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Identification of Demand Response Potential for Microgrids Using the Distributed Energy Resources Customer Adaption Model

A Case Study of the Alameda County Santa Rita Jail for 2011

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PREFACE

The California Energy Commission Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
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- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Identification of Demand Response Potential for Microgrids using Distributed Energy Resource Customer Adaption Model is the final report for the Automated Demand Response and Micro Grid Demonstration at the Santa Rita Jail project (contract number 500-03-026, work authorization number 3 conducted by the Lawrence Berkeley National Laboratory. The information from this project contributes to PIER's Energy Research and Development Division's Energy Systems Integration Program.

For more information about the PIER Program, please visit the Energy Commission's website at www.energy.ca.gov/research/ or contact the Energy Commission at 916-654-4878.

ABSTRACT

As renewable energy production increases and the electricity market paradigm changes Demand Response (DR) programs are at the forefront of the effort to reduce peak loads. Another emerging trend is microgrids, which allow for the integration of renewable distributed energy resources (DER) into power systems controlled at the local level. Therefore, the potential of microgrids to participate in DR simultaneously lowering electricity costs and supporting reliable macrogrid operation should be analyzed.

Santa Rita "Green" Jail (SRJ), run by the local County government, is a microgrid demonstration project integrating 1MW fuel cell, 1.2MW PV and 2MW 4MWh of electrical storage. The interaction of these DER can save electricity costs and lower demand peaks. As the markets and tariffs for DR are not straightforward an analysis is needed to tap the full potential of the installed infrastructure. As a public sector demonstration project SRJ can encourage broader adaption of DER and electric storage.

This report evaluates the potential for DR for SRJ focusing on the value of electric storage under different utility DR programs. Key operating characteristics are determined to ensure viable operation in different use cases. Also, load shed and shift capabilities are evaluated to identify their economic value under DR programs compared to electrical storage. The Distributed Energy Resources Customer Adoption Model (DER-CAM) is able to find the optimal battery operation schedule. DER-CAM was enhanced by DR capabilities and load shed and shift modules to optimize operational behavior based on DER generation, load and DR events.

This report demonstrates how much the microgrid can save by participating in DR. It is identified which DR program is most viable and which barriers and success factors must be considered. Finally, the amount of peak load mitigation that can be delivered to the macrogrid by SRJ to help meet national and federal policy targets for DR is presented.

Keywords: California Energy Commission, demand response, microgrids, on-site generation, load shed, load shift, precooling, optimization, electrical storage, fuel cell, photovoltaic

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EXECUTIVE SUMMARY

With the increasing penetration of renewable and distributed energy resources and the correlated change in the electricity infrastructure, two concepts are emerging in the electricity sector that are expected to ease the change in the electricity supply paradigm while ensuring reliability of supply. The first emerging concept, microgrids, entails the grouping of different DER and loads at a local level. Microgrids assist in the grid integration of intermittent resources and can help to ensure reliability of supply even further. First, on a local level, all loads connected to the microgrid benefit from the microgrids ability to island in case of a macrogrid disturbance, fault, or other unfavorable conditions. Second, on a more regional level, microgrids could use their controllable resources to provide additional services to the grid. One of these services is demand response. Demand response is the second emerging concept. It evolves around the idea that, as energy production becomes more volatile and less controllable due to renewable resources such as PV or wind, the demand needs to be more flexible to ensure constant alignment of load and supply.

It was evaluated in this project, if under current market conditions in California, the participation in demand response would be financially viable for one of the world's most modern microgrids. Although being clearly focused on the facility under research, the study can serve as an entry point to this topic of involving microgrid in demand response markets.

The project focused on the evaluation of the applicability of different tariffs and DR programs to Santa Rita Jail. The following tariffs and DR programs have been evaluated:

- E-20 Time of Use
- Peak Day Pricing
- Demand Bidding Program
- Base Interruptible Program

Apart from the standard time of use tariff, Peak Day Pricing, the Demand Bidding Program and the Base Interruptible Program have been evaluated in detail and selected for inclusion in the analysis.

As the analysis of the DR potential was specifically conducted for SRJ, it was necessary to understand the detailed load and generation behavior as well as the key load drivers. For this purpose a detailed load and generation analysis has been conducted that showed that the Fuel Cell cannot be considered a reliable source of supply. Apart from this it was determined that SRJ has a rather flat daily load profile as the mid-day peak is almost perfectly compensated for by PV output. As detailed load break-downs were not available, an existing building energy simulation model was leveraged and adapted to serve as a good approximation of the actual loads. It showed that lighting is a significant and very constant load share, while the next big load driver, cooling load, fluctuates more on a day-to-day basis. Based on these detailed load splits and additional wiring information provided by SRJ load shed potential by lighting shed and load shift potential by precooling was identified and quantified.

Based on these findings the optimization model DER-CAM has been extended by demand response, lighting shed and precooling capabilities. So called DR-DER-CAM minimizes the total electricity costs under each of the given tariffs and programs by optimally scheduling the usage of electric storage, lighting shed, and precooling.

Using DR-DER-CAM, the different tariffs were evaluated under four different load scenarios. These scenarios are:

- Fixed demand
- Usage of battery by itself
- Usage of battery and lighting shed
- Usage of battery and precooling

First, Peak Day Pricing (PDP) shows a significant savings potential across all different scenarios analyzed in comparison to the current TOU tariff SRJ is served under. Most remarkably, costs under PDP would even be lower if absolutely no reaction to the called events is implemented due to the PV-driven, relatively flat specific load shape of SRJ. Second, Demand Bidding Program (DBP), a price responsive DR program, was evaluated and it was determined that the savings potential in 2011 would have been relatively low under this program. On the upside, however, it must also be stated that these minor savings could be realized at absolutely no risk as the participation in the called events is voluntary and no penalties for non-compliance apply. Third, Base Interruptible Program (BIP), an emergency DR program, was analyzed. BIP was evaluated for numerous sub-scenarios. The sub-scenarios are differentiated by the battery capacity that is set aside to fulfill the demand reduction promise, by the expected maximum event duration, and by the capability of charging the electric storage between event notice and the beginning of the event. It was shown, that only if accepting some risk, savings can be generated by partaking in this program. Under a risk-averse approach the participation in this program is not viable.

The results also generated findings with regard to the different opportunities to influence the load and their viability. The electric storage at SRJ is able to drive savings from flattening the demand levels and conducting energy charge arbitrage on a daily level. The electric storage is able to generate significant savings at SRJ, but when taking the investment costs into consideration it is not financially viable under current market conditions. For Lighting shed, it was shown that small amounts of lighting shed can generate savings. Lighting shed is optimally used on demand-setting days under TOU or event days under PDP. The vast majority of savings from lighting shed are generated during summer. For precooling the generated savings were relatively small under all tariffs and programs researched and were mainly resulting from reductions in demand charges while energy costs actually increased.

The total annual electricity costs for all evaluated scenarios are presented in the table below:

[$]	Fixed Demand	Battery	Load Shed	Load Shift
TOU	1,447,368	1,319,246	1,302,071	1,316,170
PDP	1,428,923	1,304,252	1,285,942	1,299,692
DBP		1,303,527	1,285,503	
BIP		1,253,306	1,228,723	

Overview of Annual Electricity Costs by Scenario

Concluding this analysis, it can be stated that the microgrid at SRJ with its installed electric storage, on-site PV arrays and load management capabilities shows potential for the participation in DR under tariffs and programs offered by the local utility.

CHAPTER 1: Introduction

In today's industrialized world, the reliable supply of electricity is most essential and is considered a commodity for private households as well as for industrial production. Without the reliable supply of electricity, economic growth is endangered and every-day life-style in the developed world cannot be maintained. To provide this essential commodity to the people, electricity can be generated in two ways: either by burning fossil fuels in its various forms or from renewable energy resources such as wind, solar or water flow. With the increasing share of renewable generation in the overall electricity mix, the traditional market paradigms are challenged and existing market frameworks need to be extended and modified.[1] To be able to understand this need for change, electricity markets must first be understood in general.

Electricity markets around the world are structured in different ways but as diverse as the settings and frameworks may be, they all have the common goal of supplying a constantly changing power demand through a continuous, but flexible generation and a reliable transmission network at affordable electricity prices.[2] In the past decades, this core goal has been extended by requiring electricity generation to be as environmentally friendly as possible.

Two concepts that are closely related to the issues of reliability of supply and the integration of renewable energy resources are the concept of demand response and the concept of microgrids.

Demand response refers to the idea that a paradigm shift in the electricity markets is underway. Traditionally, the generation was adapted to the demand level that could not be influenced by electricity providers and grid operators. Demand response refers to the effort to increase the flexibility of load demand. The demand is influenced in such way that in times of short supply or especially high demand, some or all customers can be advised or incentivized to lower their demand for a certain period of time. In doing so, demand response is a key load management tool representing an inexpensive alternative to additional generation resources that would otherwise be needed to ensure supply during peak hours. Furthermore, with an increasing share of renewable energy generation, demand response can also be leveraged to buffer volatile output of intermittent resources such as solar and wind.

The second concept also related to the issue of integration of renewable energy resources and the reliability of supply is the concept of microgrids. Microgrids are aggregations of interconnected loads and Distributed Energy Resources within clearly defined electrical boundaries that act as a single controllable entity with respect to the macrogrid. On the one hand, microgrids provide a framework for the seamless integration of distributed energy resources, including but not limited to renewable energy resources, at the point of consumption. Microgrids can foster the integration of renewable energy resource in the generation mix. On the other hand, microgrids also tackle the issues related to reliability of supply. The microgrid concept entails the capability that the microgrid can disconnect from the macrogrid at any point

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[1] (Ströbele et al., 2010)

[2] (Erdmann and Zweifel, 2008)

of time and provide an increased level of reliability of supply to its customers. Especially for customers with critical loads, a microgrid is an opportunity to ensure continuous supply in times or areas where the macrogrid cannot provide this service as needed. Furthermore, microgrids can provide additional service to the macrogrid including the back-feed of power to the macrogrid or the provision of ancillary services.

This last point is where the concepts of demand response and microgrid need to be researched and evaluated in close combination to determine if and how microgrids can participate in demand response to support the macrogrid operator. The participation of microgrids in demand response will only be adapted by the operators of microgrids if the incentives for such participation are applicable to the special situation and needs of their microgrids.

