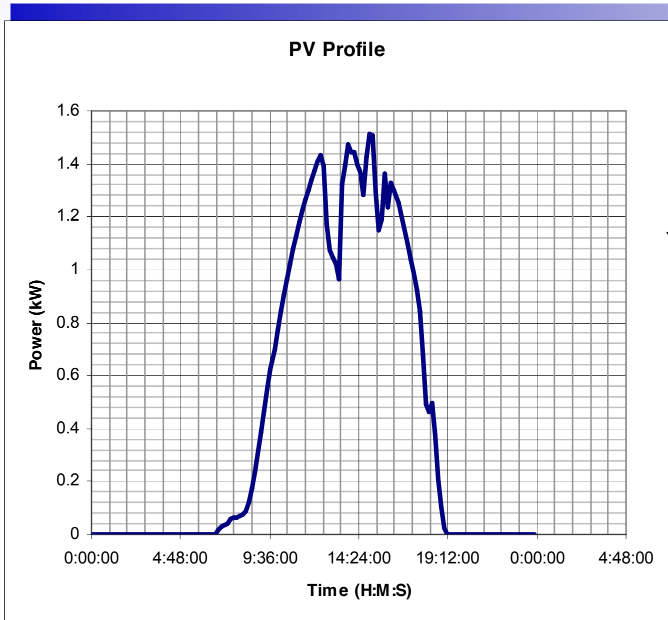
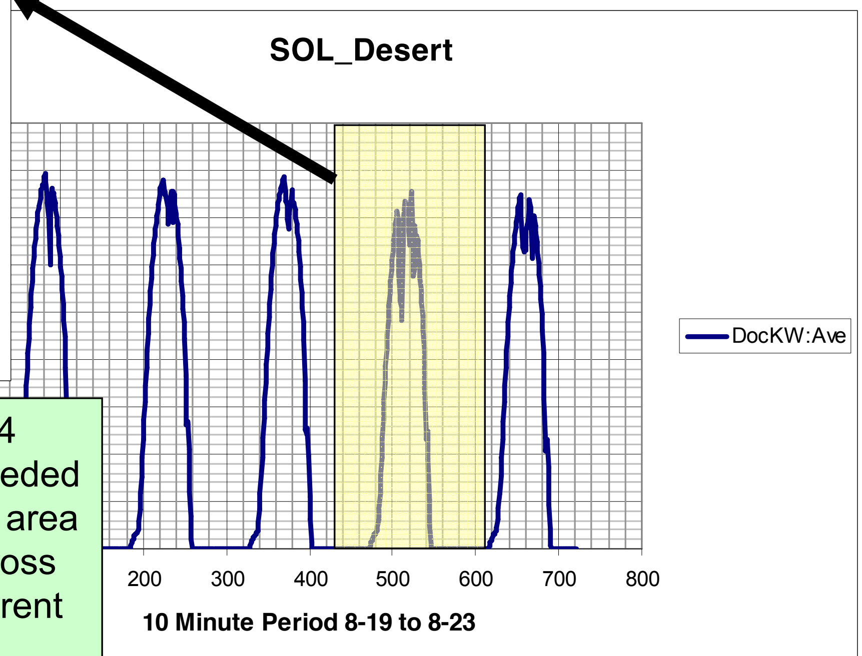
PV Model Used for Analysis – SOL_Desert: Fixed Latitude (residential size) PV system at Lake Pleasant 2008-8-19 to 2008-8-23



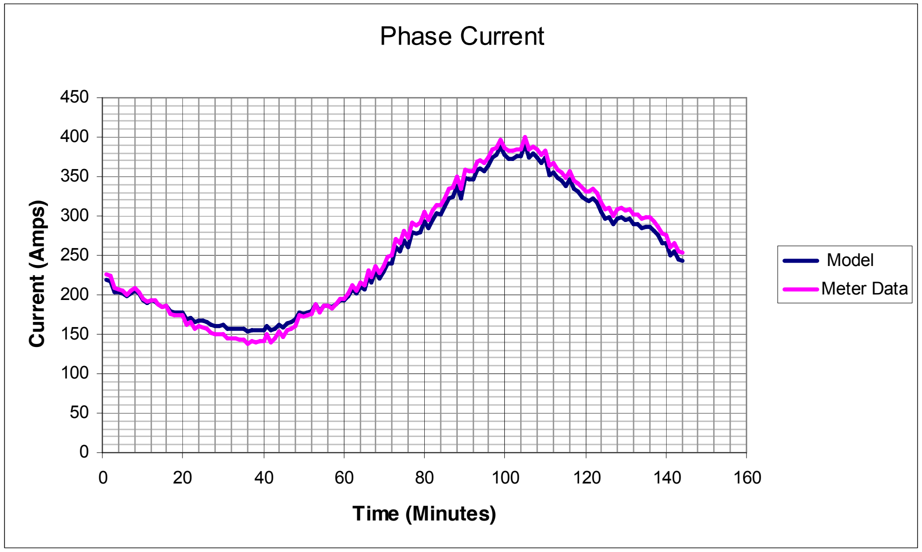
Profile with most deviation over 24 hour period used for voltage profile simulation



Profile also selected because DM04 consists of mostly residential loads. Needed a representation of same geographical area i.e. assumes average cloud cover across entire feeder so two profiles from different locations is unusable.

Voltage Regulation Model

- Same base model used for loss studies
- Load model based on 1 minute load current data provided in " EMS Report - 07/03/2008" (Averaged to 10 minutes to match PV profile)
  – Highest load day for high-res data
- Total kvar on system was adjusted to match load profile
- Greenfield model used (exception of SWH and day lighting)



Comparison of Phase Currents from Model to Meter Data.

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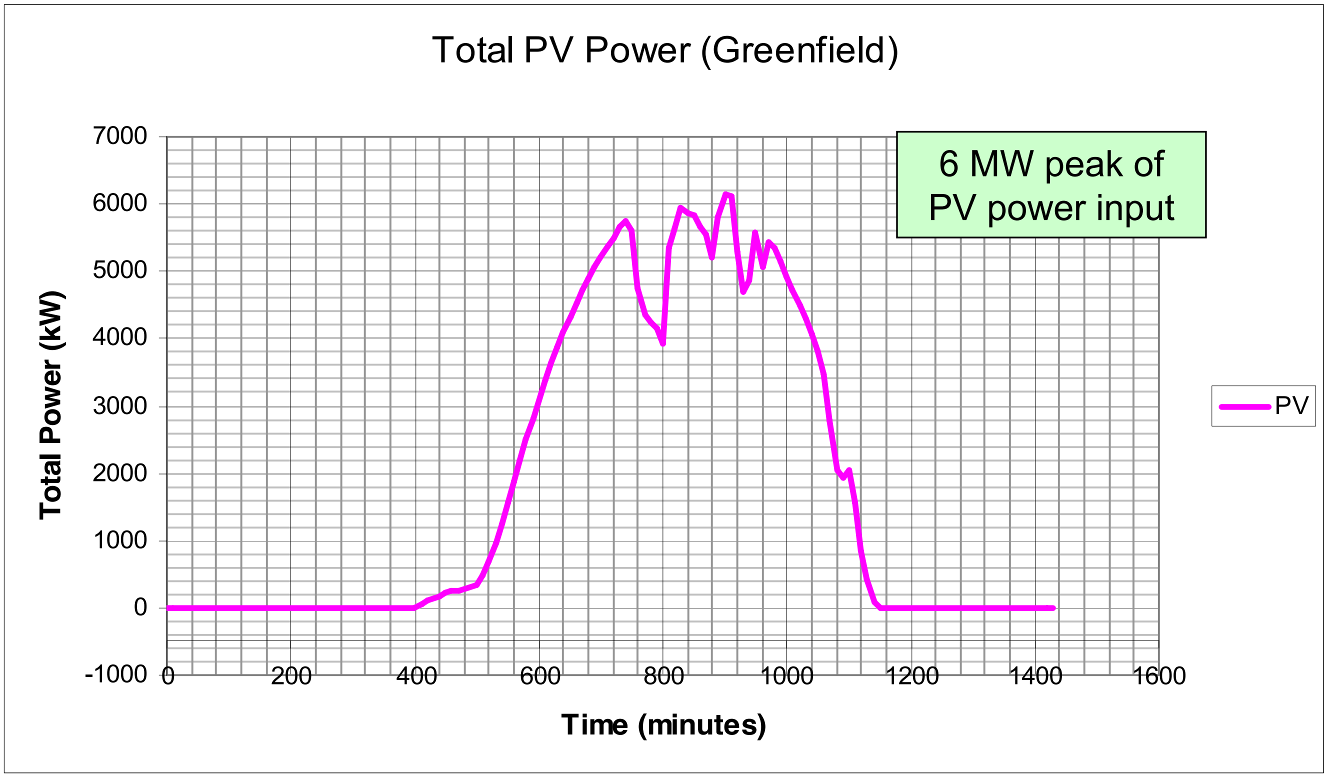
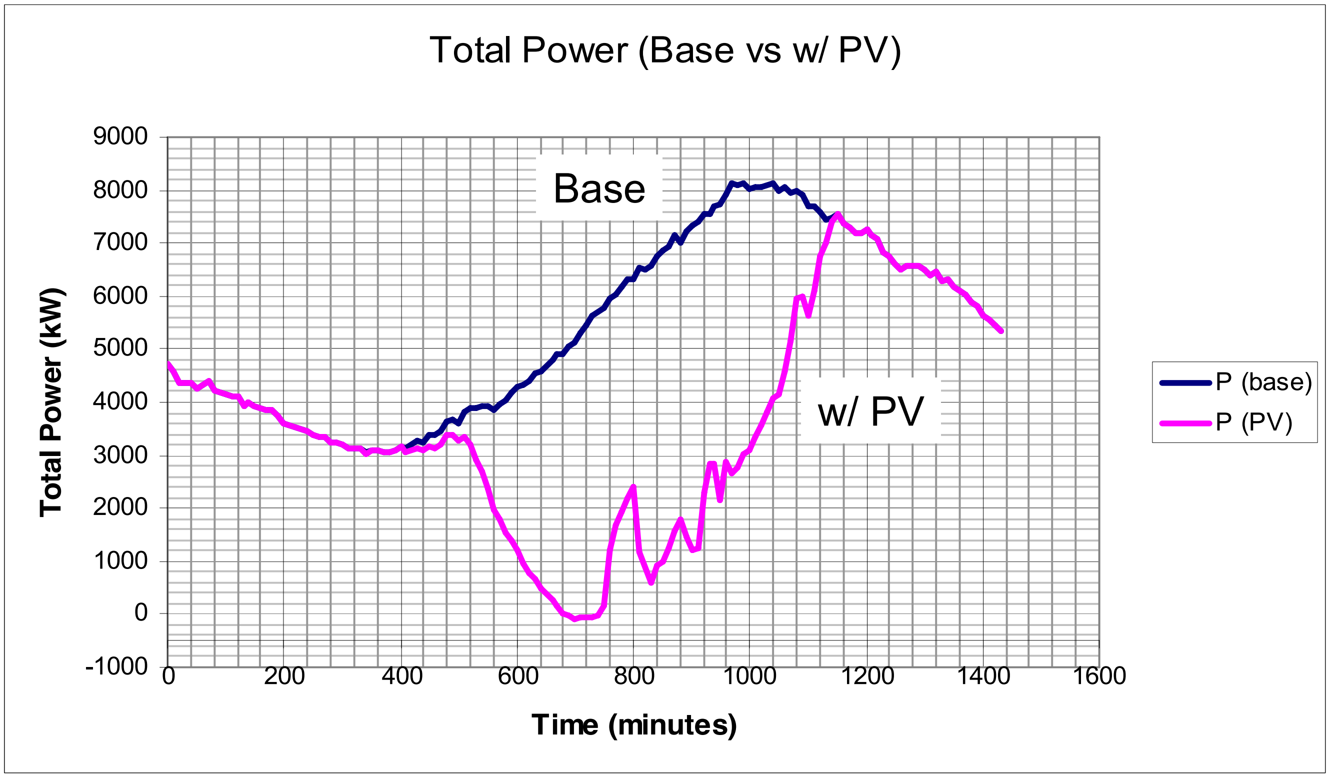
Greenfield Results

Total PV Power Input



Effect of PV Power on Total Power Profile



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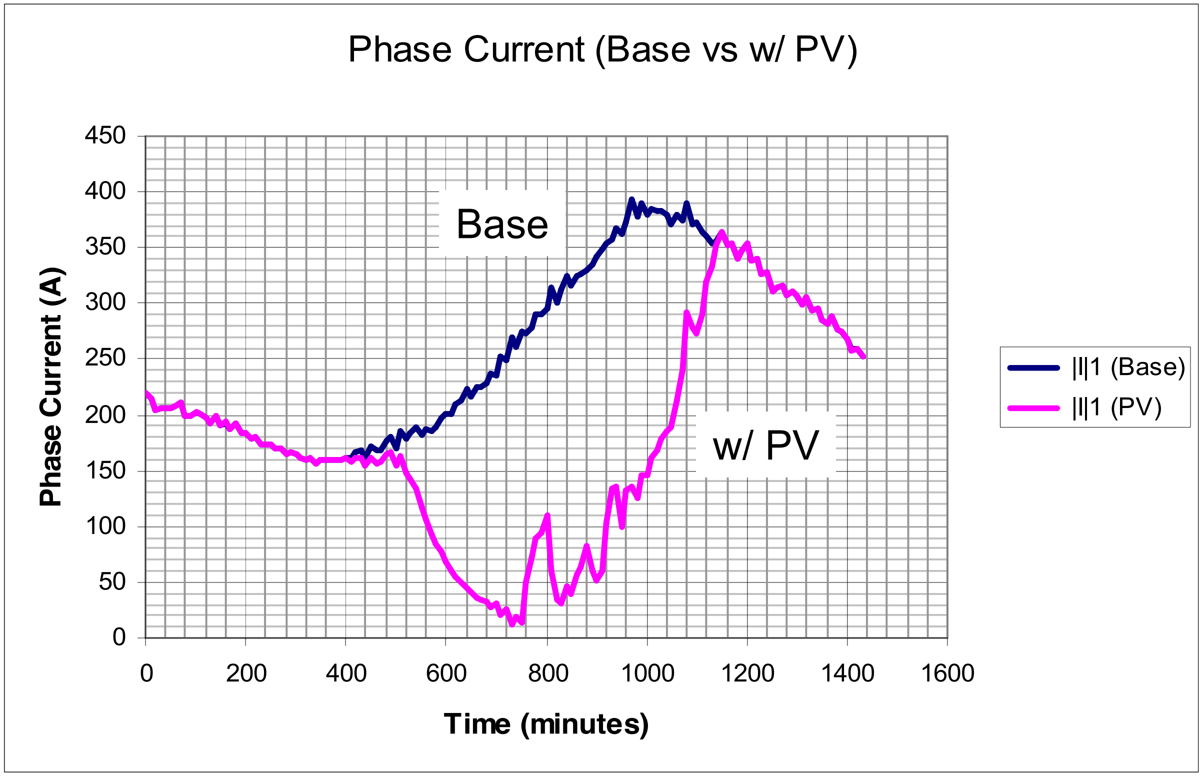
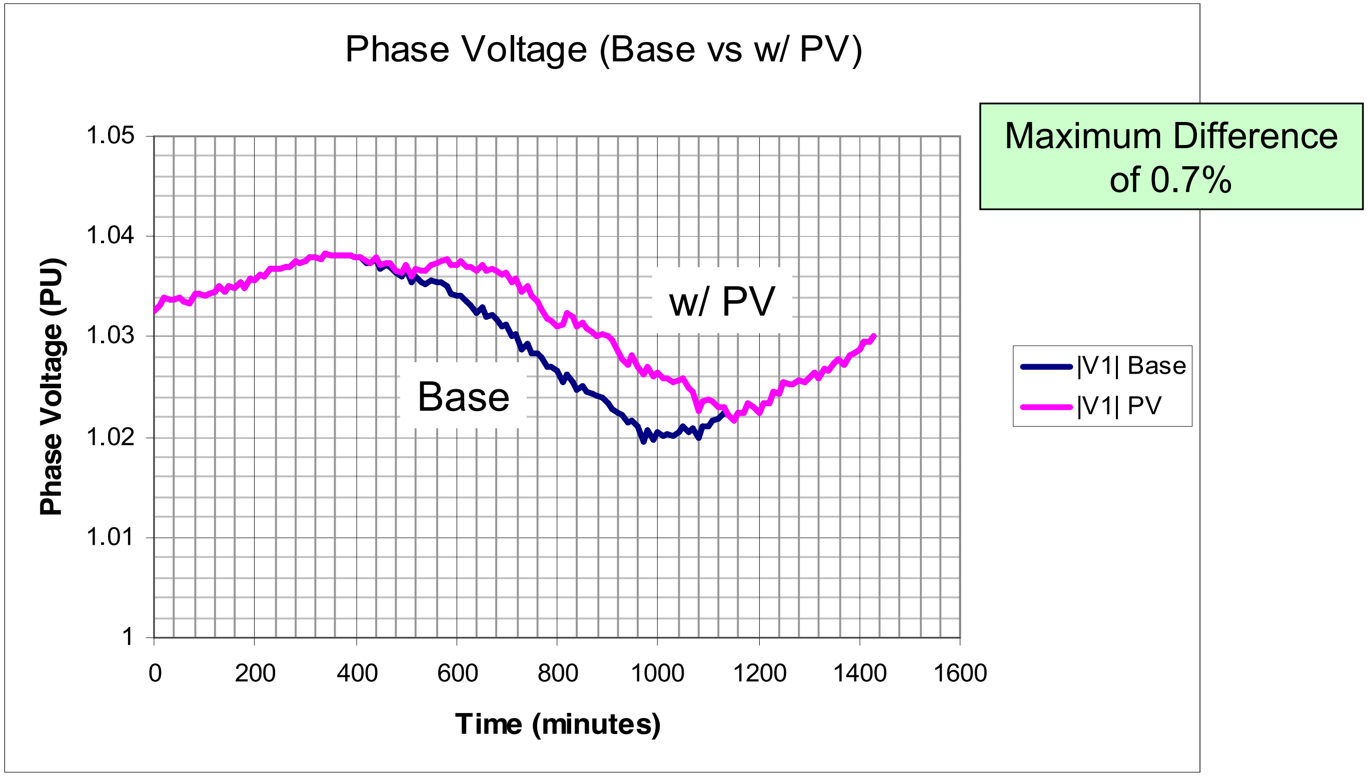
Effect of PV Power on Phase Current Profile



Effect of PV Power on Voltage Profile



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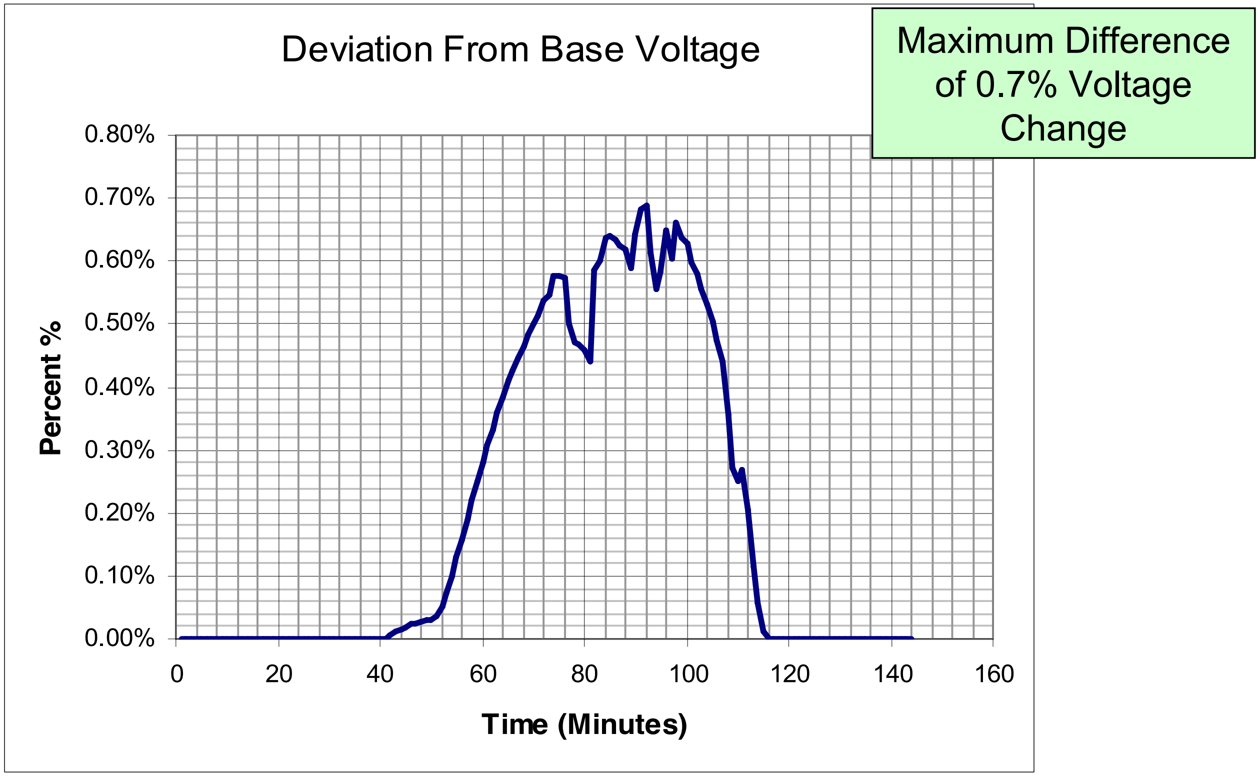
Deviation between Voltage Profile



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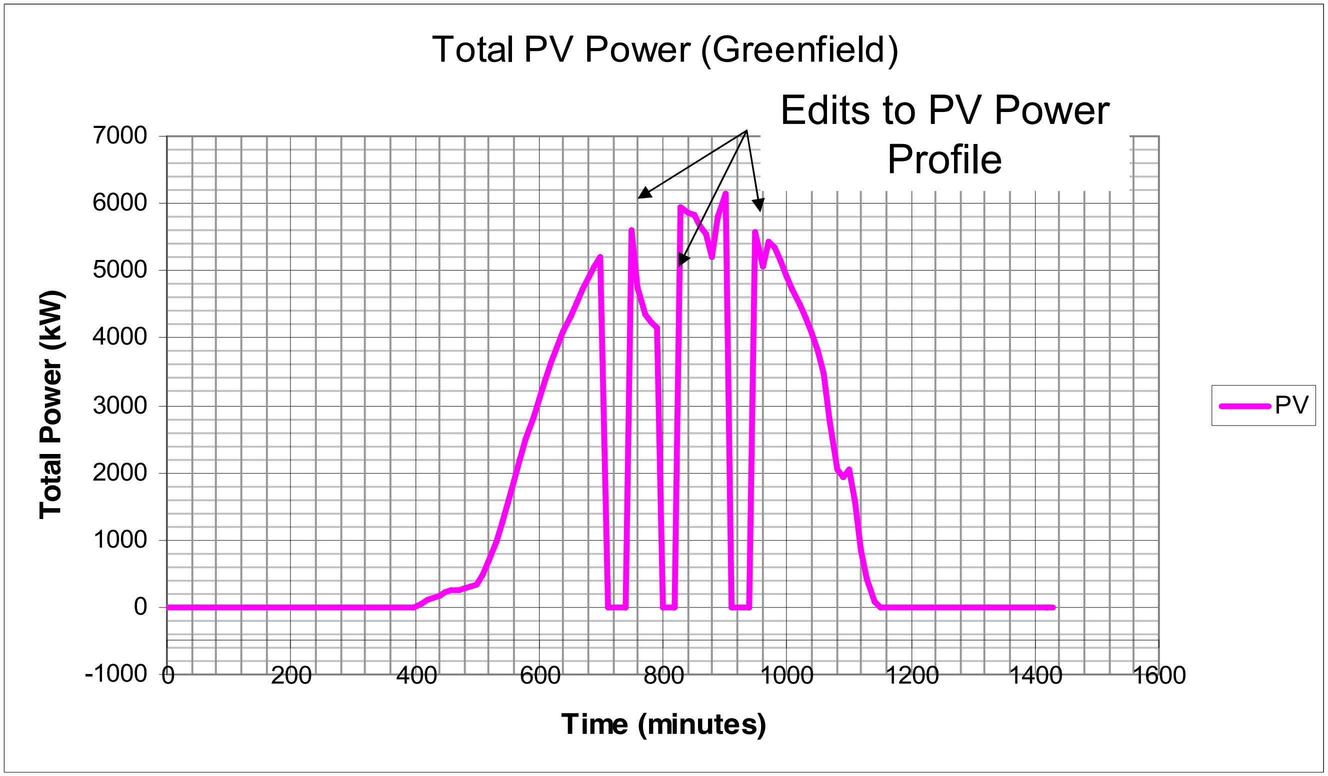
Greenfield Results with Manually Edited Profile

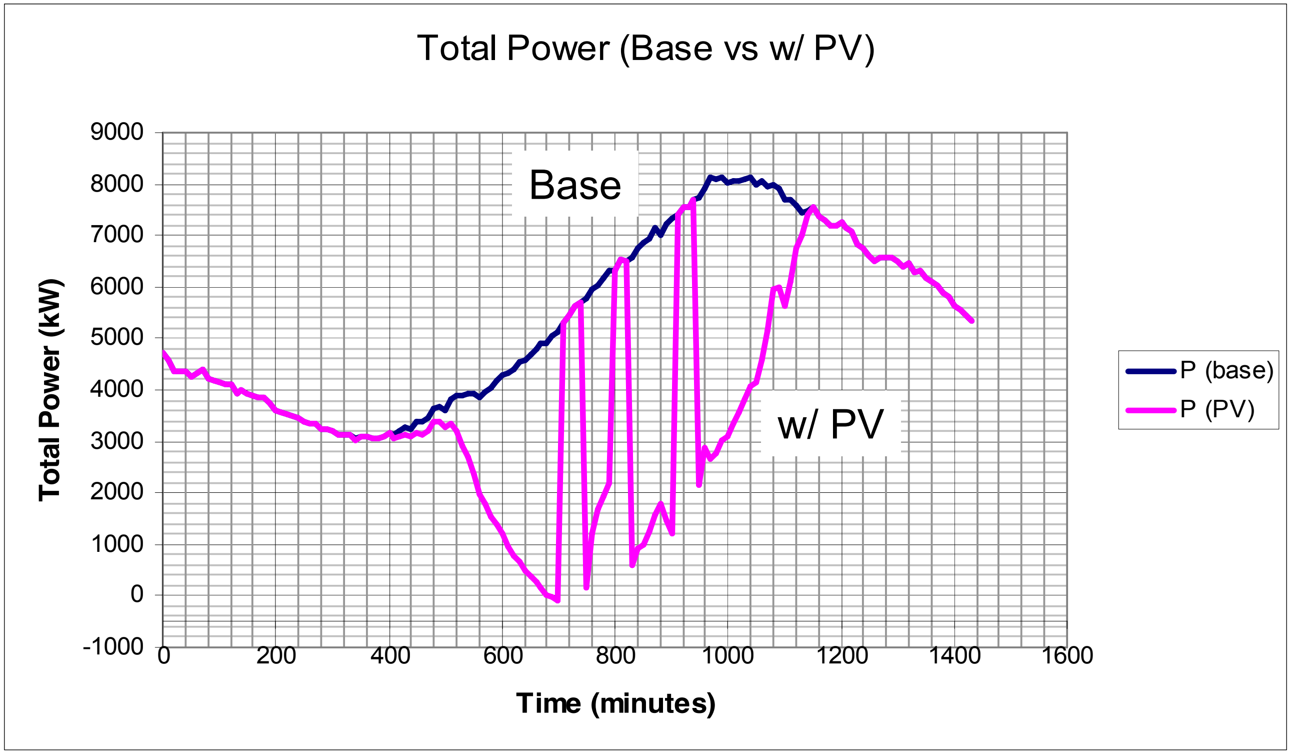
Greenfield Results with Manually Edited Profile

- The PV Profile was edited to increase PV profile deviation
- This increase in deviation modeled the system to analyze the effects on system if the PV supply were lost
- Same base model used for loss study
- Load model based on 1 minute load current data provided in " EMS Report - 07/03/2008" (Averaged to 10 minutes to match PV profile)
- Greenfield model used (exception of SWH and day lighting)
- No SWH or day lighting modeled

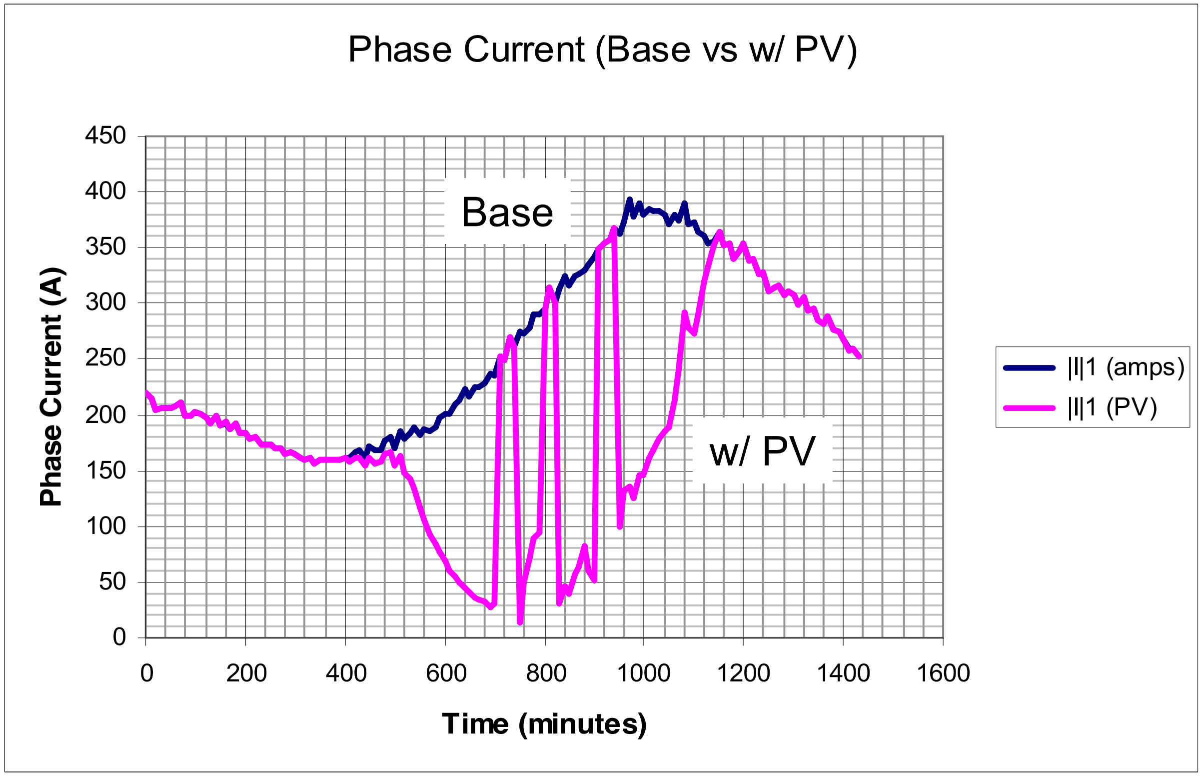
Total PV Power Input of Edited PV Profile



Effect of Edited PV Profile on Total Power Profile



Effect of Edited PV Profile on Phase Current Profile



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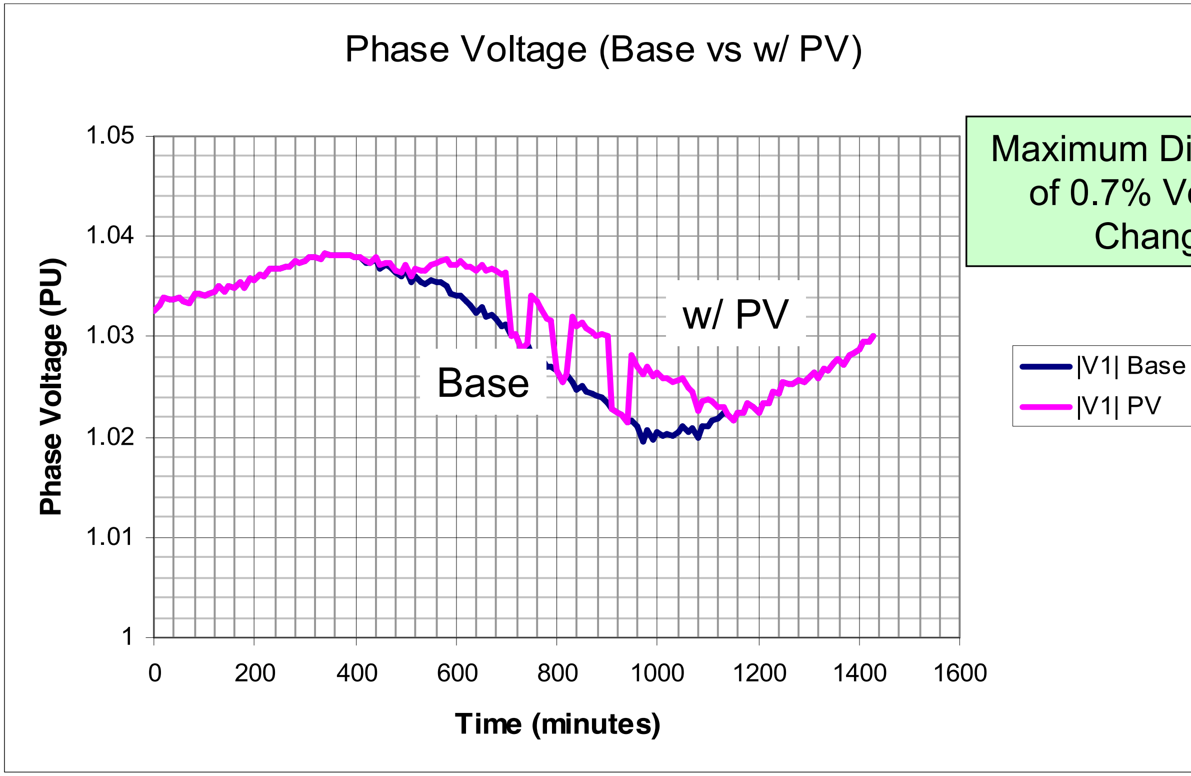
Effect of Edited PV Profile on Voltage Profile



Maximum Difference of 0.7% Voltage Change

Conclusions

- DM 04 included no LTCs or line regulators
- Therefore, the adverse effects on voltage regulation equipment could not be studied
- Based on the analysis performed herein no adverse effects on voltage regulation were experienced
- A maximum of 0.7% voltage deviation occurs when PV supply is disconnected