1.1. Research Objective

The research objective of the report at hand is to go into detail on adaption of demand response by microgrids. As demand response tariffs and programs are usually laid out for standard, non-microgrid customers, it will be interesting to see if the incentive structures of the programs are lucrative to microgrids as well. So far, microgrids have mostly been viewed by the macrogrid as a potential source of power supply due to their installed generation resources. This report will extend this view to a potential participation of microgrids in the demand response market.

To answer this research objective a case study will be conducted for one of the most modern microgrids in the world, the CERTS[3] microgrid at Santa Rita Jail in California, U.S.A. The Jail's performance and available demand response programs from the utility macrogrid will be analyzed and viable options to lower the costs of electricity supply for the microgrid will be determined. To be able to answer this question, detailed simulations will be conducted using and extending the Distributed Energy Resource Customer Adaption developed by the Lawrence Berkeley National Laboratory. The analyses will be conducted based on Santa Rita Jail's 2011 load profiles.

1.2. Structure of Work

To be able to assess the economical viability of the microgrids participation in demand response this study is structured as follows:

In section two, an overview on the California electricity market will be given. The section will elaborate on the framework of the market, the current state of generation, transmission, distribution, and consumption as well as future energy goals and policies. This introduction will give the setting of the analysis and ensure a thorough understanding of the underlying market structures.

In section three, the concepts of demand response and microgrids will be presented and discussed to ensure a common understanding of these terms throughout the report. For the concept of demand response, this also includes the description of applicable demand response programs offered by the local utility at the Santa Rita Jail facility.

[3] Consortium for Electric Reliability Technology Solutions

In section four, a detailed description of the microgrid at Santa Rita Jail will be given to ensure an in-depth understanding of the opportunities and restrictions that apply when participating in demand response. This description includes a presentation of all distributed energy resources on-site as well as a description of the grid architecture that connects loads and generation resources to each other and to the macrogrid.

Section five focuses on analyzing the load and generation profiles within the microgrid. First, an analysis with an extended time horizon will be conducted for the most relevant DER, the grid consumption, and the total load. Afterwards a building energy simulation of Santa Rita Jail will be introduced and leveraged in order to arrive at a deeper understanding of the specific load drivers. Finally, load shedding and shifting opportunities will be identified and quantified.

Section six will present the DER-CAM optimization tool to the reader and detail the changes and additions made to the program to be able to evaluate demand response potential at Santa Rita Jail.

Section seven will then present the detailed analysis of the identified demand response tariffs and programs applicable to the jail. The analysis will be conducted for up to four different load scenarios, including battery usage as well as load shedding and shifting, for each of the tariffs. For each of the numerous cases and scenarios the most relevant findings and key insights will be presented and explained. Finally, resulting annual electricity costs and their split will be discussed.

CHAPTER 2:
California Electricity Market

This section will give an overview of the California electricity market as this is the setting of the following analyses. First, a description of the historic development as well as the current framework of the electricity market will be given. Second, the current situation of the California Electricity market will be described along the pillars of generation, transmission, distribution and consumption. Section two will conclude with an overview of current energy policies and outline future energy goals for the California electricity market set by federal and state legislators.

2.1. Framework

This chapter describes the framework of the California electricity market in three stages. First, the pre-crisis framework in California will be described as it was derived from and integrated into the national framework. Second, the Energy Crisis will be summarized briefly. Third, the changes, made to the California market framework after the crisis, are described.

2.1.1. Pre-Crisis Framework

To be able to understand the pre-crisis framework in the California Electricity market, first the structure of the federal US electricity market must be outlined as California, as independent as it is, is still part of the federal energy market and national grid structure and must oblige federal regulations in its market setup and respond to federal agencies.

Federal Structures

After the oil crisis in the 1970's the US Congress created the Department of Energy (DOE) and as part of it – but independently operating – the Federal Energy Regulatory Commission (FERC) that supervises the U.S. energy market.[4]

In 1978 the utility companies throughout the U.S., which had until then been operating regulated natural monopolies on electricity supply in their territory, were forced to start buying power from independent generators as the legislators aimed to unbundle the market. The utilities could still produce their own electricity but had to buy from third-party generators if their price was lower than the utilities' own production costs.[5] However, utilities still operated the grid and could therefore circumvent this legislation by restricting the access to the grid. Also, the customers still faced a monopoly as they could only purchase power from their local utility. In 1992, the U.S. electricity market took the next step to deregulation and a system was put in place that allowed independent generators to access the grid at fair rates all the way down to the customer. At this point, the customers in the U.S. had the opportunity to purchase electricity from someone else than their local public utility.[6] The deregulation took its next big

[4] (U.S. Department of Energy, 2011)

[5] (Joskow, 2003)

[6] (Joskow, 2001)

step in 1996, when Order 888 and Order 889 were issued.[7] Through these orders, the competitors of the public utilities that had entered the markets were granted guaranteed, non-discriminatory access to transmission lines under an open-access transmission tariff.[8] In order to control this new regulation, FERC created two new entities: the Independent System Operator (ISO) and the Regional Transmission Organization (RTO). ISOs and RTOs are both responsible for the operation of the grid in deregulated markets[9] with the sole difference that ISOs operate in a single state and RTOs across state lines.[10]

In addition, investor-owned utilities (IOU) had to unbundle their transmission and generation services.[11] Before the deregulation the vertically integrated utilities were responsible for serving the total demand and they also controlled all generation that was used to do so. Therefore, it was their responsibility to match the demand and generation at all times.[12] However, with different generators using one grid to serve the total demand, a centralized institution had to be put in place to coordinate the matching of demand and generation. This matching is done by wholesale spot markets in each ISO/RTO territory.[13] Although each ISO/RTO territory has its own spot market, the wholesale markets are monitored and regulated by FERC.[14] While wholesale market mechanisms and prices are monitored by a federal agency, the retail electricity prices are controlled by each state's public utility commission.[15]

Within this general federal framework, the progress of the deregulation varies significantly from state to state and therefore a description of the electricity markets must be state specific. This report will focus on the state relevant for the further analyses, California.

California

Before the deregulation, the California electricity market was run by three vertically integrated IOUs with geographical monopolies on generation, transmission, and distribution within their distinct regions. These IOUs were:

- Pacific Gas & Electric (PG&E)[16]
- Southern California Edison (SCE)
- San Diego Gas & Electric (SDG&E)

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7 (Kumkar, 2002)

8 (Federal Energy Regulatory Commission, 2010b)

9 The implementation of FERC orders did not happen simultaneously throughout the country. Some regions are still in progress today.

10 (ISO/RTO Council, 2005)

11 (Federal Energy Regulatory Commission, 2010b)

12 (Joskow, 2005)

13 For more information on the spot markets as well as additional tasks of the ISO/ROT and an overview of the existing ISOs and RTOs in the U.S. please refer to Appendix A.

14 (Federal Energy Regulatory Commission, 2010c)

15 (Joskow, 2003)

16 A geographic overview of the PG&E service territory is given in Appendix A. Only PG&E is shown as the further analysis is located in the PG&E service territory.

Apart from their own generation, the IOUs had long-term contracts in place with outside-state generators in order to fulfill the growing demand of the state with the highest population in the U.S. The IOUs itself and especially the electricity retail prices were regulated by the California Public Utilities Commission (CPUC). CPUC would set retail prices at the production cost for the electricity plus a mark-up to ensure a regulated return of investment for the invested capital.[17]

Between 1996 and 1998 California started to reform its electricity market aiming to not only implement but also exceed the FERC guidelines. The government aimed to create a market framework that would allow the existing IOUs to better compete with each other and motivate new players to enter the market place.[18] The first step in doing so was to found the California Independent System Operator (CAISO) that was put in charge of running the transmission networks of the IOUs and ensure non-discriminating access. Simultaneously, the IOUs were encouraged to sell most of their generation assets to create a diversified generation market. After these two steps the previously fully integrated IOUs were basically left with the retail business only and had to externally purchase all electricity that they needed to supply their customers. As another big step in the changed framework it was determined that the IOUs could only purchase the power they needed from a single source: the newly founded California Power Exchange (CALPX). CALPX was open to generators inside and outside California and by establishing this single wholesale spot market platform, legislators aimed to create transparent and fair prices. IOUs were no longer allowed to commit to long-term bilateral contracts with suppliers directly.[19]

2.1.2. California Energy Crisis

The California Energy Crisis started in 2000 when wholesale electricity prices started to rise dramatically from an average monthly price of about $ 50/MWh to a peak of $ 407/MWh in December 2000.[20, 21]

The trigger for the crisis was an atypical increase in demand. With the high economic growth, electricity demand grew beyond expectations and therefore California was dependent on out-of-state imports. These imports were challenged in the summer of 2000 as droughts in the Northwest lowered the output of hydropower plants. These droughts were caused by higher than average summer temperatures that did not only influence the generation but also caused a significant increase in consumption, especially for heating, ventilation and air conditioning (HVAC) equipment. In addition, natural gas prices rose, which was especially hard for California as it used a high share of gas-fired electricity plants.[22] To worsen the situation even more the new market set up and the lack of coordination between CAISO and CALPX opened arbitrage opportunities for energy traders that started to game the system.[23] Companies like

[17] (Sweeney, 2006)

[18] (Beer and Momber, 2010)

[19] (Federal Energy Regulatory Commission, 2005)

[20] (Kumkar, 2002)

[21] A detailed development of the CALPX day-ahead prices from January 2000 to June 2001 is given in Appendix A.

[22] (Federal Energy Regulatory Commission, 2005) and (Joskow, 2008)

[23] (Borenstein, Bushnell, Knittel and Wolfram, 2004)

Enron placed orders that artificially overbooked transmission lines, causing congestions and ultimately increasing prices even more.[24]

As said, the aforementioned can be considered the triggers of the crisis but they are not the reasons. The new market design had two major flaws, apart from the insufficiencies that Enron & Co. gamed. The retail prices were capped at a level 10 % below the 1996 level, which was expected to be enough for a competitive and functioning market. Additionally, the IOUs were forced to buy almost all their power from the spot market and were not allowed to hedge through long-term contracts that could have ensured supply at a fixed rate. This meant that the IOUs were fully exposed to the volatile and significantly increasing market prices whilst having no opportunity to increase retail prices. As prices for customers were fixed anyway, the consumers did not help to mitigate the problem due to the lack of price responsiveness in these adverse conditions.[25]

In this situation, rolling black-outs occurred especially in Northern California in the summer of 2000 and the whole market was close to a breakdown in beginning of 2001.[26] The utilities lost money with every kilowatt hour (kWh) they sold and all three of them were endangered by bankruptcy or illiquidity in 2001. As a result of this imminent threat, the third-party electricity generators lowered their output, as they could not be sure to be paid by the utilities for the electricity they delivered. This additional drop in supply increased wholesale market prices even further and in addition, the supply could hardly be guaranteed anymore. Rolling blackouts occurred more often. Stuck at negative margins, the IOUs stopped paying their fees to CAISO and CALPEX and as a result CALPEX had to discontinue operation on February 1st 2001.[27] The governor of California declared the state of emergency and the Department of Water Resources was instructed to purchase electricity for the IOUs to ensure supply. After the State of California spent almost $ 8 billion on electricity purchases to keep up the supply, the prices normalized in May 2001.[28]

2.1.3. Post-Crisis Framework in California

After prices normalized it was obvious that California could not just go back to the operation of its electricity market but substantial changes to the framework had to be made to prevent re-occurrence of such events. While the basic layout of the framework was kept as it was, three substantial changes were made to avoid another fault.

First, CALPX operation was not re-launched and instead IOUs can now purchase power through a functioning day-ahead and intra-day market being operated by CAISO and supervised by FERC on a federal level. However, the main point of this first adaption is that the framework now allowed long and short-term contracts between IOUs and independent power generators - outside the spot market - to secure supply in advance and allow for long-term capacity planning. The long-term procurement is regulated by specific CPUC framework.

[24] (California Council on Science and Technology, 2004) and (Federal Energy Regulatory Commission, 2003).

[25] (Beer and Momber, 2010, p. 12 f.)

[26] (von Appen, 2011, p. 14)

[27] (Beer and Momber, 2010, p. 13)

[28] (Joskow, 2001)

California did not only allow long-term procurement but took one step more and basically forced it on market participants by demanding that 90 % of the forecasted load must be covered by forward contracts one year in advance.[29]

Second, the IOUs were given the right to self-generate electricity again and were forced to maintain at least 15 % reserve margin during the summer months. This margin can be covered by contracted or self-generated electricity but must be available at all times. Parallel to allowing self-generation for IOUs, California legislators set incentives to diversify the generation equipment run by the IOUs as well as by independent generators. This push for diversification is the reason why California has the largest share of clean and renewable electricity production in the U.S.[30]

Third, and most important in the context of this report, the problem of non-responsive load behavior was addressed. If, during the peak hours of the crisis, especially larger customers had curtailed their loads, peak prices and rolling blackouts might have been prevented. To encourage such behavior, numerous Demand Response (DR) programs were put in place aiming to incentivize customers to reduce load during critical peak times. Most of these programs are run by the IOUs in their respective territories.[31] The concept of DR will be discussed soon in more detail - after an overview of the current state of the California electricity market is given – as it has the outmost importance for this analysis.[32, 33]

2.2. Current State of California Electricity Market

In this chapter the current state of the California electricity market will be described along the lines of generation, transmission and distribution and consumption to give the reader an idea of the size of the market and especially the mix of generation and consumption. It will be outlined how the market developed and operates within the setting of the previously outlined regulatory framework.

2.2.1. Generation

In 2011 the total annual energy generated in California amounted to 200 GWh, 2.2 % less than in 2010. As imports from out-of-state were about constant compared to 2010 with 85 GWh, this decline is caused by a slightly lower demand than in 2010.[34]

The 2011 in-state generation mix[35] highly relies on electricity from natural gas that accounts for over 45 % of California electricity production. Next to this, with similar shares of 18 % each, electricity is generated from hydro and nuclear power plants. Renewable energy sources makes

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[29] (California Public Utilities Commission, 2009)

[30] (Beer and Momber, 2010, p. 13 f.)

[31] See chapter 3.2.

[32] See chapter 3.1.

[33] (California Public Utilities Commission, 2009)

[34] For details see sub-chapter 2.2.4.

[35] In-state means electricity from plants within the state or plants outside the state that are owned by California utilities. (California Energy Commission, 2011b)

up for almost 17 % of the in-state generation in 2011 with the biggest shares being geothermal, wind and biomass based generation. Solar electricity represents 0.5 % of generation.

In addition to the in-state generation, California imported a total of 85 TWh of electricity from out-of-state; 28 TWh from the Northwest and 57 TWh from the Southwest. The largest share of imports from the North was produced from wind, while the imports from the South were mainly based on coal and natural gas production.[36] Generation capacity within California grew by 1,609 MW[37] and is now at 71,318 MW.[38]

2.2.2. Transmission

The transmission network in California is operated at 500 kV, 230 kV, 115 kV and 70 kV with a standard frequency of 60 Hz.[39, 40] The transmission grid in California consists of over 25,000 miles of lines that are owned by the different utilities within their respective service territories but under the centralized control and management of CAISO. CAISO is responsible for forecasting total demand and ensuring that the utilities receive the electricity they purchased to supply their customers. In addition, CAISO is responsible for the real-time dispatch of reserve resources as well as congestion management on the transmission lines.[41] When operating the transmission lines, it is CAISO's responsibility, apart from ensuring reliable operation, to guarantee non-discriminating access to transmission lines for all market participants.[42] Finally, CAISO is responsible for the transmission lines that connect California to out-of state resources.

To achieve all these various goals related to the operation of the transmission network, CAISO operates three different competitive markets, economically and physically. First, the transmission market helps to allocate the transmission line capacity without discriminating customers. Second, the real-time spot market ensures the availability of supplemental energy that is dispatched every five minutes. Third, CAISO also runs the ancillary services market to trade ancillary services needed for the reliable and stable operation of the transmission lines.[43]

2.2.3. Distribution

The high-voltage on the transmission lines previously described is stepped down to 12 kV or 21 kV when fed into the local utilities' distribution networks. While large customers can obtain power at either of these levels, the standard residential customer will be connected at 220 V or 120 V.[44]The five largest electricity distributors are the three IOUs, PG&E, SCE and SDG&E, and two publicly owned load-serving entities, the Los Angeles Department of Water and Power and the Sacramento Municipal Utility District. The three IOUs serve over 80 % of California's electricity demand.

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36 (California Energy Commission, 2011a)

37 (California ISO, 2011c)

38 (California Energy Commission, 2011b)

39 (Wiser et al., 2003)

40 Some of the 500 kV transmission lines are operated under direct current.

41 (California ISO, 2011a)

42 See chapter 2.1.3.

43 (Beer and Momber, 2010, p. 15)

44 (California ISO, 2011b) and (Beer and Momber, 2010, p. 14).

As the facility under research is located in the PG&E service territory[45], PG&E operations will be outlined briefly by some operating figures. The PG&E service area spans about 70,000 square miles and PG&E directs electricity to 15 million people under 5.1 million customer accounts. It is the second largest IOU in California and delivered about 83.6 GWh of electricity in 2011.[46] PG&E owns over 141,000 circuit miles of distribution lines and almost 19,000 circuit miles of transmission lines.[47] PG&E is regulated by CPUC.[48] As a core part of this regulation, CPUC reviews and approves the retail tariffs offered by PG&E. The average retail price over all customers in the PG&E territory was $ 0.13 per kWh.[49, 50]

2.2.4. Consumption

In 2011 California consumed 263 GWh[51] of electricity with a peak load of 45,545 MW in the afternoon of September 7th. This consumption breaks down to 6,721 kWh of annual electricity consumption per capita in California. The per capita consumption in California is comparable to European per capita consumption[52] but significantly lower than the U.S. average of 12,146 kWh per capita and year. California actually is the state with the lowest per capita electricity consumption in the U.S.[53] Of the total consumption in California, 31.7 % were allocated in the PG&E service territory in 2011. Within PG&E, 37.3 % of consumption is residential, 12.6 % industrial and 41.1 % commercial.[54]

2.3. Energy Policies and Future Goals

This subchapter will give a brief overview on the energy policies relevant for the California electricity market and outline the future goals to give the reader an understanding of the expected future direction of the California electricity market. Although this document clearly focuses on the California market, at first some federal measures and subsidies will be presented, as these are also relevant for decisions made by players in the California electricity market.

2.3.1. Federal Energy Policies

Already in 1992, the federal government implemented a production tax credit (PTC)[55] for the operators of wind, geothermal, landfill gas, hydroelectric and biomass power plants. Up to 2.1 ct/kWh were granted if the site had been constructed before 2011. As part of the large

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45 See Appendix A for map of PG&E service territory.

46 (California Energy Commission, 2011c)

47 (Pacific Gas and Electric Company, 2013a)

48 More correctly, the utility PG&E is a subsidiary to PG&E Corporation, which is the CPUC-regulated entity.

49 $0.15 /kWh for residential, $0.13 per kWh for commercial, and $0.10 per kWh for industrial customers

50 In 2009. See (von Appen, 2011).

51 (California Energy Commission, 2011d)

52 7,253 kWh in Germany, according to (Bundesministerium für Wirtschaft und Technologie, 2011) and (Statistisches Bundesamt, 2010).

53 In 2010. See (California Energy Commission, 2011e).

54 The remainder is contributed by agricultural and mining sector as well as street lighting. See (California Energy Commission, 2011c).

55 PTC means that the tax credit is granted per kWh of produced electricity.

American Recovery and Reinvestment Act of 2009 (ARRA)[56] this PTC was extended to facilities constructed until 2013 and 2014.[57] Instead of the PTC, investors of the aforementioned plants can also choose to receive an investment tax credit (ITC).[58] ARRA allowed for an ITC of up to 30 % of the total investment costs.[59, 60]

In the technologies eligible for ARRA support, solar is not included. However, based on the Energy Improvement and Extension Act of 2008 solar plant investors are also able to receive a 30 % ITC if the site is built before 2016.[61] To further support solar powered electricity production the DOE launched the SunShot program in 2011 that aims at making the production from solar price competitive by 2020. It does so by mainly supporting four areas: solar cell technology, electronics to optimize solar system installation, the solar manufacturing process and installation, and the design and permission process for solar systems.[62]

In addition to these measures, the federal government supports the environmental friendly development of the U.S. electricity industry by loan guarantees for investments in renewable energy and transmission projects.[63] Furthermore, the federal government supports research and development related to the modernization of the electricity supply and demand structure, for example by funding research at the 17 national laboratories throughout the country.