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APPENDIX L — MODEL RESULTS

Figure L-1 Residential 85020 Annual Energy Savings

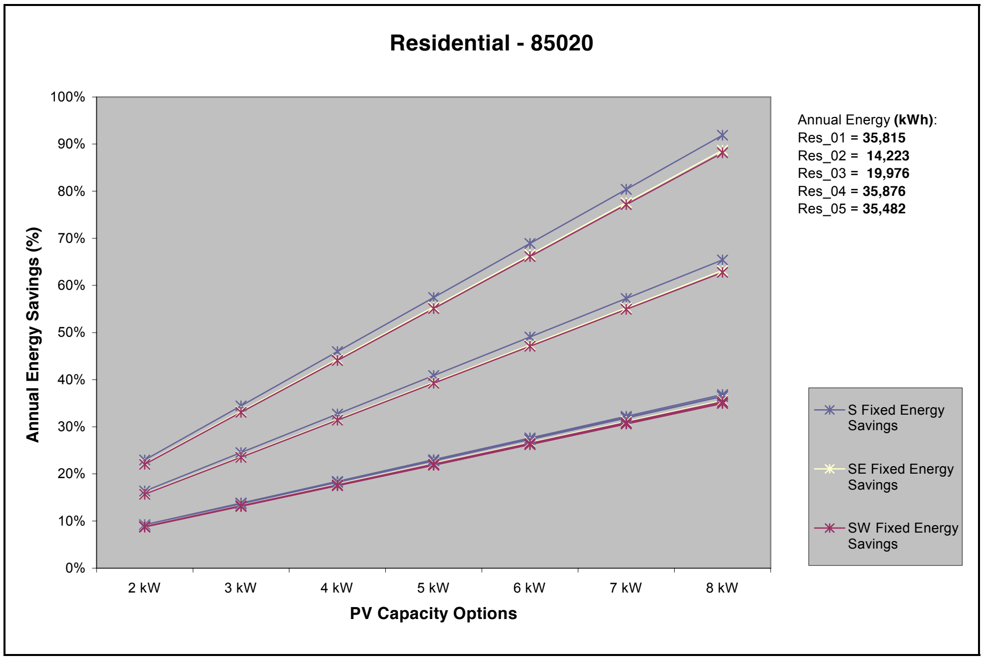


Figure L-2. Residential 85020 Annual Peak Demand Savings

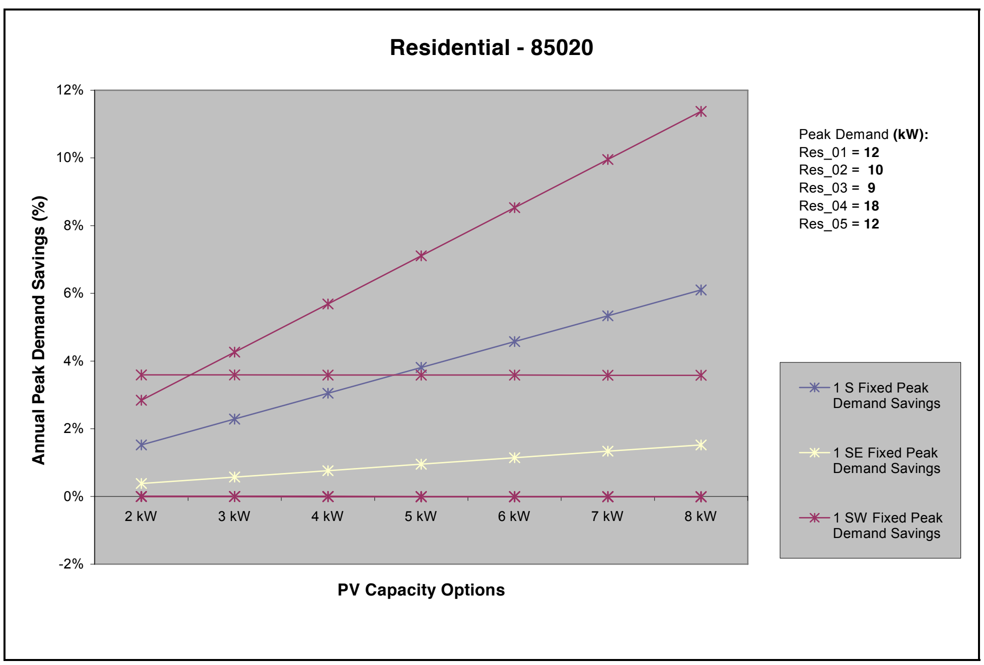


Figure L-3. Residential 85022 Annual Energy Savings

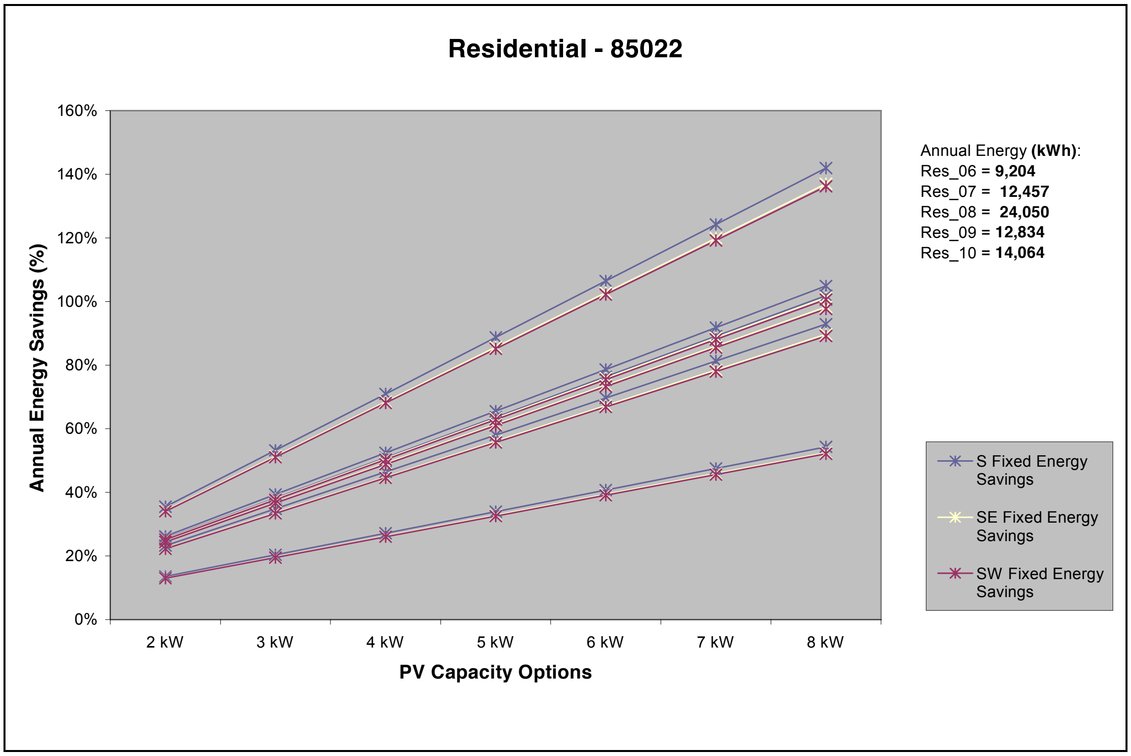


Figure L-4. Residential 85022 Annual Peak Demand Savings

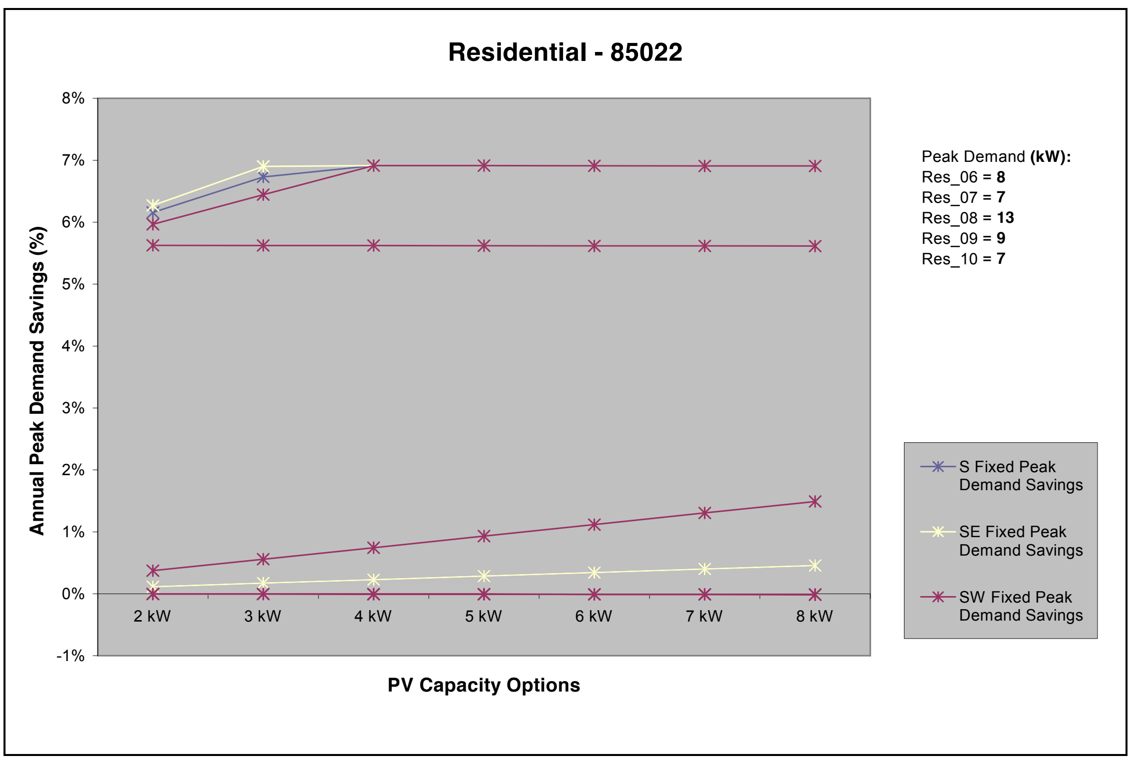


Figure L-5. Residential 85028 Annual Energy Savings

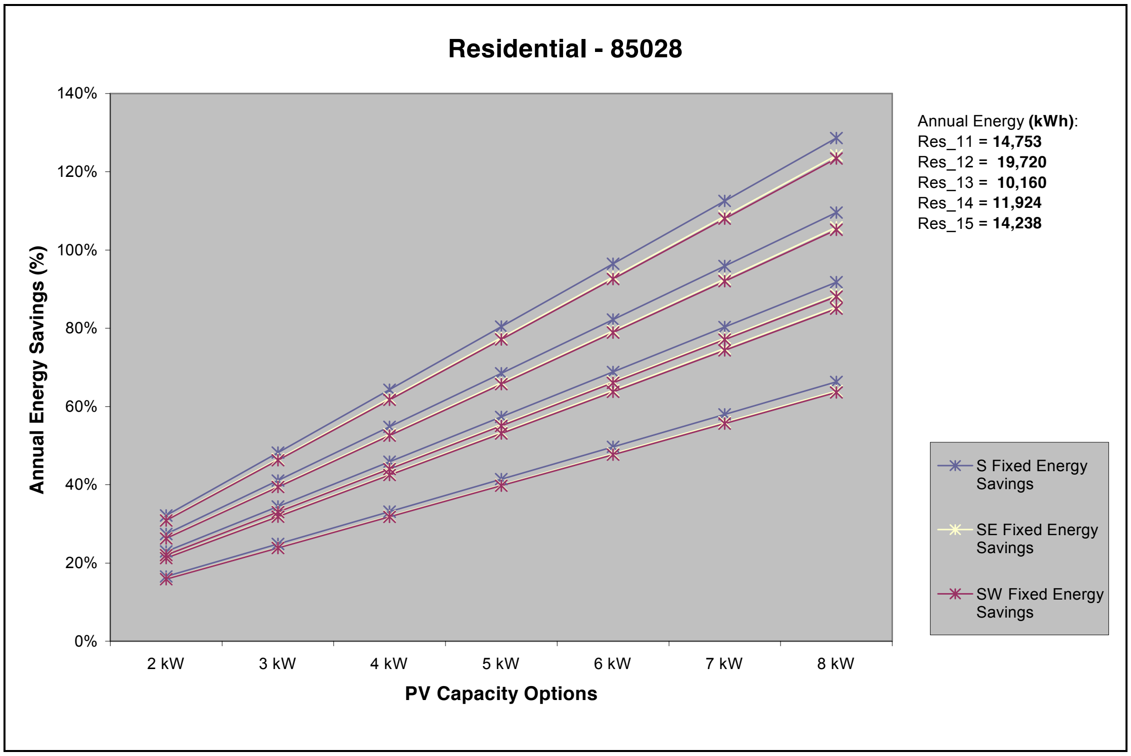


Figure L-6. Residential 85028 Annual Peak Demand Savings

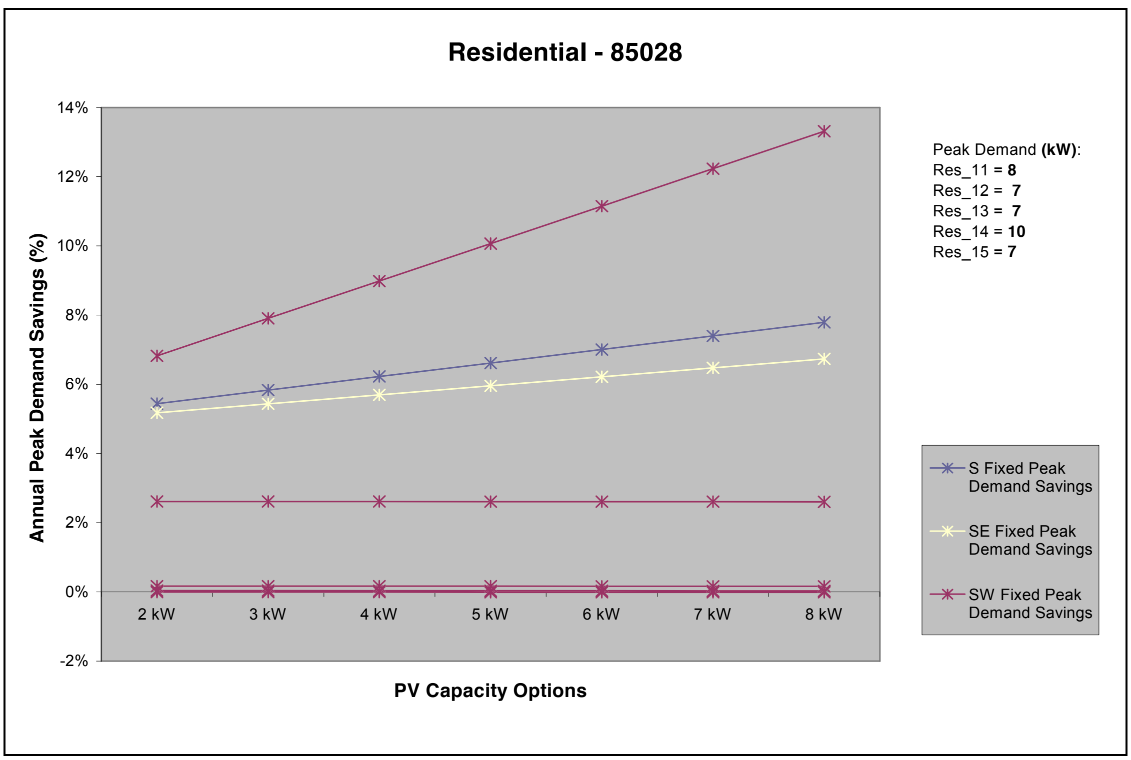


Figure L-7. Residential 85032 Annual Energy Savings

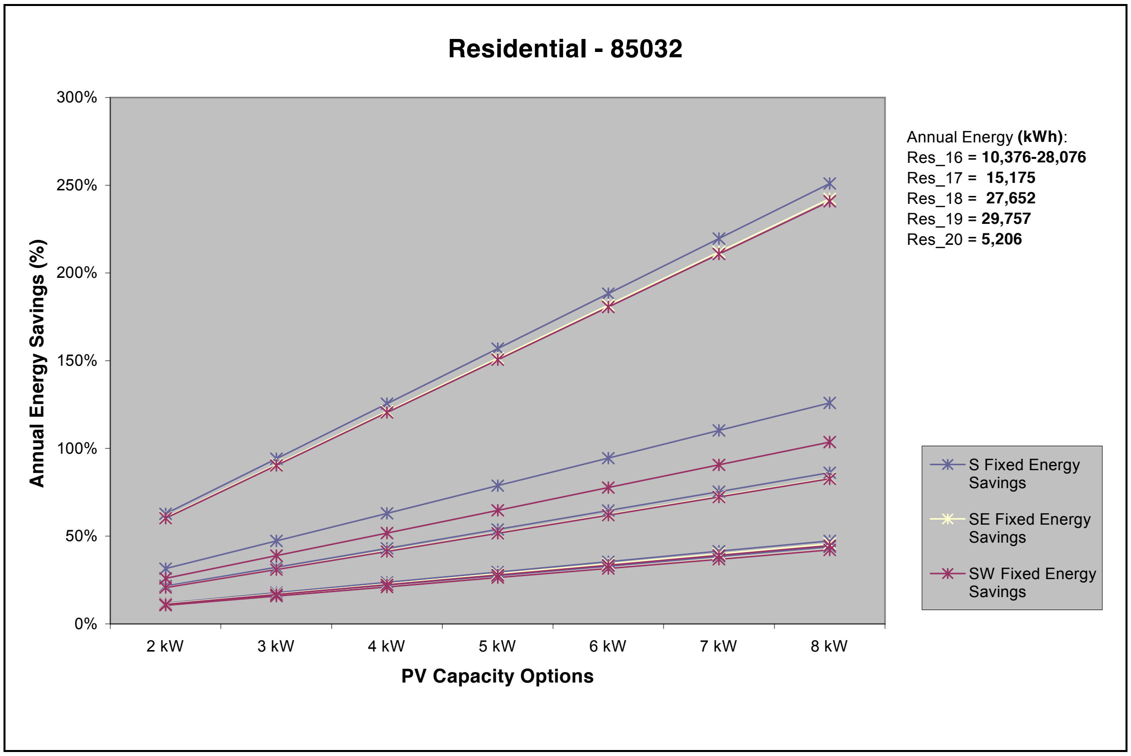


Figure L-8. Residential 85032 Annual Peak Demand Savings

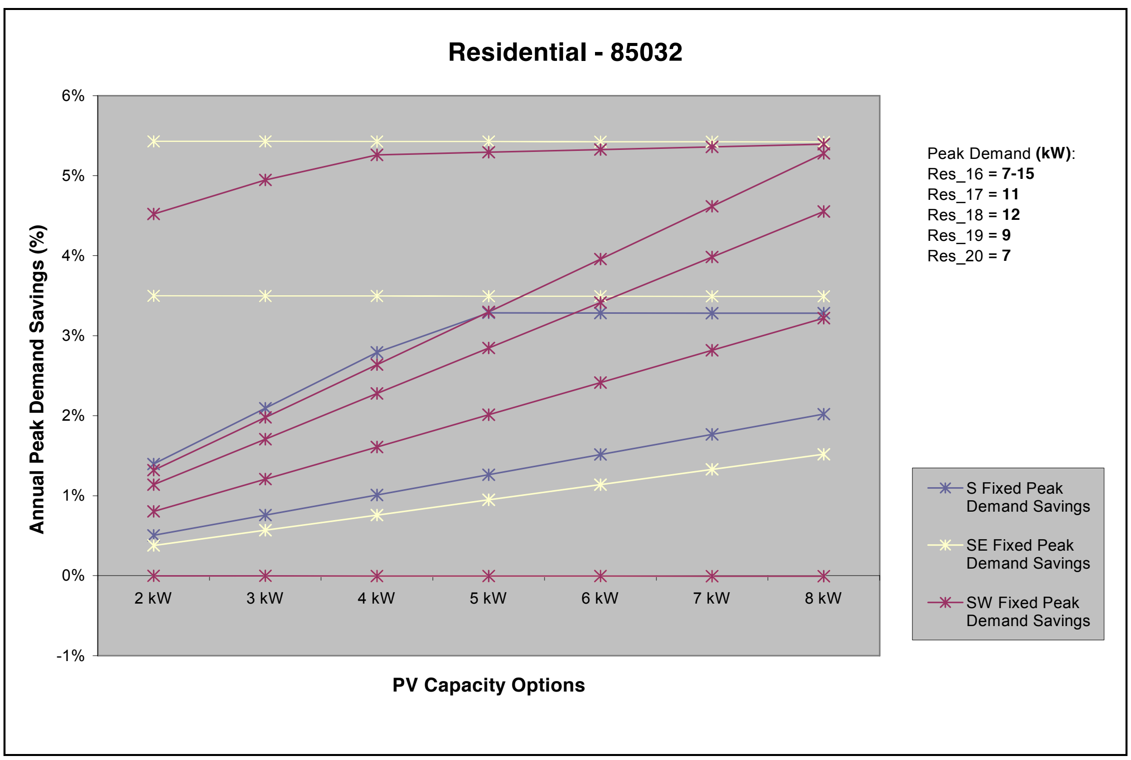


Figure L-9. Residential 85258 Annual Energy Savings

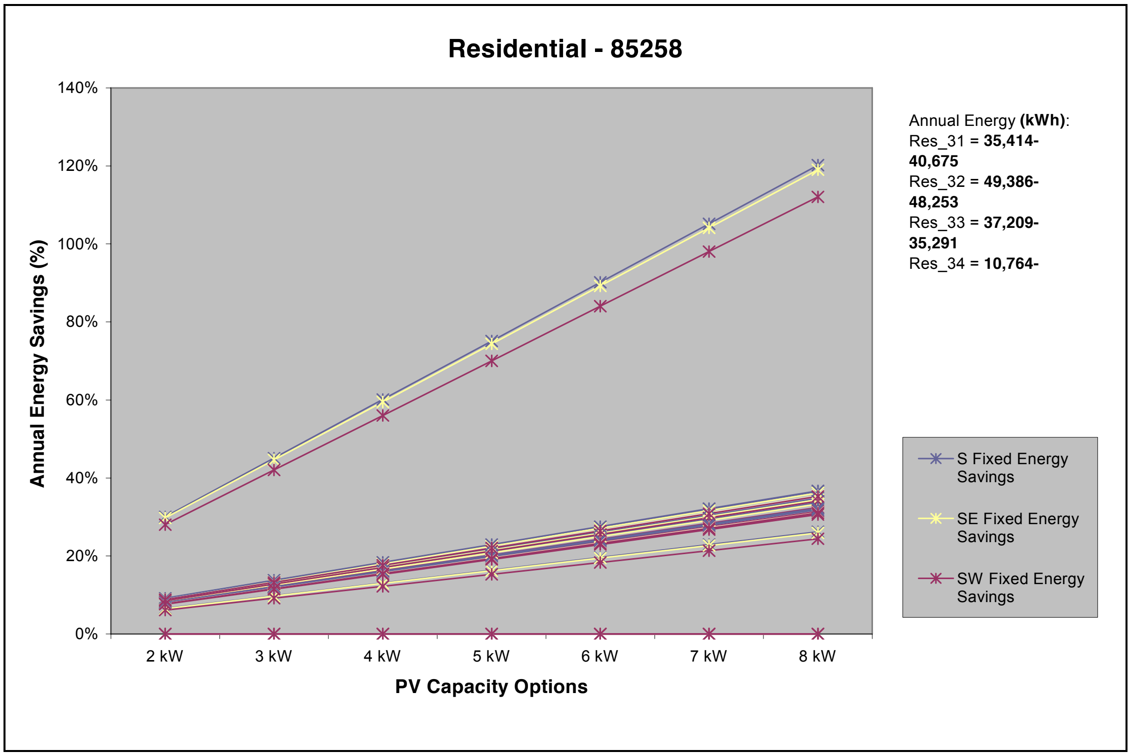


Figure L-10. Residential 85258 Annual Peak Demand Savings

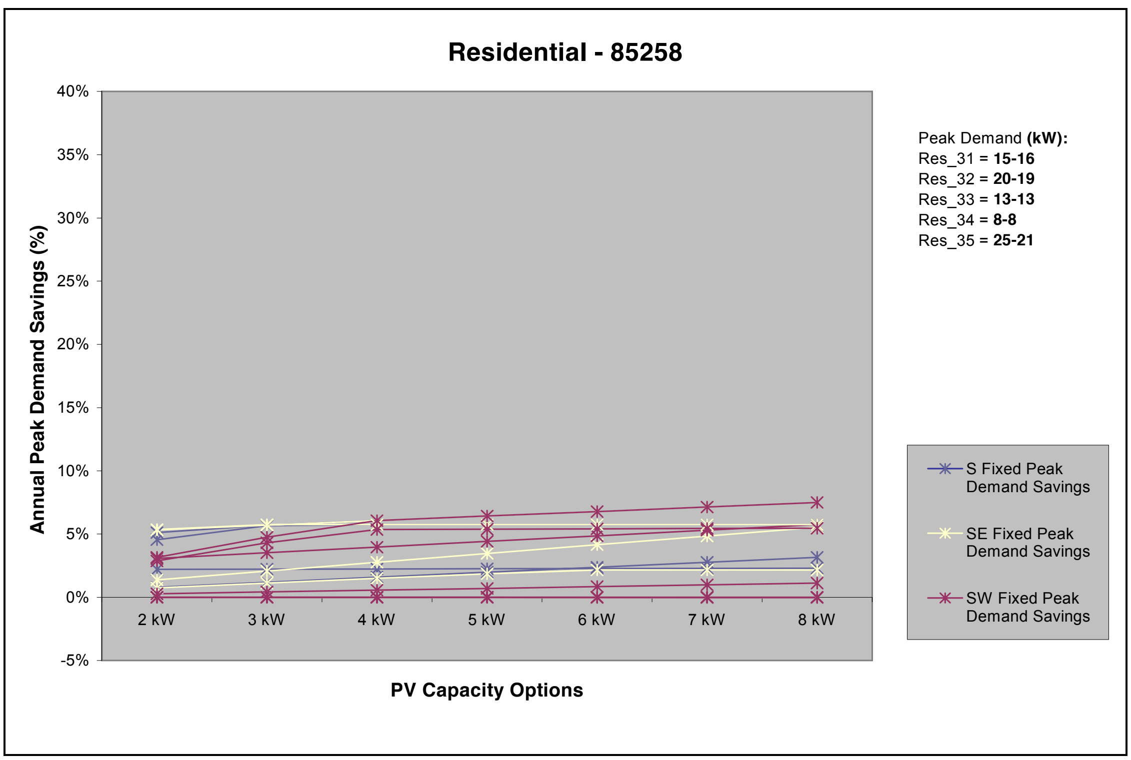


Figure L-11. Residential 85260 Annual Energy Savings

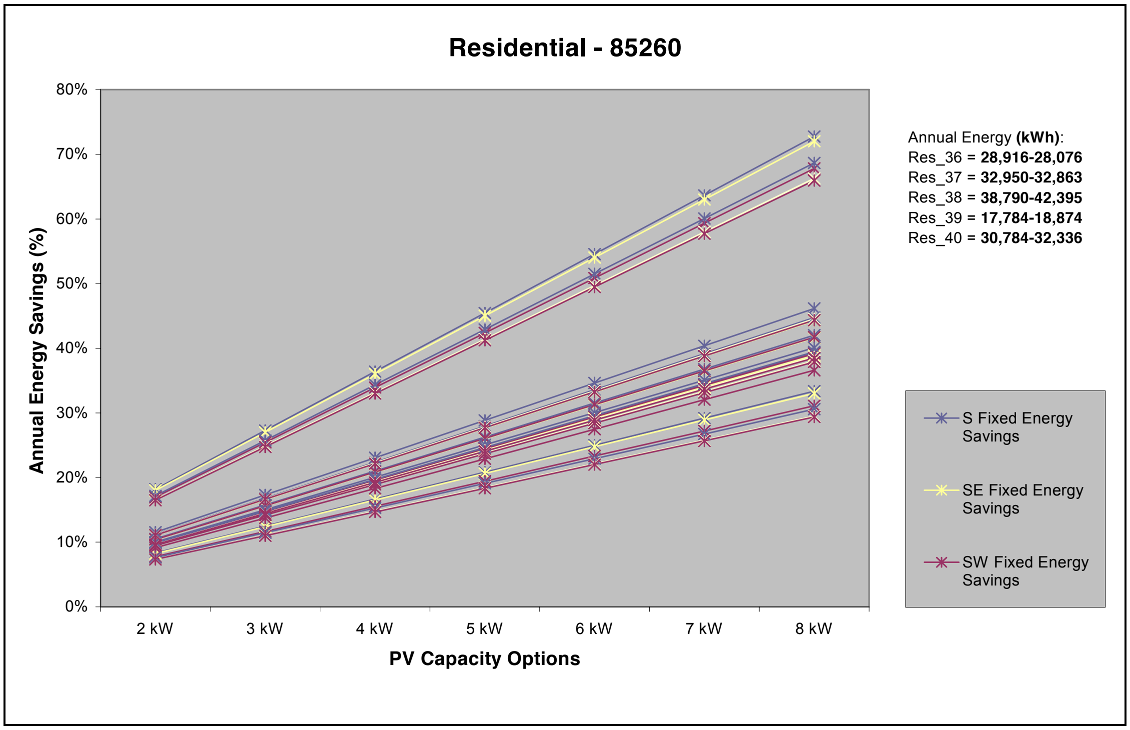


Figure L-12. Residential 85260 Annual Peak Demand Savings

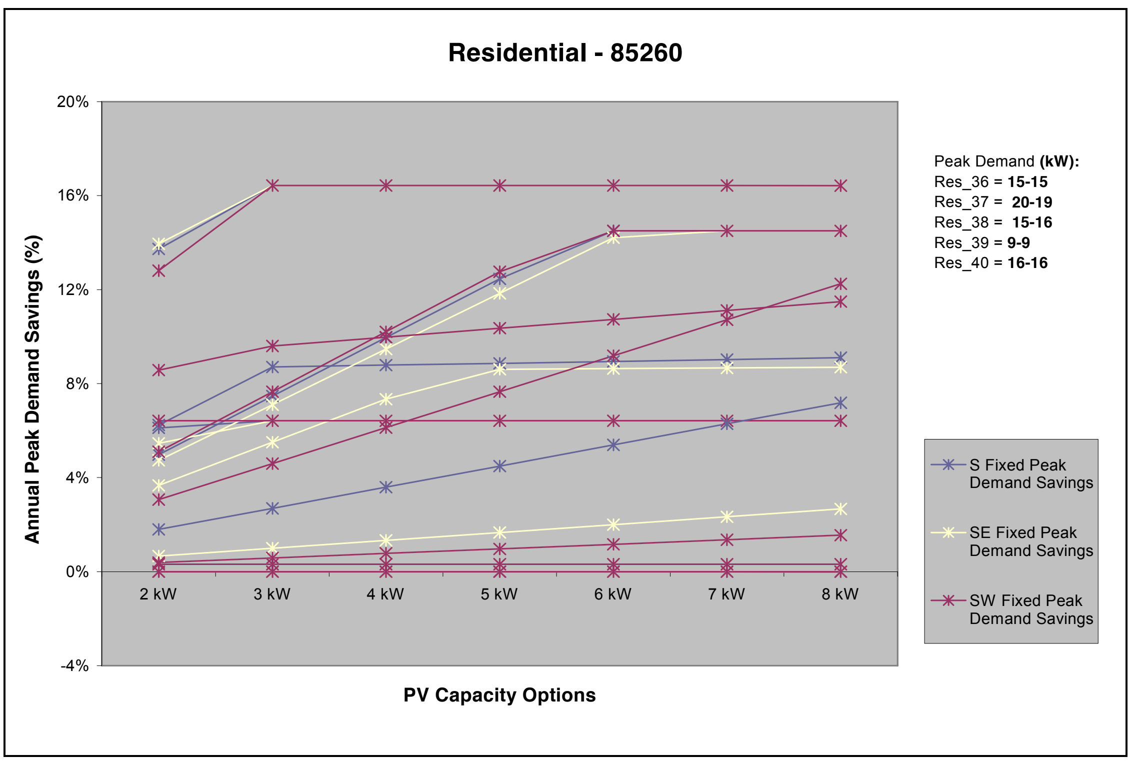


Figure L-13. Residential 85331 Annual Energy Savings

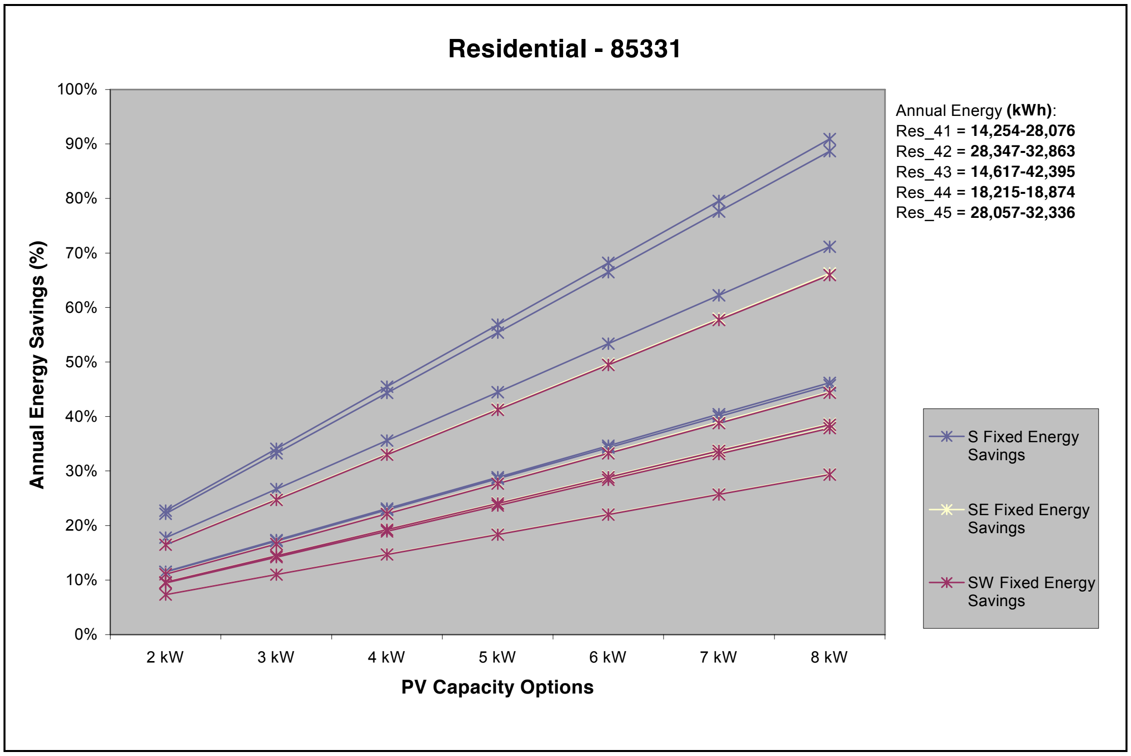


Figure L-14. Residential 85331 Annual Peak Demand Savings

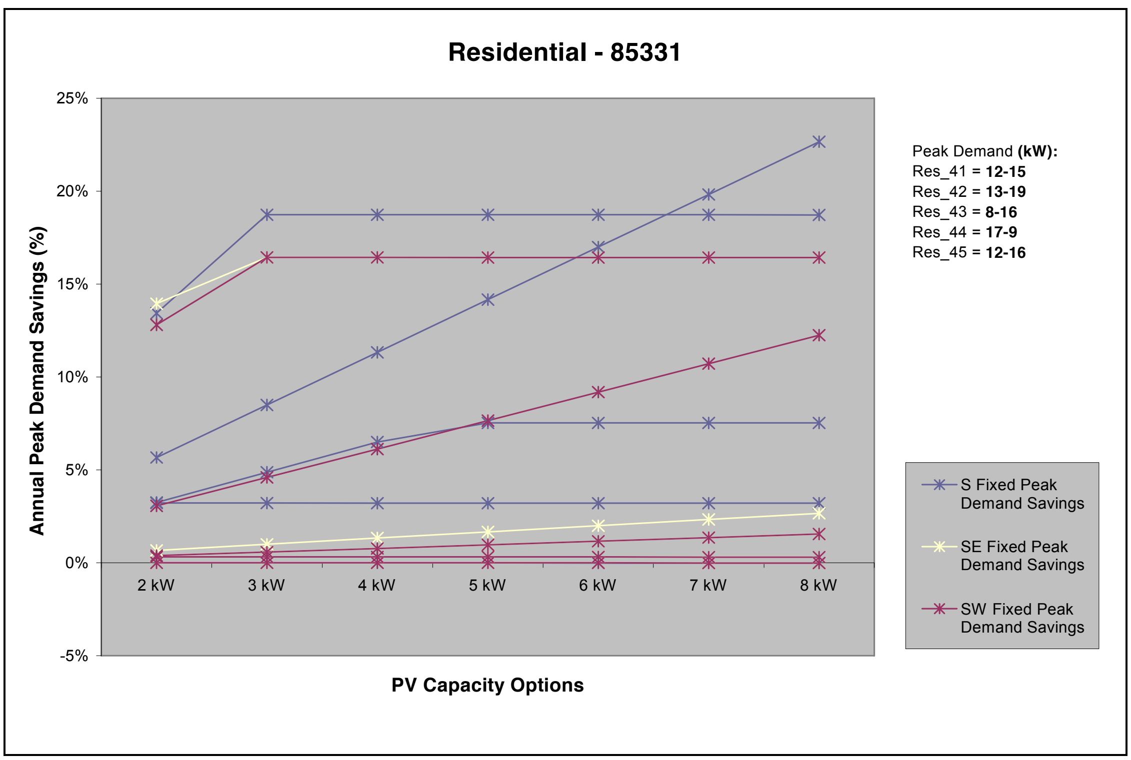


Figure L-15. Residential 85351 Annual Energy Savings

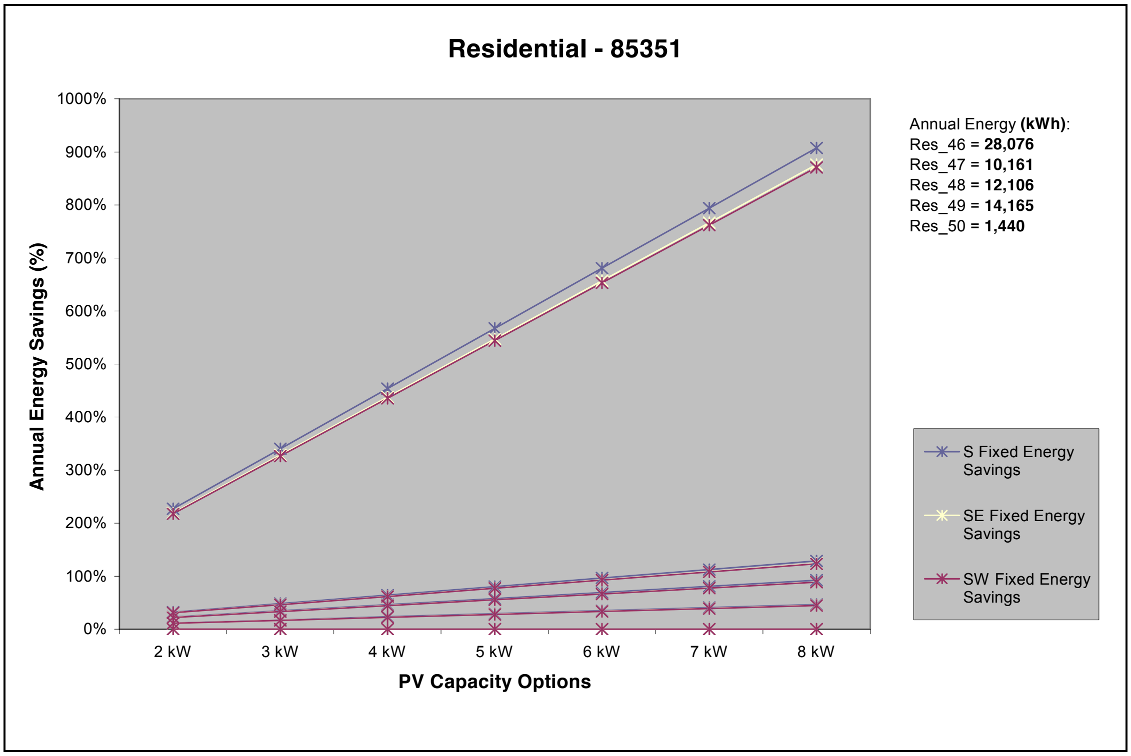


Figure L-16. Residential 85351 Annual Peak Demand Savings

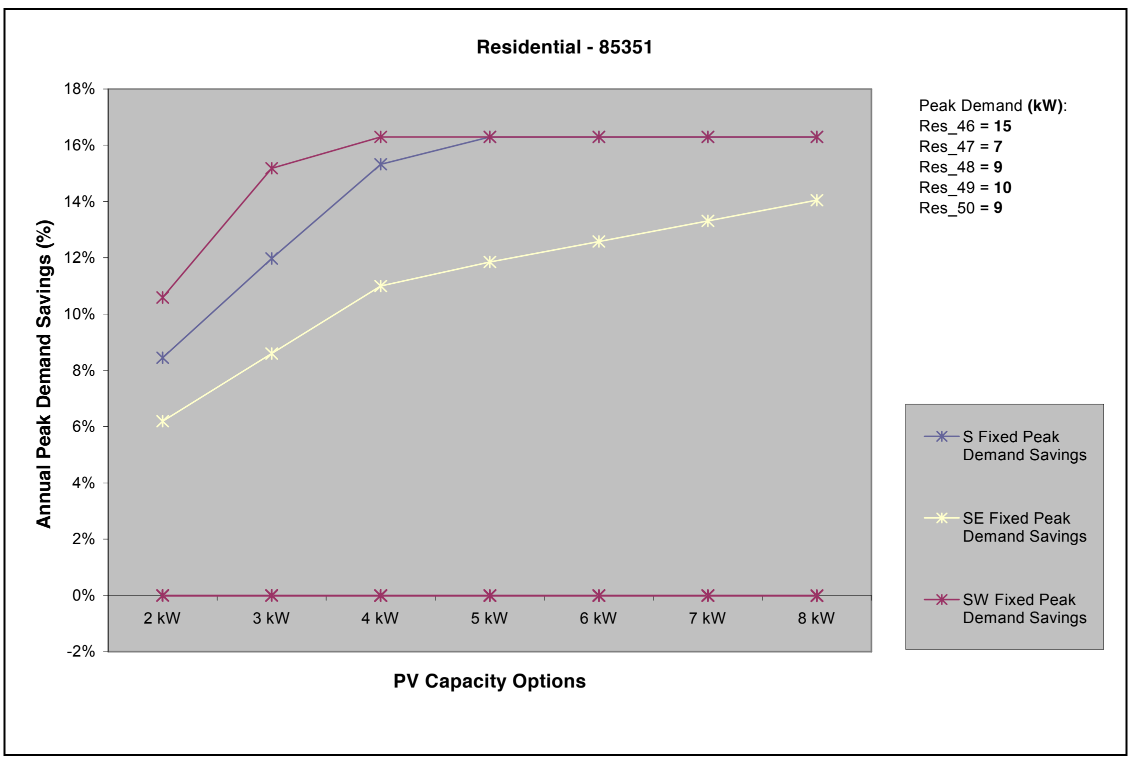