After President Obama has been re-elected for his second term it can be expected that new federal programs will be set up to support renewable energy production. A first description of a possible future development is given in the White House's "Blueprint for a Secure Energy Future" that summarizes the President's aims and potential measures to reach these aims. While a clear focus lies on the security of supply from national resources, renewable and clean energy technologies are seen as a part of this larger development and thereby would profit if the ideas of the blueprint document were to be turned into legislation.[64], [65]

2.3.2. California Energy Policies and Goals

The above-mentioned federal programs are only one pillar of electricity policies in the U.S. Due to the federal structure the single states have the authority to implement their own policies and energy development goals. In California these state-specific goals often exceed the federal guidance by far.

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56 ARRA was passed to overcome the economic downturn during the financial crisis.

57 Depending on the technology. See (U.S. Government, 2011) and (U.S. Energy Information Administration / U.S. Department of Energy, 2011)

58 An ITC is a tax deduction depending on the amount of investment costs. Usually, it is fixed as percentage of the total investment costs.

59 If the ITC exceeds an investors' tax liabilities the ITC can be transferred into an after-tax grant.

60 (U.S. Government, 2011) and (U.S. Energy Information Administration / U.S. Department of Energy, 2011).

61 (U.S. Government, 2011) and (U.S. Energy Information Administration / U.S. Department of Energy, 2009).

62 (Schwartz, 2011)

63 (von Appen, 2011, p. 7)

64 (The White House, 2011)

65 For more detailed presentation of Federal Energy Polices refer to (von Appen, 2011).

California started its major initiative related to a greener energy production in 2006 with the Global Warming Solutions Act of 2006. This act sets the goal to reduce greenhouse gas emission by 2020 to the level of 1990 and by 2050 to 20 % of the 1990 level. This aim shall mainly be achieved by reaching a share of one third renewable energy production by 2020. To get to one third renewable energy production California outlined a roadmap that focuses on energy supply, transmission and distribution as well as energy demand.[66]

Energy Supply

The goals for the energy supply can be outlined very briefly. Basically, to achieve the overall goal of one third electricity supply coming from renewable sources in 2020, the authority forces all load serving entities to have 33 % of Renewable Energy Sources (RES) in their generation mix by that time. In addition, stricter emission standards are implemented for in-state traditional generation and coal-based electricity imports must be reduced. Furthermore, to support the top-level goal of reducing greenhouse gas emissions, technologies and research related to the exploration of carbon capture and storage are being funded.[67]

Transmission and Distribution

Although California did not define a direct goal to change its transmission and distribution network, the transportation and distribution grid is still core to the planned developments. At a share of one third of renewable energy sources, the supply structure will change significantly from several large plants to numerous distributed generation resources. The grid needs to be prepared for this change in order to ensure reliable supply in the process and after 2020.

To be able to cope with the increased volatility of supply caused by an increasing share of renewable resources such as wind or sun, the price responsiveness of customers shall be increased. By rolling out smart meters and smart grid technology equipment, the customers will be enabled to better understand their energy usage and to respond to pricing signals. The pricing signals will be directly correlated to the demand-supply situation, meaning that in periods of short supply and/ or high demand, prices will increase. If retail prices mirror the peak in spot market prices – at least to some extent – customers expected to lower their demand and thereby realize electricity cost savings while simultaneously stabilizing grid operation. To ensure the faster adaption of this concept all industrial and commercial customers will be automatically enrolled in tariffs that have some sort of dynamic pricing and will motivate customers to lower demand during critical times and manage their electricity usage in accordance with price and system conditions. Today, customers can still opt-out of these programs but will have to pay a premium in exchange to not being exposed to dynamic prices. This concept is implemented by PG&E within its service territory through its Peak-Day Pricing program.[68], [69]

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[66] (Governor of the State of California, 2010a)

[67] (Governor of the State of California, 2010b)

[68] See sub-chapter 3.2.2. Customers can also still opt out of this program and remain in their old tariff. However, if they chose PDP and are able to react somewhat price sensitive, they will realize savings by not opting out.

[69] (Governor of the State of California, 2010a)

Under the transmission and distribution part, California also fosters the development of electric storage to allow for the integration of larger amounts of intermittent wind and solar renewable resources. The batteries installed centrally at utility-scale or decentralized at smaller scale at the customers' sites help to mitigate peaks in demand and supply by shifting loads. To foster the development the authorities especially support technology pilot studies.[70] The aim is to integrate 1,000 MW of additional storage into the system until 2020.[71] Furthermore, the involved agencies and authorities are optimizing the regulatory approval process for new generation facilities to shorten the entire construction cycle and avoid unnecessary delays.[72]

Energy Demand

On the demand side, the goal of lowering carbon emissions to the desired level is mostly build around lowering and shifting of demand. Basically, three initiatives can be distinguished; energy efficiency programs, distributed generation (DG) and DR.

Energy efficiency programs are expected to contribute 40,000 GWh of reduced electricity consumption and a peak demand reduction of 12,000 MW annually. This is realized mostly through building and appliance standards. New buildings have to fulfill strict new energy standards such as the net-zero energy-building goal and existing buildings have to lower their electricity consumption to 70 % of their 2008 level by 2020.[73]

The second initiative focuses on promoting DG.[74] The idea behind increasing penetration of DG in California is basically to geographically bring demand and supply closer together and reduce transmission line losses. DG can be done behind the meter, at the customers' site, or on the wholesale level under the control of the utility. As part of this, the California Solar Initiative fosters the installation of 3,000 MW of solar-based capacity until 2017 by providing investment incentives. In addition, a feed-in tariff shall support the deployment of combined heat and power plants.[75]

The third pillar of the demand side revolves around the concept of DR.[76] DR means to implement tariffs and technologies[77] that allow influencing customer load profiles based on current or forecasted market and grid conditions.[78] As DR is at the very core of this project it will be discussed in more detail in the following chapter[79] including a section outlining the future goals for DR.[80]

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[70] Such as the microgrid and battery project discussed in chapter 4.4.

[71] (Governor of the State of California, 2010a)

[72] (von Appen, 2011)

[73] (California Energy Commission, 2011a) and (Governor of the State of California, 2010b)

[74] The distributed generation (DG) part of the project could also be classified under the supply section of the concept but was categorized as a demand measure by the state of California and will therefore be presented in this section.

[75] (Governor of the State of California, 2010b)

[76] (Ibid.)

[77] Such as SmartMeters.

[78] See more detailed definition under 3.1.1.

[79] See chapters 3.1.1.

[80] See chapter 3.1.2.

CHAPTER 3:
Demand Response and Concept of Microgrids

In section three the most relevant key facts regarding the concepts of DR and microgrids will be presented and briefly discussed to ensure a common understanding of these ideas throughout this report. The two concepts are grouped in one joint section as the very core of this project is the evaluation of DR potentials for a microgrid.[81]

In the following, first DR will be introduced to the reader in general before the available DR tariffs and programs in the PG&E service territory will be depicted. Finally, the concept of microgrids will be discussed.

3.1. Demand Response

This chapter will look into the topic of DR from two angles. First, a definition of DR will be given to ensure a common understanding throughout this report. Second, the state of the art of DR and future developments will be described, both on a national level first and in then more detail for the state of California. This last part serves as a basis for the following analyses of the facility under research.

3.1.1. Definition

In academic literature as well as in everyday use of the term DR many different understandings and definitions occur. As FERC defines DR in the most comprehensive way and because FERC can be considered one of the most influential institutions in the U.S. electricity market their wording is chosen to define DR:

"*DR refers to the ability of customers to respond to either a reliability trigger or a price trigger from their utility system operator, load-serving entity, regional transmission organization/ independent system operator, or other DR provider by lowering their power consumption. DR means a reduction in the consumption of electric energy by customers from their expected consumption in response to an increase in the price of electric energy or to incentive payments designed to induce lower consumption of electric energy*."[82]

From a broader grid management perspective DR is any measure that helps to ensure the continuous balance of load and supply not by – as traditionally done – controlling the electricity production but by changing the rate of electricity consumption at the customer side. In doing so, DR is a key load management tool representing an inexpensive alternative to additional generation resources that would be needed to ensure supply during peak hours.[83]

For many years DR was understood to only focus on peak shaving measures. Today, DR can also occur during non-peak hours, if required by the state of the grid, and influence any part of the customers load profile. The core of this definition of DR is that the customer has some

[81] See section 1 for scope and section 7 for analyses.

[82] (Federal Energy Regulatory Commission, 2010a, p.3)

[83] (California's Clean Energy Future, 2011)

expected consumption and is willing to deviate from his habitual usage pattern based on pricing or other signals[84] that occur on short notice. This short notice can either be day-ahead or only a few seconds in case of automated DR.

DR according to FERC's understanding can be split into two groups: dispatchable and non-dispatchable DR. Dispatchable DR basically means that customers agree to alternate from their planned consumption based on signals from someone else.[85] This measure includes direct control of customers' loads by the utility or any other party mentioned above. This load control is mostly implemented through smart controls of customer appliances such as refrigeration or HVAC systems. It also embraces the curtailment of load based on the provision of lower rates or other incentives.[86] At the core of dispatchable DR is the characteristic that once a customer committed to this program the curtailment has to happen if the third party requests a change in load pattern i.e. calls a DR event. In contrast, the non-dispatchable programs do not force the partaking customers to lower their demand in an event but they are motivated to do so by a dynamic rate design. One form of non-dispatchable DR could be that the price for either energy or power changes in case of a DR event and that the customer can then decide whether he wants to lower his demand depending on its opportunity costs for lowering the demand.[87]

Other publications differentiate DR into two groups called reliability-based and price-based. Though the difference in wording, this is basically the same concept FERC differentiates DR by. Reliability-based programs mean that customers are under interruptible tariffs and their supply is automatically or manually limited in case of an event. In price-based programs the customers are either charged higher prices during event hours or paid for reduced consumption during those hours.[88]

DR also embraces the use of devices that control the demand of a customer and can manage power flow from and to the grid. These devices can be plug-in electric vehicles as well as stationary electric storage units, installed centrally at utility-scale or locally at customer sites in smaller scale. Using storage devices of any kind is in accordance with the DR definition by FERC, even though it does not mean to lower consumption but to shift load from event or peak to non-event or non-peak hours.

Although load shifting is also supported and encouraged by Time-of-Use (TOU) tariffs that charge higher rates during daily peak hours,[89] TOU tariffs are not considered DR as they do not fulfill an essential part of DR. TOU tariffs have a predetermined price structure and do not include customers' reactions to a dynamic signal that is given on short notice.[90] Thus, TOU

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[84] Other signals could be reliability triggered event calls that the customer agreed to follow by enrolling in specific DR tariff or program.