Figure L-17. Residential 85373 Annual Energy Savings

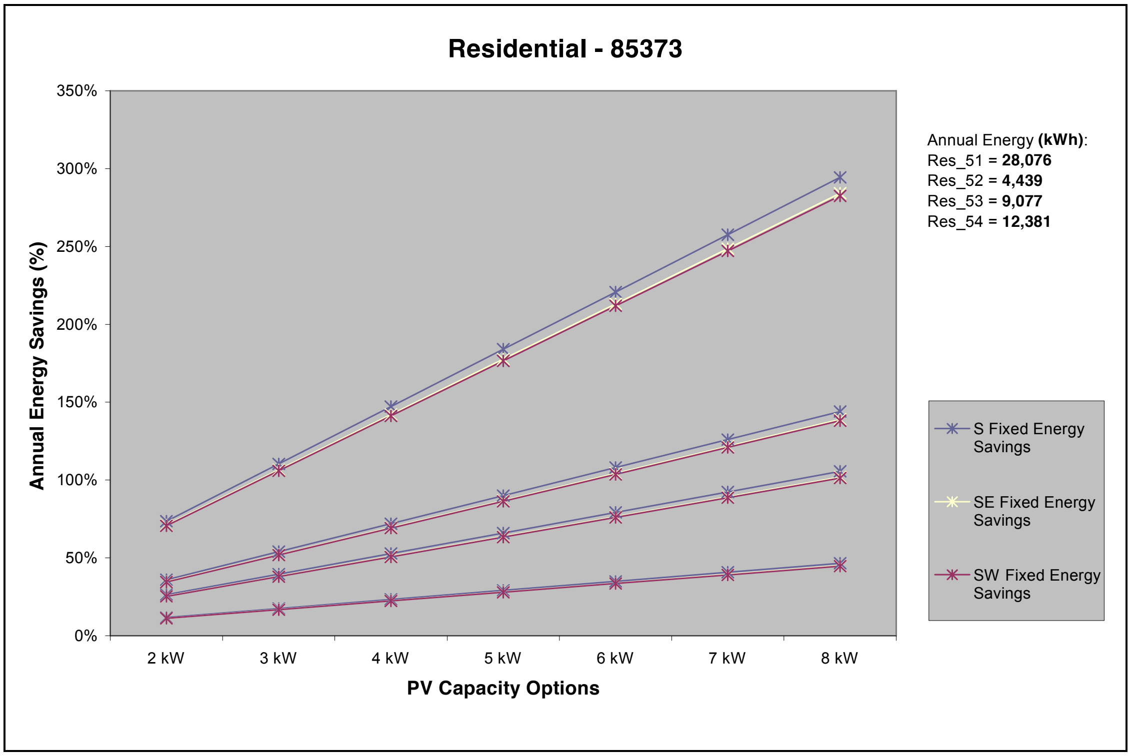


Figure L-18. Residential 85373 Annual Peak Demand Savings

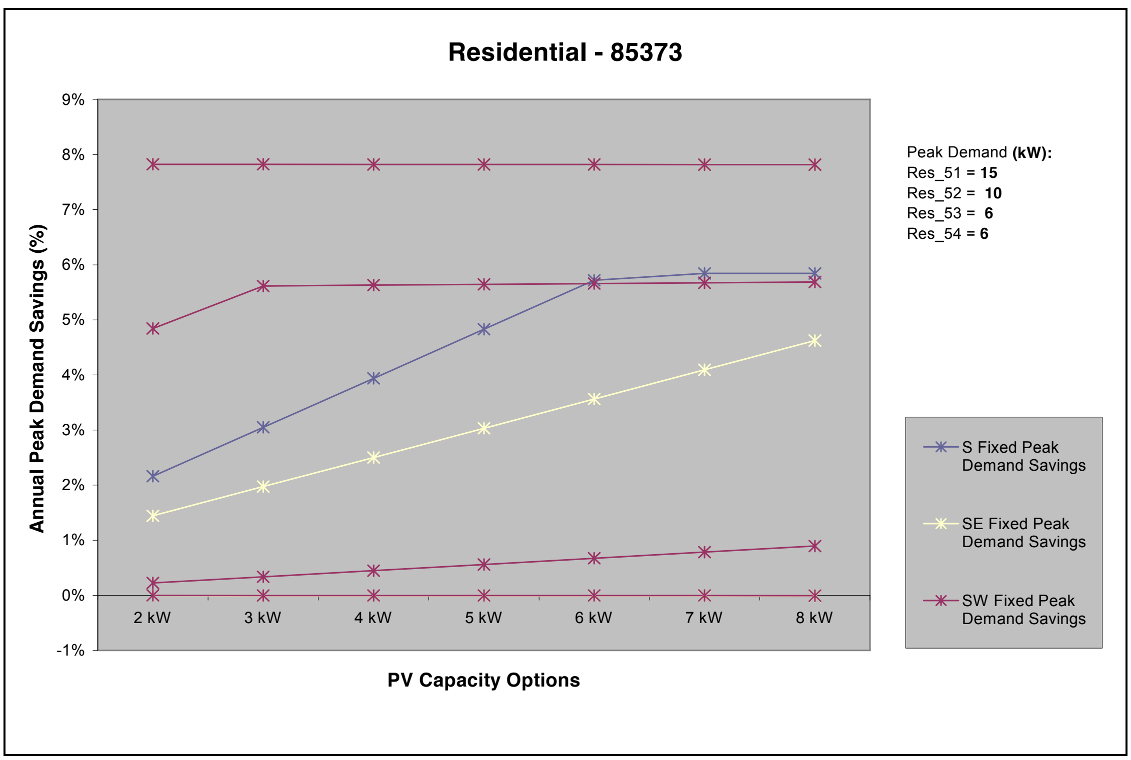


Figure L-19. Commercial – Schools Annual Energy Savings

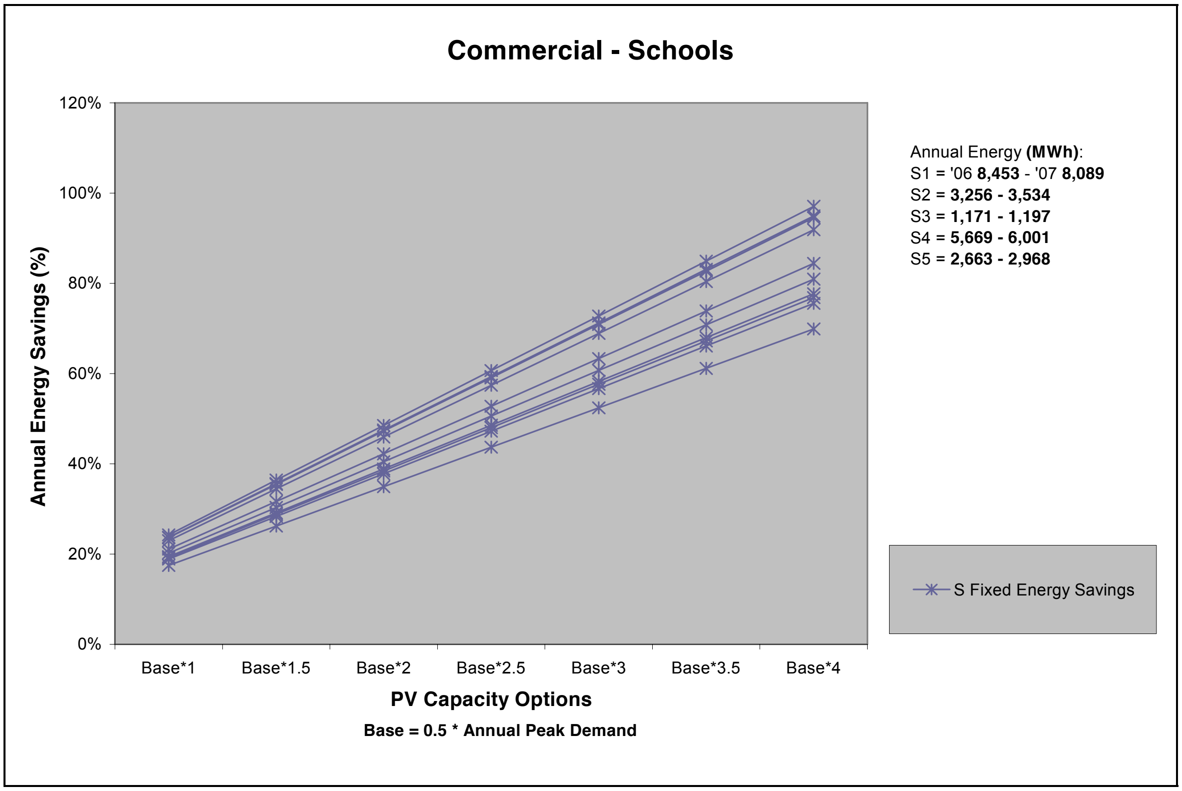


Figure L-20. Commercial – Schools Annual Peak Demand Savings

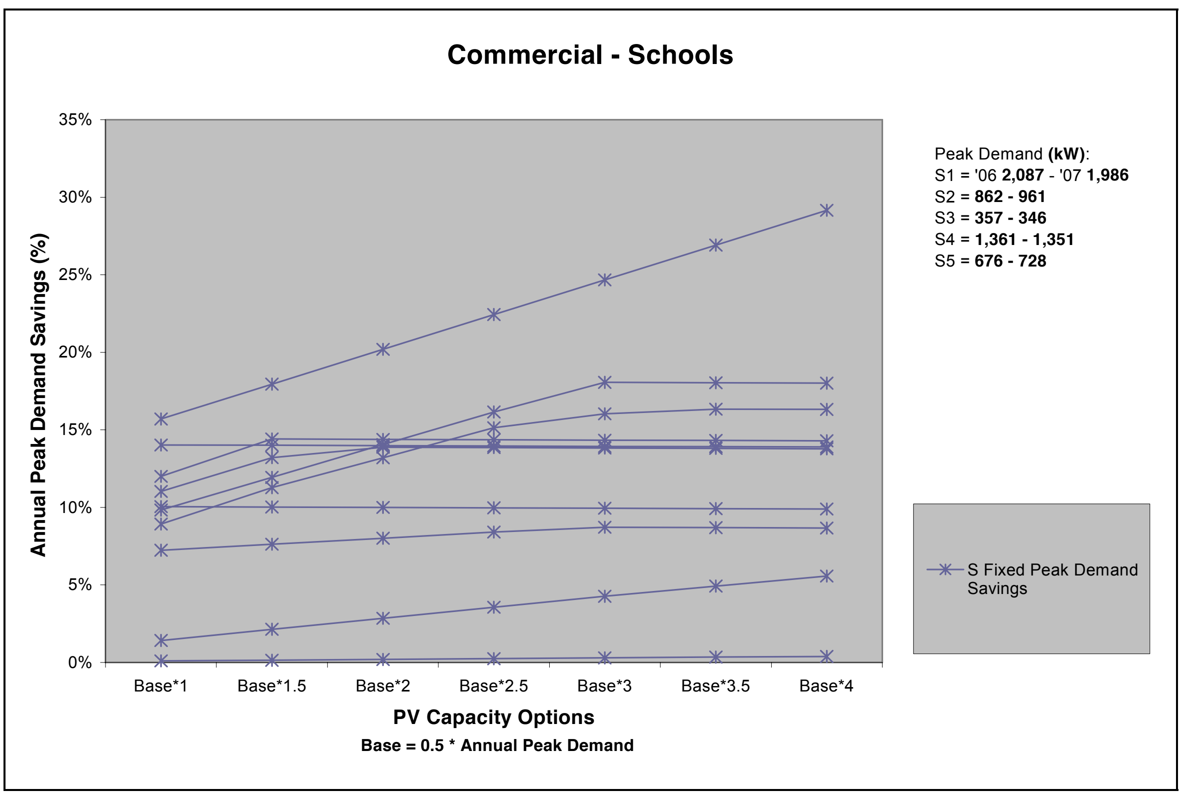


Figure L-21. Commercial – Church Annual Energy Savings

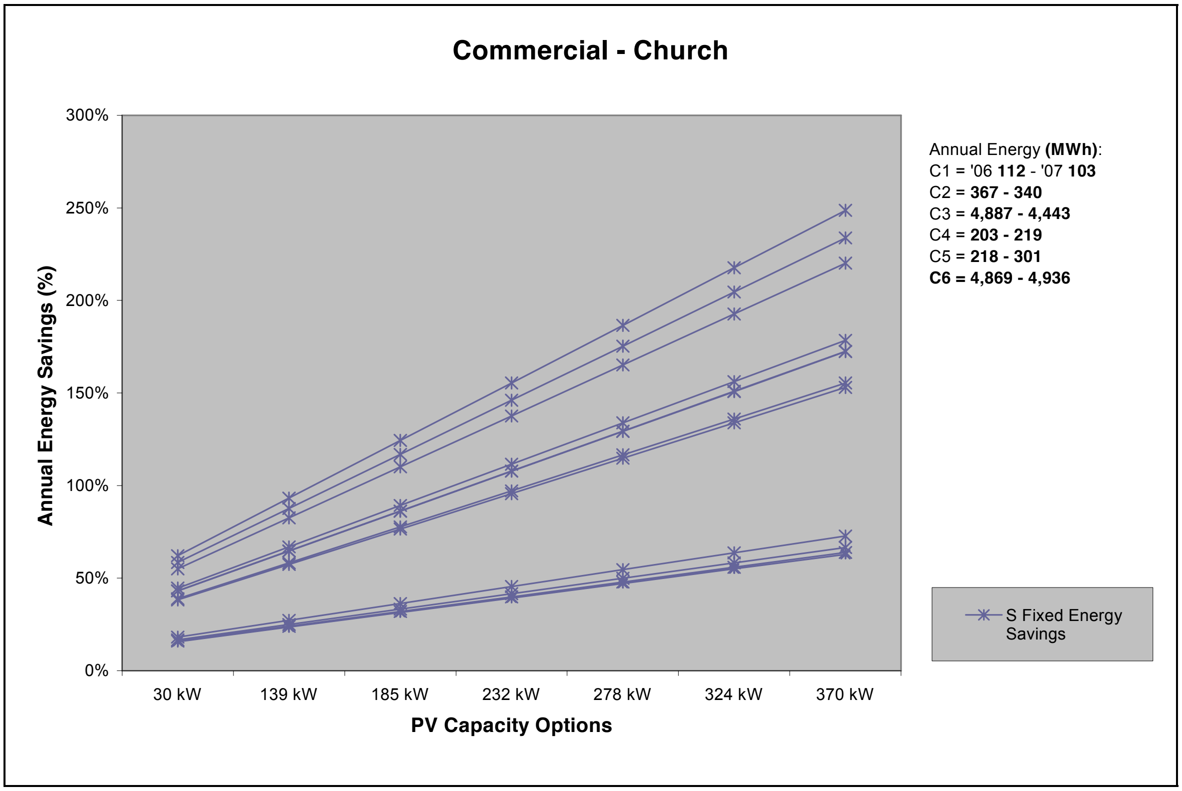


Figure L-22. Commercial – Church Annual Peak Demand Savings

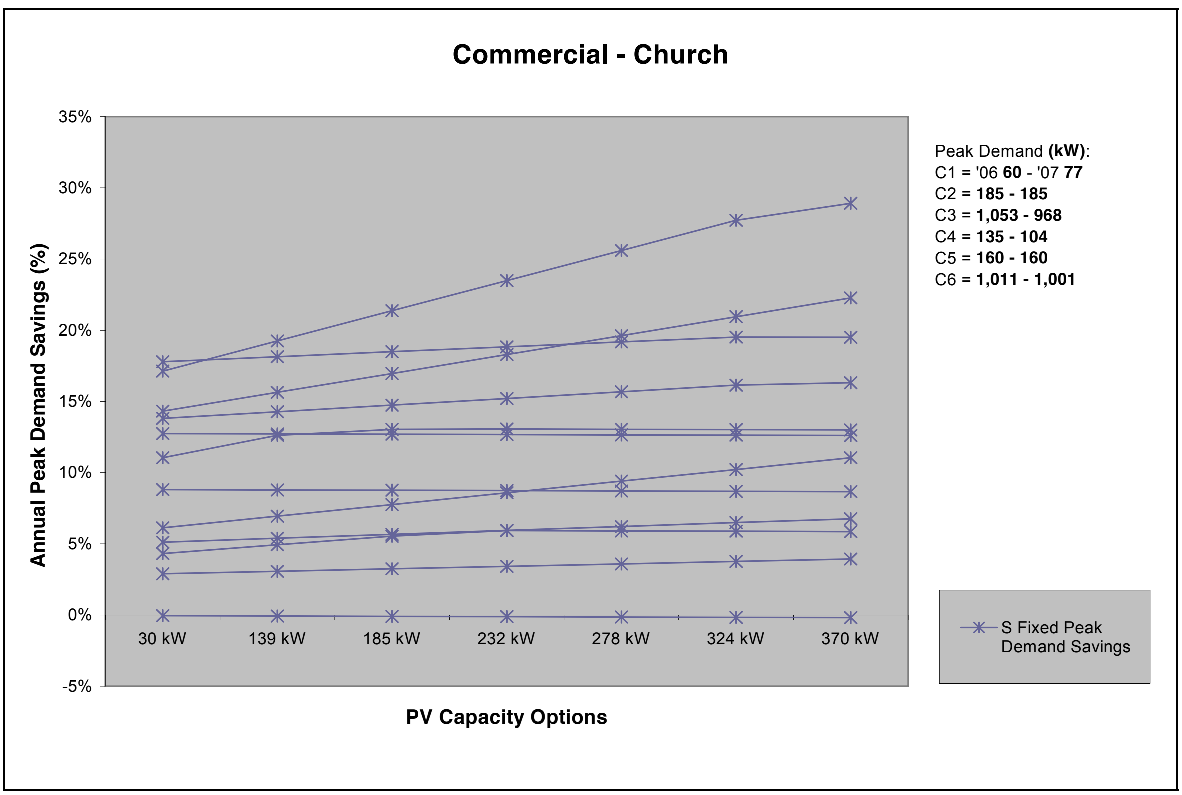


Figure L-23. Commercial – Distribution Center Annual Energy Savings

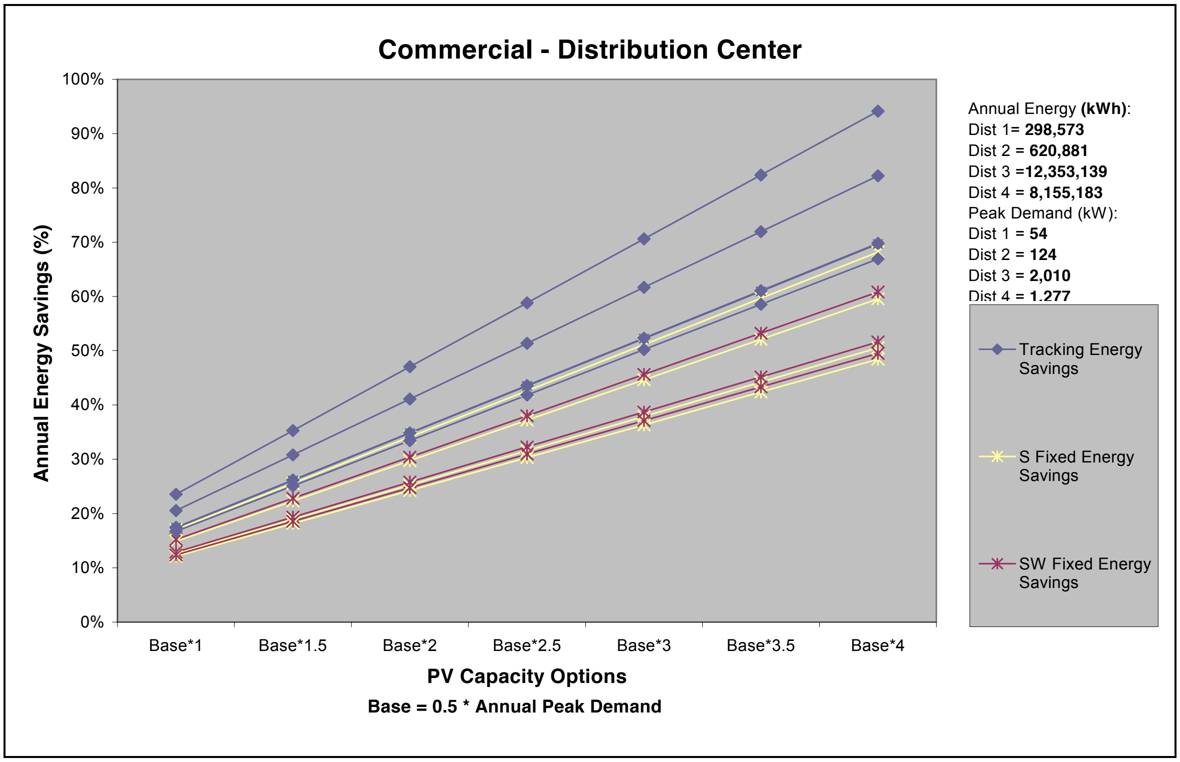


Figure L-24. Commercial – Distribution Center Annual Peak Demand Savings

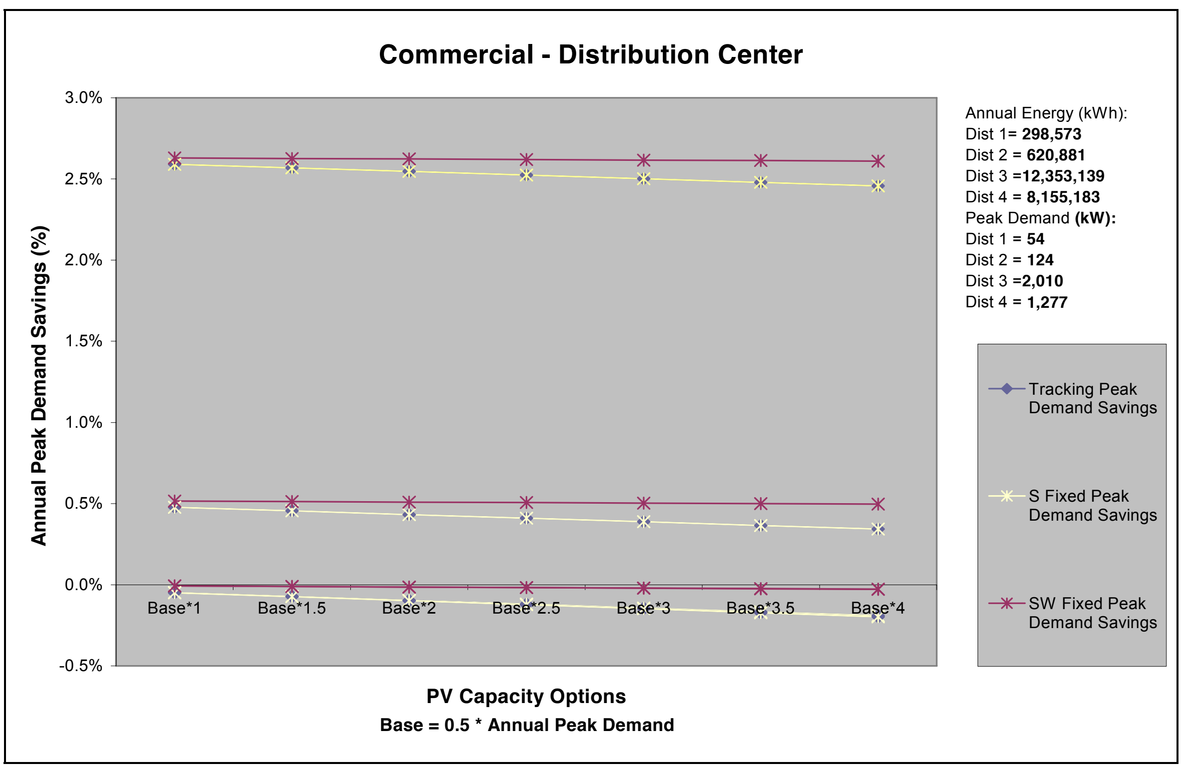


Figure L-25. Commercial – Grocery Stores Annual Energy Savings

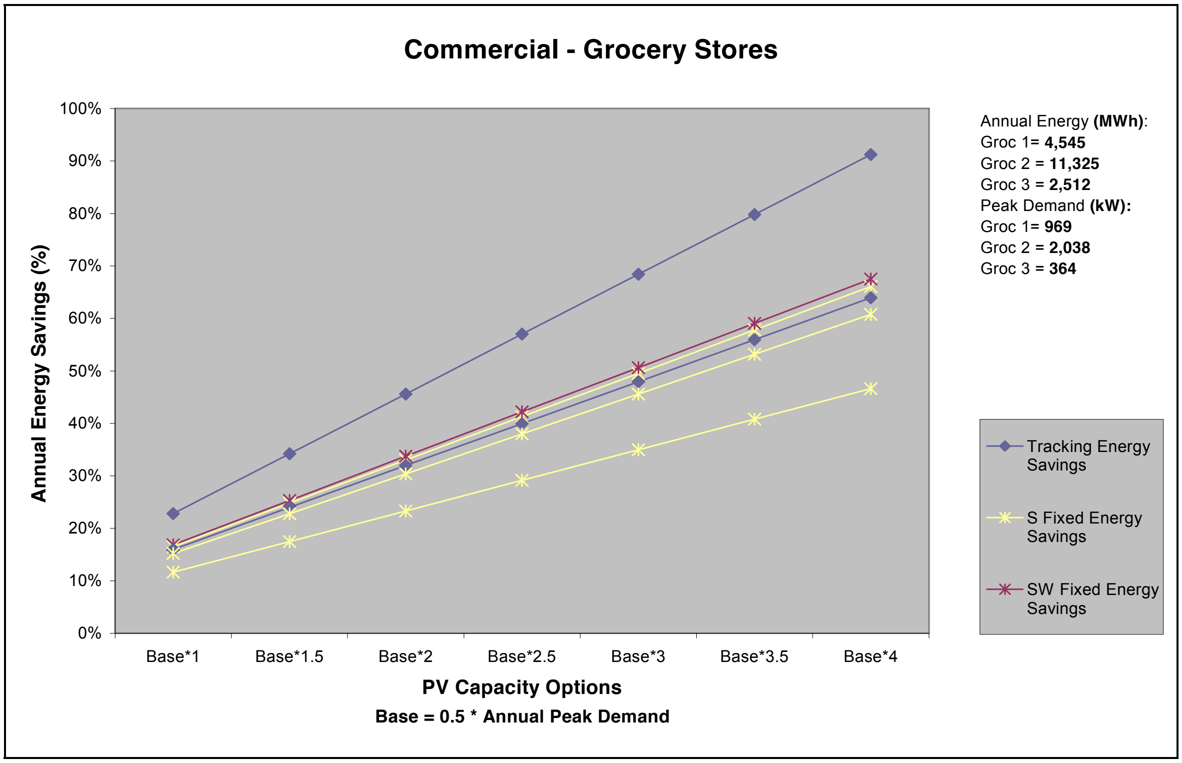


Figure L-26. Commercial – Grocery Stores Annual Peak Demand Savings

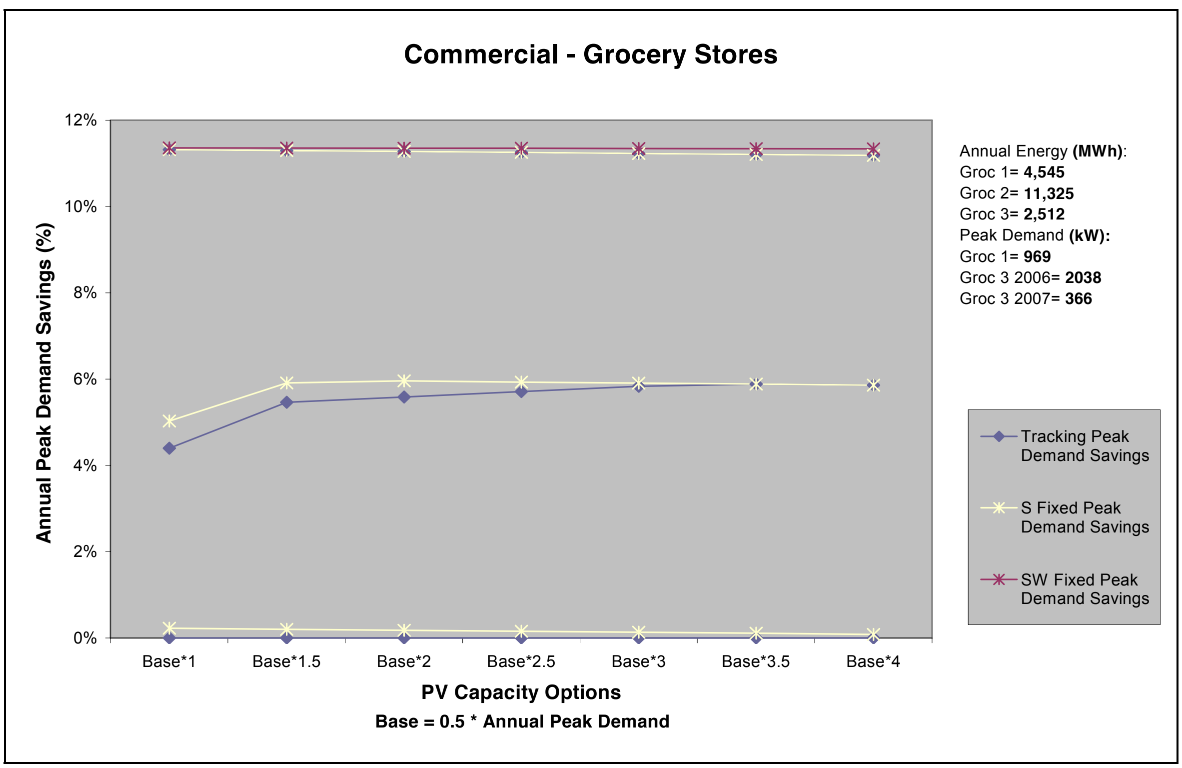


Figure L-27. Grocery Day Lighting Energy Savings

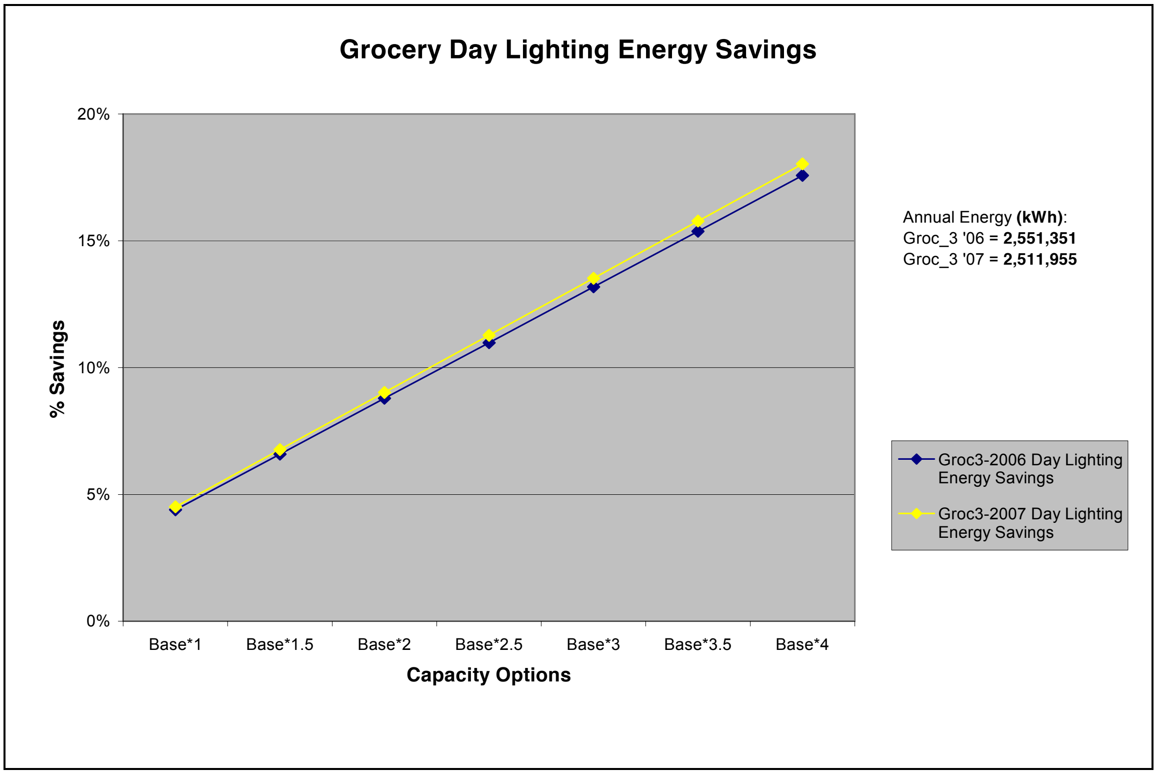


Figure L-28. Grocery Day Lighting Demand Savings

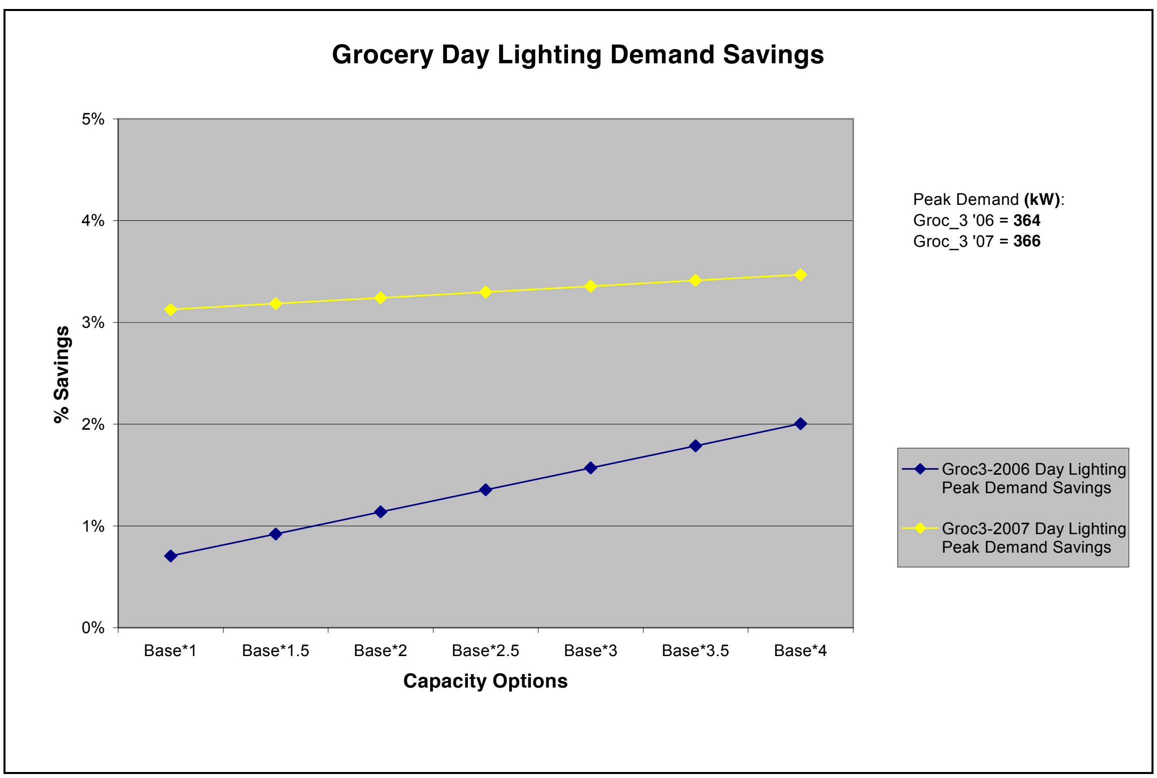


Figure L-29. Large Commercial & Healthcare Annual Energy Savings

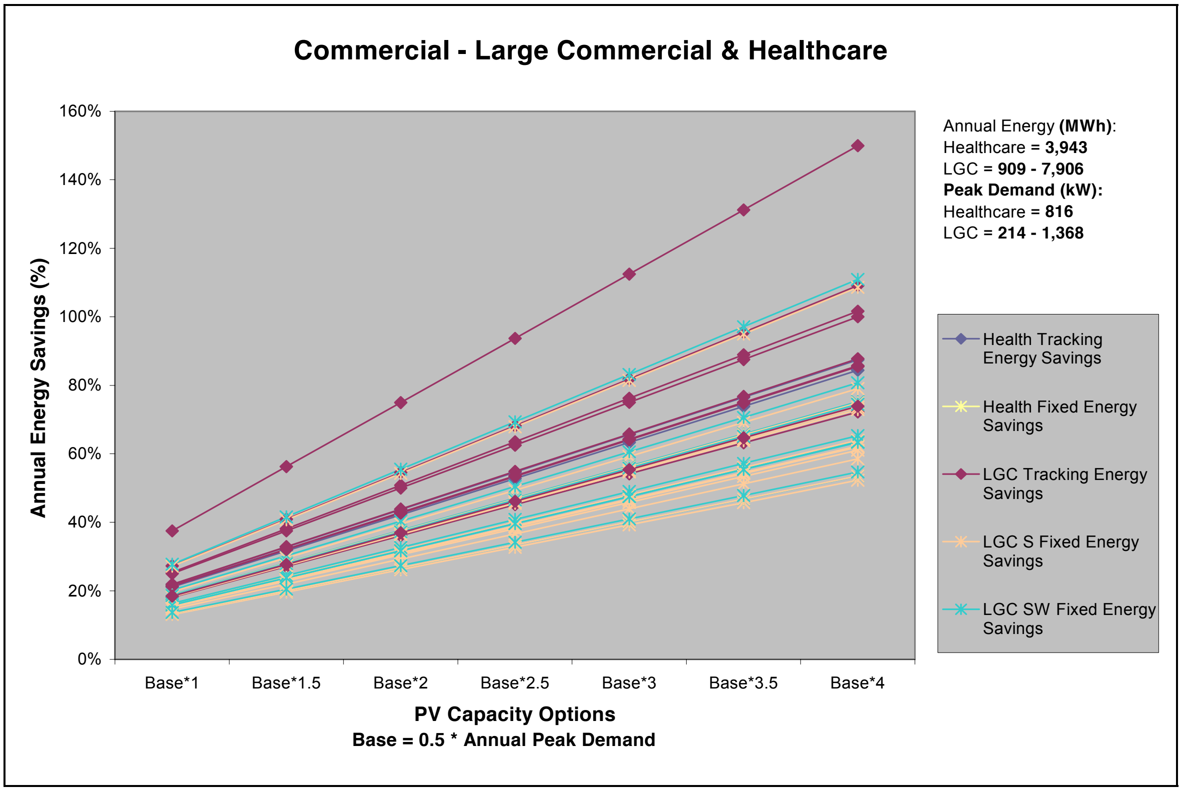


Figure L-30. Large Commercial & Healthcare Annual Peak Demand Savings

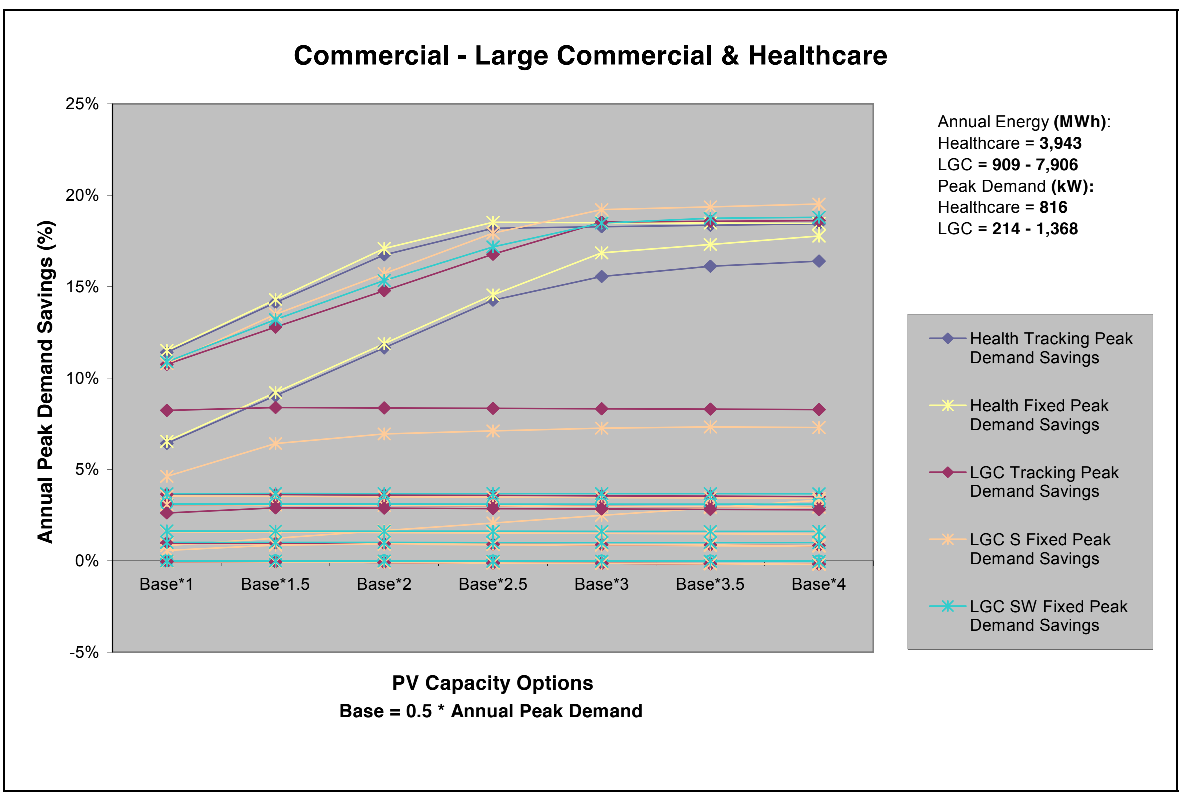


Figure L-31. Commercial – Medium Retail, Retail, & Storage Annual Energy Savings

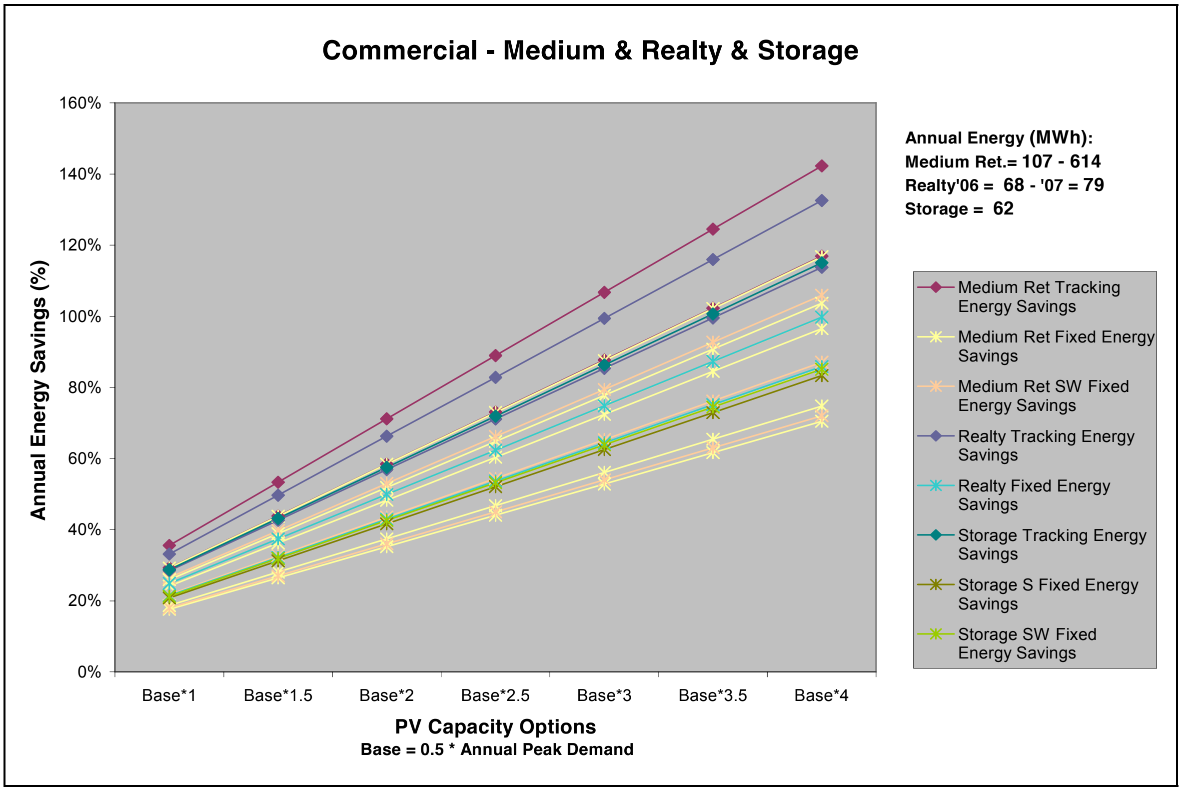


Figure L-32. Commercial – Medium Retail, Retail, & Storage Annual Peak Demand Savings