[85] For example utility system operator, load-serving entity, regional transmission organization/ independent system operator, or other DR provider.

[86] Incentives can also be non-monetary.

[87] (Federal Energy Regulatory Commission, 2010a, p.3)

[88] (BloomEnergy, 2010, p. 14)

[89] This is often limited to weekdays.

[90] Day-Ahead or Intra-Day.

tariffs lack the dynamic pricing element of DR but, nevertheless, will be discussed later on as a base case to compare DR tariffs and programs to.[91, 92, 93]

Finally, DR is closely linked to another emerging trend in the electricity sector, the smart grid concept. Numerous benefits that are hoped to be delivered by smart grids, such as improved price-responsiveness of consumers to real-time pricing signals, are in fact DR measures. The other way round, the application of smart grid technology, i.e. smart meters, does increase the total DR potential.[94, 95]

3.1.2. State of the Art and Future Goals

In the following, the state of the art of the DR development in the U.S. and especially in California shall be presented. Like in previous chapters on the electricity markets, the clear focus lies on the situation in California. Nevertheless, it is helpful to first provide a broader, national perspective before detailing the specific circumstances in California.

National Level

Due to the federal and geographically diverse structure of the U.S. electricity market, only few DR initiatives exist on a national level. An effort worth mentioning, though, is the development of the National Plan on DR by FERC in 2010. The plan neither provides distinct DR measures nor does it define goals for the future development. However, it gives an overview of the current situation in the different states and tries to foster the national DR deployment. FERC defined three main objectives for its National Plan on DR:[96]

- Identify need for technical assistance to the federal states to support development of DR
- Identify need for a national communications program supporting the concept of DR
- Identify and/or develop tools, model contracts, model regulatory provisions and other supporting materials that can ease the implementation of DR on a state level

FERC identified that if DR continues at its current level DR would reduce national peak demand by 38,000 MW in 2019. However, FERC also states that the penetration varies significantly between different geographic regions. They assess that if all regions caught up to today's best practice regions by 2019 U.S. peak demand could be reduced by 82,000 MW, representing about 9 % of the total load. These reductions would mainly be based on reliability-based programs[97] with almost no influence of price-based DR programs[98]. In 40 states absolutely no influence of

[91] Also, the underlying standard tariff at the facility under research is a TOU tariff.

[92] Including TOU in the analysis is considered reasonable as TOU tariffs also aim at reducing peak loads, except for the difference that TOU tariffs incentivize a load shift or shed on a daily basis, while DR only does so on select critical DR event days.

[93] (Federal Energy Regulatory Commission, 2010a, p.4)

[94] Especially residential customers often lack appropriate meters to be able to partake in DR. Smart meter application would help to overcome this issue.

[95] For definition of Smart Grids see (Bundesnetzagentur, 2011).

[96] (Federal Energy Regulatory Commission, 2010a, p. 1)

[97] Non-dispatchable DR.

[98] Dispatchable DR.

price-based DR was detected in 2010. However, if more price-based options were offered, the potential for price-based DR would significantly increase, according to FERC analyses. If price-based programs are offered as opt-in tariffs, the total potential is assumed to be 14 % of the total U.S. demand, equal to 138,000 MW peak load reduction. This potential could be increased to 20 % or 188,000 MW if all states implemented price-based DR tariffs on an opt-out scheme.[99]

These figures show that there is a gap between different regions in the U.S. and that the challenge FERC tries to tackle by its National Plan is to get all states equally involved in DR. FERC sees the best opportunity on a national level in bringing all states to the level of DR implementation that has already been reached by most advanced states. FERC therefore concludes that the national DR development is an issue of communication and learning from the leading states. California is at the forefront of the DR development and could be leveraged as a leading example to foster national development.[100] Thus, and because it is the focus of the report at hand, the DR situation and future goals in California will be presented in the following.

California

With California taking a leading role in the DR development within the U.S. its involvement in DR related measures dates back to the year 1978 when a mandatory TOU tariff was issued for all large commercial customers[101]. The next big leap in the development was made after the electricity crisis in 2000 and 2001. After the crisis, California developed the Energy Action Plan, which stated the priorities of the government with regard to the future electricity market developments. DR was given the second highest priority for the future of the electricity market, directly after energy efficiency measures and even prior to renewable energy resource development.[102] Nowadays, California expects price-driven DR programs to grow significantly and provide growing potential, while reliability-based programs are expected to only develop slowly but are still available to ensure system operationability during critical peak moments of the grid.[103] To support the development of price-driven DR programs, California took a landmark step in 2010 by making dynamic pricing the default choice for all non-residential customers, although leaving the possibility to opt-out of the change in rate structure.[104]

In California the majority of DR programs is offered and operated by the three large IOUs,[105]but CAISO also offers customers the possibility to participate in spinning and non-spinning reserve as measures of DR[106]. The majority of DR measures offered by IOUs, target large commercial and industrial customers as with higher loads the absolute reduction potential is higher. In addition, most of these customers are already equipped with interval meters[107] that are a

[99] (Federal Energy Regulatory Commission, 2010a, p. 5f.)

[100] (Federal Energy Regulatory Commission, 2010a, p. b-2)

[101] (Ibid.)

[102] (Governor of the State of California, 2010b, p. 2)

[103] (Ibid., p. 4)

[104] (Federal Energy Regulatory Commission, 2010a, p. b-3)

[105] (Governor of the State of California, 2010b)

[106] (Beer and Momber, 2010)

[107] Consumption is measured in hourly time steps or less.

necessity for the participation in DR.[108] In a more recent effort during 2011, California utilities started to roll-out smart-meters to smaller customers as well, including small commercial and industrial as well as residential customers. Once these meters are installed and customers are informed about their possibilities the DR potential in California is expected to increase. The ongoing effort to involve smaller type customers in DR is also mirrored in the below-depicted past and expected development of the Aggregate Demand Response volume:

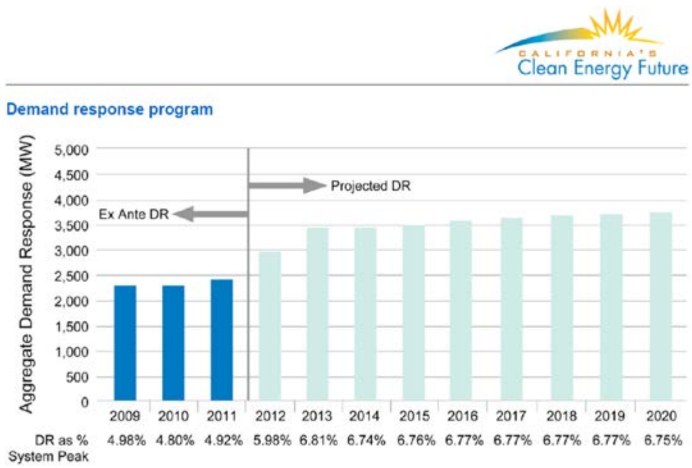

Figure 1: Aggregated Demand Response Potential in California[109]

Concluding this paragraph it shall be stated that high implementation level[110] and the expected development in California are mainly achieved through better communication and information measures, as the FERC National Plan states. First, California is doing well with communicating the need for DR to its population and business owners using programs such as “Flex your Power” that make customers realize about pending shortages and how curtailing even small loads can benefit the system.[111] In addition to this basic communication, California also delivers more detailed information in form of assessment tools to customers, who picked up interest based on the broader communication campaigns.[112]

After this general review of the DR situation in the U.S. and in California, in the following actual DR programs will be presented for the PG&E service territory in California. The following descriptions will show how the theoretical DR concept presented above translates into actual tariffs and programs. The presented tariffs and programs also form the basis for the later analysis of the DR potential case study.[113]

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[108] This is due to the fact that only with interval/ smart meters the consumption/ reduction during the event can be measured exactly as a basis for the calculation of the incentives.

[109] (California’s Clean Energy Future, 2011, p. 2)

[110] In comparison to other U.S. states.

[111] (Federal Energy Regulatory Commission, 2010a, p. b-3)

[112] Two interesting assessment tools that help customers to get more involved with DR are presented in Appendix B.

[113] See section 7.

3.2. Pacific Gas and Electric Tariffs and Demand Response Programs

In this chapter the relevant tariffs as well as applicable DR programs will be described briefly. This report will only discuss PG&E tariffs and DR programs as the case study facility under research is located in the PG&E area and is committed to purchase power from PG&E. Actually, only two of the PG&E DR programs are relevant for the analysis of the case study facility presented later on in this report.[114] The other DR programs, not applicable to or beneficial for the facility under research, will be described in the appendix of this project. Along with each program the reasons why this program was not chosen for a more detailed analysis in the main part of the report will be given.[115]

Before presenting the distinct DR programs[116], the standard electricity tariff that the case study facility is currently served and billed by will be presented[117]. This is especially important as the tariff with its TOU structure is the foundation to some of the DR programs.[118] Even if the specific DR program is independent from the standard non-DR tariff, this tariff must be thoroughly understood as DR incentives can only be analyzed in combination with the underlying tariff. This is due to the effect that if customers influence their load to confirm with a DR program this also implies that the demand and energy charges of the underlying tariff are affected as well and may generate more savings or counterbalance the savings achieved through DR participation.

3.2.1. E-20 Time-of-Use Tariff

The facility in question is served under the Electric Schedule E-20 tariff, which applies to all customers within the PG&E territory with maximum demands over 999 kW. Existing customers will be served under this tariff if their maximum demand exceeded 999 kW for three consecutive months during the last 12-month period and if no more than 70 % of their energy use is for agricultural end-uses.[119]

Time-of-Use

The E-20 tariff is a TOU tariff meaning that charges are differentiated by use time. The tariff clearly defines these times and differentiates three categories called *peak*[120], p*artial-peak*[121], and o*ff-peak*. During the summer months from May through October the *peak* period is defined as lasting from noon to 6 p.m. on weekdays. *Off-peak* is the period from 9:30 p.m. to 8:30 a.m. the next morning on weekdays. Saturday, Sunday and holidays[122] are considered *off-peak* all day long. The remaining times are called *partial-peak*.[123] During the winter months November

[114] See section 7.

[115] Please refer to Appendix B.

[116] See sub-chapters 5.2.2. to 5.2.4.

[117] See sub-chapter 5.2.1.

[118] See sub-chapter 5.2.2.

[119] (Pacific Gas and Electric Company, 2010a, p. 1)

[120] Also referred to as *on-peak* in this document.

[121] Also referred to as *mid-peak* in this document.

[122] New Year's Day, President's Day, Memorial Day, Independence Day, Labor Day, Veterans Day, Thanksgiving Day and Christmas Day.

[123] 08:30 a.m. to noon and 6 p.m. to 09:30 p.m. On weekdays.

through April the *peak* period does not exist, meaning that during weekdays *partial-peak* charges apply from 08:30 a.m. to 09:30 p.m.[124] Weekends and holidays are considered *off-peak* all day long.

Energy Charges

Under TOU the customer pays an energy charge per kWh as known from every residential electricity tariff. The energy charges are differentiated beyond the TOU by the voltage level that the customer is connected to. The facility under research is connected at primary voltage and therefore the applicable charges at this voltage level will be presented.[125] An overview of the applicable energy charges in $/kWh by season[126] and TOU period is given below.[127]

Energy Charges TOU			
[$/kWh]	***Peak***	***Partial-Peak***	***Off-Peak***
Summer	0.12242	0.08938	0.07006
Winter	0	0.08565	0.07306

Table 1: Energy Charges E-20 TOU[128]

This table shows that PG&E tries to incentivize customers to shift load to the evening and night hours as well as to the weekends by charging a higher price during *peak*. During winter no *peak* period exists and also it can be seen that prices for the other TOU periods differ between summer and winter.[129]

Demand Charges

In addition to the energy charge, customers also have to pay demand charges that are differentiated by the TOU periods presented above. To calculate the demand charge the maximum demand is determined. For this purpose the demand is averaged over 15-minute intervals and the highest demand in one 15-minute interval is used to set the maximum demand to which the demand charge is applied. The maximum demand charge is determined each month.[130, 131] Under E-20 three demand charges exist: *peak-period* demand charge, *partial-peak* demand charge and maximum demand charge. The maximum demand charge is based on the highest load[132] of the month, regardless of TOU periods. For *peak-period* demand charge only

[124] (Pacific Gas and Electric Company, 2010a, p. 7)

[125] (Pacific Gas and Electric Company, 2010a, p. 6)

[126] *Summer* is defined as the months May through October, while *winter* is defined as the remaining months from January to March, November, and December.

[127] Total customer and meter charges are not considered in this analysis as they are not affected by optimized load scheduling and are equal under the tariffs discussed herein.

[128] (Pacific Gas and Electric Company, 2010a, p. 3)

[129] With a smaller price difference between *partial-peak* and *off-peak*, PG&E gives the customers less incentive to shift load during winter months.

[130] (Pacific Gas and Electric Company, 2010a, p. 2)

[131] Actual billing cycles may differ from calendar months. However, in this analysis billing cycles are assumed to be equal to the calendar months.

[132] This is averaged over 15 minutes.

loads during the *peak* periods of the month are considered and for the *partial-peak* demand charge respectively. There is no demand charge for the *off-peak* period but it must be considered that the maximum demand charge is set regardless of the TOU periods meaning that excessive consumption during the *off-peak* period could still cause increased demand charges. For a better understanding the demand charges are presented in $/kW by season[133] and TOU period below.

Demand Charges TOU				
[$/kW]	*Maximum Demand*	*Peak*	*Partial-Peak*	*Off-Peak*
Summer	9.36	13.93	2.97	0
Winter	9.36	0	0.25	0

Table 2: Demand Charges E-20 TOU[134]

This overview underlines what the electricity rates already indicated above. By applying higher charges during the *peak* period, PG&E tries to motivate customers to consume less electricity during this period. For the demand charges the price differs by approximately a factor of five between *peak* and *partial-peak* is higher than the ratio included in the energy charges. This shows that PG&E is especially interested in penalizing - even short - demand peaks during the *peak* period to avoid stress to the grid during high load and potentially critical times.[135]

The demand charge is calculated month by month, meaning that at the end of the month the respective month is reviewed to identify the respective maxima. At the start of the next month the maxima are reset to zero with the result that a high demand in one month does not affect the demand charges in any other month.

3.2.2 Peak Day Pricing

Reacting to a CPUC initiative for dynamic pricing, PG&E introduced Peak-Day-Pricing (PDP) in 2010. In the statewide initiative CPUC ordered all IOUs to introduce dynamic pricing. With this initiative CPUC aimed to improve system reliability, level peak loads during summer and mitigate future power plant development costs. Therefore, PG&E introduced its PDP tariff with higher rates during so-called event days and lowered rates on non-event days in exchange.[136]

Since May 2010 large commercial and industrial customers[137] are automatically transferred to PDP but still have the option to opt-out of this automatic transition.[138] To support the transition customers can also choose a bill stabilization option when they change to PDP. This means that they are insured to not pay more than they would have paid under their prior tariff while

[133] *Summer* is defined as the months May through October, while *winter* is defined as the remaining months from January to March, November, and December.

[134] (Pacific Gas and Electric Company, 2010a)

[135] See chapter 5.1. for more detailed description of relevance of demand peak reduction.

[136] (Pacific Gas and Electric Company, 2010b, p. 8 f.)

[137] Those are customers with a monthly demand above 200 kW.

[138] (Pacific Gas and Electric Company, 2013c)

potential savings from PDP can be realized.[139] PG&E groups PDP as *Price Responsive DR Program*[140], meaning that customers are not obligated to curtail during an event but are motivated to do so by the rate structure, which will be presented in the following.[141]

Structure and Rates

PDP is based on the structure of a customer's underlying TOU tariff.[142] PDP concept basically means that based on a set of different triggers PG&E can call between nine and 15 event days during a year. The customers will be informed by 2 p.m. the previous day if the next day will be an event day, meaning that from of 2 p.m. to 6 p.m. the next day a price mark-up is added to the normal energy charge. For customers on E-20 this PDP adder is $ 1.20 per kWh during these four hours, which is an almost ten-time increase of the energy charge. This steep increase shall motivate customers to shed or shift load away from this event period. As PDP was not meant to deliver an electricity cost increase to PG&E customers, the *peak* and *partial-peak* energy and demand charges are lowered in compensation for the price adder.[143] When designing the tariff, PG&E aimed to keep prices stable for customers that show some reaction in form of load shedding or shifting to the called events. This means that customers who do not react to the event signal will look at increased electricity costs, while customers who shed or shift significant amounts of load will be able to realize electricity cost savings.[144] The applicable energy and demand charges for a PDP customer are presented below.

Energy Charges PDP				
[$/kWh]	***Peak***	***Partial-Peak***	***Off-Peak***	***PDP Event***
Summer	0.11998	0.08889	0.07006	1.32242
Winter	0	0.08565	0.07306	1.28565

Table 3: Energy Charges PDP[145]

It can be seen that compared to E-20 another time period was introduced that is only applicable on event days from 2 p.m. to 6 p.m. The emergency or event rate is the standard E-20 rate plus[146] the previously mentioned adder of $ 1.20. During summer, the standard E-20 rate during *peak* period is reduced by $ 0.00244 per kWh and during *partial-peak* period by $ 0.00049 per kWh.

Demand Charges PDP					
[$/kW]	***Maximum demand***	***Peak***	***Partial-Peak***	***Off-Peak***	***PDP Event***

[139] (Pacific Gas and Electric Company, 2010a, p. 11)

[140] FERC refers to this type of program as *Dispatchable DR*.

[141] (Pacific Gas and Electric Company, 2012a, p. 8)

[142] This tariff would be E-20 in this case.

[143] (Pacific Gas and Electric Company, 2010a, p.3)

[144] In chapter 7.2 PDP will be compared to the standard E-20 tariff under different scenarios for the case study facility.

[145] (Pacific Gas and Electric Company, 2010b)

[146] As presented in Table 1.

Summer	9.36	7.63	1.82	0	0
Winter	9.36	0	0.25	0	0

Table 4: Demand Charges PDP[147]

There is no additional demand charge during PDP event times. Load during PDP event times will still drive the *peak* period maximum demand charge as well as the maximum demand charge. However, during summer the *peak* demand charge is reduced by $ 6.30 per kW and the *partial-peak* charge by $ 1.15 per kW. The maximum demand charge and the *off-peak* maximum demand charge remain unchanged.

Event and Participation Data

PDP events are triggered by different causes defined in the rate schedule. These triggers are:[148]

- Temperature at or above 98° F on weekdays or 105° F on weekends and holidays
- Emergency grid condition declared by CAISO
- Extremely high forecasted spot market prices
- Need to meet annual PDP event limits[149]
- Testing/ evaluation purposes

In 2011 these triggers caused a total of nine event days: one in June, two in July and August, and four in September.[150] During these events the 2,207 customers enrolled[151] in the program[152] were able to achieve an average of 33.89 MW load reduction per event.[153]

3.2.3 Demand Bidding Program

The Demand Bidding Program (DBP) is the first actual DR program presented in detail in this report. As DBP does not define rates for non-event hours but only determines an incentive for lowered consumption during a called event it is classified as a DR program rather than a tariff.[154] However, DBP does not force its participants to curtail load but – much like PDP – provides an economic incentive for doing so. Therefore, DBP is considered a *Price Responsive DR program*.[155, 156]

147 (Pacific Gas and Electric Company, 2010b)

148 (Pacific Gas and Electric Company, 2010a, p. 12 f.)

149 A minimum of 9 events per year must be called.

150 See Appendix B for detailed dates.

151 2,207 is the number of average of service accounts per month.

152 In total, there are 161,391 eligible accounts.

153 (Pacific Gas and Electric Company, 2012a)

154 Compared to PDP, that is considered a dynamic pricing or DR tariff.

155 By FERC definition this would be called a *Dispatchable DR program.*

156 (Pacific Gas and Electric Company, 2012a)

DBP is available to all non-residential customers on TOU tariffs, who have had a maximum demand of more than 200 kW during any of the last twelve months and who are willing to lower their demand by at least 50 kW during an event.[157]

Structure and Incentives

The rate schedule defines two versions of DBP: Day-Ahead and Day-Of. Day-Ahead means that PG&E will notify its customers on the day prior to the event day while customers will only be notified shortly before the event on the event day in the Day-Of version. This analysis will focus on Day-Ahead DBP only, since no Day-Of DBP event was called in 2011.[158], [159]

A Day-Ahead event is called by PG&E by noon of the last business day prior to the event day. Events are restricted to business days between noon and 8 p.m. After PG&E announced an event for the next day DBP participants can submit their bids for load reduction, i.e. how much they can curtail during which hour of the event, until 3 p.m. At 4 p.m. PG&E will then publish which bids have been accepted. Usually, all bids are accepted, only if a MW limit was announced by PG&E for the specific event, bids will be accepted on first-come first-serve basis.[160] Bids have to cover at least two consecutive hours of the event and must result in a curtailment of at least 50 MW for each hour.[161] Once the bid is accepted the customers will curtail their load according to their bid during the respective hours of the event.