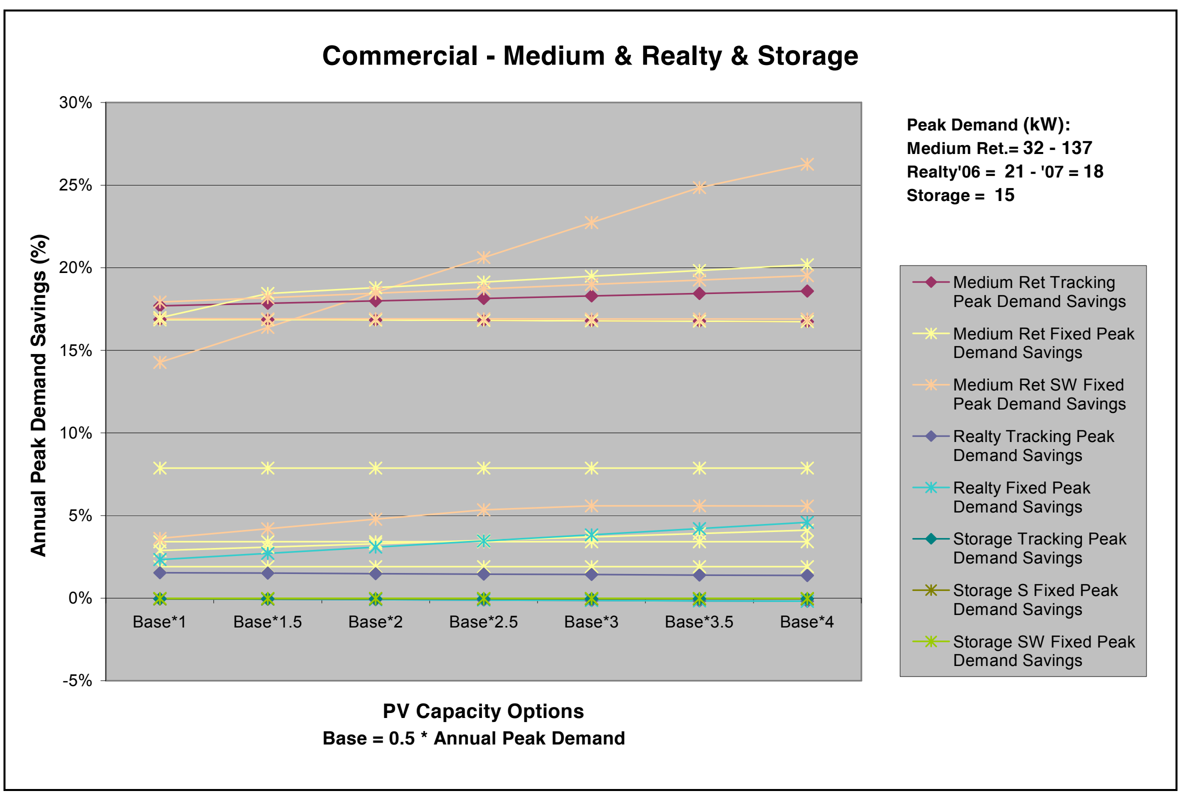


Figure L-33. Solar Hot Water - 85020 Annual Energy Savings

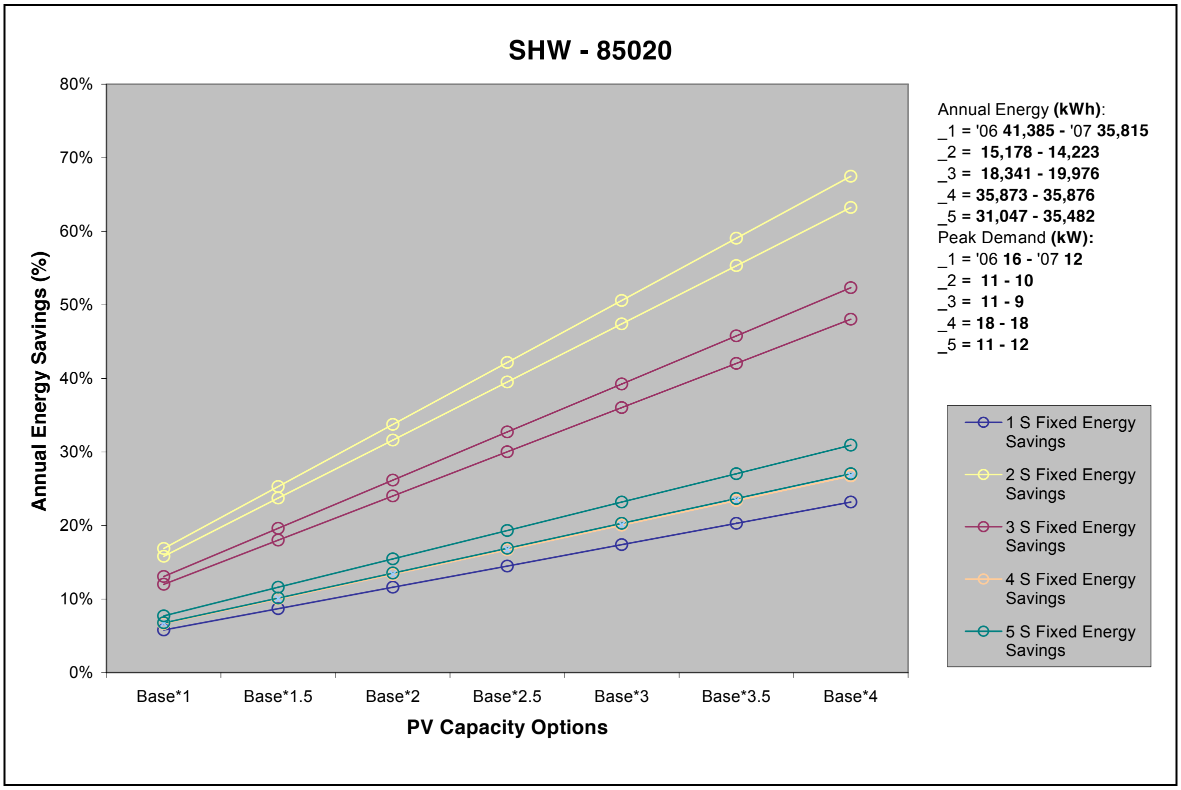


Figure L-34. Solar Hot Water - 85020 Annual Peak Demand Savings

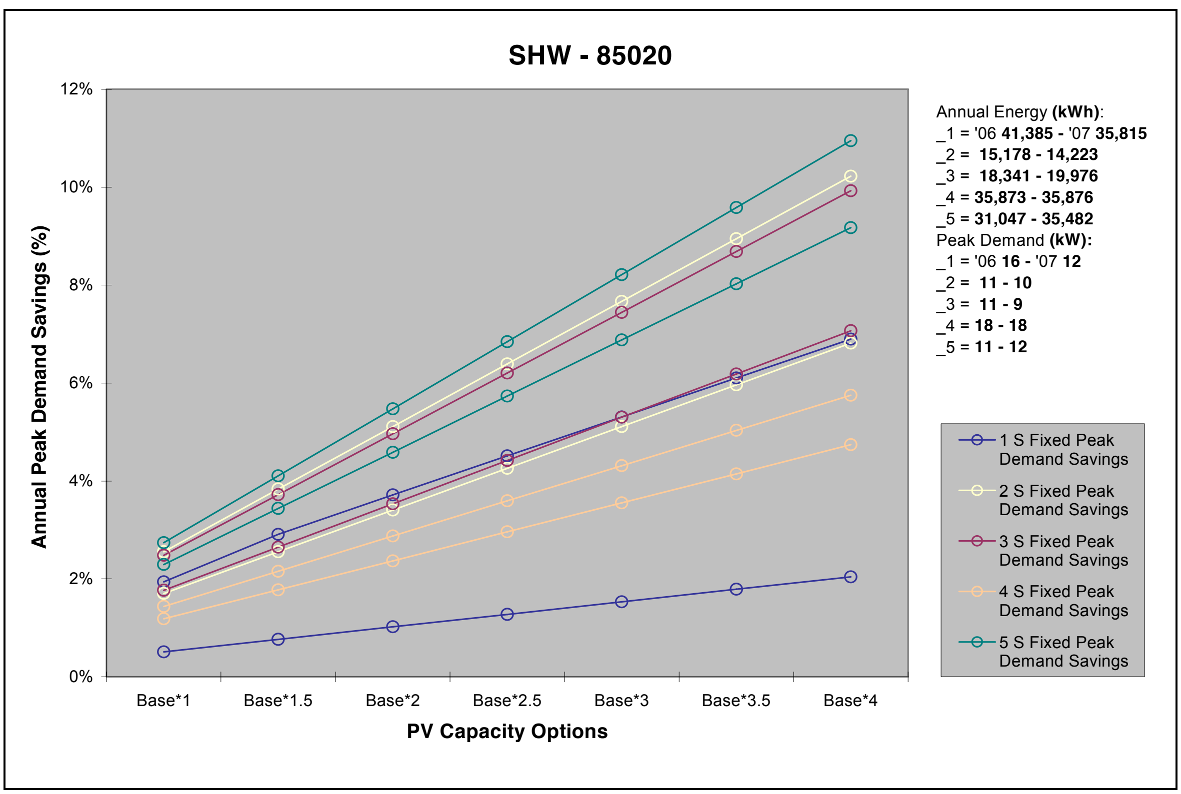


Figure L-35. Solar Hot Water - 85022 Annual Energy Savings

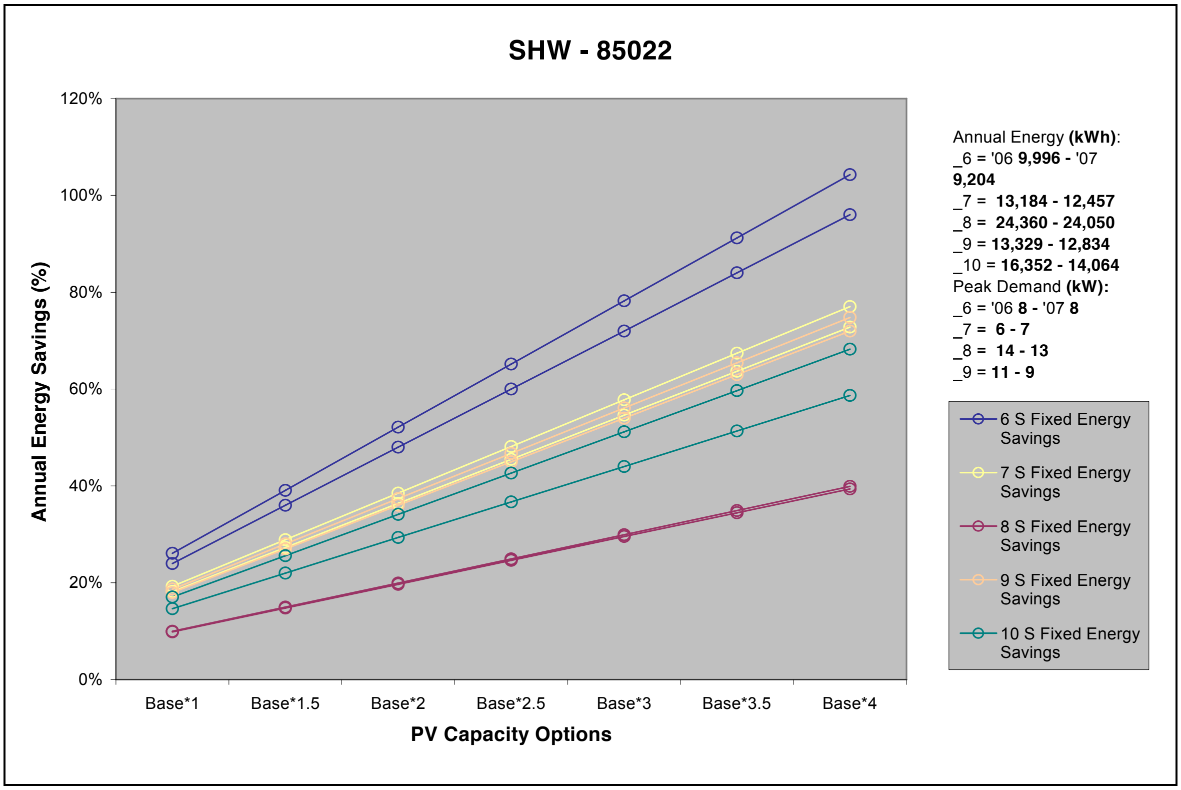


Figure L-36. Solar Hot Water - 85022 Annual Peak Demand Savings

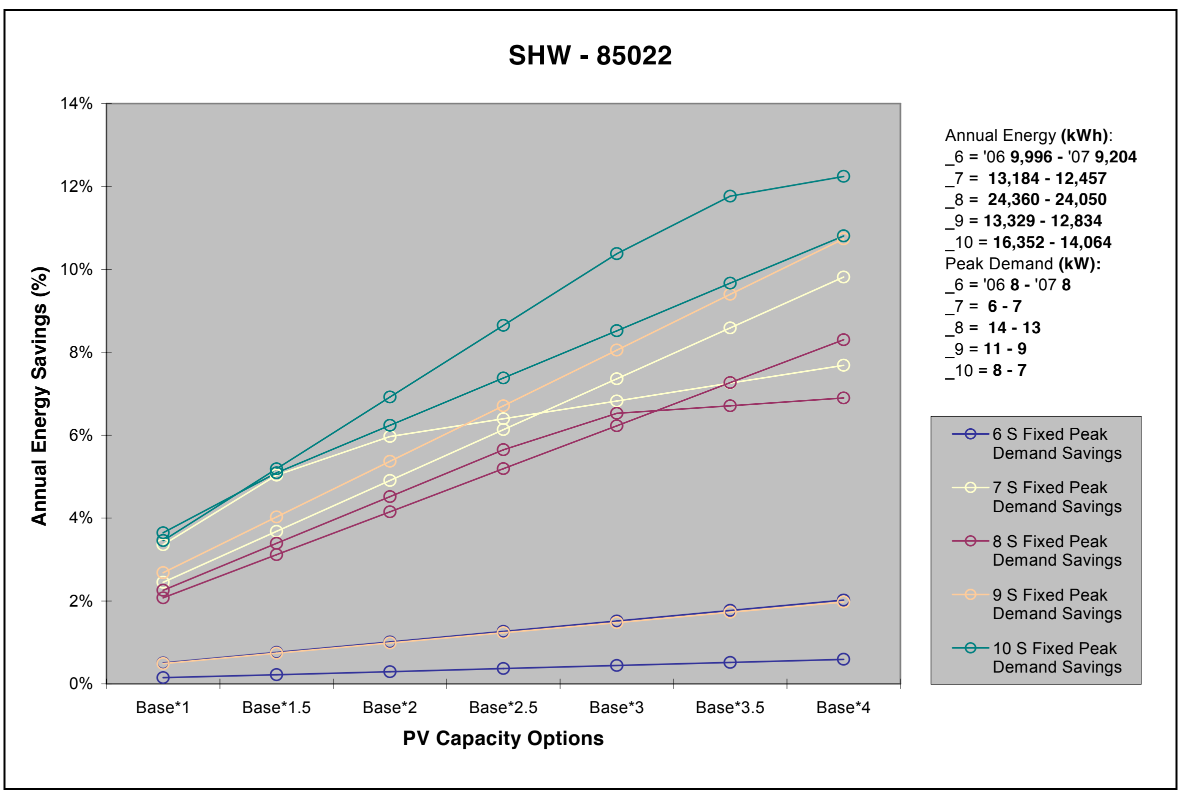


Figure L-37. Solar Hot Water - 85028 Annual Energy Savings

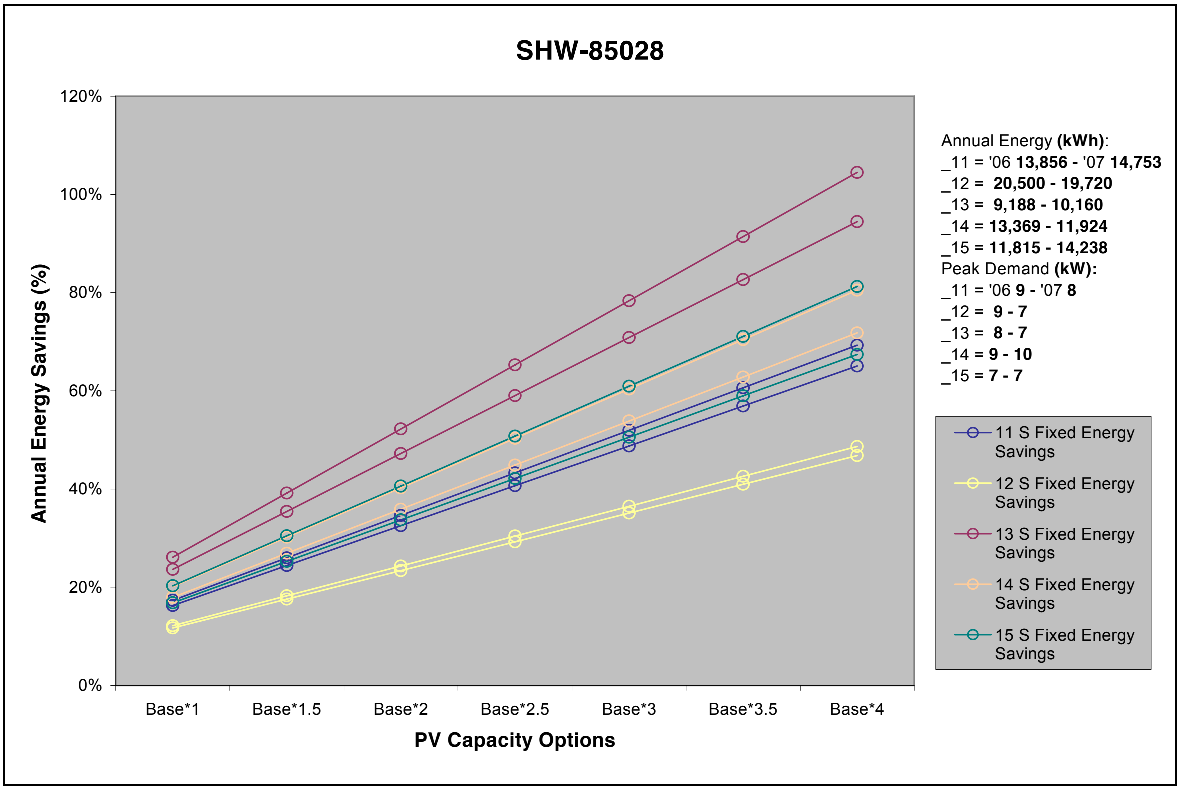


Figure L-38. Solar Hot Water - 85028 Annual Peak Demand Savings

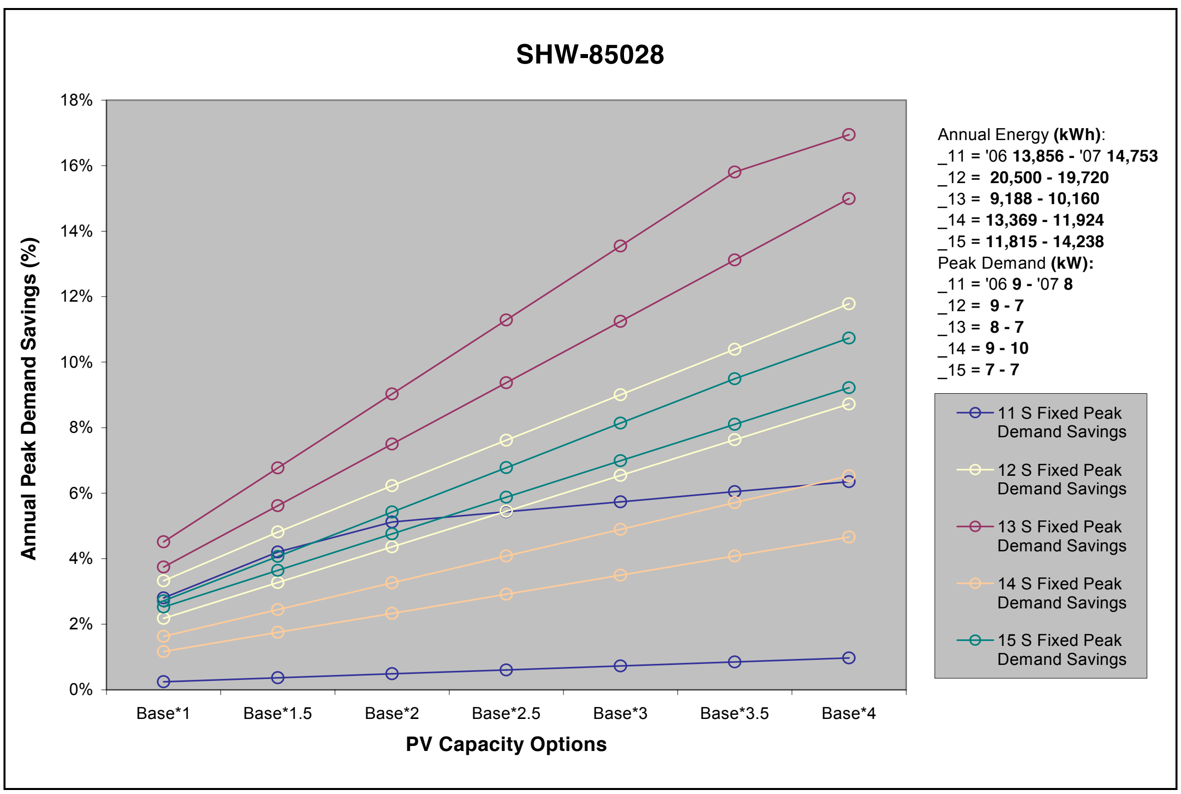


Figure L-39. Solar Hot Water - 85032 Annual Energy Savings

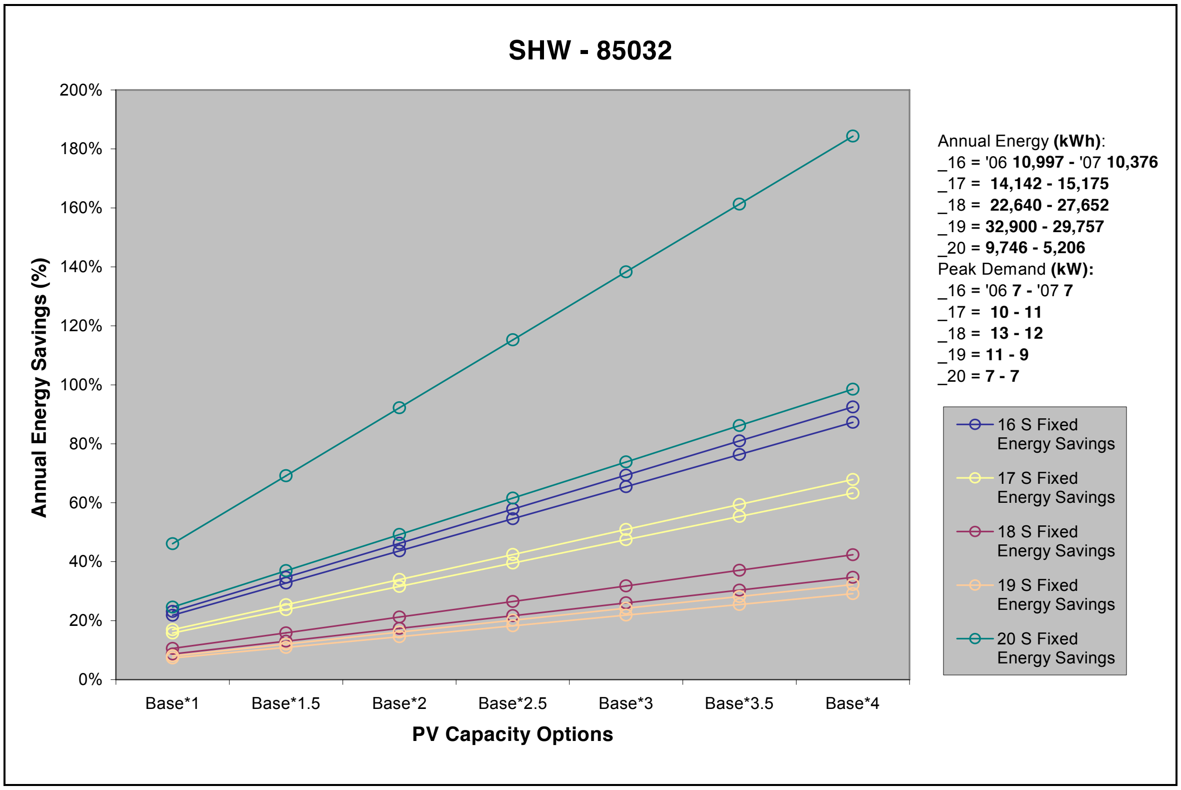


Figure L-40. Solar Hot Water - 85032 Annual Peak Demand Savings

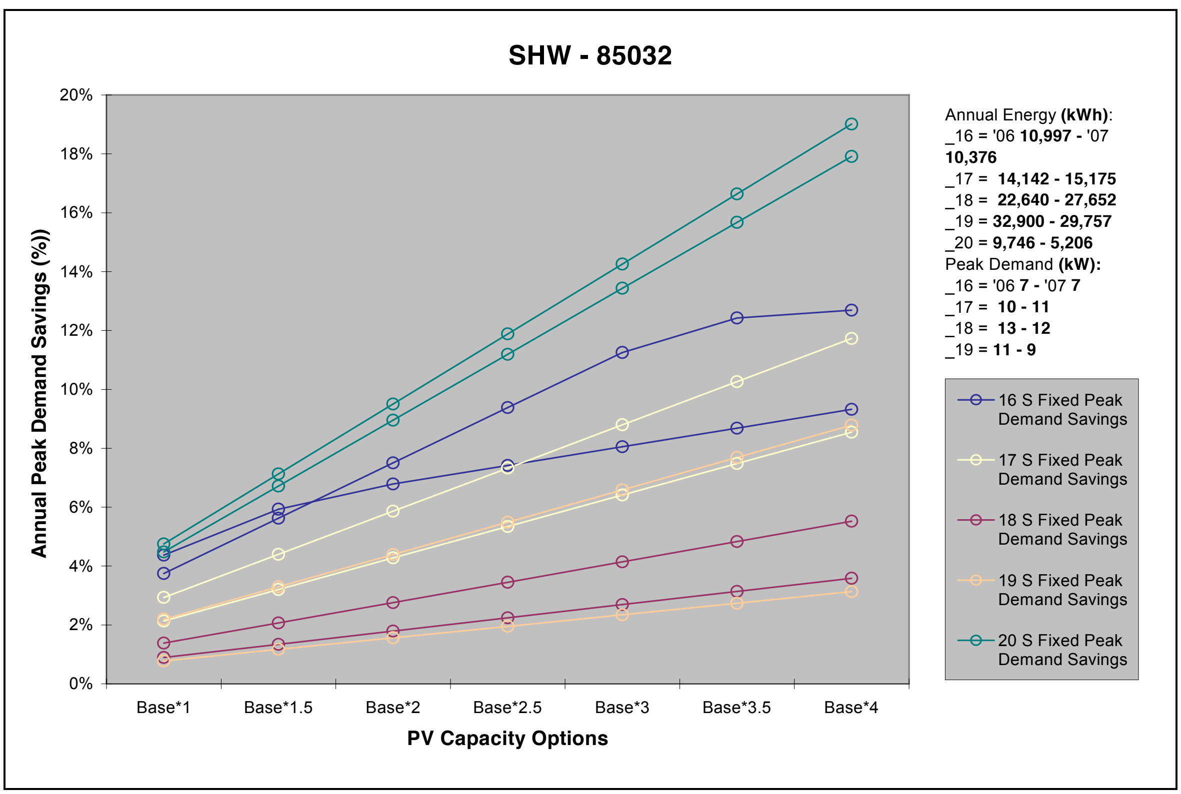


Figure L-41. Solar Hot Water - 85331 Annual Energy Savings

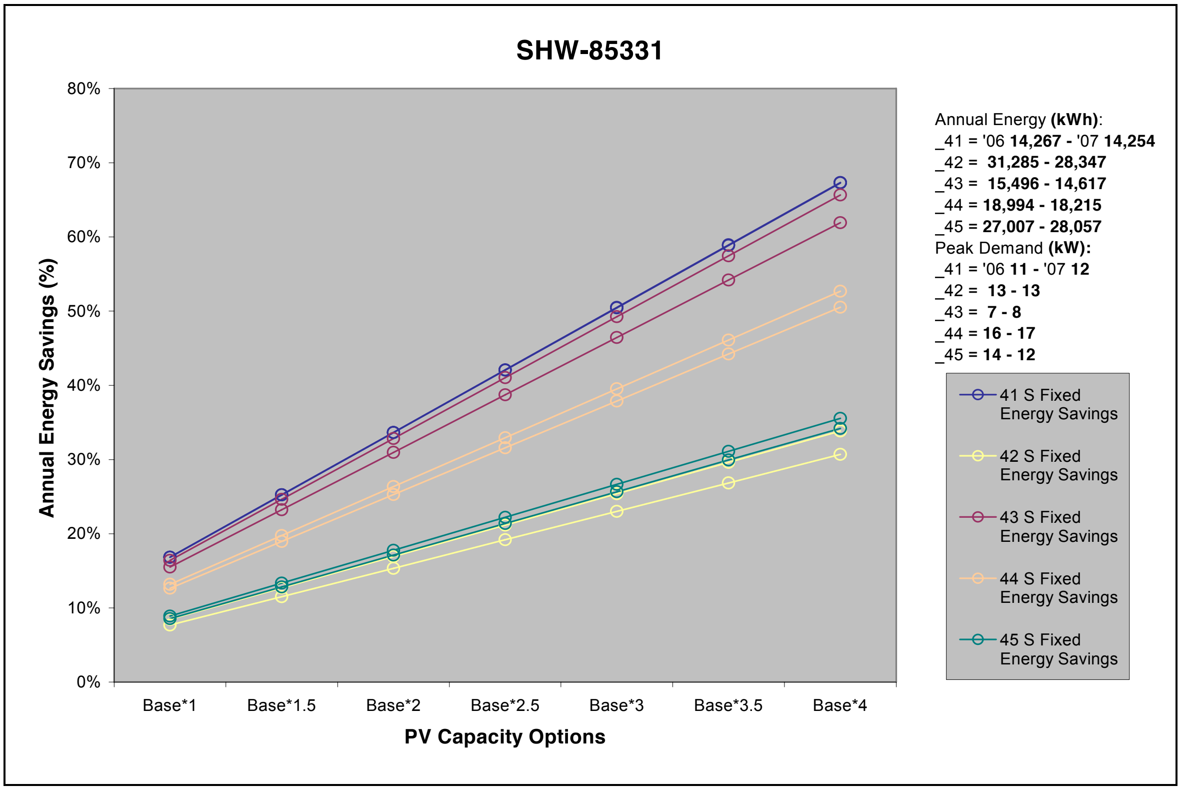


Figure L-42. Solar Hot Water - 85331 Annual Peak Demand Savings

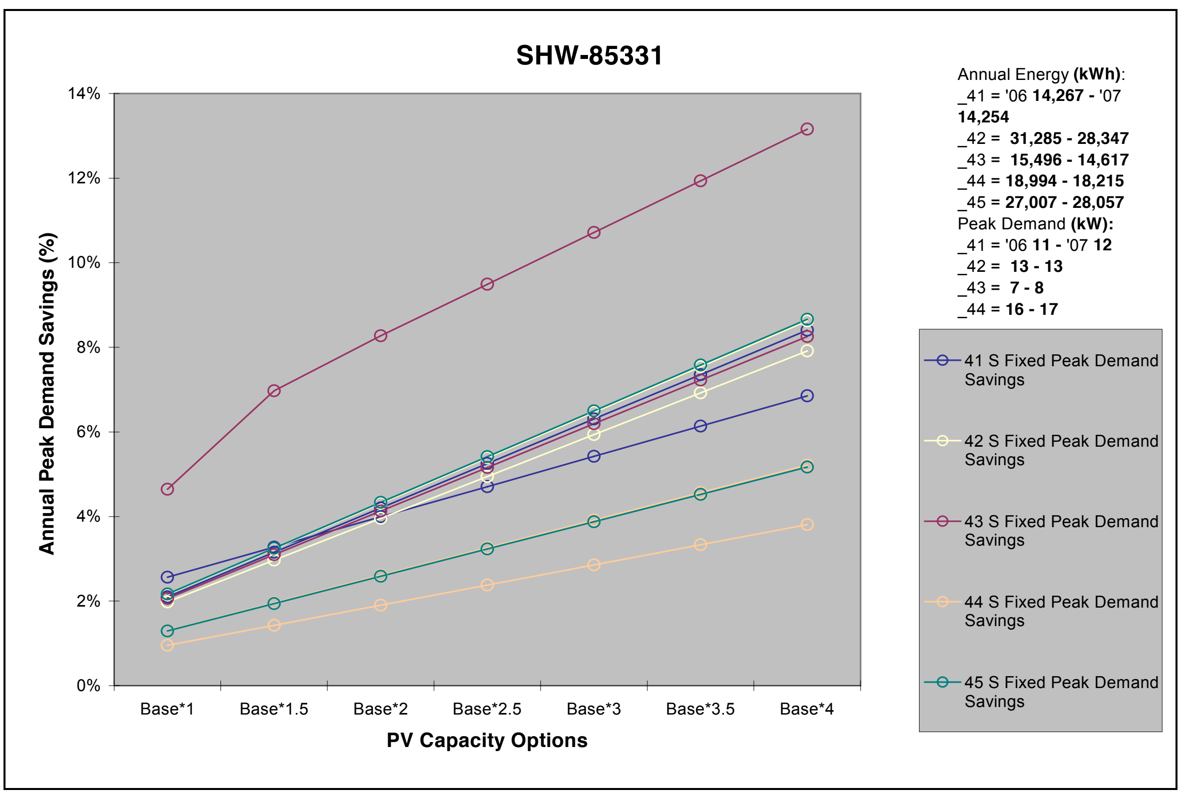


Figure L-43. Solar Hot Water - 85351 Annual Energy Savings

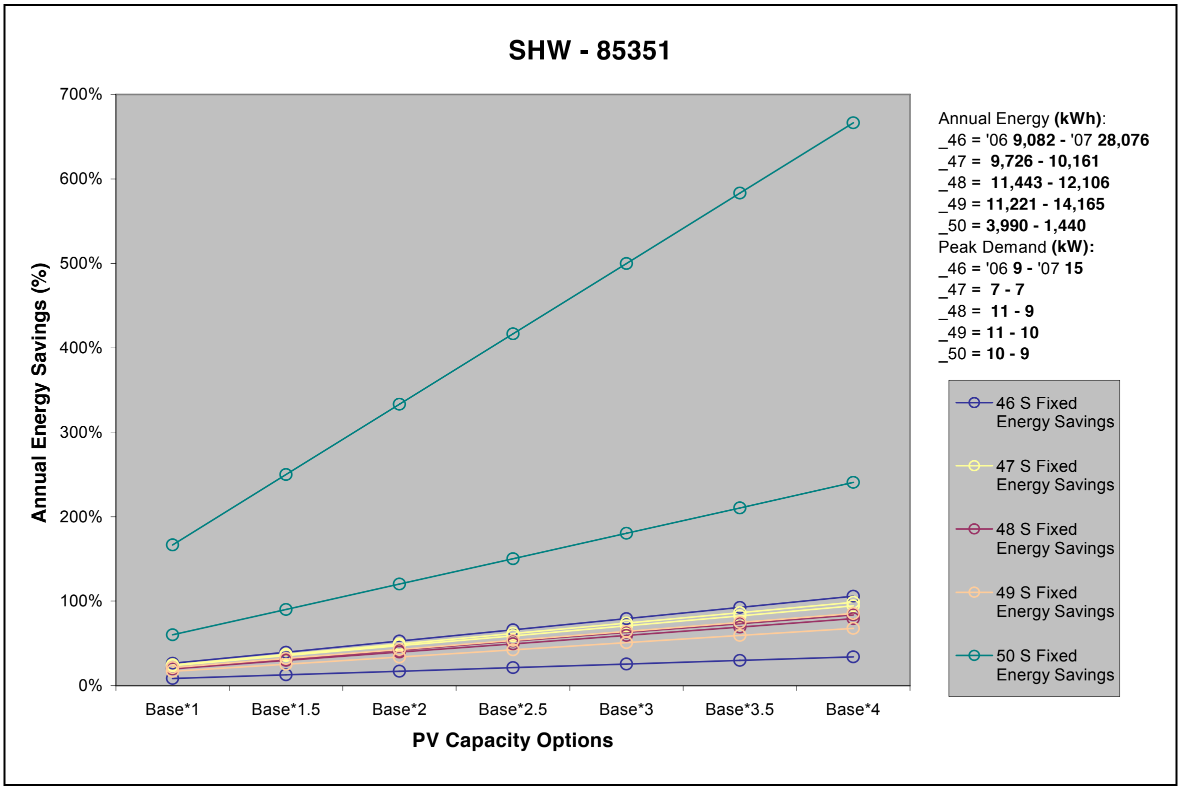


Figure L-44. Solar Hot Water - 85351 Annual Peak Demand Savings

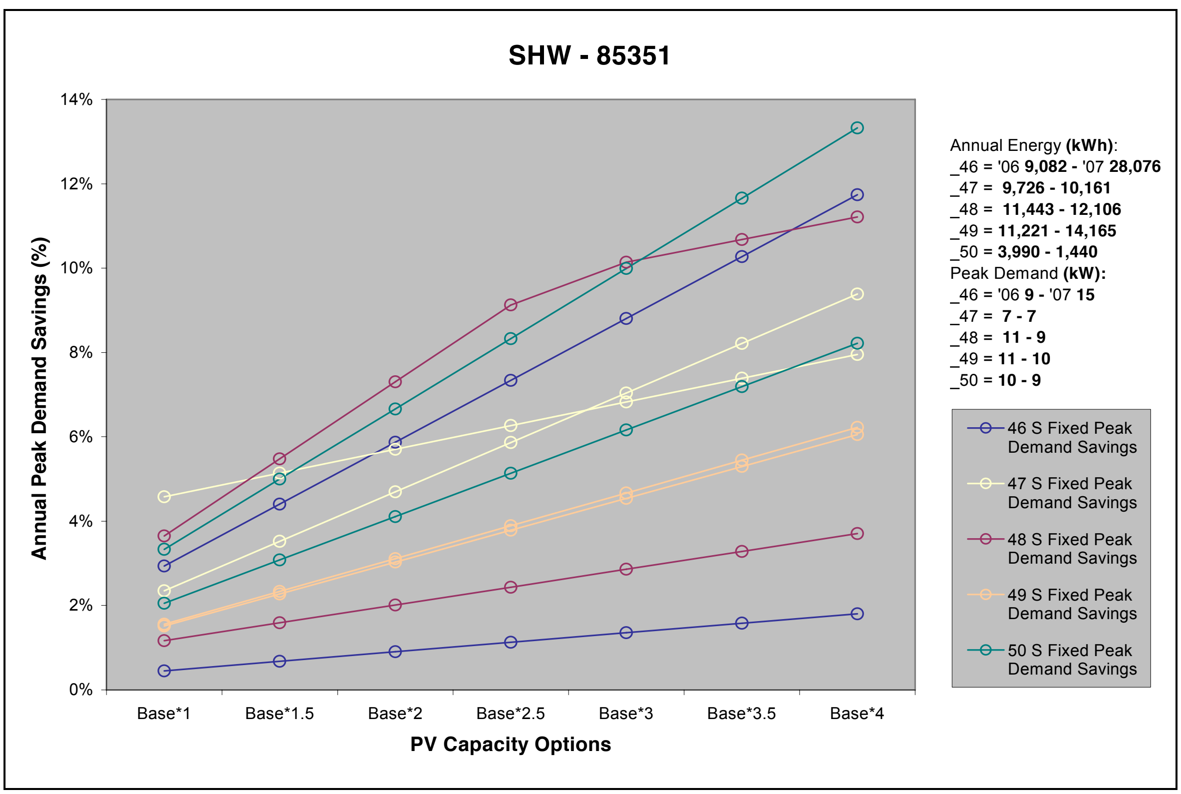


Figure L-45. Solar Hot Water - 85373 Annual Energy Savings

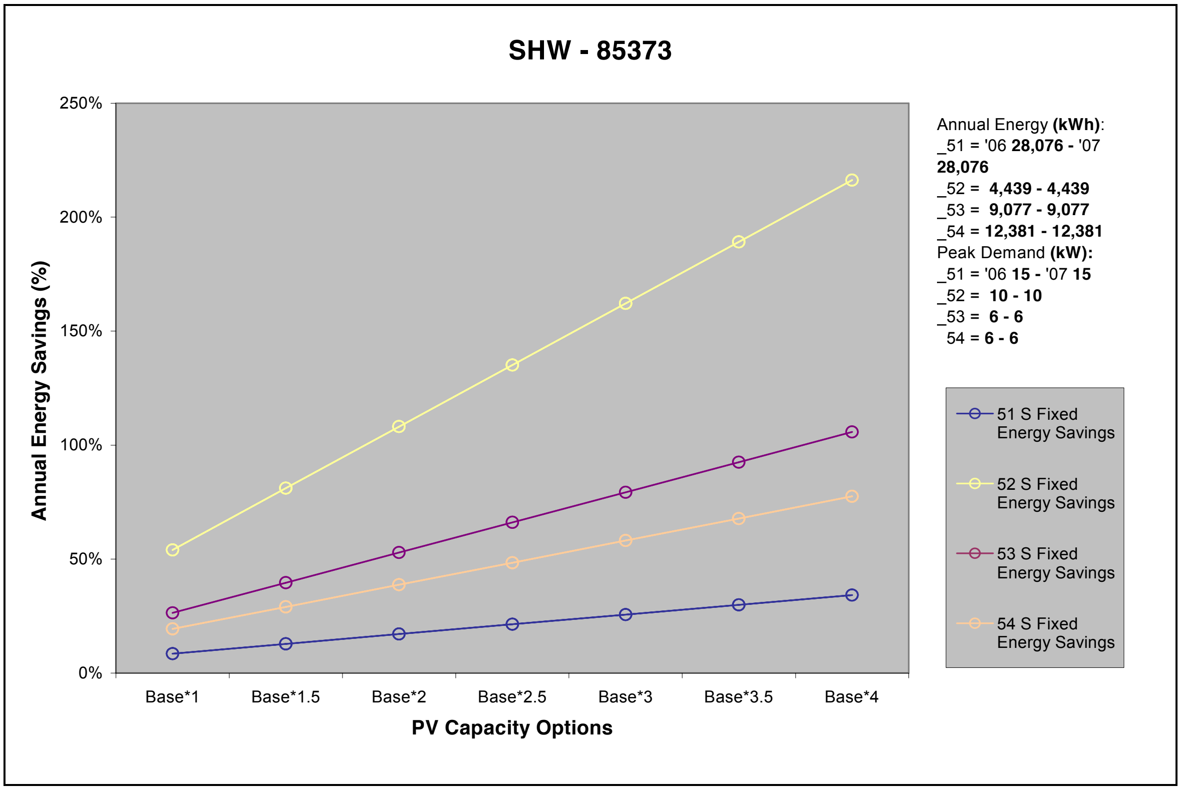


Figure L-46. Solar Hot Water - 85373 Annual Peak Demand Savings

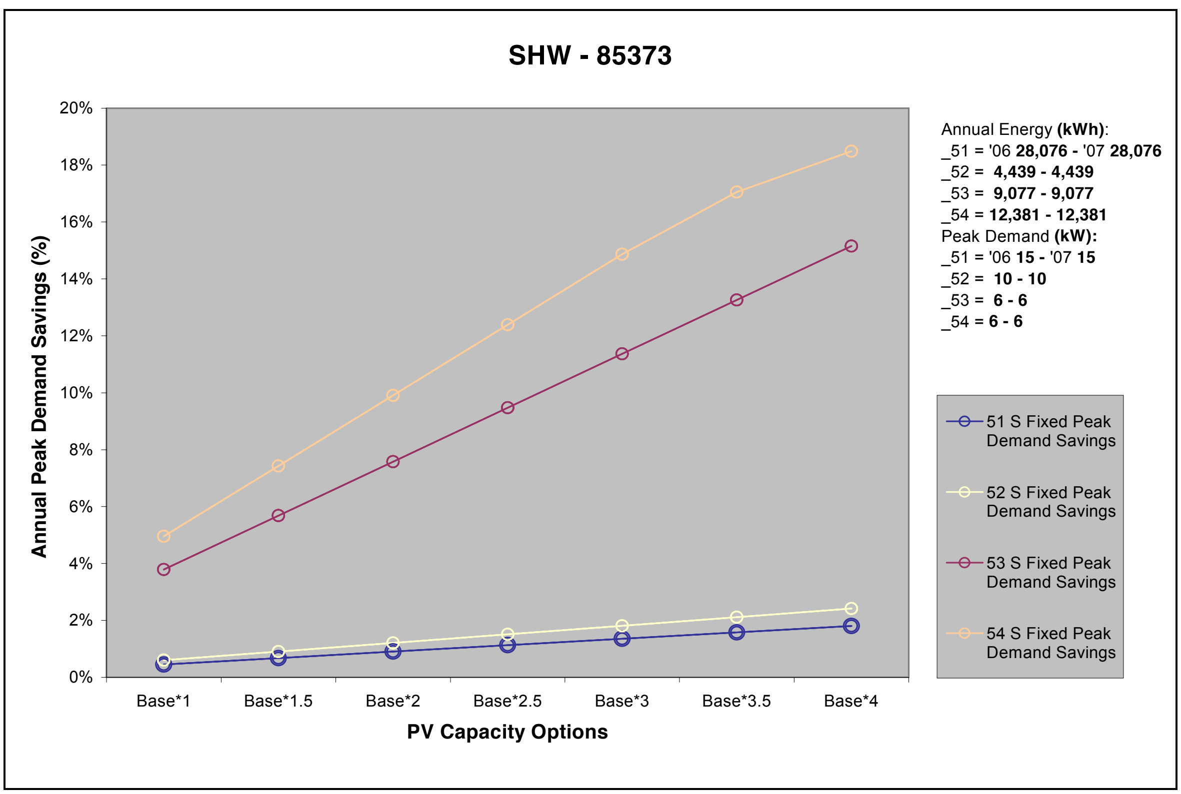


Figure L-47. Arrowhead Annual Energy Savings

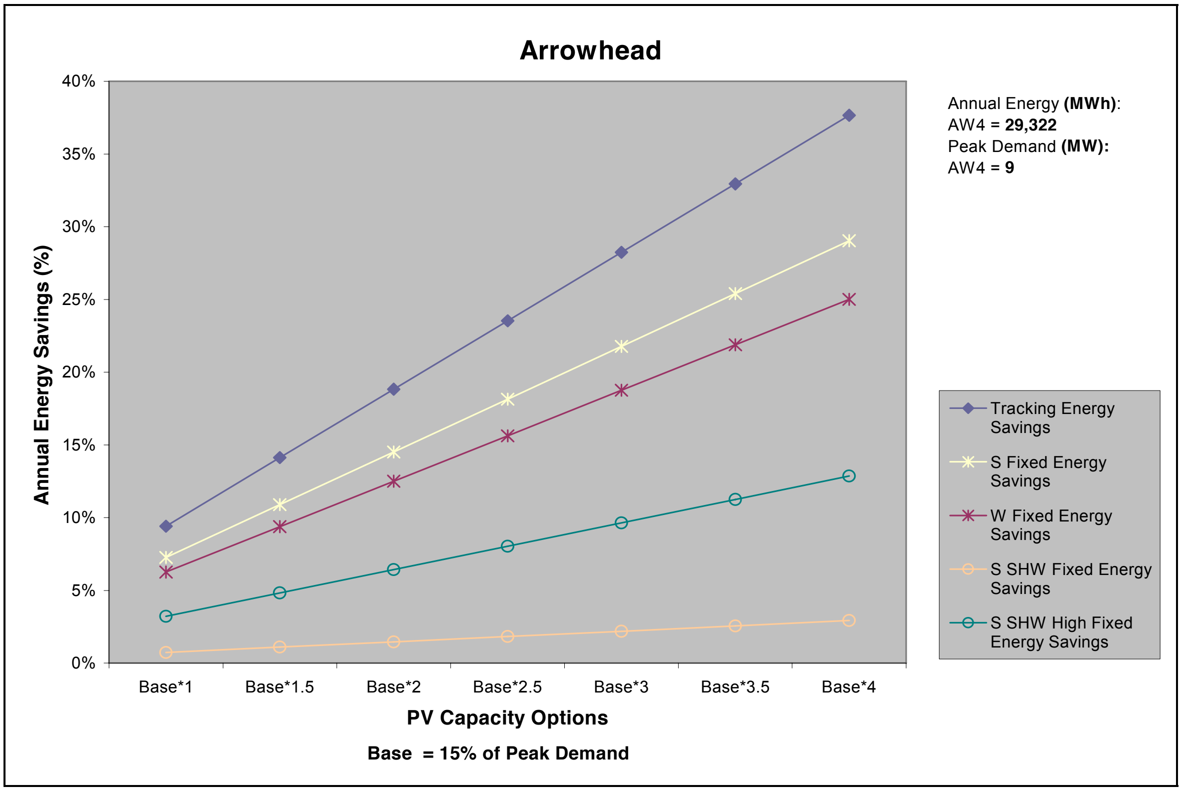


Figure L-48. Arrowhead Annual Peak Demand Savings

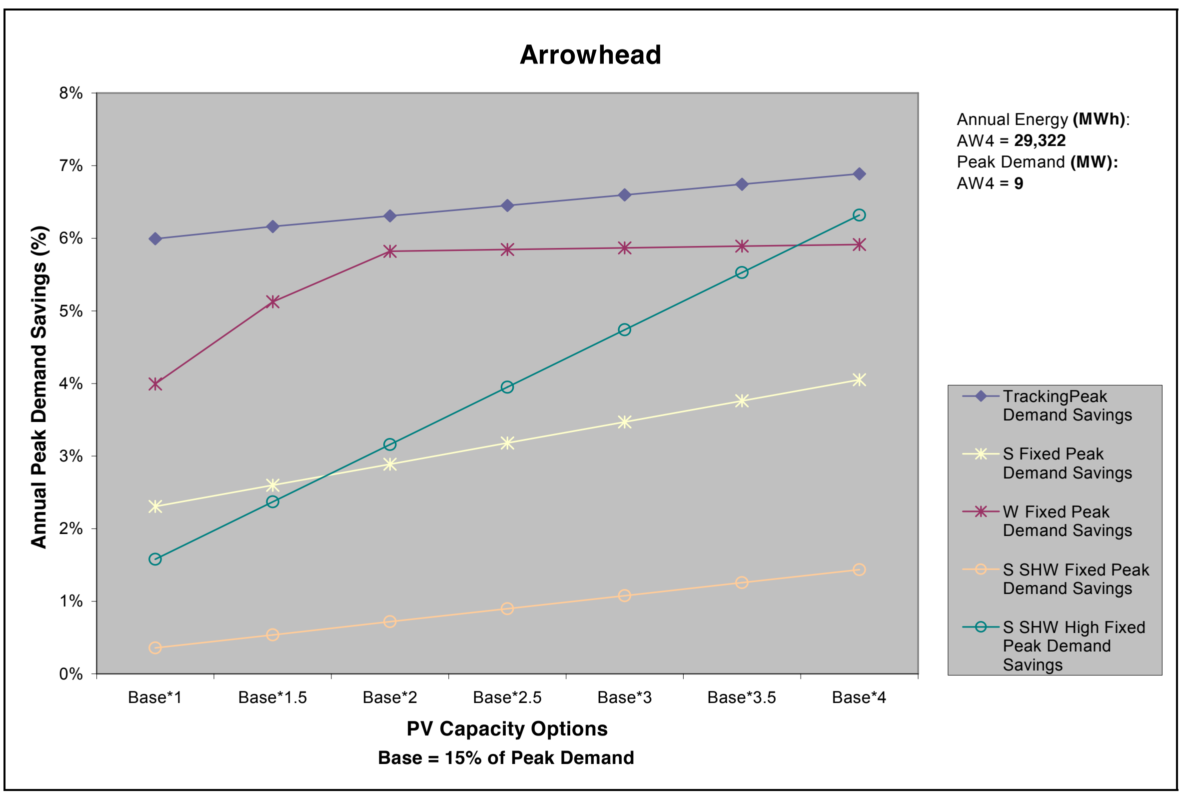


Figure L-49. Cactus Annual Energy Savings

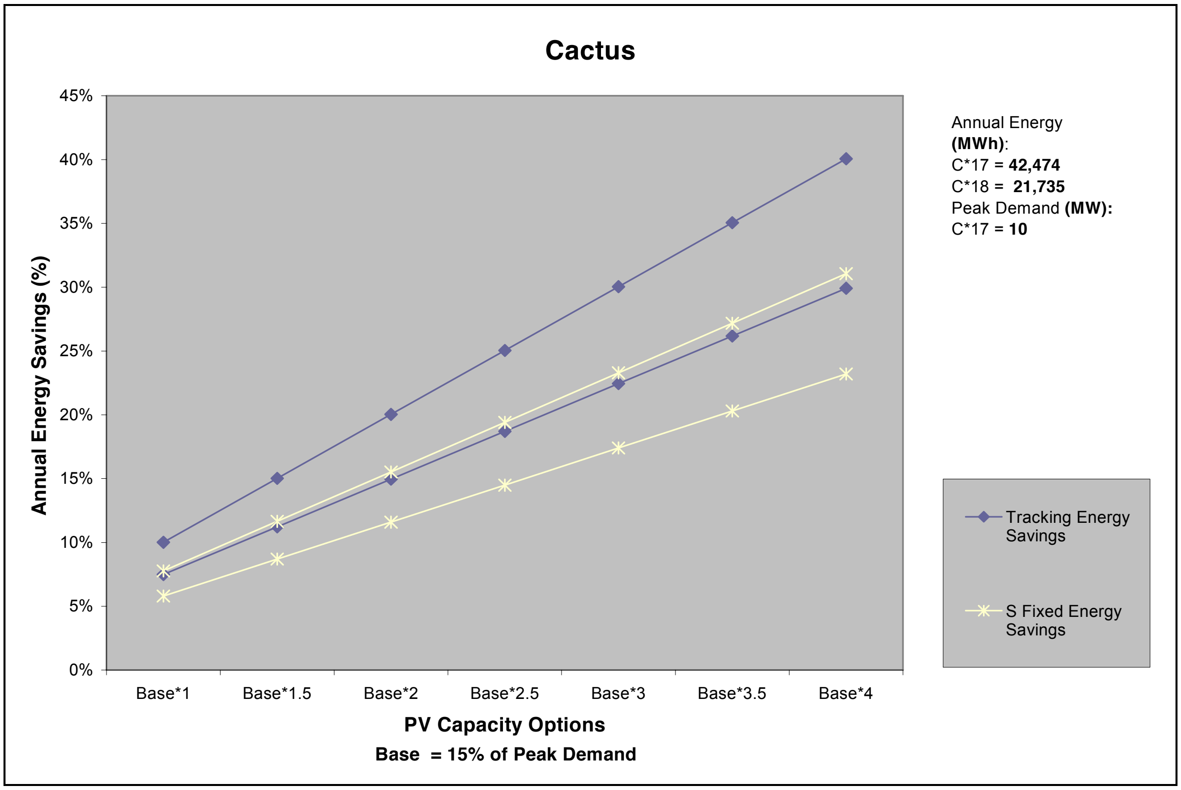


Figure L-50. Cactus Annual Peak Demand Savings

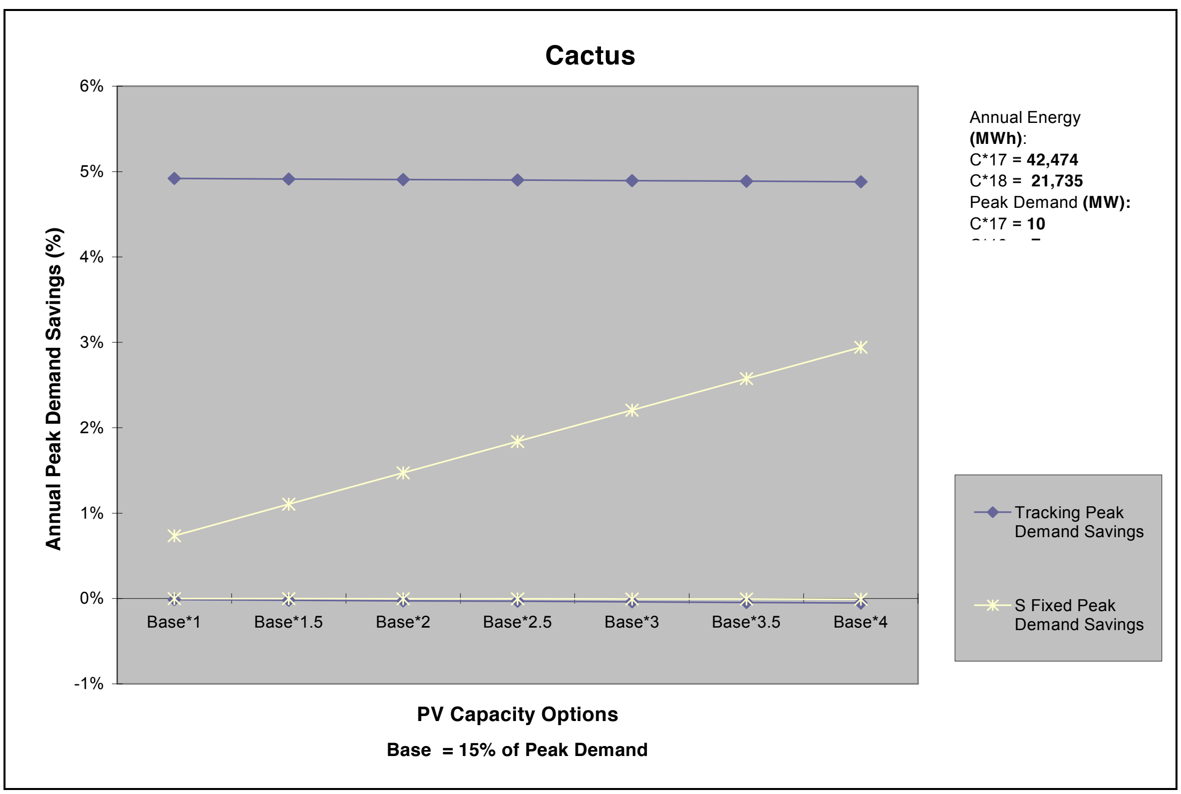


Figure L-51. Deadman Wash Annual Energy Savings