After the event, the actual curtailment achieved by each customer is calculated. The calculation of the curtailment is based on the typical consumption of the customer compared to the event hours. The typical consumption is calculated as the average of the last ten similar weekdays prior to the event. This average is calculated for each hour of the event separately. Assuming that an event takes place on Monday between noon and 2 p.m., two values must be calculated: the average consumption of the hour from noon to 1 p.m. and from 1 p.m. to 2 p.m. on the ten prior Mondays[162]. These values will then be compared to the consumption of the respective hours during the event.[163] If the calculated reduction is within 50 % to 200 % of the bid, the incentive will be paid. The incentive is $ 0.50 per kWh load curtailment.[164]

There is no limit to the number of events called under DBP, which is due to the fact that customers can always choose if they want to submit a bid for a respective event or not without facing penalties. Even if customers submit a bid but then fail to reach a curtailment within 50 % to 200 % of their bid, they still face no penalty charges or exclusion from the program.[165] Thus, the bid must clearly be categorized more as statement of intent rather than a binding bid.

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157 (Pacific Gas and Electric Company, 2008)

158 (Pacific Gas and Electric Company, 2012a)

159 In addition, the effects and mechanisms of a Day-Of DR program will be studied under BIP.

160 For this analysis it will be assumed that events have no MW limit, which is true for the events in 2011.

161 (Pacific Gas and Electric Company, 2008, p. 3)

162 Holidays are excluded.

163 If the event day shows a significantly higher consumption, a Day-Of adjustment is possible that can potentially increase the average by 20 % if the consumption in the hours prior to the event were extraordinarily high.

164 (Pacific Gas and Electric Company, 2008, p. 5 f.)

165 (Pacific Gas and Electric Company, 2013d)

Event and Participation Data

DBP events can be triggered by three different conditions:

- When CAISO's load forecast for the next day exceeds 43,000 MW
- When CAISO issued an Alert Notice
- When PG&E forecasts that resources for the following day will not be adequate
- When PG&E decides to run an emergency simulation test event

However, even if one or both of the first two conditions are fulfilled, PG&E can still choose not to call an event if they assume that resources will be adequate within their service area.[166] A test event is treated as a normal event with respect to the incentive but can only be called twice a year and is limited to a maximum of four hours per event.[167]

In 2011 two events under DBP were called, both in September.[168] During these events the 1,050 customers enrolled[169] in the program[170] were able to achieve 66.3 MW load reduction in the first event and 47.7 MW in the second.[171, 172]

3.2.4. Base Interruptible Program

BIP is the second actual DR programs presented in this report in detail. PG&E classifies BIP as an *Emergency DR Program*[173] meaning that once enrolled in this program, customers must curtail[174] to ensure system stability in emergency situations.[175] While PDP can be considered a measure of DR, PDP also defines rates for non-event hours and, therefore, is more of a mixture between a normal tariff and an actual DR program. However, BIP is a real DR program and is a pure DR add-on to the underlying electricity tariff of the customer. The normal consumption is billed based on the underlying tariff while participation in DR is billed in accordance with the BIP schedule. BIP is available to customers under industrial and agricultural tariffs with at least 100 kW average monthly demand.[176]

Structure and Incentives

BIP is a capacity-based DR program, meaning that participants are incentivized not based on the energy saved during a DR event but based on the amount of kW they can lower their demand by. When enrolling in the program customers must determine a Firm Service Level (FSL). The

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166 (Pacific Gas and Electric Company, 2008, p. 3)

167 (Pacific Gas and Electric Company, 2008, p. 5)

168 See Appendix B for detailed dates.

169 1,050 is the average number of service accounts per month. Monthly variation of the average is rather low.

170 In total, there are 10,199 eligible accounts.

171 No reliable information was available on incentives paid under DBP in 2011.

172 (Pacific Gas and Electric Company, 2012a)

173 FERC categorizes these type of programs as *Non-Dispatchable DR programs.*

174 If customers do not curtail they face drastic penalties.

175 (Pacific Gas and Electric Company, 2012a, p. 8)

176 (Pacific Gas and Electric Company, 2012b, p. 1)

FSL[177] is the level that customers promise to lower their demand to, or below, in case of a BIP event. The FSL is basically the level of power that the customer can lower its load to during a BIP event without endangering its operation or security. It is the level of power that PG&E will ensure to provide the customer during a BIP event. The FSL must be below 85 % of the customer's monthly maximum demand during summer *peak* periods[178] over the past twelve months. At the same time the FSL must be selected in such a way that the load reduction during an event is at least 100 kW.[179] The FSL can be re-selected once a year during the month of November.[180]

A BIP event is called at least 30 minutes in advance and limited to one event per day and a maximum of four hours per event. PG&E can call up to ten events a month and a total of 120 hours per year. Events can be called year round but mostly occur during summer season.[181]

As a capacity-based program the customer is paid for the Potential Load Reduction (PLR) that he promises to deliver during a BIP event. The incentive is paid based on the kW the customer promises to reduce its load by, even if no event is called in the respective month. The PLR is calculated each month as the difference of the month's average *peak* period demand and the chosen FSL:[182, 183, 184]

$$PLR = \frac{\sum_{on-peak} Energy[kWh]}{\sum_{on-peak} Time[hours]} - FSL \qquad \text{(Eq. 3.1)}$$

The resulting PLR is then multiplied by the respective incentive level:[185, 186]

Potential Load Reduction	Incentive Multiplier
Up to 500 kW	$ 8 per kW
Between 500 kW and 1,000 kW	$ 8 per kW
Over 1,000 kW	$ 9 per kW

Table 5: BIP Incentive Multipliers

Nevertheless, if the customer fails to deliver the load reduction he promised, meaning he consumes more than his designated FSL during an event, steep penalty charges apply[187] and repeated failure to reduce to or below the FSL during an event, results in exclusion from BIP.[188, 189]

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177 In kW.

178 Or winter *partial-peak* periods.

179 (Pacific Gas and Electric Company, 2012b, p. 1)

180 (Ibid., p. 7)

181 (Ibid., p. 4)

182 The calculation in winter considers the average partial-peak period demand.

183 Days, on which the customer participated in any kind of DR event, are not considered in this PLR calculation.

184 (Pacific Gas and Electric Company, 2012b, p. 5)

185 (Pacific Gas and Electric Company, 2012b)

186 This is done on a monthly basis.

Event and Participation Data

BIP events are called by PG&E on CAISO's request. CAISO can request PG&E to call a BIP event when one of the following four conditions applies.[190]

- CAISO issued a public warning and a Stage 1 emergency is imminent
- During a Stage 1, Stage 2, or Stage 3 emergency
- Forecasts of system conditions and operating procedures predict critical states
- Transmission system contingency

In addition, PG&E can trigger two events per year to test and verify the promised load drop. These drills will be operated and counted as normal program events.

In 2011 these triggers caused two events with a total of 2.25 event hours.[191] During these events the 215 customers enrolled[192] in the program[193] were able to achieve an average of 99.85 MW load reduction per event. This average, however, is intriguing as in the first BIP event only a 4.4 MW reduction was achieved while during the second event the customers delivered 195.3 MW although the number of customers enrolled increased only very slightly between the two events. PG&E paid a total of $ 19,698,026 in incentives to its BIP customers in 2011.[194] The discrepancy between the number of events and the high amount of incentives paid is explained by the previously mentioned fact that the incentive does not depend on the number of events actually called but the PLR.

3.3. Concept of Microgrids

As outlined in the motivation of this work[195], microgrids are a promising concept that might provide ease to the pressing issue of changing the electricity supply paradigm. Microgrids can be of help to integrate fluctuating renewable energy resources into the macrogrid without threatening supply reliability. In a first step on the way to a smarter macrogrid, microgrids could participate in DR programs[196] and thereby support overall system energy efficiency while lowering the energy costs of the microgrid operating facilities.

To ensure a common understanding of the term *microgrid*, this chapter will define the term, highlight key advantages and finally outline the critical functions of a microgrid.[197] Following,

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[187] In the analysis the penalties are not considered in detail as the implementation of the optimization is set up to ensure compliance with the FSL. For details see sub-chapter 7.4.1.

[188] (Pacific Gas and Electric Company, 2012b, p. 6)

[189] For the first failure, a customer is charged $ 6 per kWh consumed above its FSL during the event.

[190] (Pacific Gas and Electric Company, 2012b, p. 7)

[191] See Appendix B for detailed event dates and times.

[192] 215 is the average number of service accounts per month.

[193] In total, there are 10,199 eligible customers.

[194] (Pacific Gas and Electric Company, 2012a)

[195] See chapter 1.1.

[196] Like those outlined under 3.2.

[197] See sub-chapter 5.5.1.

the expected future development of microgrids will be outlined.[198] At the end of this chapter, a specific manifestation of this concept, the CERTS protocol, will be presented as it is specifically relevant to SRJ.[199]

3.3.1. Definitions, Key Benefits and Functions

In this sub-chapter microgrids will be defined and key benefits and functions will be presented.

Definitions

According to the Microgrids Exchange Group "*a microgrid is a group of interconnected loads and distributed energy resources within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid. A microgrid can connect and disconnect from the grid to enable it to operate in both grid-connected or island-mode.*"[200]

This definition is the least common denominator that most researchers in this field can agree on, but there are numerous other definitions, each with a slightly different spin to it.[201] As the general definition above does not specifically include the integration of storage, one slightly more detailed definition will be given to show the diversity in this relatively young field of research. The Hohai University of China presented its own definition of a microgrid on an IEEE conference in the United Kingdom as following: *"A microgrid is a low-voltage system with DG, storage systems and loads. The major energy resources in a microgrid are clean energy, and power electrics converters are used to implement energy conversion. A microgrid can be balanced by itself with some control strategies. It can be operated in independent mode or grid-connected mode. As an autonomic unit it can meet the requirements of high quality and security power supply."*[202] This definition shows that the integration of electric storage can also be considered within the microgrid concept.