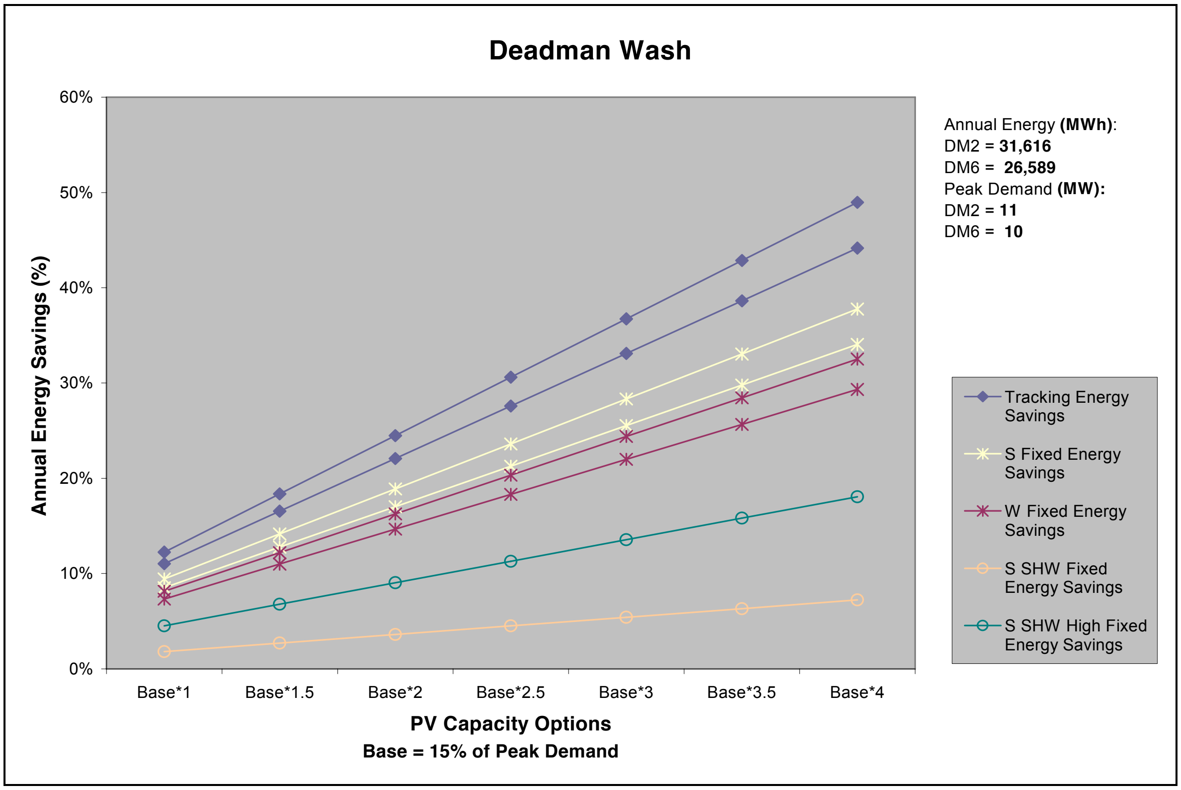


Figure L-52. Deadman Wash Annual Peak Demand Savings

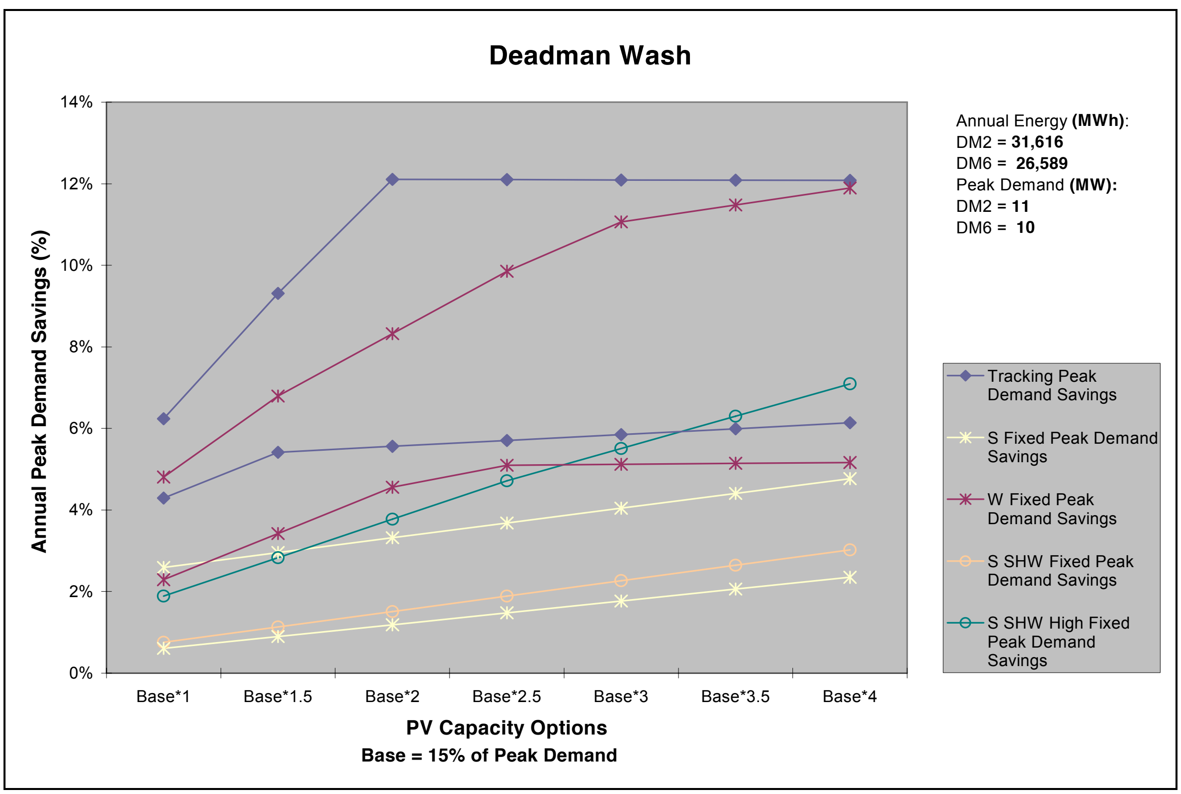


Figure L-53. East Valley - Acoma Annual Energy Savings

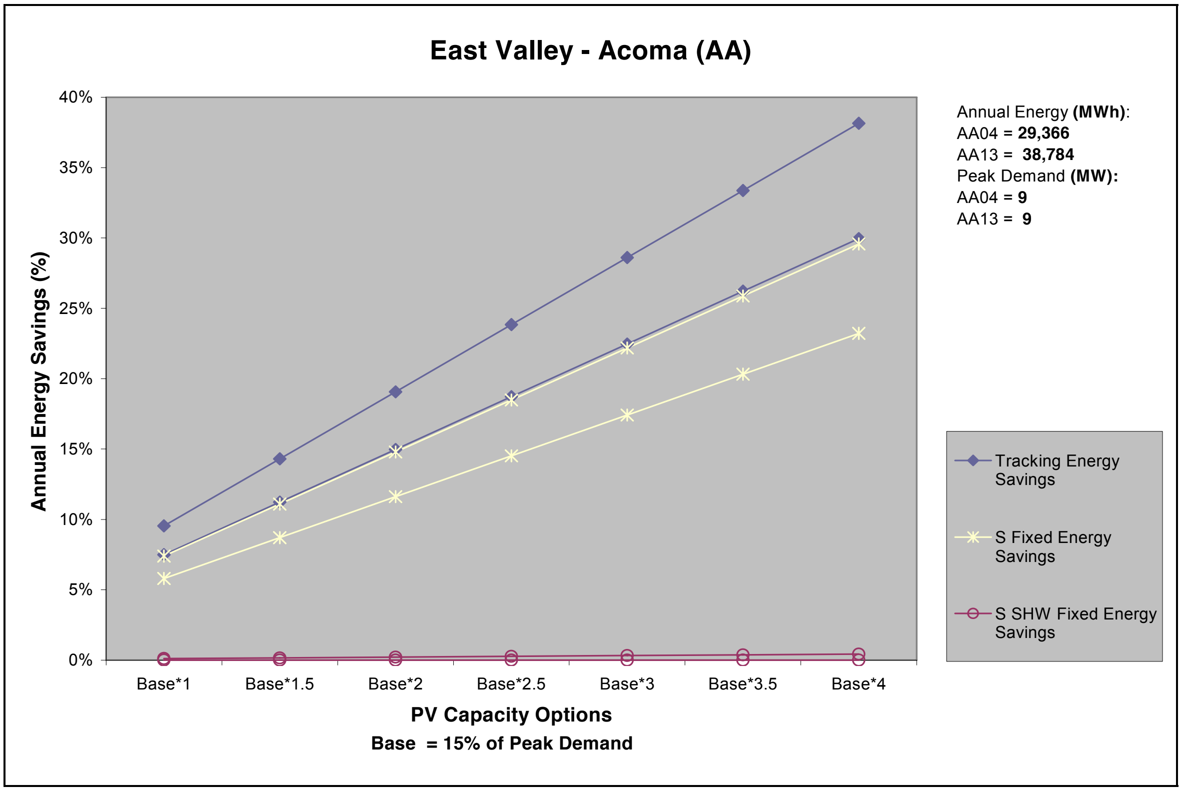


Figure L-54. East Valley - Acoma Annual Peak Demand Savings

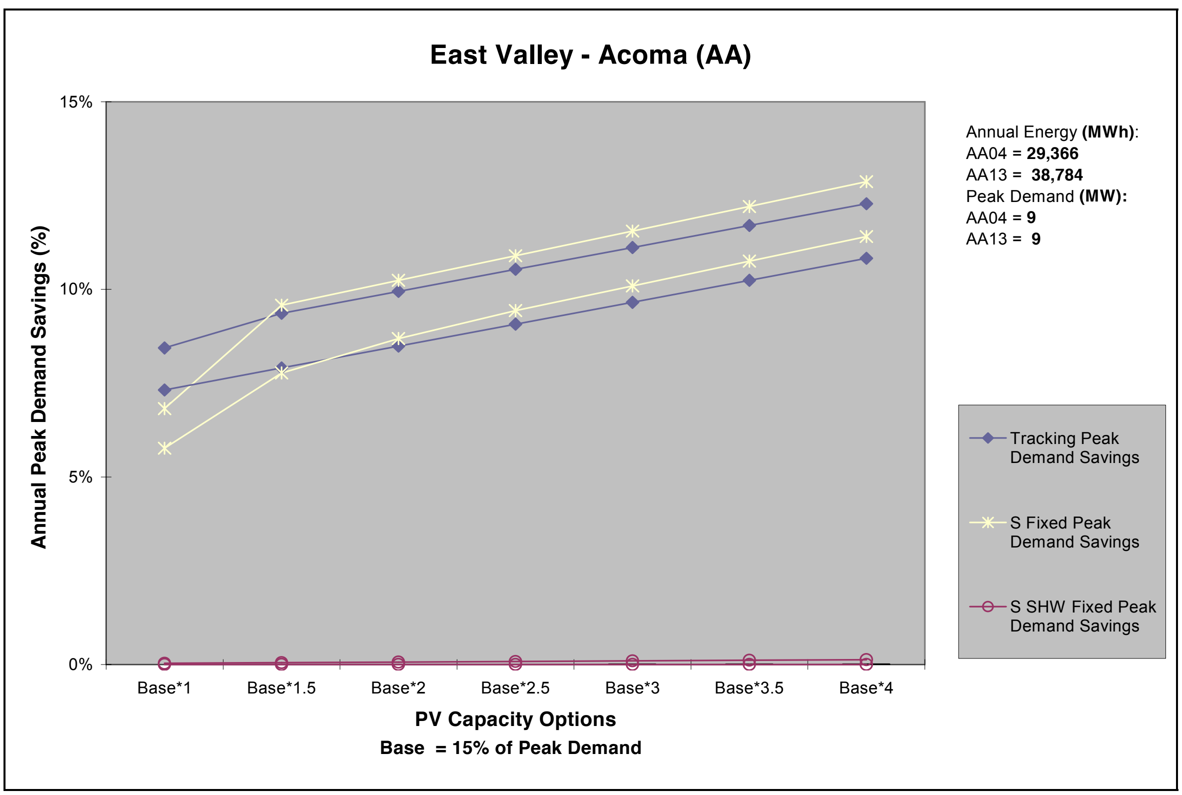


Figure L-55. East Valley – Cave Creek Annual Energy Savings

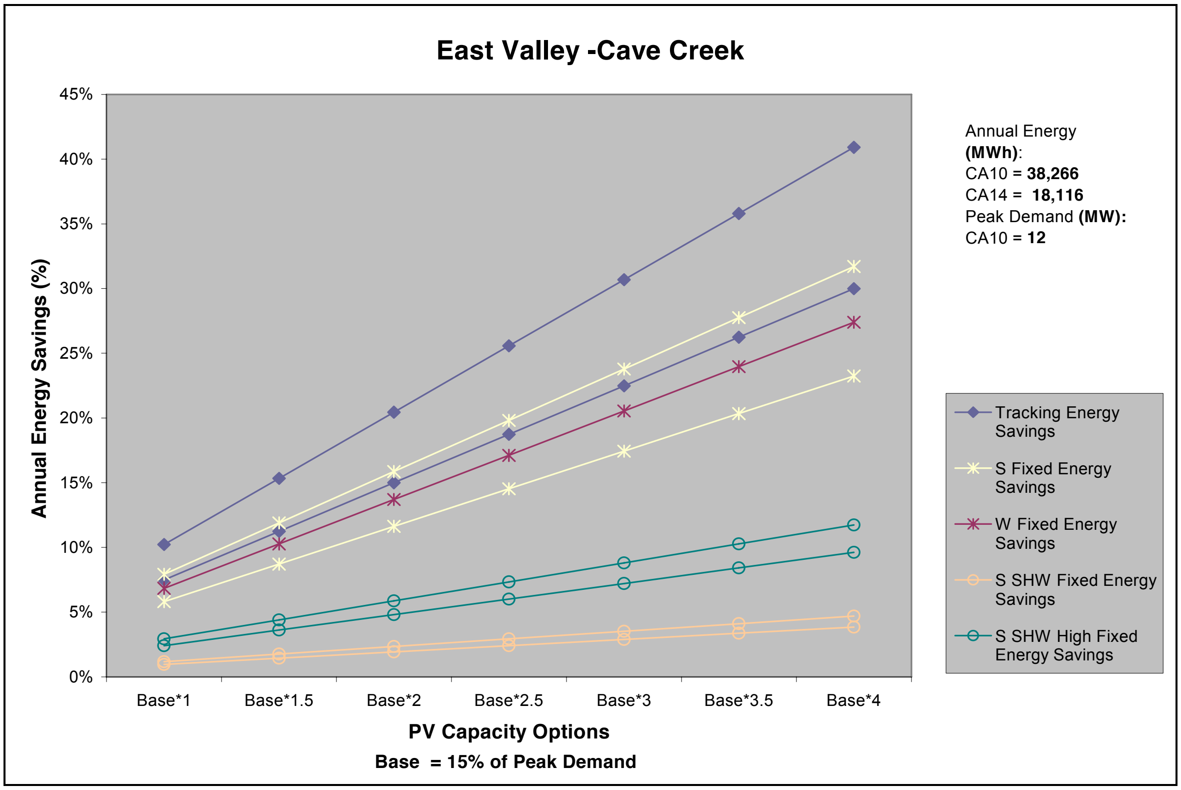


Figure L-56. East Valley – Cave Creek Annual Peak Demand Savings

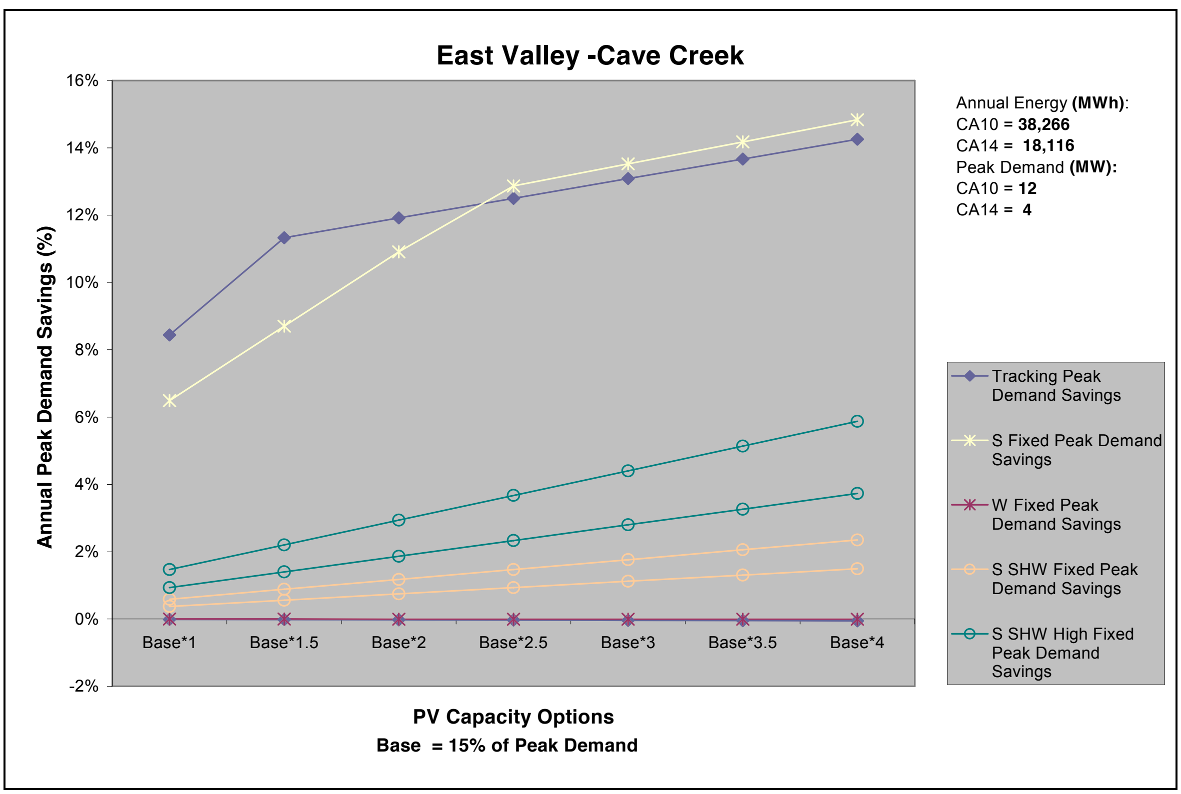


Figure L-57. East Valley - Chaparral Annual Energy Savings

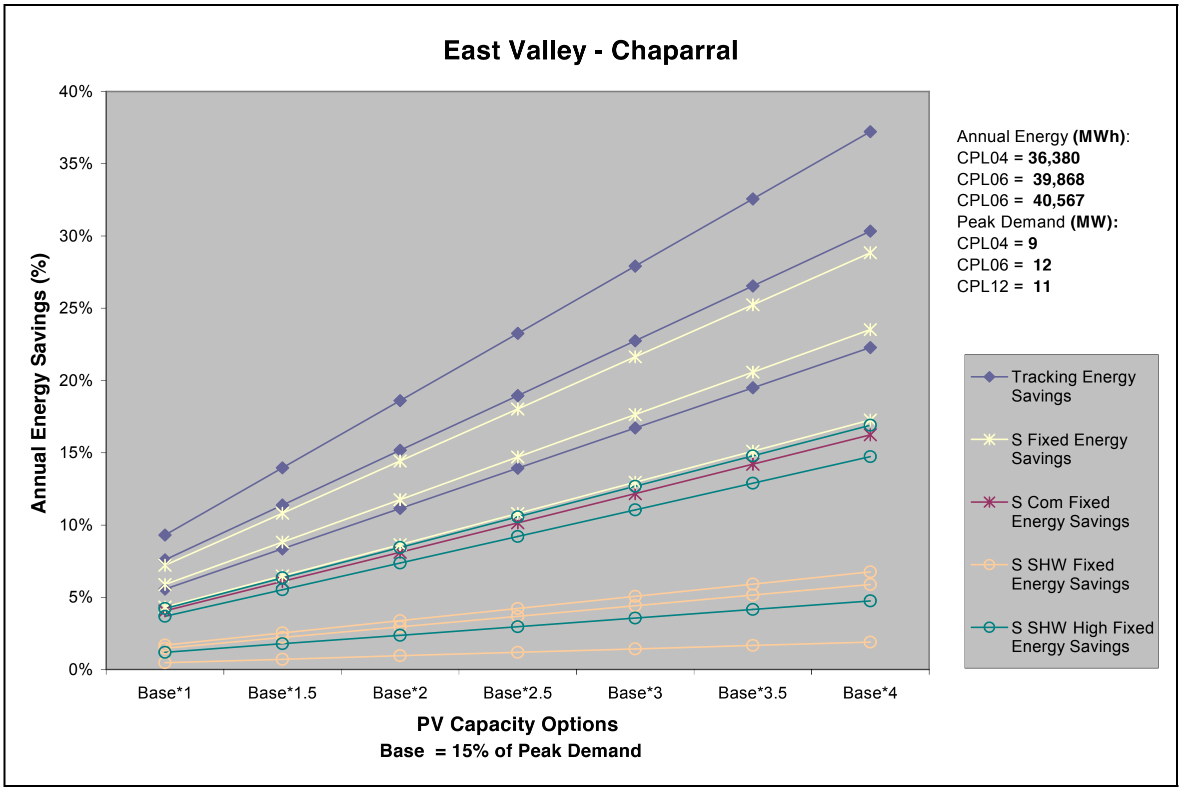


Figure L-58. East Valley - Chaparral Annual Peak Demand Savings

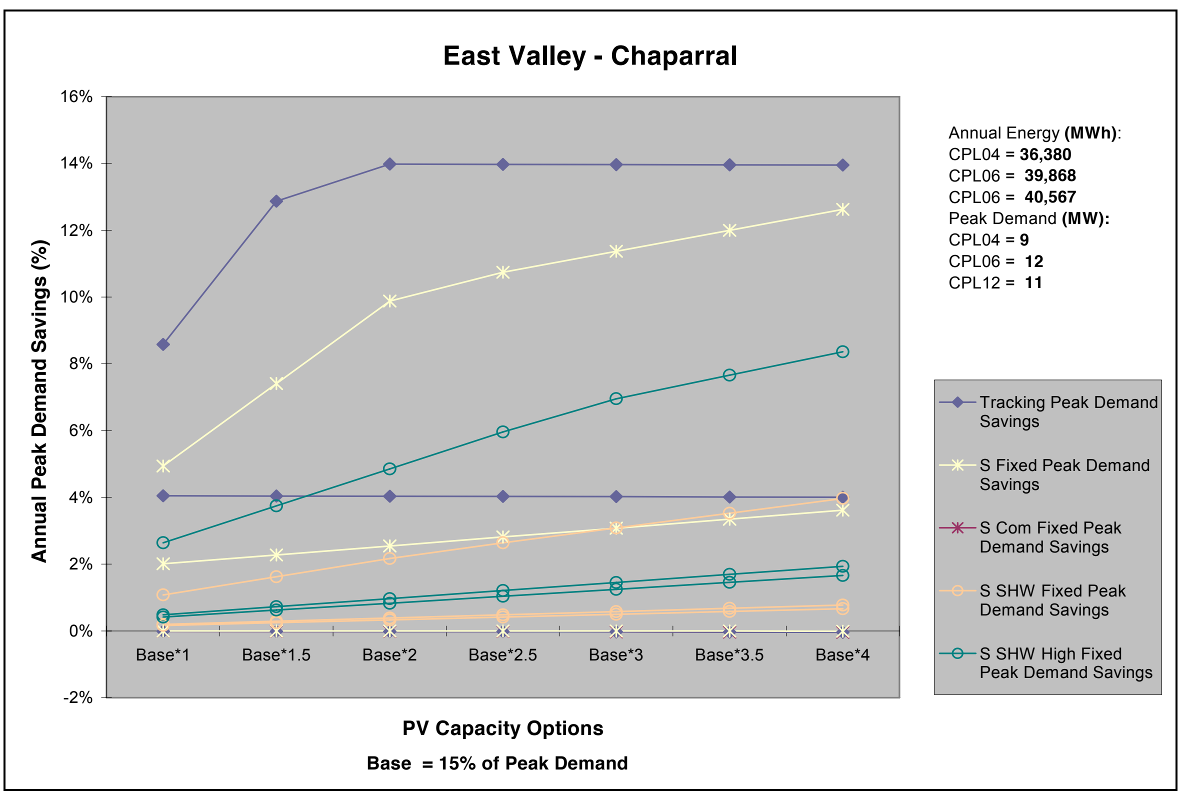


Figure L-59. East Valley – Thompson Peak Annual Energy Savings

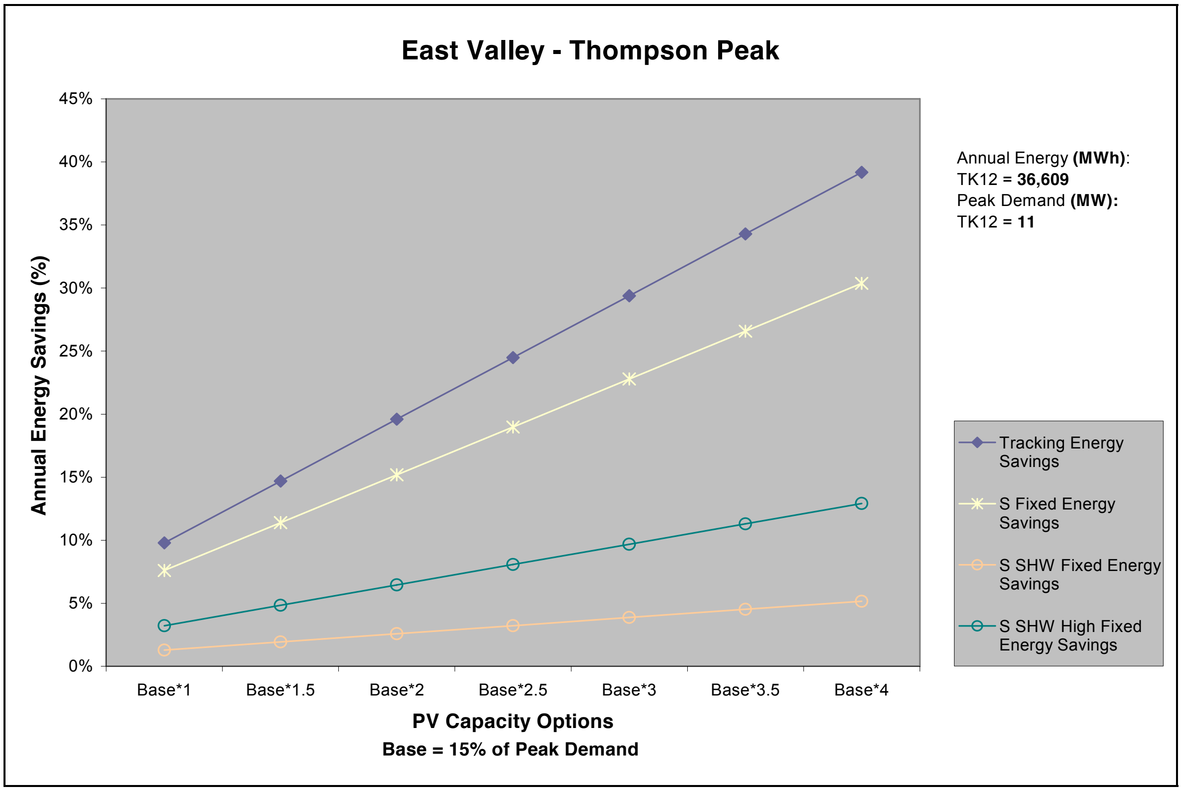


Figure L-60. East Valley – Thompson Peak Annual Peak Demand Savings

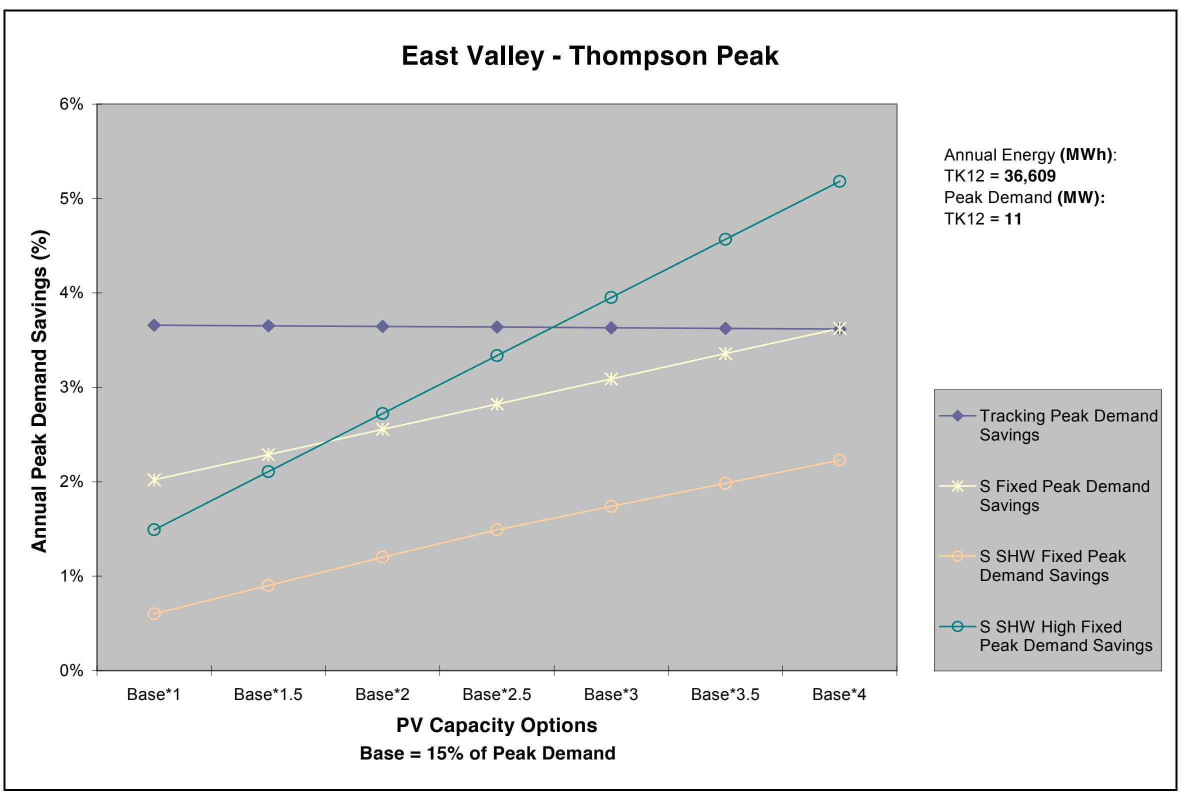


Figure L-61. Galvin Peak Annual Energy Savings

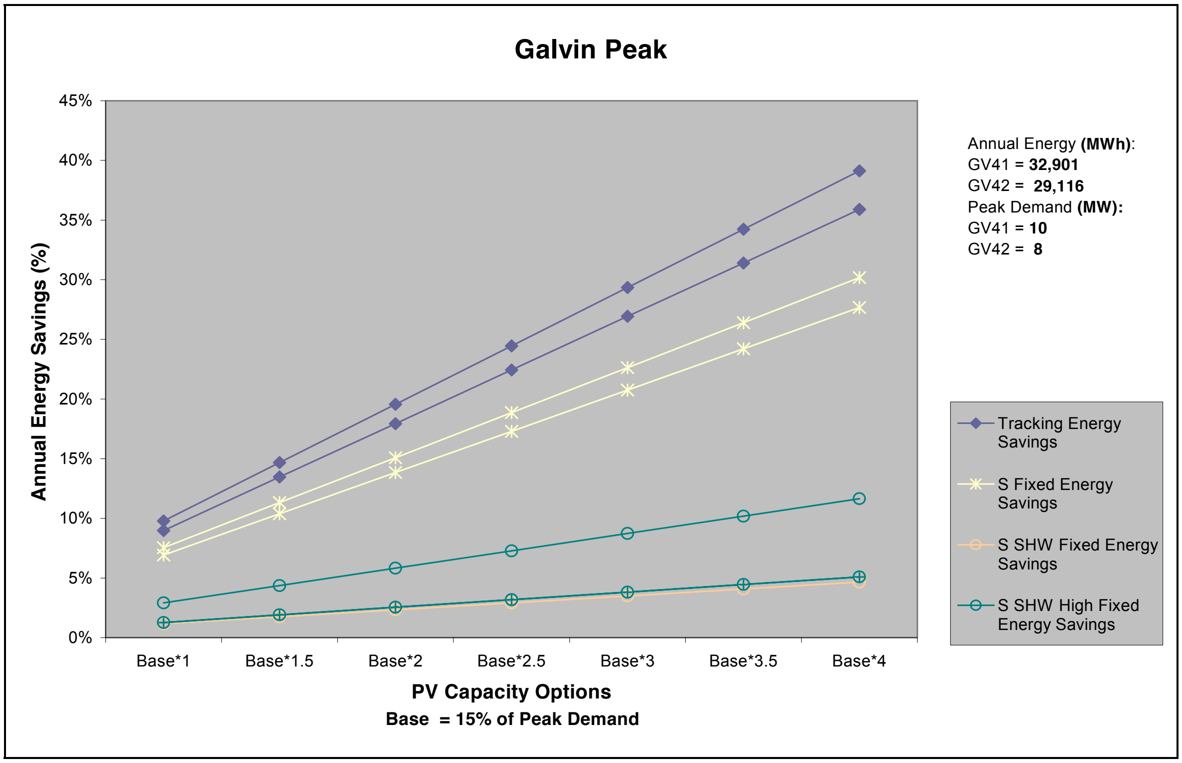


Figure L-62. Galvin Peak Annual Peak Demand Savings

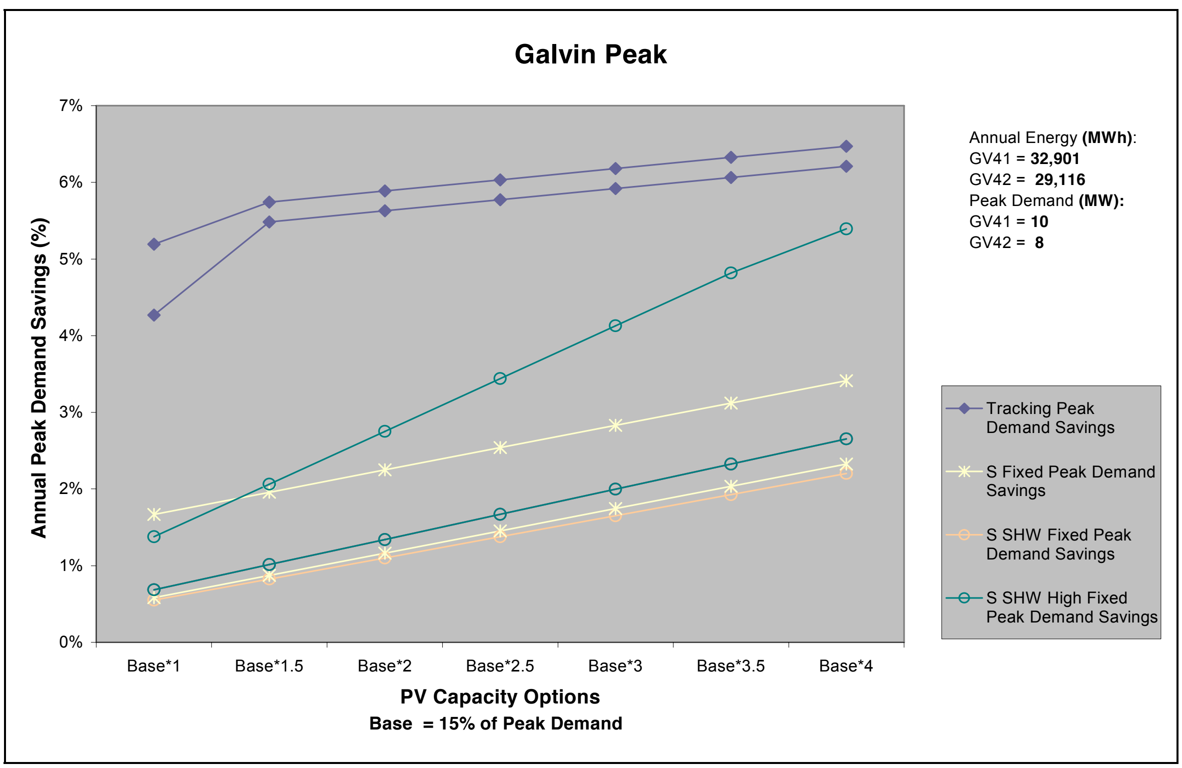


Figure L-63. Indian Bend Annual Energy Savings

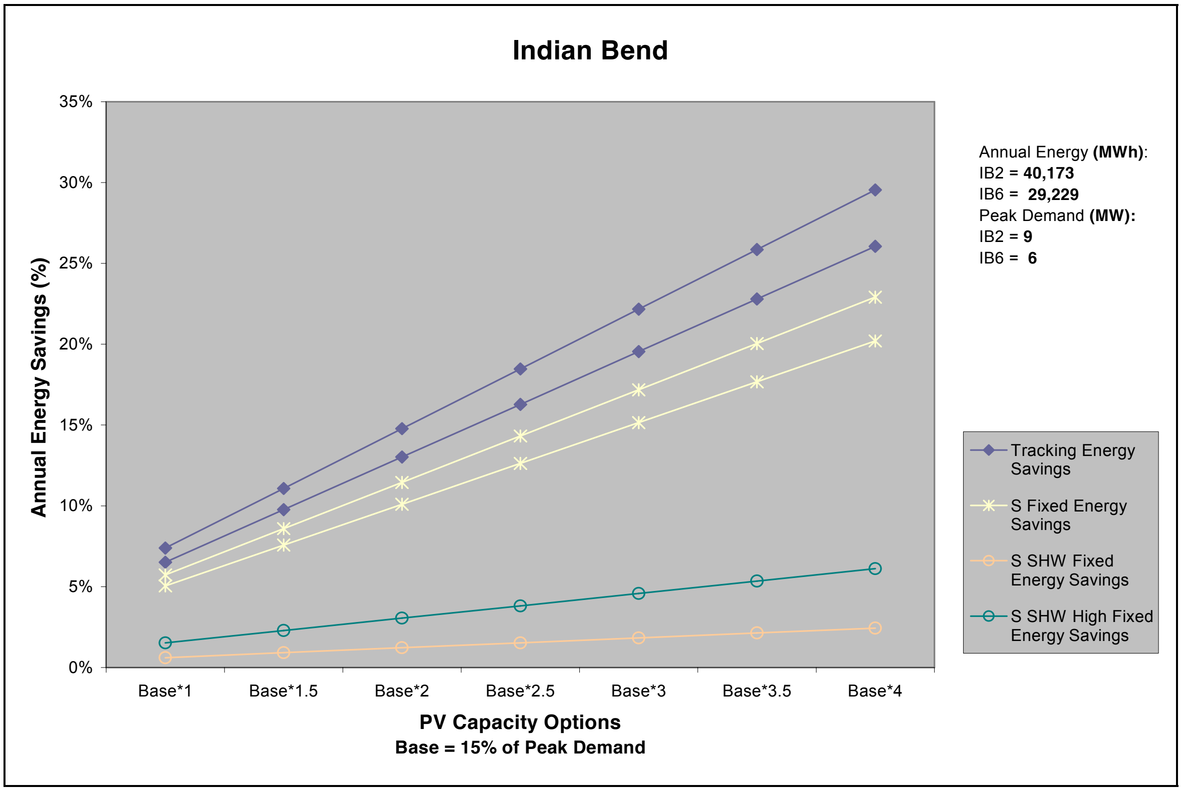


Figure L-64. Indian Bend Annual Peak Demand Savings

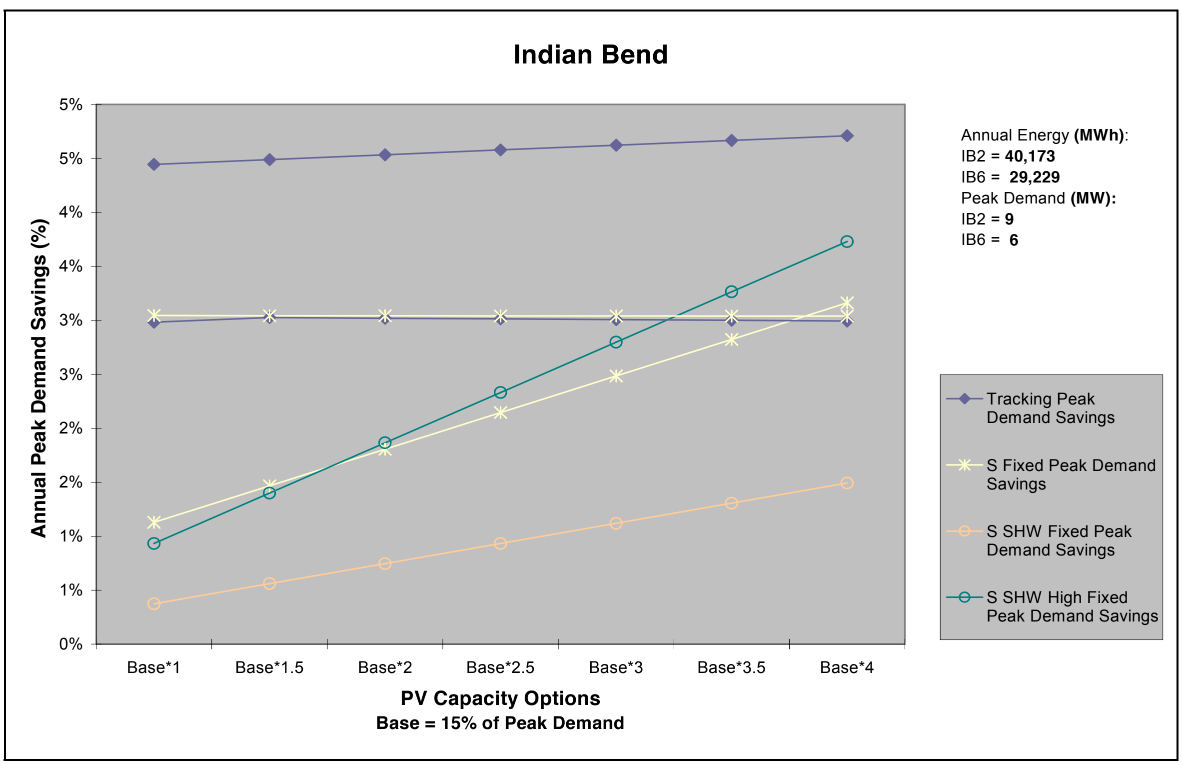


Figure L-65. Javalina Annual Energy Savings

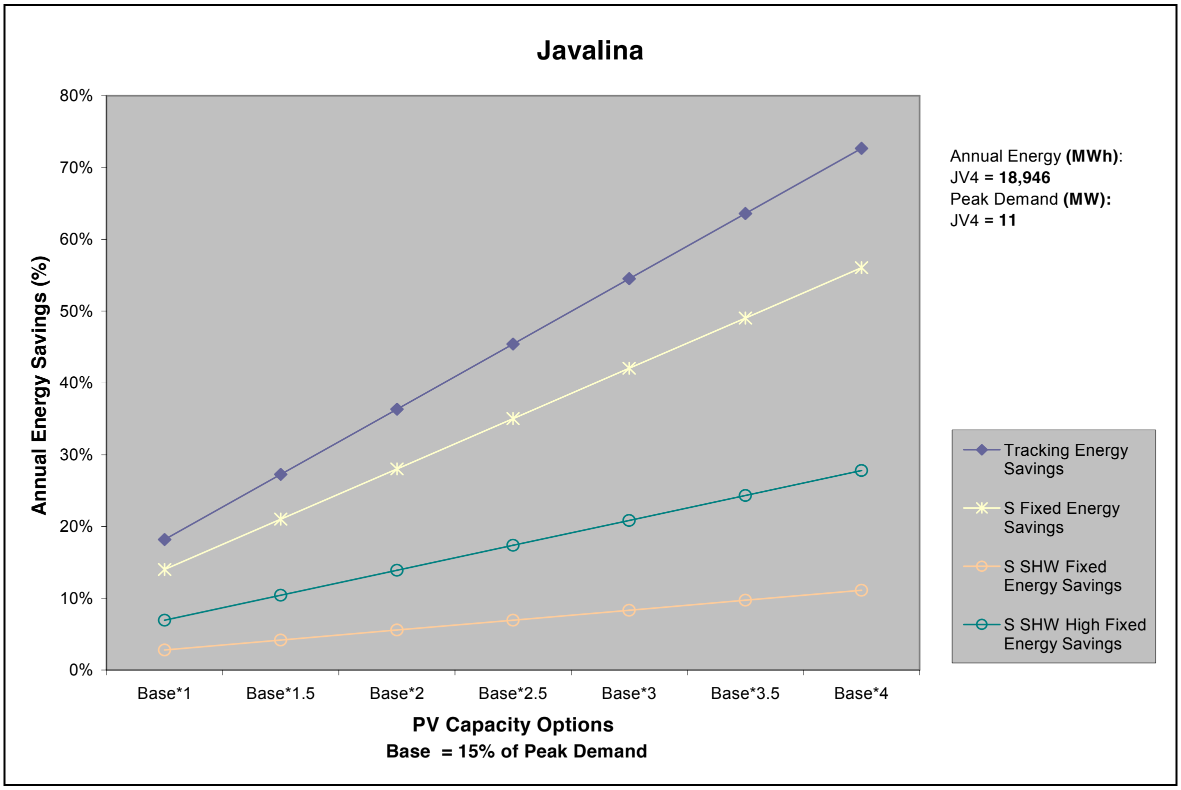


Figure L-66. Javalina Annual Peak Demand Savings

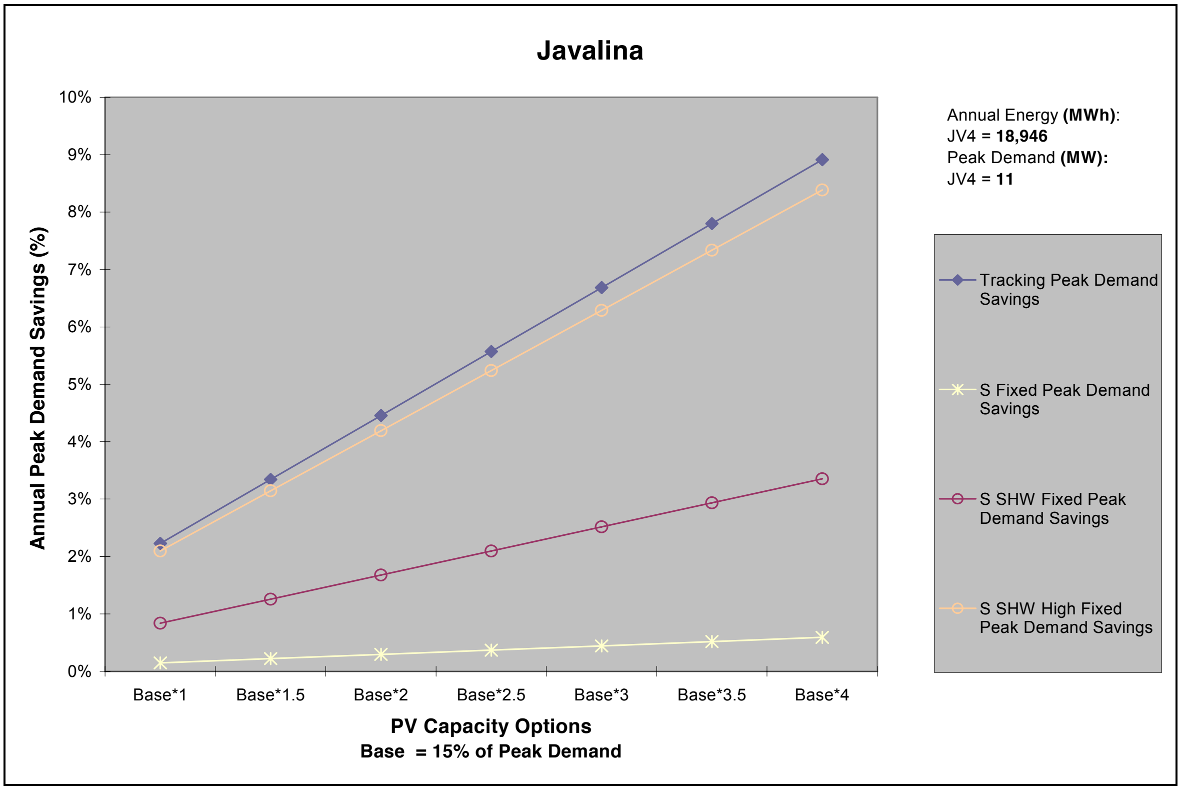


Figure L-67. Mountain View Annual Energy Savings

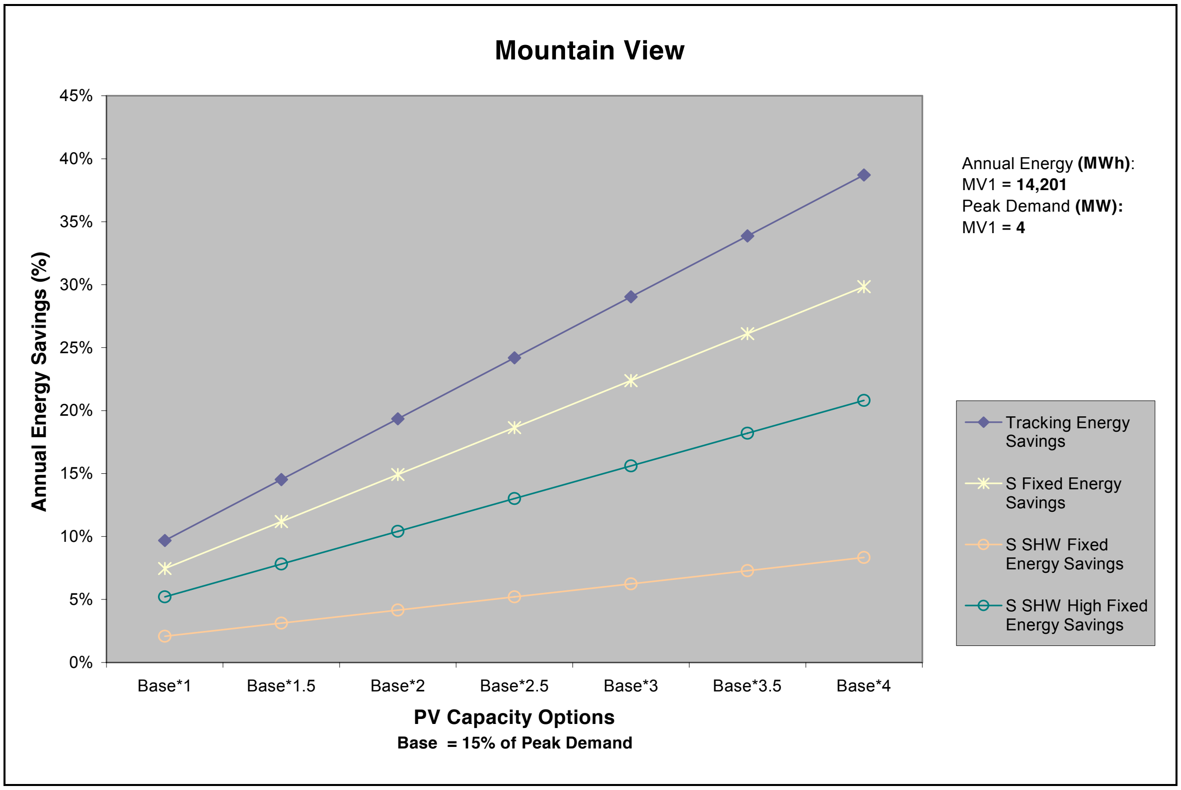


Figure L-68. Mountain View Annual Peak Demand Savings

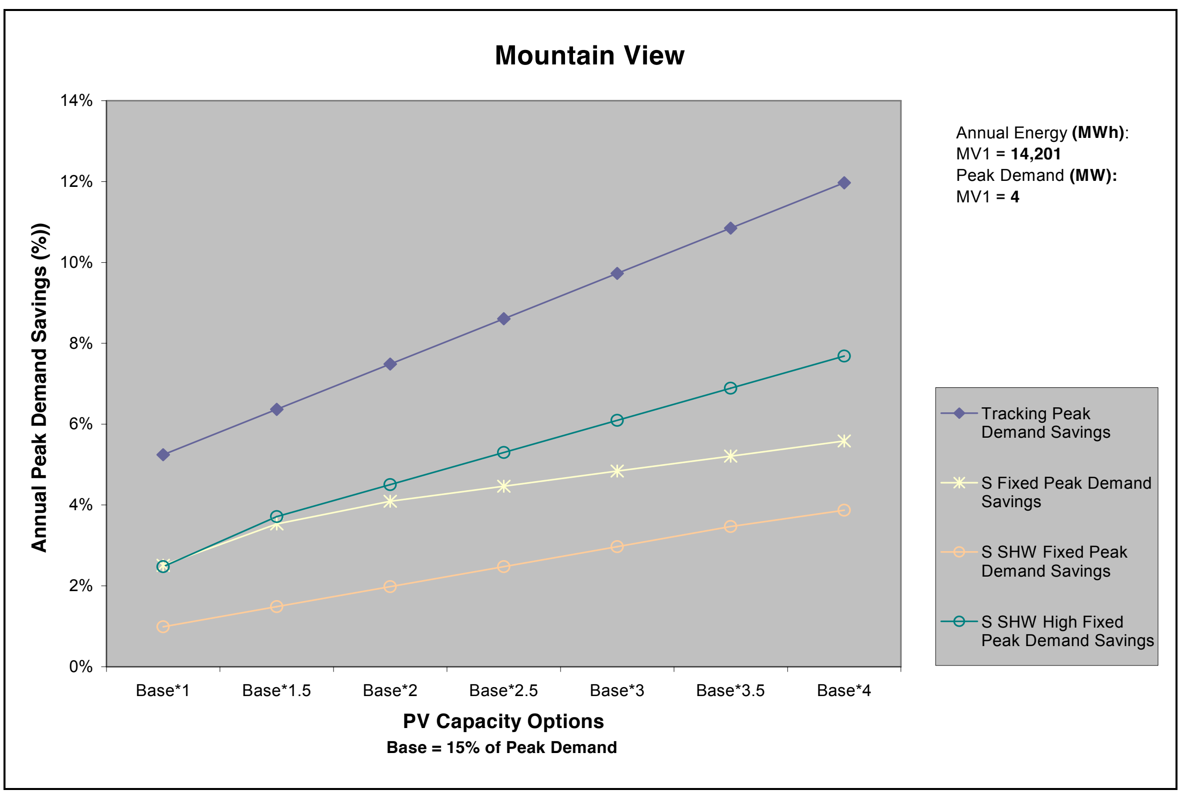


Figure L-69. Pioneer Annual Energy Savings

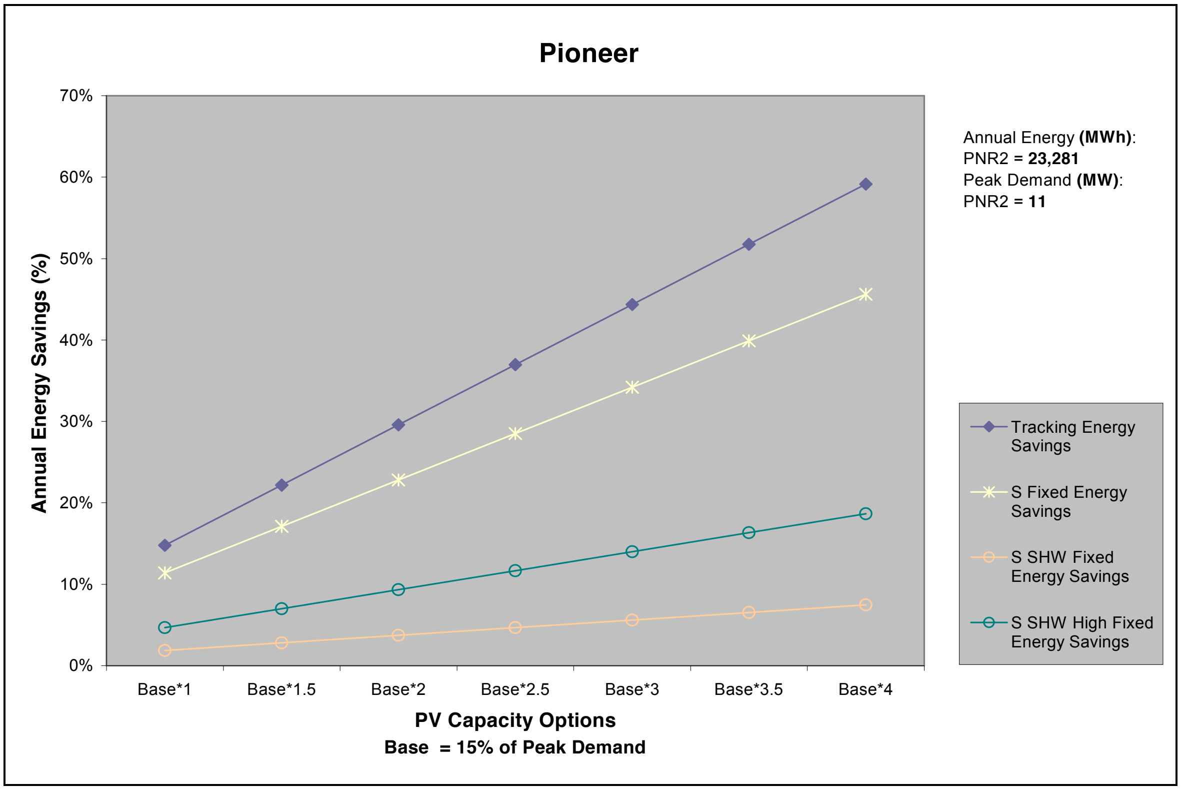


Figure L-70. Pioneer Annual Peak Demand Savings

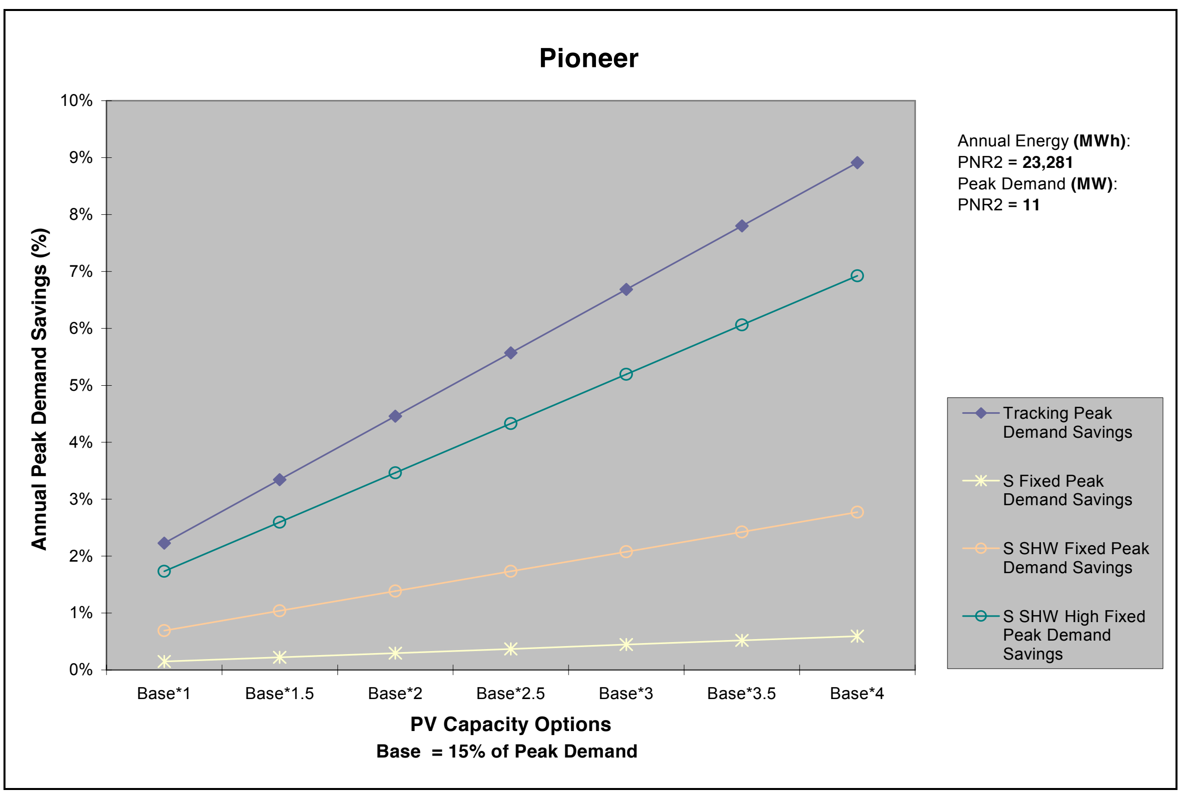


Figure L-71. Acoma Substation Annual Energy Savings

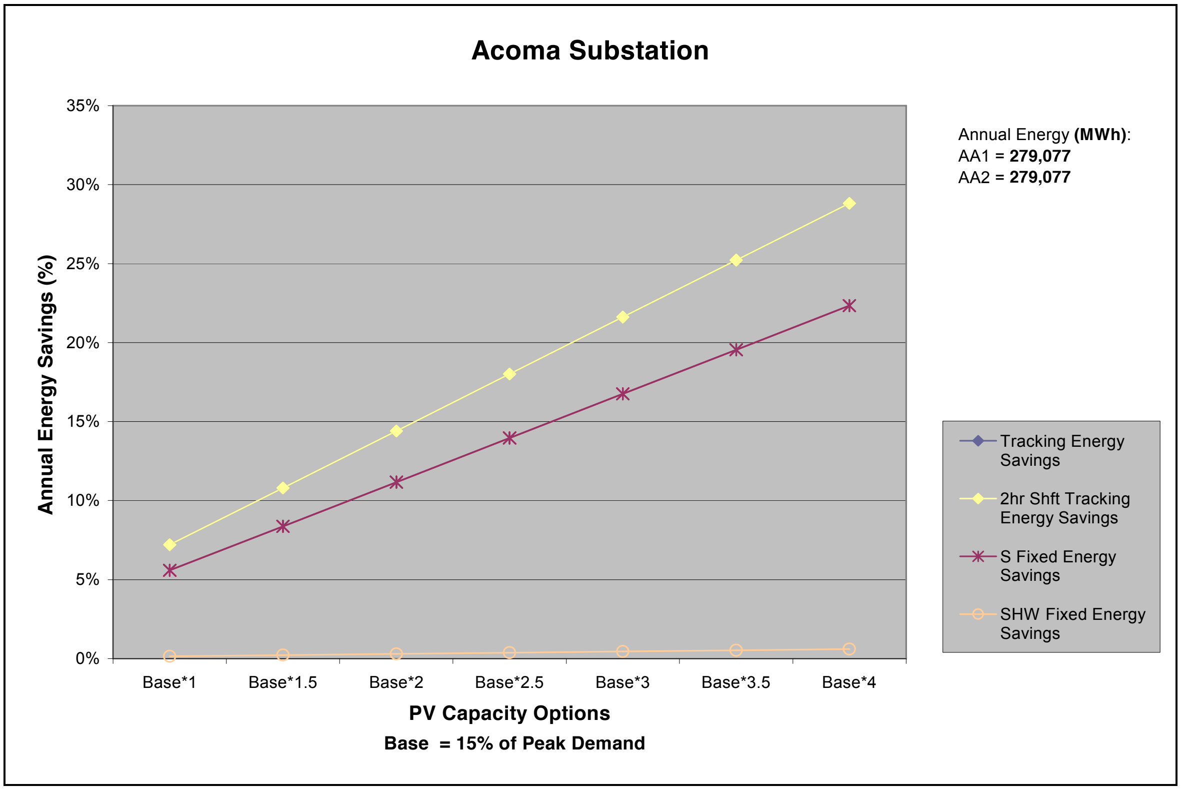


Figure L-72. Acoma Substation Annual Peak Demand Savings

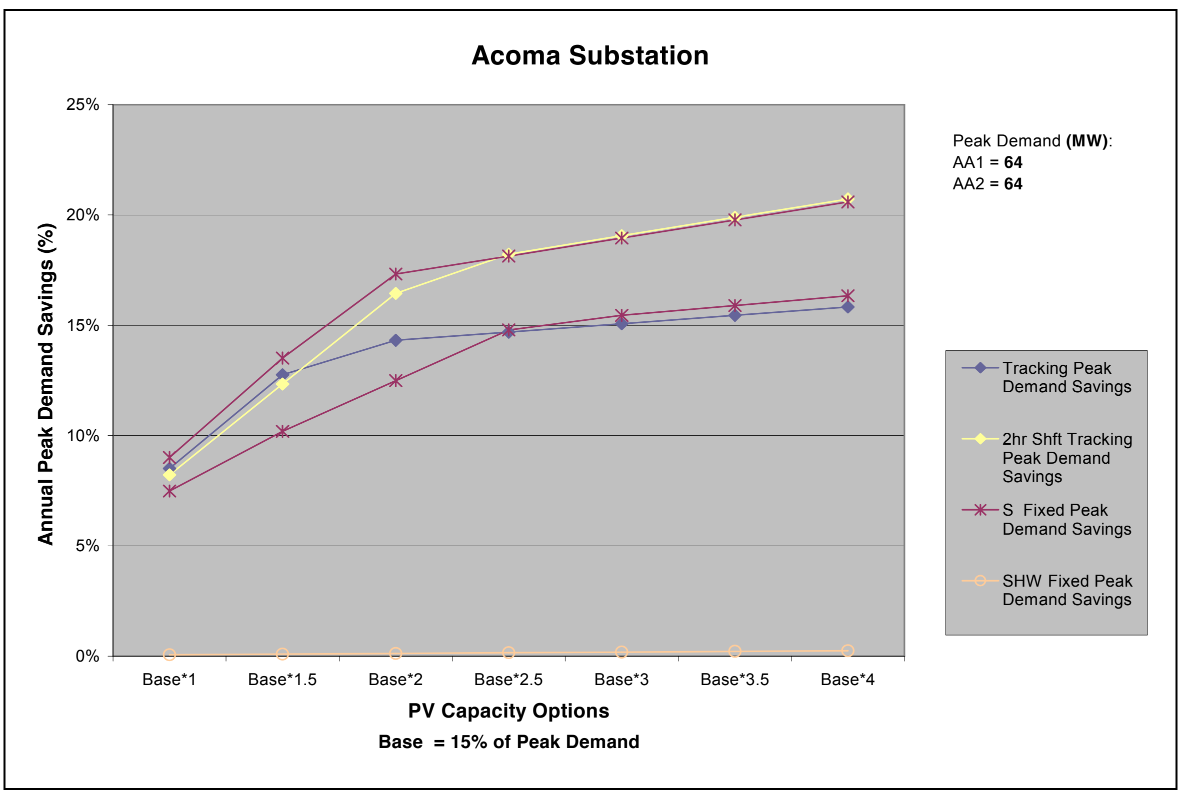


Figure L-73. Thompson Peak Substation Annual Energy Savings

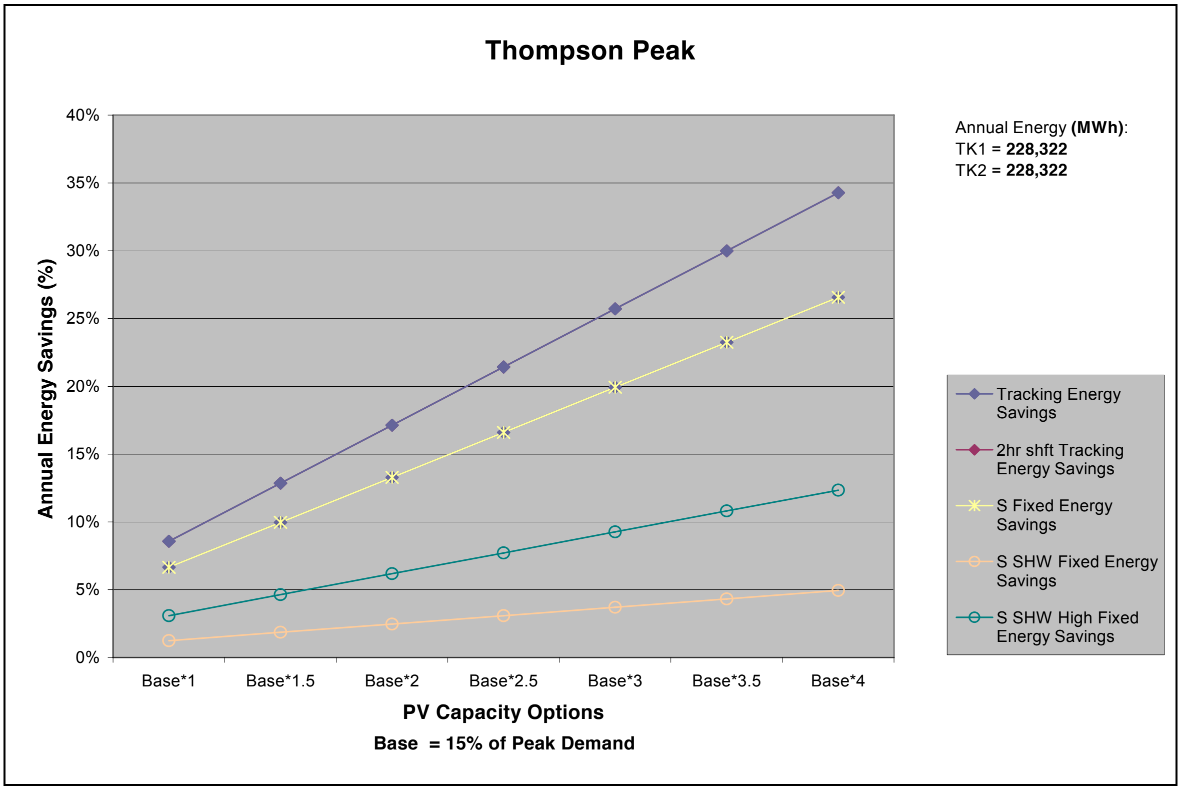


Figure L-74. Thompson Peak Substation Annual Peak Demand Savings

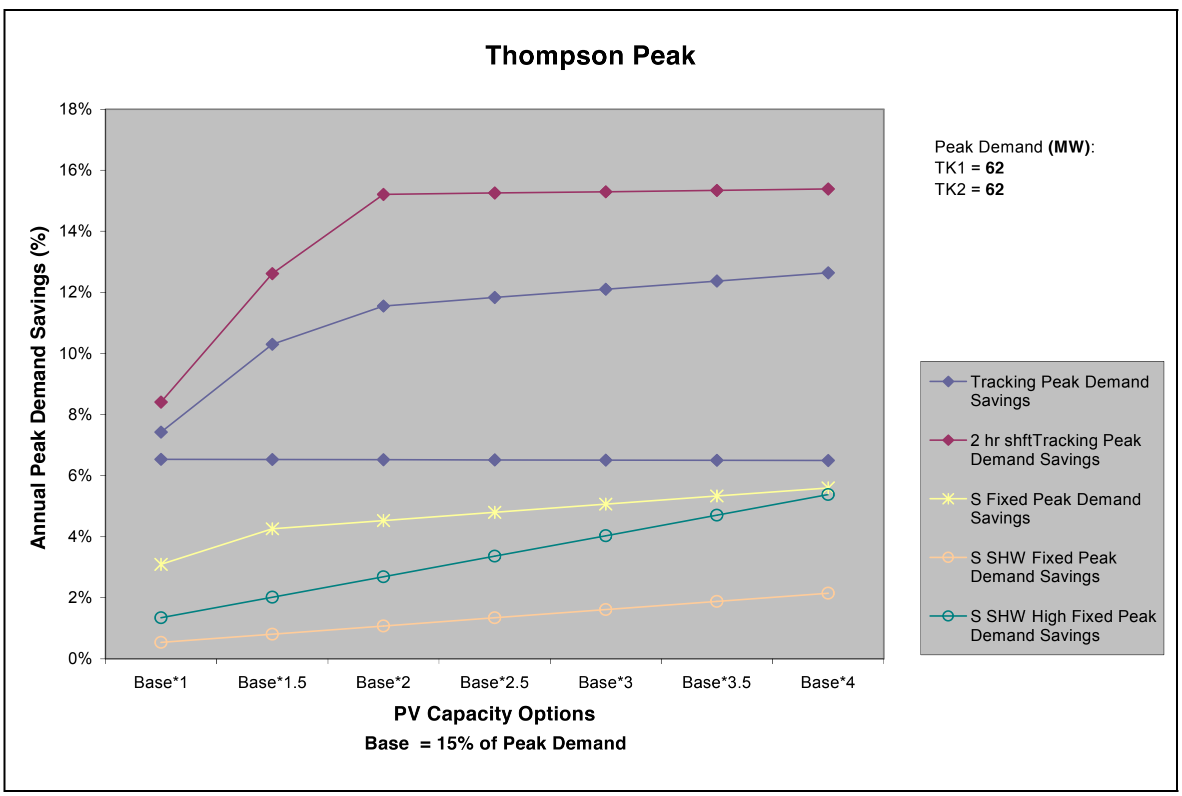


Figure L-75. DE Impact w/ Storage (2 hr shift) Annual Energy Savings

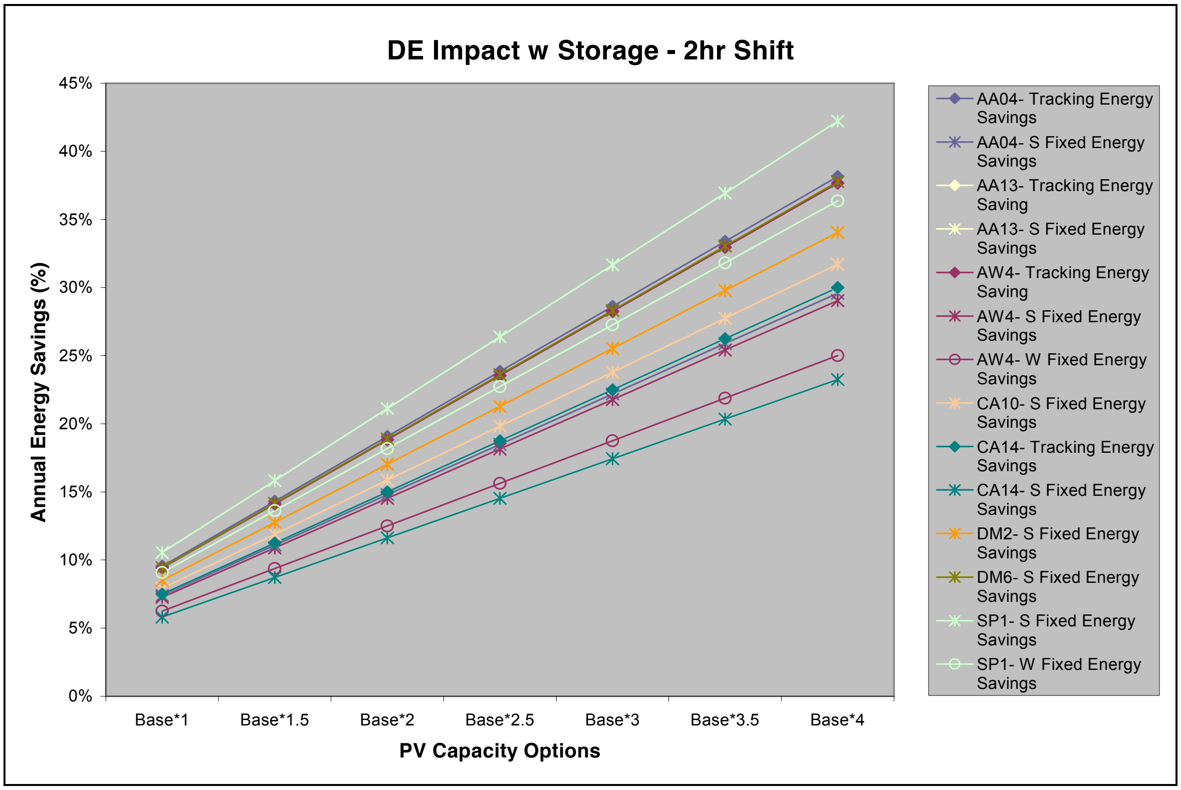


Figure L-76. DE Impact w/ Storage (2 hr shift) Annual Peak Demand Savings

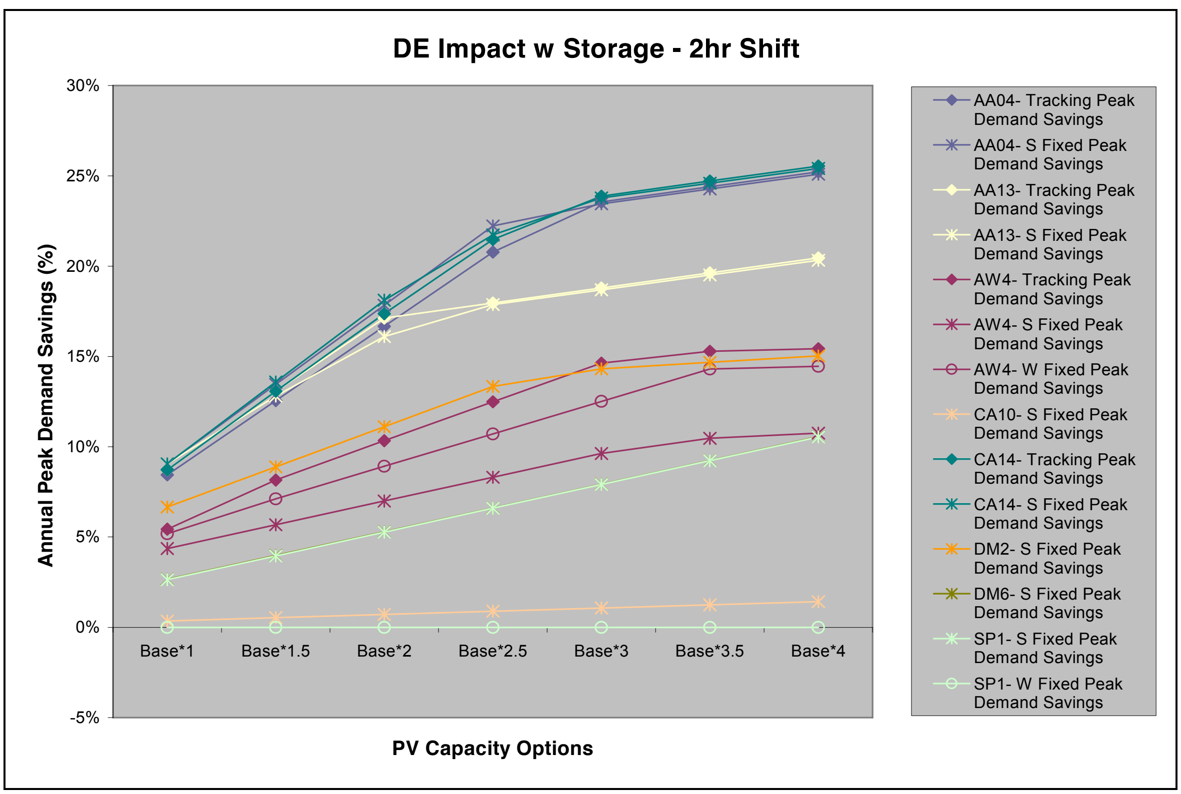


Figure L-77. DE Impact w/ Storage (4 hr shift) Annual Energy Savings

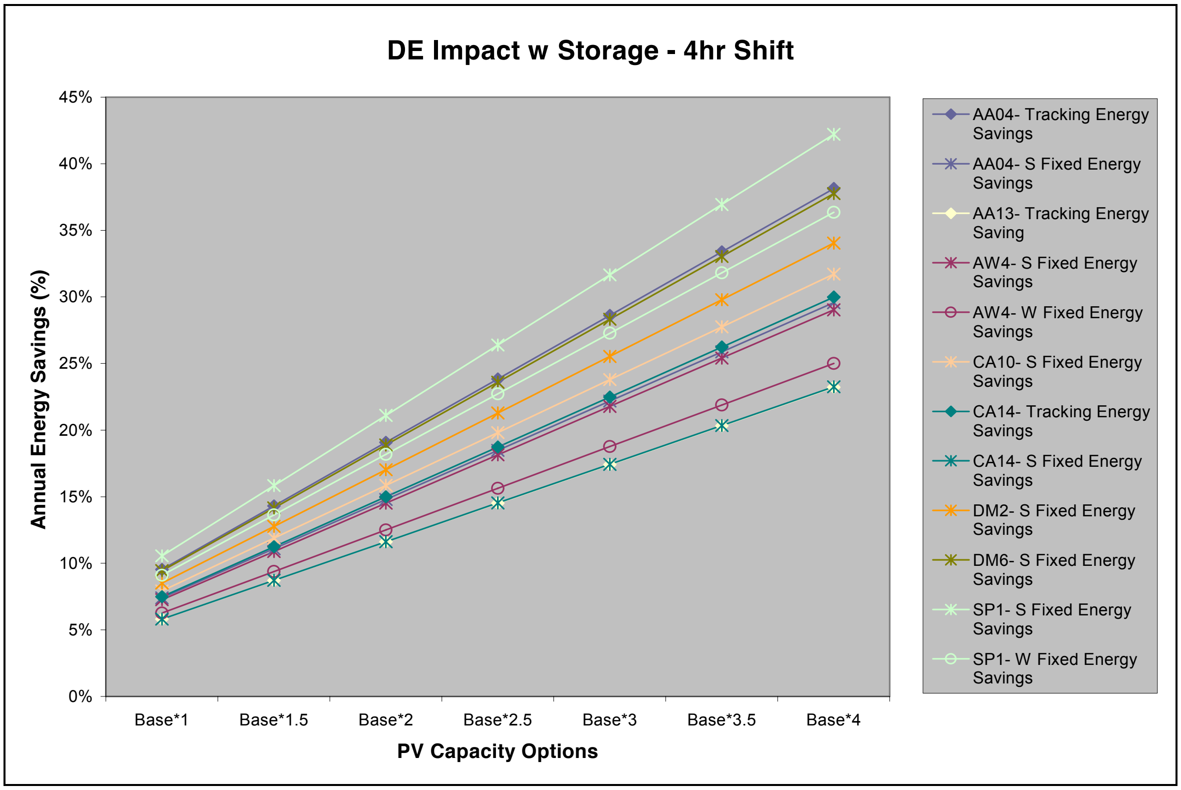
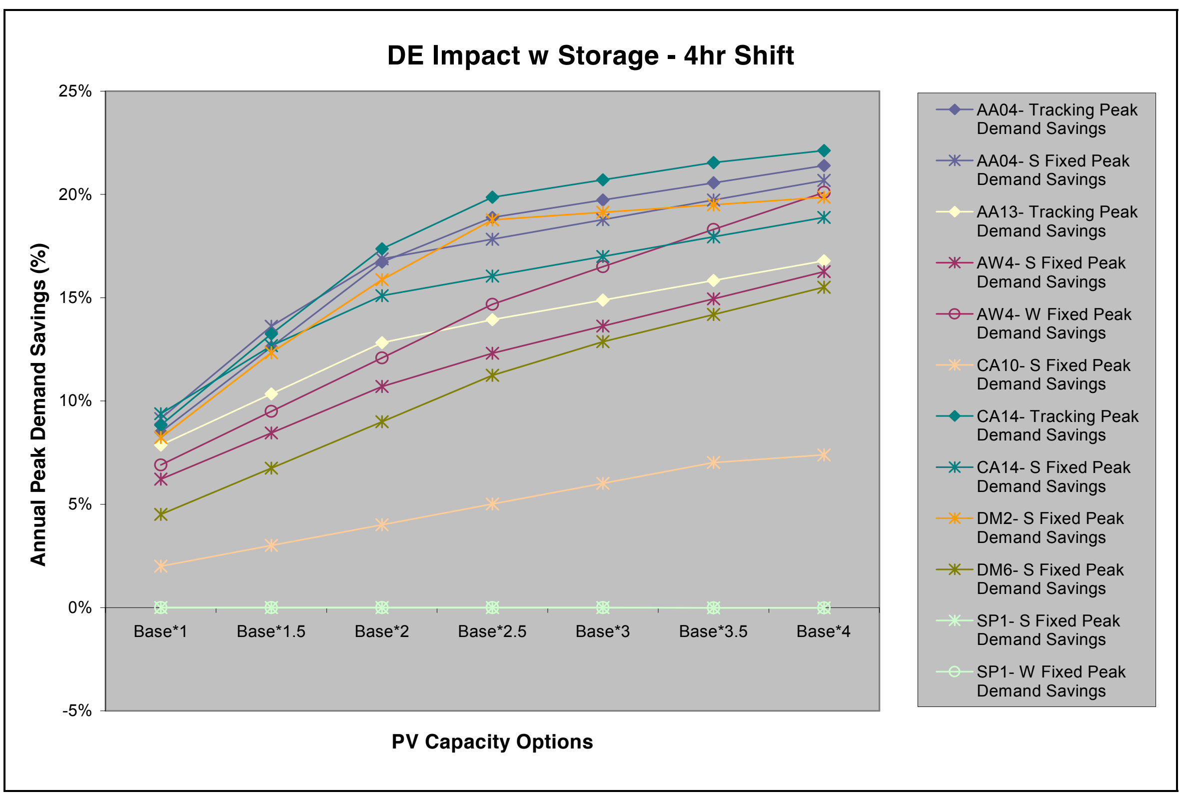


Figure L-78. DE Impact w/ Storage (4 hr shift) Annual Peak Demand Savings



APPENDIX M — EMPIRICAL TESTING RESULTS

M.1 Results

Following is the output from the test equipment used in the field test at the Prescott Airport solar plant. In addition, the test equipment settings and parameters are included at the end of this appendix.

Figure M-1. RMS Voltage and Current for 15-Minute Period Prior to Test

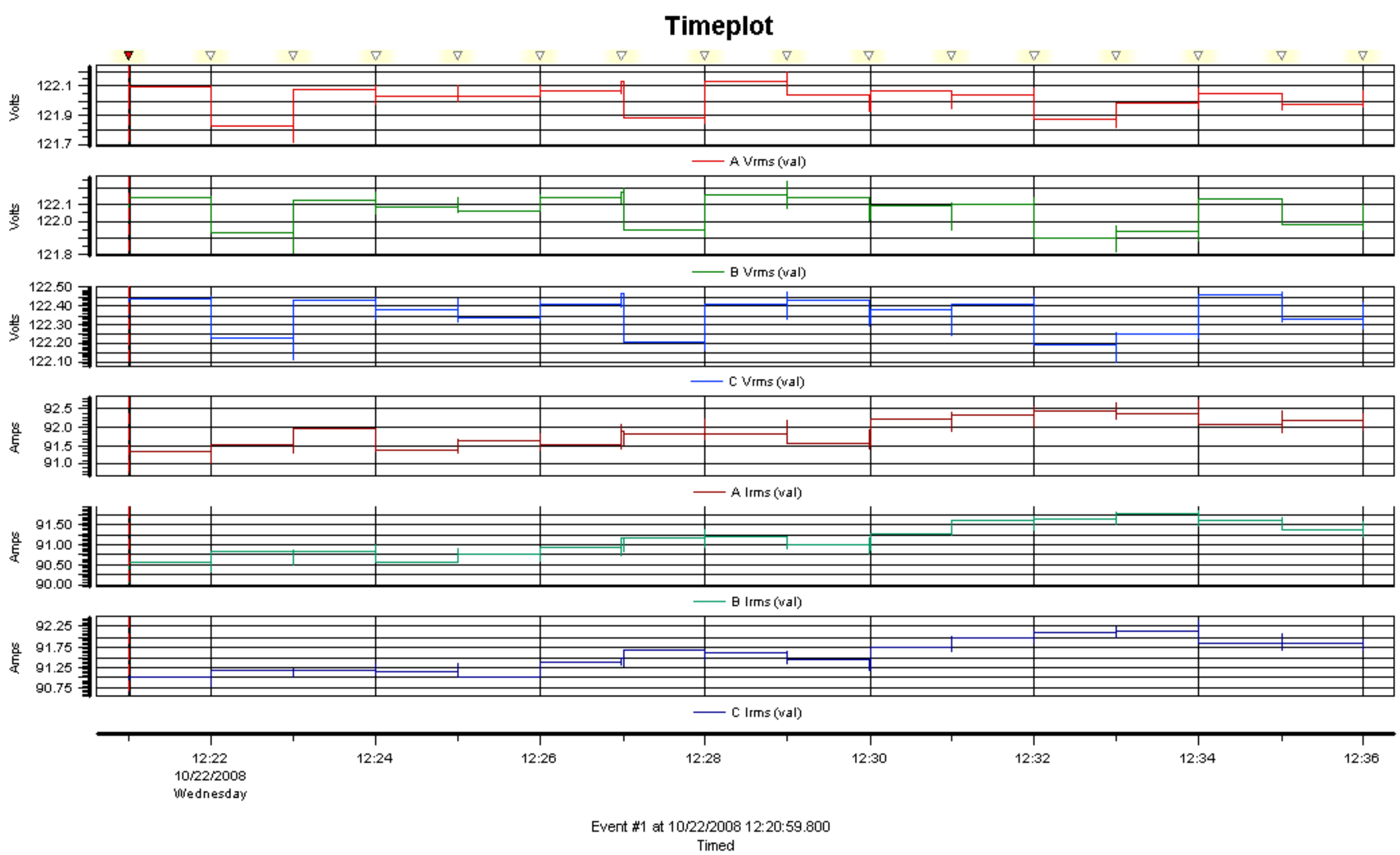


Figure M-2. Power Factor

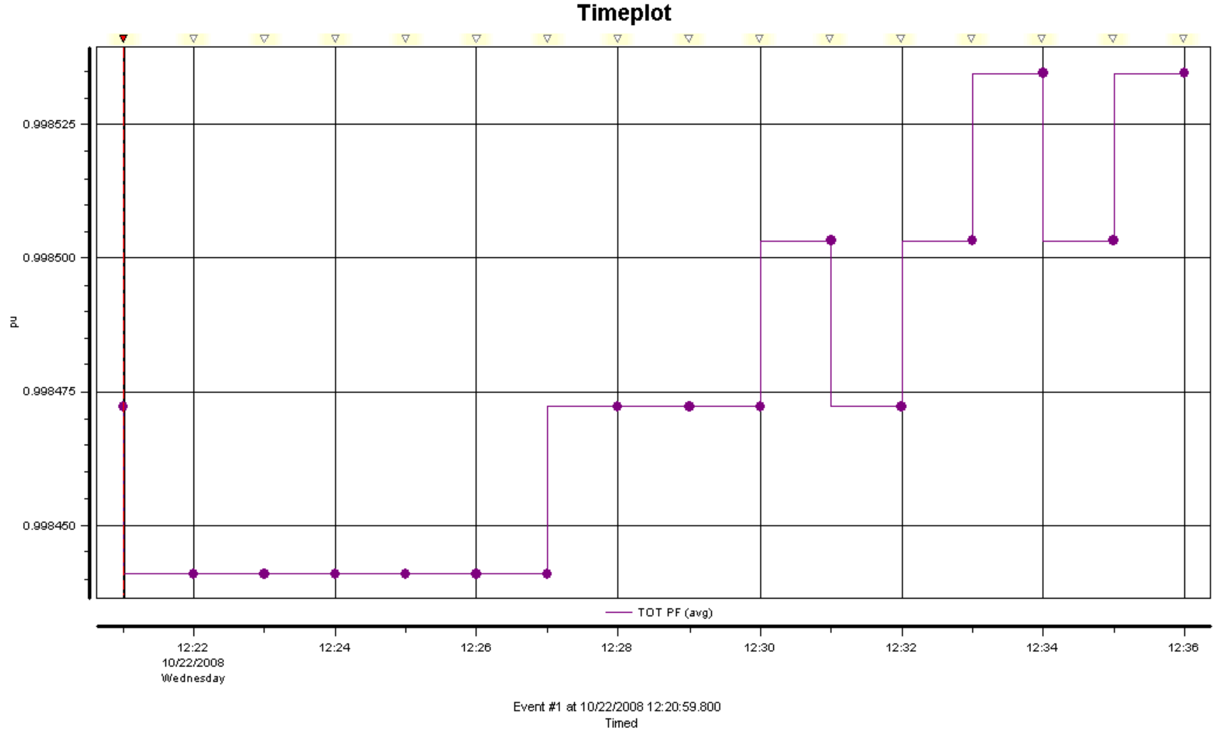


Figure M-3. Voltage and Current Phasors

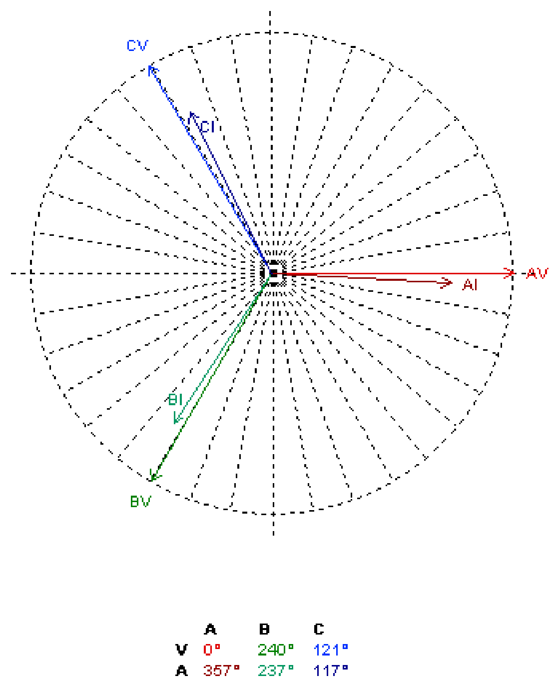


Figure M-4. V THD and I THD During 15-Minute Monitoring Period

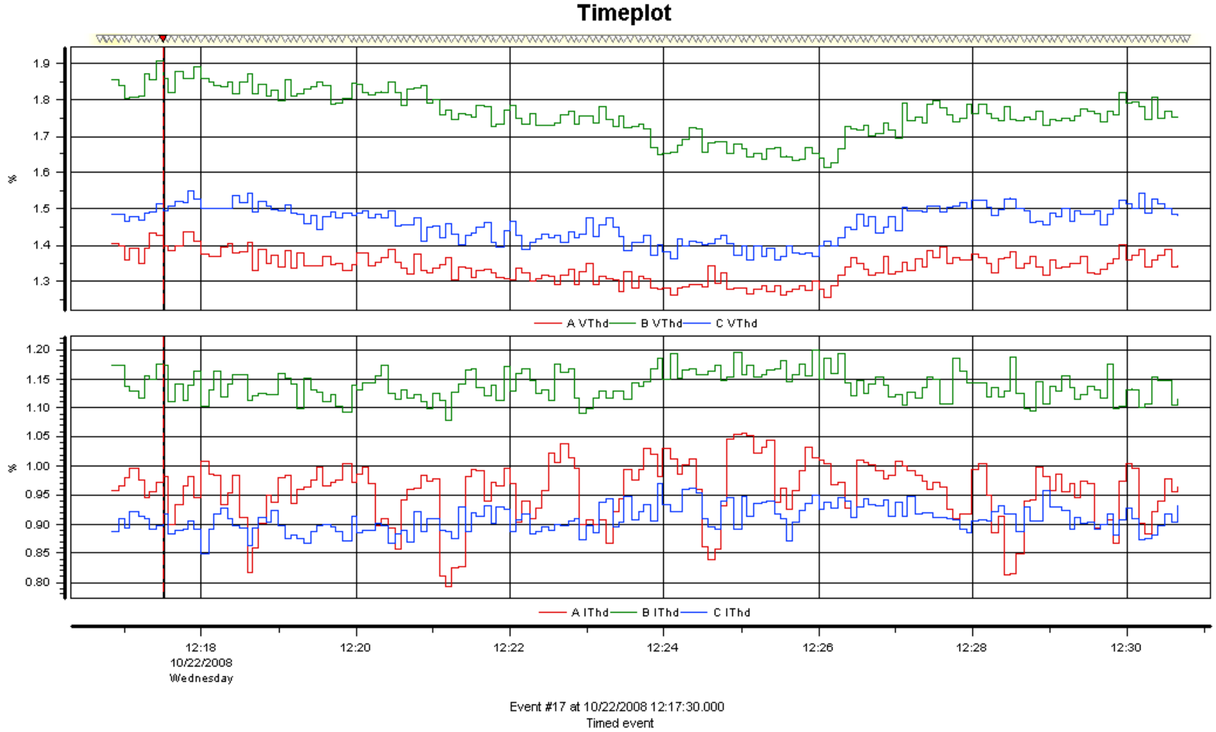
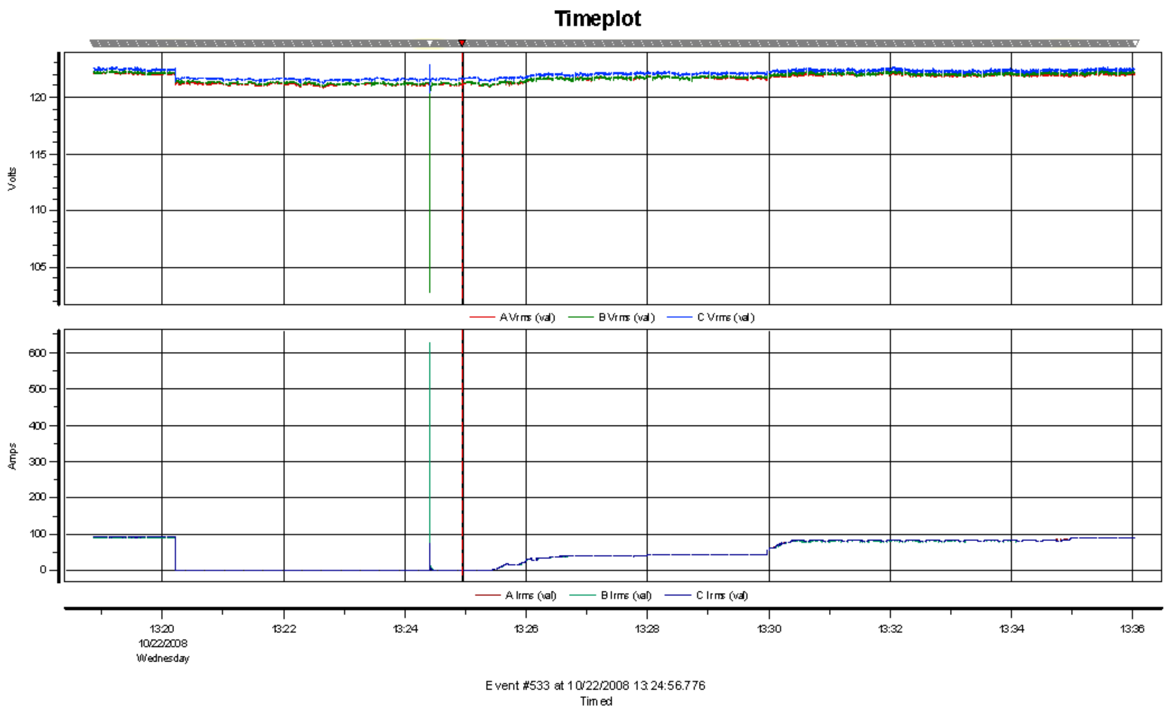


Table M-1
Data Points for Harmonics for Voltage and Current for One Cycle
Event #17 at 10/22/2008 12:17:30.000

X-Data	AVHarm Value [%]	BVHarm Value[%]	CVHarm Value[%]	AIHarm Value[%]	BIHarm Value[%]	CIHarm Value[%]
THD	1.8717	2.1757	1.6947	1.5157	1.2654	1,2699
60	100	100	100	100	100	100
120	1.0606	0.6807	0.6799	0.9506	0.26228	0.4692
180	0.30436	0.657	0.8973	0.6295	0.3602	0.7722
240	0.396	0.2537	0.3041	0.3731	0.5384	0.27523
300	1.3025	1.5303	0.9796	0.22615	0.5788	0.23633
360	0.27331	0.23006	0.16163	0.23679	0.3319	0.18074
420	0.16511	0.9685	0.6416	0.5439	0.6297	0.6474
480	0.22597	0.02241	0.03432	0.20536	0.07819	0.10339
540	0.22705	0.5698	0.18713	0.20215	0.09018	0.1858
600	0.15476	0.10775	0.07805	0.16144	0.09853	0.10852
660	0.12235	0.09961	0.05075	0.14004	0.20275	0.05323
720	0.12208	0.07388	0.0649	0.14338	0.12307	0.09847
780	0.18179	0.12607	0.10989	0.08051	0.10651	0.032
840	0.11457	0.05261	0.06234	0.08556	0.05392	0.03279
900	0.08419	0.07195	0.08496	0.19336	0.12448	0.0694
960	0.08496	0.05878	0.0475	0.148	0.10126	0.10078
1020	0.08325	0.05496	0.026131	0.008539	0.06674	0.09155
1080	0.08212	0.06104	0.03381	0.12298	0.1356	0.03613
1140	0.04252	0.04586	0.020581	0.24306	0.21451	0.21282
1200	0.09255	0.05663	0.05261	0.05879	0.024146	0.05407
1260	0.09134	0.05647	0.05262	0.09967	0.09186	0.10892
1320	0.08587	0.05454	0.007486	0.09444	0.02198	0.09152
1380	0.04582	0.026971	0.04408	0.13159	0.12871	0.03574
1440	0.08172	0.04529	0.03512	0.025669	0.05222	0.026862
1500	0.0649	0.04681	0.03542	0.07894	0.021807	0.11925

Figure M-5. RMS Voltage and Current Before, During, and After Main Breaker (see one-line breaker VV461208) Between PV Site and Distribution System Was Opened



Note: Breaker opened at: 13:20:13; Breaker closed at: 13:24:24

Figure M-6. Zoomed Plot of RMS Voltage and Current at Breaker Opening

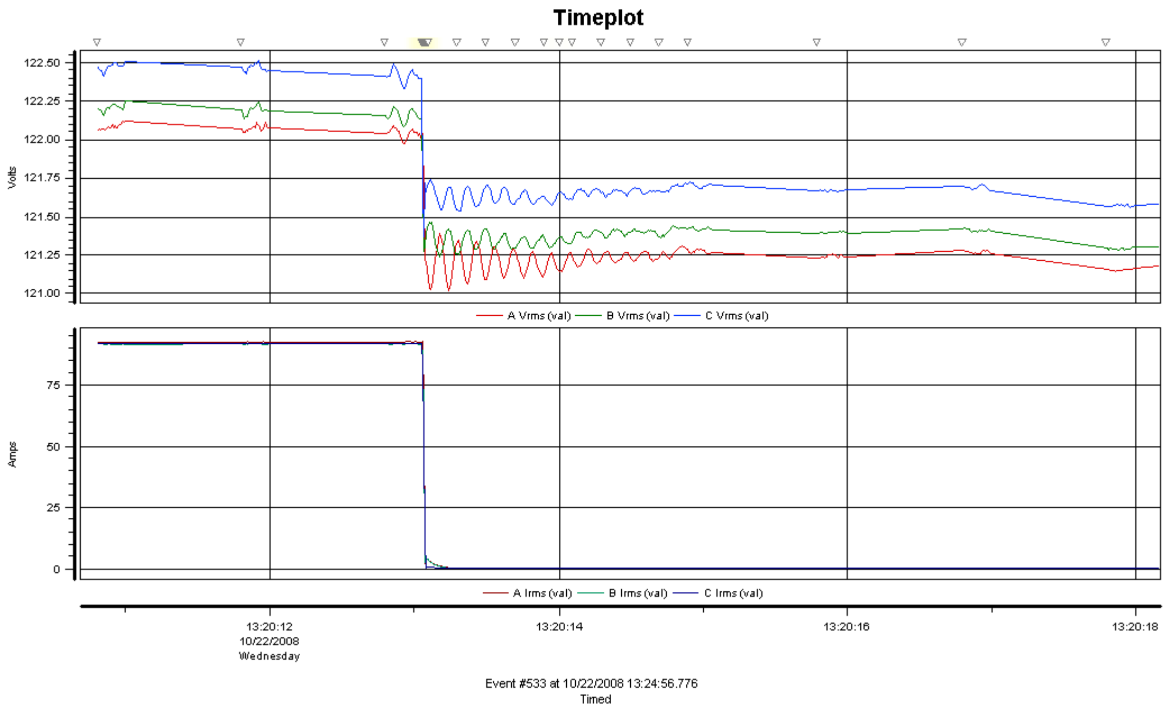


Figure M-7. Zoomed Plot of Cyclic Voltage and Current at Breaker Opening

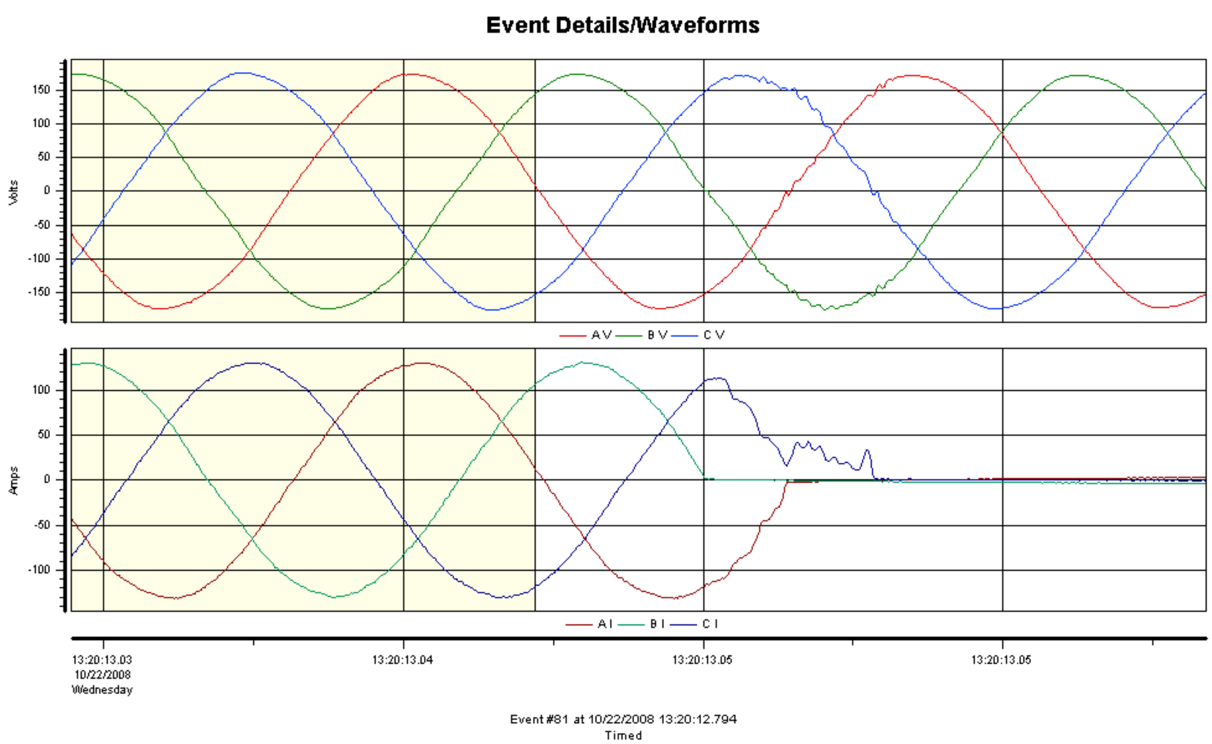


Figure M-8. Zoomed Plot of RMS Voltage and Current at Breaker Closing

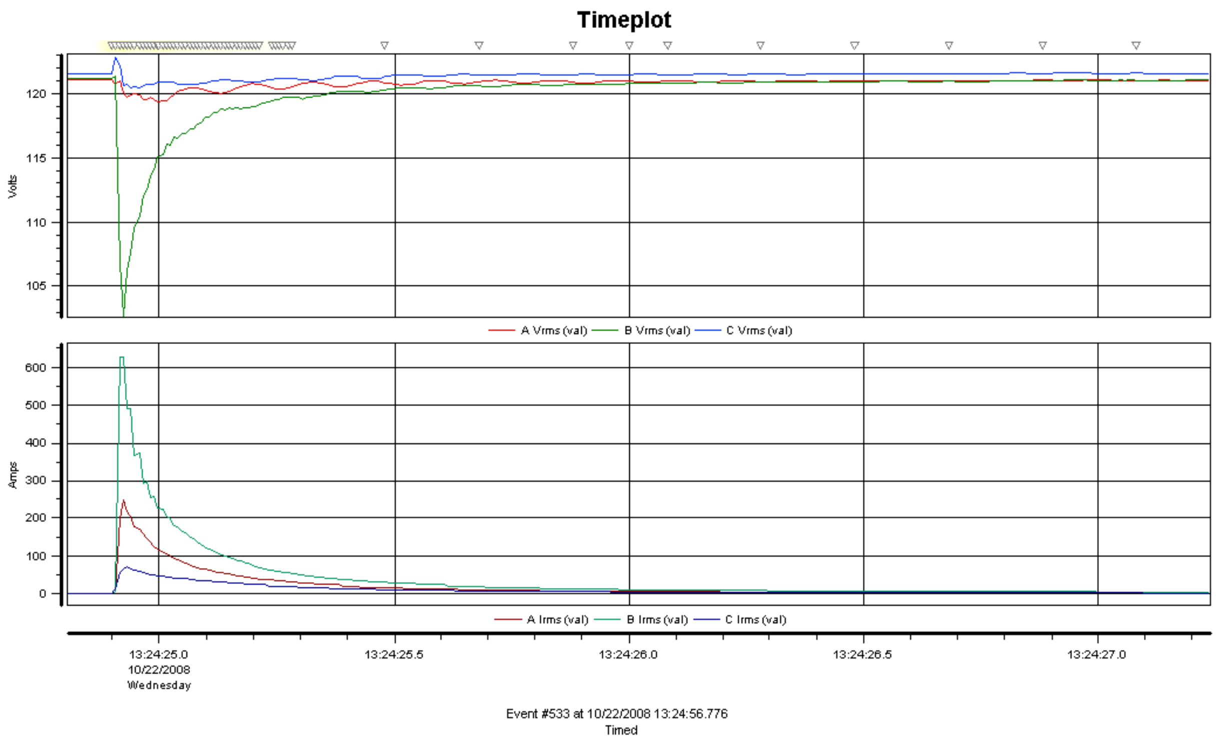


Figure M-9. Zoomed Plot of Cyclic Voltage and Current at Breaker Closing

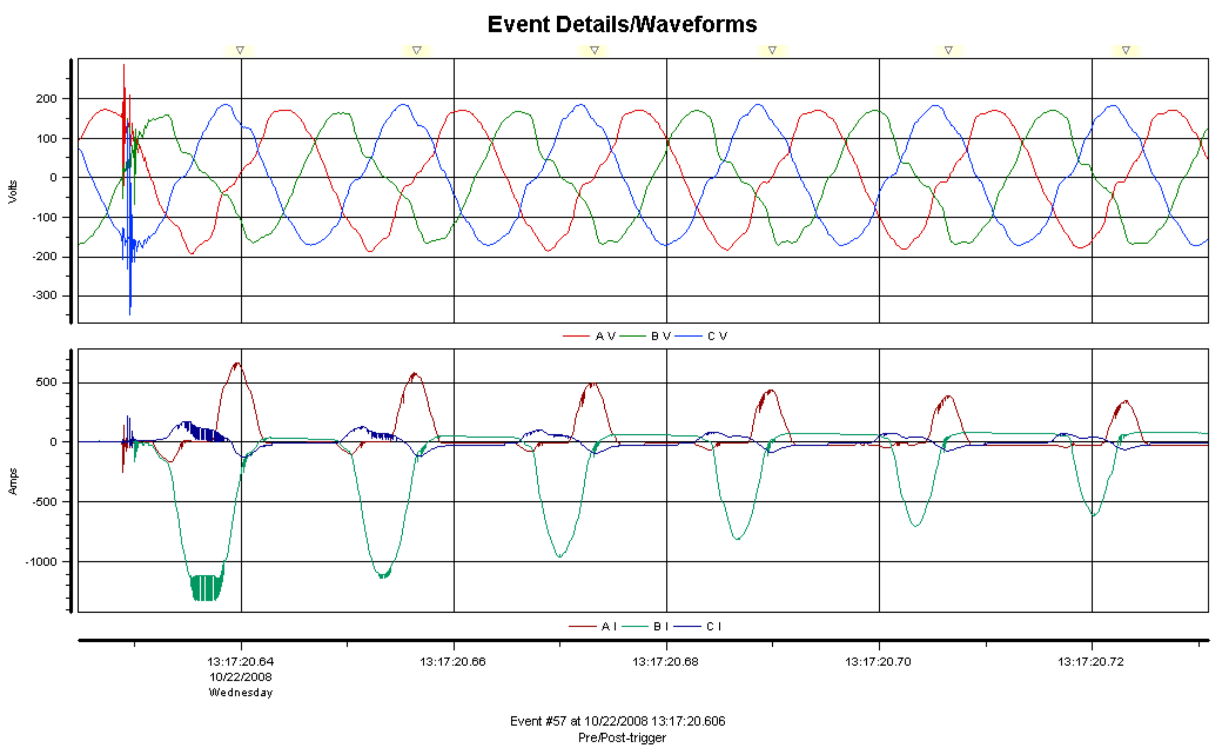
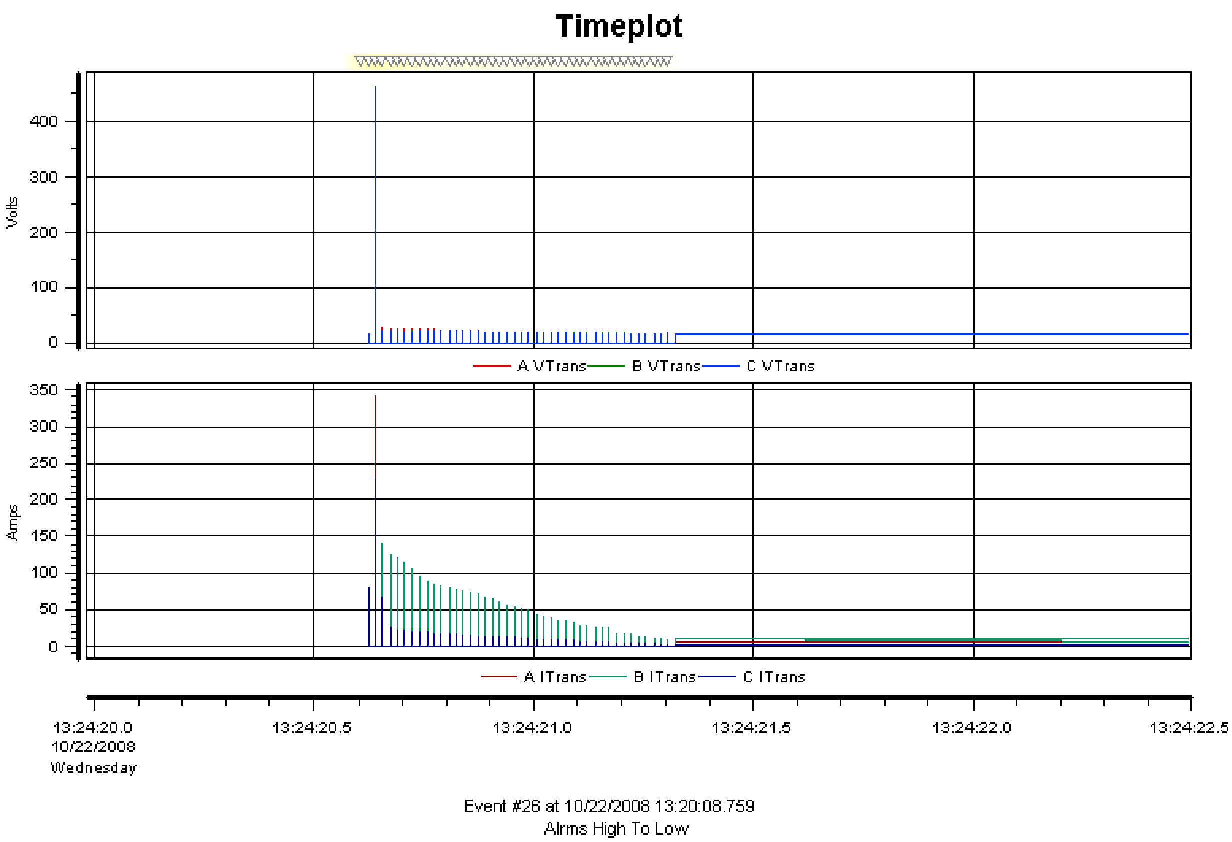


Figure M-10. Plot of Transients During Closing



Note: No triggered transients measured when opening.

M.2 Setup of PP1 Instrument

M.2.1 Dranetz-BMI PP1 PQPlus TASKCard Configuration

- Effective from 10/22/2008 13:14:19
- Instrument ID: MODEL PQPLUS
- Database ID: bV3.20
- Site ID: PRST PV

Memory Configuration

- Memory card auto transfer: ON
- Memory type: OVERWRITE

Timed Readings

- Interval: 5 seconds

Analog Input Configuration

- Input configuration: 4 WIRE / 3 PROBE
- Enabled channels: AV,BV,CV,AI,BI,CI,
- Channel D: OFF
- Frequency: 60.0
- Frequency sync. Mode: EXTERNAL

Table M-2

	AV	BV	CV	DV	AI	BI	CI	DI
Internal	0.603392	0.606388	0.605400	0.605007	0.013766	0.013902	0.014298	0.000000
Scale	1.000000	1.000000	1.000000	1.000000	40.000000	40.000000	40.000000	10.000000
Final K-factor	0.603392	0.606388	0.605400	0.605007	0.550658	0.556091	0.571910	0.000000
Final Peak K-factor	3.010923	3.023147	3.016721	3.014466	0.651848	0.651891	0.651948	0.000000

Threshold Configuration

- Active setup: 4
- Name of setup: 3-PHASE WYE 120 VOLT
- V harmonic number: 3

- I harmonic number: 3
- Easy start nominal voltage: 120.000
- Easy start nominal current: 30.000
- Easy start percent tolerance: 0.000
- Monitor current: ON

Table M-3

	A	B	C	D	Wave Capture
V High RMS limit	127.0	127.0	127.0	5.0	ON_ALL
V Low RMS limit	114.0	114.0	114.0	0.0	ON_ALL
V Transient magnitude	50.0	50.0	50.0	25.0	ON_ALL
V THD percent limit	5.0	5.0	5.0	OFF	OFF
V Freq. sensitivity	OFF	OFF	OFF	OFF	OFF
I High RMS limit	150.0	150.0	150.0	OFF	ON_ALL
I Low RMS limit	80.0	80.0	80.0	OFF	ON_TRIG
I Peak limit	200.0	200.0	200.0	OFF	ON_ALL
I THD percent limit	OFF	OFF	OFF	OFF	OFF
I Transient magnitude	400.0	400.0	400.0	OFF	ON_ALL
Watts High limit	OFF	OFF	OFF	OFF	OFF
VA High limit	OFF	OFF	OFF	OFF	OFF
VAR High limit	OFF	OFF	OFF	OFF	OFF
PF Low limit	OFF	OFF	OFF	OFF	OFF
V Sens out limit	3.0	3.0	3.0	2.0	ON_ALL
V Sens in limit	3.0	3.0	3.0	OFF	ON_ALL
I Sens out limit	10.0	10.0	10.0	OFF	ON_ALL
I Sens in limit	10.0	10.0	10.0	OFF	ON_ALL
V Trans percent Sens	OFF	OFF	OFF	150.0	OFF
I Trans percent Sens	OFF	OFF	OFF	150.0	OFF
V Harmonic percent	OFF	OFF	OFF	OFF	OFF
I Harmonic percent	OFF	OFF	OFF	OFF	OFF

Table M-4
Instrument PQ Config

	AV	BV	CV	DV
RMS hysteresis (V)	5.0	5.0	5.0	5.0
Sag/swell timeout (ms)	30000	30000	30000	30000
Rel imp. cycles timeout (ms)	10	10	10	10
Rel cycles ret. to normal timeout (ms)	2	2	2	2
Peak imp. cycles timeout (ms)	10	10	10	10
Peak cycles ret. to normal timeout (ms)	2	2	2	2
Crest hysteresis (V)	0.5	0.5	0.5	0.5
Period hysteresis (V)	0.5	0.5	0.5	0.5

Table M-5
Instrument PQ Config

	AV	BV	CV	DV
RMS hysteresis (A)	5.0	5.0	5.0	5.0
Sag/swell timeout (ms)	65535	65535	65535	65535
Rel imp. cycles timeout (ms)	10	10	10	10
Rel cycles ret. to normal timeout (ms)	2	2	2	2
Peak imp. cycles timeout (ms)	10	10	10	10
Peak cycles ret. to normal timeout (ms)	2	2	2	2
Crest hysteresis (A)	0.5	0.5	0.5	0.5
Period hysteresis (A)	0.5	0.5	0.5	0.5

M.2.2 Dranetz-BMI Power Xplorer Configuration

- Firmware: Power Xplorer (c) 1998-2003 Dranetz-BMI
  - Nov 08 2007 @ 17:00:05
  - Ver.: V 2.7, Build: 0, DB ver.: 0
  - Serial Number PX50AB41
- Site/Filename: prescott pv
- Measured from: 10/22/2008 13:18:52
- Measured to: 10/22/2008 13:35:43

- File ending: Bad
- Synchronization Standard A
- Configuration: 4 WIRE / 3 PROBE (WYE)
- Monitoring type STANDARD PQ
- Nominal voltage: 120.0 V
- Nominal current: 91.4 A
- Nominal frequency: 60.0 Hz
- Use inverse sequence: No
- Using currents: Yes
- Characterizer mode: IEEE 1159

Current Probes

- Chan A TR2520, 300A-3000A RMS (Scale=6.67)
- Chan B TR2520, 300A-3000A RMS (Scale=6.67)
- Chan C TR2520, 300A-3000A RMS (Scale=6.67)
- Chan D LEMFlex RR3000-SD (Range1), 300A (Scale=666.67)

Voltage Scale Factors

- Chan A 1.000
- Chan B 1.000
- Chan C 1.000
- Chan D 1.000

Current scale factors

- Chan A 40.000
- Chan B 40.000
- Chan C 40.000
- Chan D 1.000

Trigger Response Setups

- Summary Pre-trigger cycles: 12 cycles
- Summary Post-trigger cycles IN-TO-OUT: 120 cycles
- Summary Post-trigger cycles OUT-TO-IN: 60 cycles
- Waveform Pre-trigger cycles: 12 cycles
- Waveform Post-trigger cycles: 60 cycles

Table M-6
Saved waveforms

Trigger-channel	Va	Vb	Vc	Vd	Ia	Ib	Ic	Id	AB	BC	CA
Volts A	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Volts B	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Volts C	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Volts D	-	-	-	-	-	-	-	-	-	-	-
Amps A	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Amps B	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Amps C	Va	Vb	Vc	-	Ia	Ib	Ic	-	-	-	-
Amps D	-	-	-	-	-	-	-	-	-	-	-
Volts A-B	-	-	-	-	-	-	-	-	-	-	-
Volts B-C	-	-	-	-	-	-	-	-	-	-	-
Volts C-A	-	-	-	-	-	-	-	-	-	-	-

Timed Waveform savings every: 1 seconds
After recording: REARM

Table M-7
Limit Setups

Voltages

	A	B	C	D	A-B	B-C	C-A
RMS High	132.0	132.0	132.0	0.0	0.0	0.0	0.0
RMS Low	118.0	108.0	108.0	0.0	0.0	0.0	0.0
RMS Very Low	12.0	12.0	12.0	0.0	0.0	0.0	0.0
Crest	255.0	255.0	255.0	0.0	0.0	0.0	0.0
Wave	5.0	5.0	5.0	0.0	0.0	0.0	0.0
DC	0.0	0.0	0.0	0.0	0.0	0.0	0.0
DEG	0.0	0.0	0.0	0.0	0.0	0.0	0.0
WAVE Window Mag	5.0	5.0	5.0	0.0	0.0	0.0	0.0
WAVE Window Dur	5.0	15.0	15.0	0.0	0.0	0.0	0.0
HF	200.0	200.0	200.0	0.0	0.0	0.0	0.0

Table M-8
Currents

	A	B	C	D
RMS High	95.0	95.0	95.0	0.0
RMS Low	85.0	85.0	85.0	0.0
RMS Very Low	0.0	0.0	0.0	0.0
Crest	160.0	160.0	160.0	0.0
Wave	10.0	10.0	10.0	0.0
DC	0.0	0.0	0.0	0.0
(null)	0.0	0.0	0.0	0.0
WAVE Window Mag	10.0	10.0	10.0	0.0
WAVE Window Dur	5.0	5.0	5.0	0.0
HF	200.0	200.0	200.0	0.0

Periodic Journal Intervals

- Voltage: 1 seconds
- Current: 1 seconds
- Power: 1 seconds
- Harmonics: 10.0 minutes
- Demand: 5.0 minutes, Subintervals/Intervals: 3

- Energy: 10.0 minutes
- Inst. Flicker: 10.0 minutes
- Short term flicker: 10.0 minutes
- Long term flicker: 120.0 minutes
- EN50160 compliance: 10.0 minutes

Appendix N

Evaluation of Economic Value of Solar DE Deployment

APPENDIX N — EVALUATION OF ECONOMIC VALUE OF SOLAR DE DEPLOYMENT

N.1 Introduction

In this study, economic value is defined to be the present value of future energy and capacity savings on the Arizona Public Service (APS) system resulting from solar DE deployment. To estimate the economic value, a revenue requirement based methodology was used consistent with the TAG™ Technical Assessment Guide developed by the Electric Power Research Institute (EPRI)[1]. The revenue requirements approach represents all elements of a utility's cost of service, including typical energy related costs (such as fuel and purchased power expenses, operating and maintenance (O&M) expenses, property taxes, etc.) and the various elements of investment and capital cost recovery (e.g. depreciation expense, interest income, net income, etc.) associated with capacity reductions. It is the present value of reduced or avoided future energy and capacity costs resulting from solar DE deployment that is used as the current economic value of these solar DE deployment levels. Such a framework provides estimates for the economic value represented by the costs APS would need to incur in future years without solar DE deployment. This framework parallels the analytical methodology APS uses to evaluate the economic costs and values of alternative supply side and other resource options.

N.2 Economic Value of Energy Savings from Solar DE Deployment

Energy savings are relatively straight forward to estimate as these are the annual avoided or reduced fuel and purchased power costs and related O&M expenses. These savings typically occur in each year and are associated with the cost reduction of energy for APS. In this study, energy savings from solar DE deployment are estimated for each test year reviewed in the study from the reduced or avoided costs estimated in 2008 dollars. In equation form this can be expressed as follows:

$$E_t = F_t + PP_t + O\&M_t$$

where E_t = APS' projected fuel expense in year t, in 2008$

F_t = APS' projected purchased power expense in year t, in 2008$

PP_t = APS' projected purchased power expense in year t, in 2008$

$O\&M_t$ = APS' projected O&M expense in year t, in 2008$

[1] TAG™ Technical Assessment Guide, EPRI TR-100281, Volume 3: Rev. 6, December 1991, Sections 5 and 8.

N.3 Economic Value of Capacity Savings from Solar DE Deployment

Capacity savings are more difficult and complicated to estimate as these savings represent an annual portion of avoided or reduced investment or capital costs in future test years. This includes the savings from an investment change in a specific year plus remaining investment savings from prior years.

Engineering economic analysis often represents these savings with the use of a carrying charge approach. Carrying charges are utility annual obligations associated with distribution, transmission, and generation plant investments placed in service and include annual obligations from prior plant investments during the economic life of investments. To accurately represent a utility's projected investment costs, the income taxes (both actual and deferred) must be included in the identification of carrying charges. Separate carrying charges are calculated for distribution, transmission, and generation facilities as these typically have different economic lives. The appropriate carrying charge for a facility is multiplied by the investment cost of the plant facility to estimate the annual revenue requirement cost of that plant facility.

In equation form the carrying charge can be expressed as follows:

$$CC_{tf} = DC_t + EC_t + IT_{tf} + CF_{tf}$$

where CC_{tf} = Carrying Charge for each facility type in year t, expressed as a percentage

DC_t = APS' debt cost in year t, expressed as a percentage

EC_t = APS' after tax equity cost in year t, expressed as a percentage

IT_{tf} = APS' effective income tax cost for each facility type f in year t, expressed as a percentage

CF_{tf} = APS' capital recovery via depreciation rate for each facility type f in year t, expressed as a percentage

Components of the carrying charge calculation can be expressed as follows:

$$DC_f = DB * COD$$

where DB = Percent of capitalization provided by debt, expressed as a percentage

COD = APS' cost of debt cost, expressed as a percentage

$$EC_f = EB * COE$$

where EB = Percent of capitalization provided by equity, expressed as a percentage

COE = APS' cost of debt equity on an after-tax basis, expressed as a percentage

It is the product of the carrying charge for a specific facility type (i.e., distribution, transmission, or generation) times the investment cost of a facility that provides an estimate of the annual investment or capacity cost saving associated with each facility that is made not necessary for APS to develop as the result of solar DE deployment.

For this study, the impacts of solar DE deployment were examined in three future test year periods—2010, 2015, and 2025. Because it was difficult to identify the specific year of capital deferrals or avoided capital investments identified in each year, specifically for distribution capacity savings, a levelized carrying charge was used in the analysis. This levelized carrying charge represented the average net present value of all carrying charges for each business sector calculated over the useful life of the relevant business sector technology. The specific number of years for APS' distribution, transmission, and generation business sectors are shown on the following pages, and are consistent with the average straight line deprecation used by APS for each business sector.

N.4 Present Value Calculation

After the total annual savings associated with solar DE deployment was calculated in 2008 dollars by adding together the capacity savings for each business sector along with the energy savings and reduced O&M costs in each test year period, the present value as of 2008 was also calculated. The present value factor used in these calculations can be expressed as follows:

$$PVF_t = 1 \div ((1 + RDR) \wedge t)$$

where PVF_t = Present value factor to discount t, years, expressed as a fraction

RDR = APS' real (inflation-adjusted) discount rate, estimated by the weighted cost of capital reduced by the inflation rate assumption.

N.5 Specific Calculations of Levelized Carrying Charges

The levelized carrying charges for APS used in this study, along with the underlying APS specific financial information and assumptions, and a graphic summary of annual and levelized carrying charges by APS business sector are provided on the following 5 pages.

	Weighted Cost of Capital			Tax Adjusted
	Cost (%)	Capital Structure (%)	Weighted Cost (%)	Before Tax Cost (%)
Cost of Capital Component				
DC -- Debt Cost	7.25	45.5	3.30	3.30
EC -- Equity Cost	10.75	54.5	5.86	9.66
ATR -- Average Tax Rate	39.36			
WCOC(g) -- Weighted Average After Tax COC				12.96
IRP -- Inflation Rate Premium				2.50
RWCOC -- Inflation-adjusted Weighted Average After Tax COC				10.20

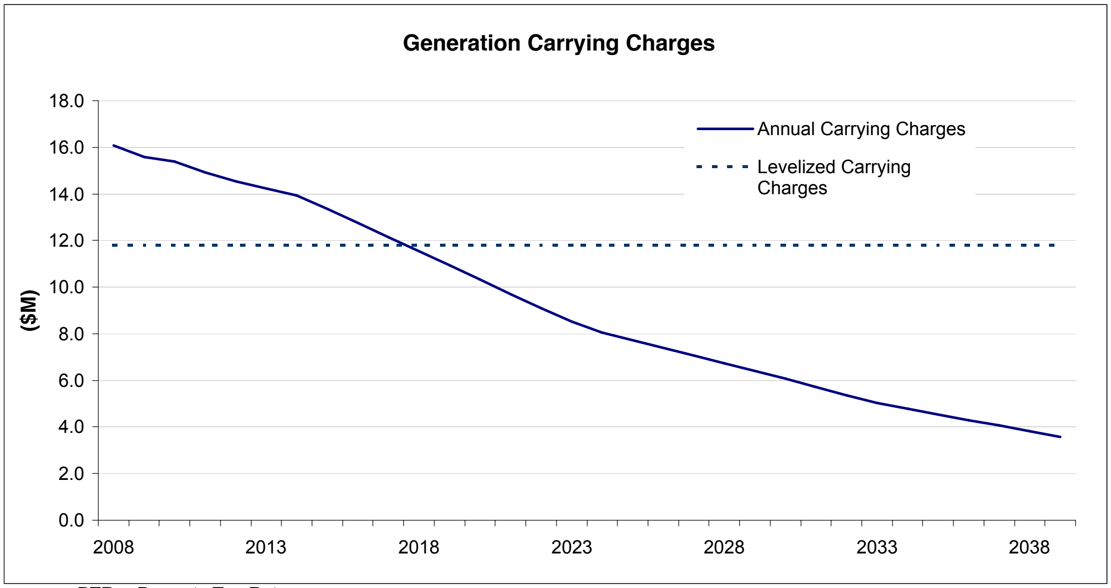
Capital Recovery Factor / Depreciation Component	Average Plant Lives	Average Depreciation Rates (%)
CF(g) -- Generation	32	3.13
CF(t) -- Transmission	50	2.00
CF(d) -- Distribution	40	2.50

Other Factors	Rates (%)
PTR -- Property Tax Rate	Calculated
AIR -- Average Insurance Rate	Neglible
IT -- Accumulated Deferred Income Tax	Calculated

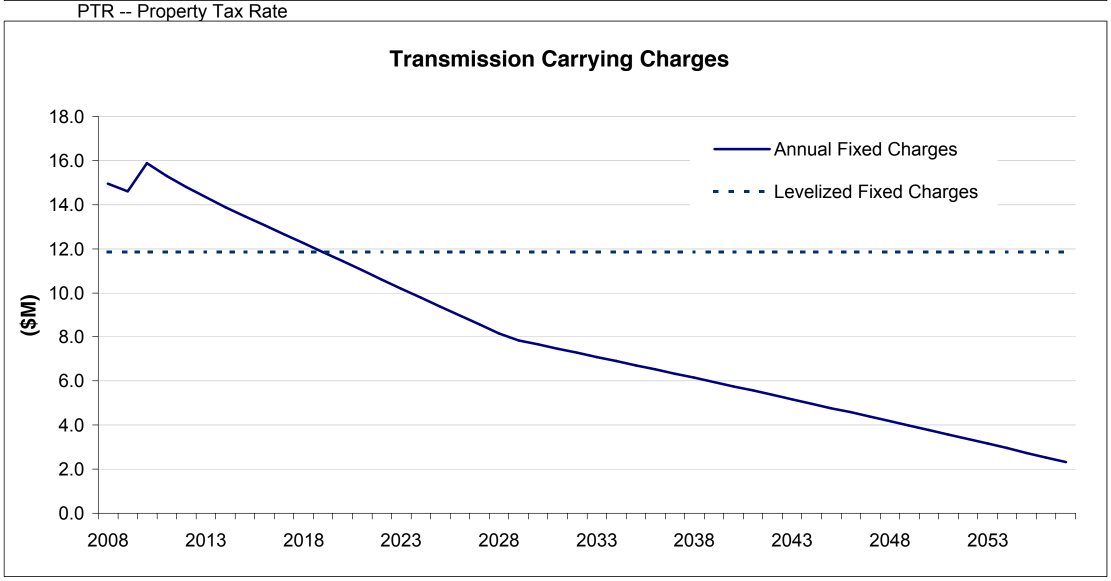
Levelized Capital Carrying Charges	(%)
CC(g) -- Generation	11.79
CC(t) -- Transmission	11.84
CC(d) -- Distribution	12.06

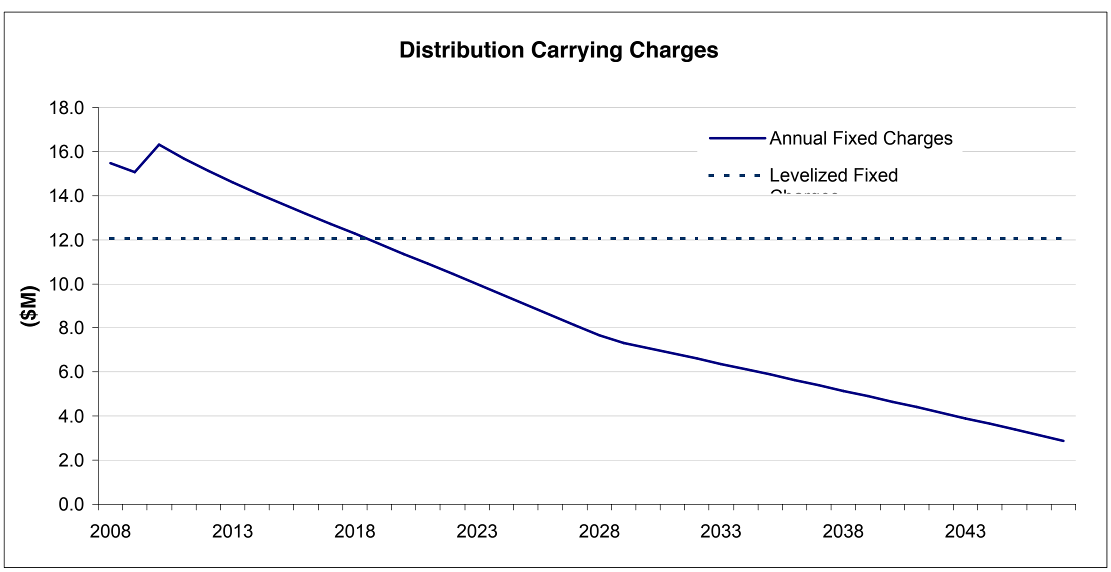
APS Discount Rates	(%)
NDR -- Nominal	7.86
IR -- Inflation Rate	2.50
RDR -- Inflation-adjusted discount rate	5.23

APS Carrying Charges



PTR -- Property Tax Rate





Calculation of APS Carrying Charges and Discount Rates
Page 6

Installed Costs, $M	100
Economic Life, Years	32
MACRS, Years	15
Installation Date	2008

APS Cost of Capital

	Ratio	Cost	WACC Before Tax	WACC After Tax
Debt	45.5%	7.25%	3.30%	2.00%
Equity	54.5%	10.75%	9.66%	5.86%
Total	100.0%		12.96%	7.86%

Annual Inflation Rate	2.50%
Income Tax Rate	39.36%
Discount Rate	7.86%

	Original Costs	Accumulated Book Depreciation	Accumulated Deferred Tax	BOY Rate Base	Return on Rate Base	Book Depreciation	Property Tax	**Annual Carrying Charges**	**Levelized Carrying Charges**
2008	100.0	3.1	0.7	100.0	13.0	3.1	0.0	**16.1**	**11.79**
2009	100.0	6.3	3.2	96.1	12.5	3.1	0.0	**15.6**	**11.79**
2010	100.0	9.4	5.4	90.5	11.7	3.1	0.5	**15.4**	**11.79**
2011	100.0	12.5	7.2	85.2	11.0	3.1	0.8	**14.9**	**11.79**
2012	100.0	15.6	8.7	80.3	10.4	3.1	1.0	**14.5**	**11.79**
2013	100.0	18.8	9.9	75.7	9.8	3.1	1.3	**14.2**	**11.79**
2014	100.0	21.9	11.0	71.3	9.2	3.1	1.6	**13.9**	**11.79**
2015	100.0	25.0	12.1	67.1	8.7	3.1	1.5	**13.4**	**11.79**
2016	100.0	28.1	13.2	62.9	8.2	3.1	1.5	**12.8**	**11.79**
2017	100.0	31.3	14.3	58.7	7.6	3.1	1.4	**12.1**	**11.79**
2018	100.0	34.4	15.4	54.5	7.1	3.1	1.4	**11.6**	**11.79**
2019	100.0	37.5	16.5	50.3	6.5	3.1	1.3	**10.9**	**11.79**
2020	100.0	40.6	17.6	46.0	6.0	3.1	1.2	**10.3**	**11.79**
2021	100.0	43.8	18.7	41.8	5.4	3.1	1.2	**9.7**	**11.79**
2022	100.0	46.9	19.7	37.6	4.9	3.1	1.1	**9.1**	**11.79**
2023	100.0	50.0	19.7	33.4	4.3	3.1	1.1	**8.5**	**11.79**
2024	100.0	53.1	18.5	30.3	3.9	3.1	1.0	**8.1**	**11.79**
2025	100.0	56.3	17.2	28.4	3.7	3.1	0.9	**7.7**	**11.79**
2026	100.0	59.4	16.0	26.5	3.4	3.1	0.8	**7.4**	**11.79**
2027	100.0	62.5	14.8	24.6	3.2	3.1	0.7	**7.1**	**11.79**
2028	100.0	65.6	13.5	22.7	2.9	3.1	0.7	**6.7**	**11.79**
2029	100.0	68.8	12.3	20.8	2.7	3.1	0.6	**6.4**	**11.79**
2030	100.0	71.9	11.1	19.0	2.5	3.1	0.5	**6.1**	**11.79**
2031	100.0	75.0	9.8	17.1	2.2	3.1	0.4	**5.7**	**11.79**
2032	100.0	78.1	8.6	15.2	2.0	3.1	0.3	**5.3**	**11.79**
2033	100.0	81.3	7.4	13.3	1.7	3.1	0.2	**5.0**	**11.79**
2034	100.0	84.4	6.2	11.4	1.5	3.1	0.2	**4.8**	**11.79**
2035	100.0	87.5	4.9	9.5	1.2	3.1	0.2	**4.5**	**11.79**
2036	100.0	90.6	3.7	7.6	1.0	3.1	0.2	**4.3**	**11.79**
2037	100.0	93.8	2.5	5.7	0.7	3.1	0.2	**4.1**	**11.79**
2038	100.0	96.9	1.2	3.8	0.5	3.1	0.2	**3.8**	**11.79**
2039	100.0	100.0	0.0	1.9	0.2	3.1	0.2	**3.6**	**11.79**
2040									
2041									
2042									
2043									
2044									
2045									
2046									
2047									
2048									
2049									
2050									
2051									
2052									
2053									
2054									
2055									
2056									
2057									
			NPV		90.7	36.2	9.8	**136.7**	**136.7**
			Levelized		7.83	3.13	0.84	**11.79**	

Annual Levelized Carrying Charge Rate is: 11.79%

Adapted from analysis received from APS, November 26, 2008.

Installed Costs, $M	100
Economic Life, Years	50
MACRS, Years	20
Installation Date	2008

APS Cost of Capital

	Ratio	Cost	WACC Before Tax	WACC After Tax
Debt	45.5%	7.25%	3.30%	2.00%
Equity	54.5%	10.75%	9.66%	5.86%
Total	100.0%		12.96%	7.86%

Annual Inflation Rate	2.50%
Income Tax Rate	39.36%
Discount Rate	7.86%

	Original Costs	Accumulated Book Depreciation	Accumulated Deferred Tax	BOY Rate Base	Return on Rate Base	Book Depreciation	Property Tax	**Annual Fixed Charges**	**Levelized Fixed Charges**
2008	100.0	2.0	0.7	100.0	13.0	2.0	0.0	**15.0**	**11.84**
2009	100.0	4.0	2.7	97.3	12.6	2.0	0.0	**14.6**	**11.84**
2010	100.0	6.0	4.6	93.3	12.1	2.0	1.8	**15.9**	**11.84**
2011	100.0	8.0	6.2	89.4	11.6	2.0	1.7	**15.3**	**11.84**
2012	100.0	10.0	7.7	85.8	11.1	2.0	1.7	**14.8**	**11.84**
2013	100.0	12.0	9.0	82.3	10.7	2.0	1.7	**14.3**	**11.84**
2014	100.0	14.0	10.1	79.0	10.2	2.0	1.6	**13.9**	**11.84**
2015	100.0	16.0	11.1	75.9	9.8	2.0	1.6	**13.5**	**11.84**
2016	100.0	18.0	12.1	72.9	9.4	2.0	1.6	**13.1**	**11.84**
2017	100.0	20.0	13.0	69.9	9.1	2.0	1.6	**12.6**	**11.84**
2018	100.0	22.0	14.0	67.0	8.7	2.0	1.6	**12.2**	**11.84**
2019	100.0	24.0	15.0	64.0	8.3	2.0	1.5	**11.8**	**11.84**
2020	100.0	26.0	16.0	61.0	7.9	2.0	1.5	**11.4**	**11.84**
2021	100.0	28.0	16.9	58.0	7.5	2.0	1.5	**11.0**	**11.84**
2022	100.0	30.0	17.9	55.1	7.1	2.0	1.5	**10.6**	**11.84**
2023	100.0	32.0	18.9	52.1	6.8	2.0	1.4	**10.2**	**11.84**
2024	100.0	34.0	19.8	49.1	6.4	2.0	1.4	**9.8**	**11.84**
2025	100.0	36.0	20.8	46.2	6.0	2.0	1.4	**9.4**	**11.84**
2026	100.0	38.0	21.8	43.2	5.6	2.0	1.4	**9.0**	**11.84**
2027	100.0	40.0	22.7	40.2	5.2	2.0	1.3	**8.6**	**11.84**
2028	100.0	42.0	22.8	37.3	4.8	2.0	1.3	**8.1**	**11.84**
2029	100.0	44.0	22.0	35.2	4.6	2.0	1.3	**7.8**	**11.84**
2030	100.0	46.0	21.3	34.0	4.4	2.0	1.3	**7.7**	**11.84**
2031	100.0	48.0	20.5	32.7	4.2	2.0	1.2	**7.5**	**11.84**
2032	100.0	50.0	19.7	31.5	4.1	2.0	1.2	**7.3**	**11.84**
2033	100.0	52.0	18.9	30.3	3.9	2.0	1.2	**7.1**	**11.84**
2034	100.0	54.0	18.1	29.1	3.8	2.0	1.1	**6.9**	**11.84**
2035	100.0	56.0	17.3	27.9	3.6	2.0	1.1	**6.7**	**11.84**
2036	100.0	58.0	16.5	26.7	3.5	2.0	1.1	**6.5**	**11.84**
2037	100.0	60.0	15.7	25.5	3.3	2.0	1.0	**6.3**	**11.84**
2038	100.0	62.0	15.0	24.3	3.1	2.0	1.0	**6.1**	**11.84**
2039	100.0	64.0	14.2	23.0	3.0	2.0	1.0	**5.9**	**11.84**
2040	100.0	66.0	13.4	21.8	2.8	2.0	0.9	**5.8**	**11.84**
2041	100.0	68.0	12.6	20.6	2.7	2.0	0.9	**5.6**	**11.84**
2042	100.0	70.0	11.8	19.4	2.5	2.0	0.9	**5.4**	**11.84**
2043	100.0	72.0	11.0	18.2	2.4	2.0	0.8	**5.2**	**11.84**
2044	100.0	74.0	10.2	17.0	2.2	2.0	0.8	**5.0**	**11.84**
2045	100.0	76.0	9.4	15.8	2.0	2.0	0.7	**4.8**	**11.84**
2046	100.0	78.0	8.7	14.6	1.9	2.0	0.7	**4.6**	**11.84**
2047	100.0	80.0	7.9	13.3	1.7	2.0	0.6	**4.4**	**11.84**
2048	100.0	82.0	7.1	12.1	1.6	2.0	0.6	**4.2**	**11.84**
2049	100.0	84.0	6.3	10.9	1.4	2.0	0.6	**4.0**	**11.84**
2050	100.0	86.0	5.5	9.7	1.3	2.0	0.5	**3.8**	**11.84**
2051	100.0	88.0	4.7	8.5	1.1	2.0	0.5	**3.6**	**11.84**
2052	100.0	90.0	3.9	7.3	0.9	2.0	0.4	**3.4**	**11.84**
2053	100.0	92.0	3.1	6.1	0.8	2.0	0.4	**3.2**	**11.84**
2054	100.0	94.0	2.4	4.9	0.6	2.0	0.3	**2.9**	**11.84**
2055	100.0	96.0	1.6	3.6	0.5	2.0	0.3	**2.7**	**11.84**
2056	100.0	98.0	0.8	2.4	0.3	2.0	0.2	**2.5**	**11.84**
2057	100.0	100.0	0.0	1.2	0.2	2.0	0.2	**2.3**	**11.84**
			NPV		106.9	24.9	15.5	**147.2**	**147.2**
			Levelized		8.59	2.00	1.25	**11.84**	

Annual Levelized Carrying Charge Rate is: 11.84%

Calculation of APS Carrying Charges and Discount Rates
Page 8

Installed Costs, $M	100
Economic Life, Years	40
MACRS, Years	20
Installation Date	2008

APS Cost of Capital

	Ratio	Cost	WACC Before Tax	WACC After Tax
Debt	45.5%	7.25%	3.30%	2.00%
Equity	54.5%	10.75%	9.66%	5.86%
Total	100.0%		12.96%	7.86%

Annual Inflation Rate	2.50%
Income Tax Rate	39.36%
Discount Rate	7.86%

	Original Costs	Accumulated Book Depreciation	Accumulated Deferred Tax	BOY Rate Base	Return on Rate Base	Book Depreciation	Property Tax	**Annual Fixed Charges**	**Levelized Fixed Charges**
2008	100.0	2.5	0.5	100.0	13.0	2.5	0.0	**15.5**	**12.06**
2009	100.0	5.0	2.3	97.0	12.6	2.5	0.0	**15.1**	**12.06**
2010	100.0	7.5	4.0	92.7	12.0	2.5	1.8	**16.3**	**12.06**
2011	100.0	10.0	5.4	88.5	11.5	2.5	1.7	**15.7**	**12.06**
2012	100.0	12.5	6.7	84.6	11.0	2.5	1.7	**15.1**	**12.06**
2013	100.0	15.0	7.8	80.8	10.5	2.5	1.6	**14.6**	**12.06**
2014	100.0	17.5	8.7	77.2	10.0	2.5	1.6	**14.1**	**12.06**
2015	100.0	20.0	9.5	73.8	9.6	2.5	1.6	**13.6**	**12.06**
2016	100.0	22.5	10.3	70.5	9.1	2.5	1.6	**13.2**	**12.06**
2017	100.0	25.0	11.1	67.2	8.7	2.5	1.5	**12.7**	**12.06**
2018	100.0	27.5	11.9	63.9	8.3	2.5	1.5	**12.3**	**12.06**
2019	100.0	30.0	12.6	60.6	7.9	2.5	1.5	**11.8**	**12.06**
2020	100.0	32.5	13.4	57.4	7.4	2.5	1.4	**11.4**	**12.06**
2021	100.0	35.0	14.2	54.1	7.0	2.5	1.4	**10.9**	**12.06**
2022	100.0	37.5	14.9	50.8	6.6	2.5	1.4	**10.4**	**12.06**
2023	100.0	40.0	15.7	47.6	6.2	2.5	1.3	**10.0**	**12.06**
2024	100.0	42.5	16.5	44.3	5.7	2.5	1.3	**9.5**	**12.06**
2025	100.0	45.0	17.3	41.0	5.3	2.5	1.2	**9.1**	**12.06**
2026	100.0	47.5	18.0	37.7	4.9	2.5	1.2	**8.6**	**12.06**
2027	100.0	50.0	18.8	34.5	4.5	2.5	1.2	**8.1**	**12.06**
2028	100.0	52.5	18.7	31.2	4.0	2.5	1.1	**7.7**	**12.06**
2029	100.0	55.0	17.7	28.8	3.7	2.5	1.1	**7.3**	**12.06**
2030	100.0	57.5	16.7	27.3	3.5	2.5	1.0	**7.1**	**12.06**
2031	100.0	60.0	15.7	25.8	3.3	2.5	1.0	**6.8**	**12.06**
2032	100.0	62.5	14.8	24.3	3.1	2.5	1.0	**6.6**	**12.06**
2033	100.0	65.0	13.8	22.7	2.9	2.5	0.9	**6.4**	**12.06**
2034	100.0	67.5	12.8	21.2	2.8	2.5	0.9	**6.1**	**12.06**
2035	100.0	70.0	11.8	19.7	2.6	2.5	0.8	**5.9**	**12.06**
2036	100.0	72.5	10.8	18.2	2.4	2.5	0.8	**5.6**	**12.06**
2037	100.0	75.0	9.8	16.7	2.2	2.5	0.7	**5.4**	**12.06**
2038	100.0	77.5	8.9	15.2	2.0	2.5	0.7	**5.1**	**12.06**
2039	100.0	80.0	7.9	13.6	1.8	2.5	0.6	**4.9**	**12.06**
2040	100.0	82.5	6.9	12.1	1.6	2.5	0.6	**4.7**	**12.1**
2041	100.0	85.0	5.9	10.6	1.4	2.5	0.5	**4.4**	**12.06**
2042	100.0	87.5	4.9	9.1	1.2	2.5	0.5	**4.2**	**12.06**
2043	100.0	90.0	3.9	7.6	1.0	2.5	0.4	**3.9**	**12.06**
2044	100.0	92.5	3.0	6.1	0.8	2.5	0.4	**3.6**	**12.06**
2045	100.0	95.0	2.0	4.5	0.6	2.5	0.3	**3.4**	**12.06**
2046	100.0	97.5	1.0	3.0	0.4	2.5	0.2	**3.1**	**12.06**
2047	100.0	100.0	0.0	1.5	0.2	2.5	0.2	**2.9**	**12.06**
2048									
2049									
2050									
2051									
2052									
2053									
2054									
2055									
2056									
2057									
			NPV		101.5	30.3	14.2	**146.0**	**146.0**
			Levelized		8.38	2.50	1.18	**12.06**	

Annual Levelized Carrying Charge Rate is: 12.06%