Beyond these minor deviations in definitions, microgrids generally embrace a more independent approach compared to the typical integration of distributed energy resources (DER) at a low-voltage level. Typically, DER only react to certain circumstances on the macrogrid following a predefined pattern of operation. In a microgrid however, DER are controlled locally based on a variety of factors and operate in two different modes. During grid-tied operation, which is the standard modus operandi, the microgrid is able to purchase energy from or supply it to the macrogrid. More elaborated microgrids are also able to supply DR or ancillary services to the macrogrid during grid-tied operation.[203] The second mode of operation is the islanding mode, where the microgrid is completely disconnected from the macrogrid and ensures its own power supply as well as voltage and frequency control. The switch to islanding mode can be triggered

[198] See sub-chapter 5.5.2.

[199] See sub-chapter 5.5.5.

[200] (Department of Energy, 2011, p. 1)

[201] (Organization for the Advancement of Structured Information Standards, 2013)

[202] (Hohai University, 2011)

[203] Microgrid involvement in DR will be discussed in the following. For details on ancillary services supplied by microgrids please refer to (von Appen, 2011).

by economic benefits or reasons related to supply reliability i.e. a black out or disturbances in power quality.[204]

In a typical microgrid the DER are located at one site but a microgrid can also be formed by geographically spread out DER as long as usage is jointly controlled.[205]

Key Benefits

Independent from the detailed technical implementation, microgrids delivers five key benefits:[206]

- Microgrids enable the integration of various smart grid technologies and the overall grid modernization.
- Microgrids help to lower peak loads and minimize losses through the integration of distributed and renewable energy resources by geographically placing generation close to the demand.
- Microgrids help customers with critical loads ensuring a continuous energy supply not depending on the state of the macrogrid, and thus give customers the ability to control power quality and reliability at the most local level.
- Microgrids foster the participation in demand-side management and DR and help to involve communities in the electricity supply.
- Microgrids support the macrogrid in handling the variability of RES at a local level and allow for the supply of ancillary services to the bulk power system.

Key functions

In order to deliver these benefits the microgrid architecture must embraces three critical functions:[207]

- *DER controller:* The DER controllers are located at each DER and regulate voltage and power flow of every DER within the microgrid. Voltage and power flow are controlled based on changing operating points and the loads connected to the feeder. DER controllers have to react quickly and ensure that each DER provides the needed power when the microgrid goes into islanding. The fast reaction time of only a few milliseconds is achieved by measuring voltage and current at numerous points throughout the microgrid. Thereby each controller is enabled to react to predetermined conditions without communication with the other DER controllers.

[204] (Microgrid Symposium, 2010)

[205] (von Appen, 2011, p. 24 f.)

[206] (Department of Energy, 2011, p. 1)

[207] (Lasseter et al., 2002)

- *Energy manager:* The different DER controllers obtain their power and voltage set points from a centralized energy manager that controls the whole microgrid. The energy manager is able to fix set points for each DER controller based on the operational, technical, and economical targets determined by the operator of the microgrid.[208] For example, if the reliability of the power supply is of highest relevance within a specific microgrid, the energy manager might reserve more back-up capacity in the electric storage, even if this causes slightly higher costs during normal operation. Other examples for the targets of a microgrid might be the minimization of emissions, the maximization of DER efficiency or the provision of DR services to the macrogrid.

- *Protection coordinator:* This third critical function ensures that smooth islanding of the microgrid from the macrogrid and a synchronized reconnection of micro- and macrogrid is possible. The protection coordinator surveillances both electrical sides at the point of common coupling (PCC) at all times and triggers islanding in case of a macrogrid fault.

3.3.2. Expected Development

To conclude this general introduction to the concept and emphasize the relevance and dynamics of this research topic, the expectations regarding the future development of microgrids will be outlined briefly. Within the U.S. the DOE Office of Electricity Delivery and Energy Reliability is fostering the development and implementation of microgrids and has clearly defined its aims for the year 2020. For commercial scale microgrids up to 10 MW, the DOE aims to reduce outage times by over 98 %, at costs comparable to uninterrupted power supply systems as they are used by most critical load customers nowadays. While doing so, microgrids are expected to reduce emissions by over 20 % and improve system energy efficiencies by more than 20 %.[209] Unfortunately, these aims come without a comprehensive national or federal policy that would help to create a market for customer driven microgrids in the U.S.[210] Nevertheless, private research firms estimate a compound annual growth rate of more than 22 % in microgrid capacity over the next five years on a global level. This means that microgrids are estimated to embrace almost 5 GW of electricity supply and demand worldwide by 2017.[211]

3.3.3. CERTS Microgrids

After previously outlining the microgrid concept in general, this sub-chapter will focus on the presentation of a specific standard developed to foster the development and allow for the technical implementation of microgrids.[212] After providing the relevant definition, the included DER will be presented. To conclude this sub-chapter the possibility of a microgrid to use its load as a resource will be discussed.

The Consortium for Electric Reliability Technology Solutions (CERTS) is a research group that conducts research for the U.S. DOE Transmission Reliability Program and for the California

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208 (Hatziargyriou et al., 2006)

209 (Department of Energy, 2011)

210 This is also true for most of the developed and developing world.

211 (PikeResearch, 2012)

212 This specific standard is chosen for more detailed presentation as the microgrid at the facility under research is built in accordance with CERTS.

Energy Commission (CEC) Public Interest Energy Research (PIER) Program. The group is formed by members of different research institutions, including the Lawrence Berkeley National Laboratory (LBNL).

Definition

As a key part of its research, CERTS developed a microgrid concept and summarized it in the following definition:

"The CERTS microgrid concept assumes an aggregation of loads and microsources operating as a single system providing both power and heat. The majority of the microsources must be power electronic based to provide the required flexibility to insure operation as a single aggregated system. This control flexibility allows the CERTS microgrid to present itself to the bulk power system as a single controlled unit that meets local needs for reliability and security."[213]

This definition is in line with the above given general definitions of a microgrid but goes more into detail on the CERTS specific view of a microgrid. It also explicitly embraces heat generation and heat load into the microgrid concept.[214]

Microsources

CERTS microgrid concept embraces five types of microsources:[215, 216]

- *Microturbines:* Fueled by natural gas, these units are acceptably clean and are common at power ranges of 25 to 100 kW per unit. The output of microturbines can be controlled in a timely manner.
- *Fuel cells:* With high efficiency and low emissions, fuel cells are well suited for the integration in environmental conscious microgrids. Commonly used around 200 kW range, larger Fuel Cells (FC) exist and are tested. The output of a FC is constant and up and down regulation is a complex matter.
- *Renewable generation:* All types of renewable generation are included in the microgrid concept. Especially PV systems and wind turbines are suited for the integration due to their connection to the grid through power electronics and inverters.
- *Storage technologies:* Batteries as well as ultracapacitors are very important components of microgrids. As load constantly changes and power output in microgrids can only be adapted in a finite short time, storage is crucial to allow for islanding. Connected to the macrogrid, the inertia of the large generators ensures the initial energy balance but in a microgrid without large generators the initial energy balance can only be maintained by fast reacting resources such as batteries or ultracapacitors.[217]

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213 (Lasseter et al., 2002, p. 1)

214 While this differentiation is worth mentioning the research of combined heat and power systems is not the focus of this report and will, therefore, not be discussed further.

215 Microsource and DER can be considered synonymous within this report.

216 (Lasseter et al., 2002, p. 3)

217 (Lasseter et al., 2002, p. 13)

- *Heat recovery:* As combined heat and power is a part of the CERTS microgrid concept, heat recovery equipment is also considered a microsource. This includes low and medium temperature heat exchangers as well as absorption chillers.[218]

The interconnection and operation of these microsources is controlled within the CERTS microgrid architecture, which is described in the appendix[219] along with detailed information regarding the power electronics that are crucial for the CERTS microgrid concept but not within the core focus of this report.[220]

Load as a Resource

Due to the advanced control electronics and overall system architecture[221] any CERTS microgrid is able to present itself to the bulk power system as a *good citizen* meaning that it will not cause any additional stress to the distribution network. This is what most customers on the grid are expected to be. However, due to its smart electronics a CERTS microgrid is also able to go one step further and can potentially behave as a *model citizen* to the macrogrid. Being a model citizen means to not only cause no additional stress to the bulk energy system but to help the macrogrid mitigate stress and congestions. A microgrid based on CERTS technology can do so by presenting itself to the grid as an interruptible load that can be partially or totally shed during critical peak and congestion times. In addition, a microgrid can theoretically provide ancillary services to the grid or export power from its DER.[222] Presenting itself to the grid as an interruptible load, is what DR basically is and what is at the core of this report.

Leveraging the energy management system in combination with load shed and shift capabilities, a microgrid can easily take part in standard DR programs where the utility calls up the program participants and requests the load to be lowered on the following day.[223] If the microgrid is able to follow this request, it will be compensated for doing so and simultaneously provide a service to the macrogrid. Most industrial production facilities could take part in this type of DR to some extent.[224] Thinking further ahead a CERTS microgrid, with its entire smart infrastructure, would also be able to take part in more demanding DR programs that are more helpful for the macrogrid operator, as well. This second type of programs[225] gives no warning[226] and curtails the power consumption of a participating customer[227] very rapidly to reduce stress to the macrogrid. If a CERTS microgrid would take part in such program the above-described layout and power electronics infrastructure could rapidly adapt the consumption and supply structure without

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[218] As mentioned before, heat recovery and combined heat and power systems will not be analyzed further in the report at hand.

[219] See Appendix B.

[220] See Appendix B.

[221] See Appendix B for details.

[222] In real-life these services still face limitations and problems described in (Lasseter et al., 2002, p. 26).

[223] DR programs and tariffs such as PDP or DBP. For details see subchapters 5.2.2. and 5.2.5.

[224] The type of business and the way operations are run determines how much DR capability a certain company or facility can provide. The Demand Response Research Center at LBNL conducts significant research evolving around this type of problems.

[225] Such as BIP. See sub-chapter 5.2.4.

[226] In a slightly softened version of these DR programs a warning might be issued but only very shortly before the event begins.

[227] The curtailment can either be to zero or more commonly to a previously agreed upon power level.

any effect on the supported operations and thereby leverage its technology to support the larger goal of an improved and more reliable macrogrid.[228] This more demanding type of DR programs is also expected to drive higher financial benefits for the microgrid operator.[229] Being able to leverage the microgrid infrastructure in the most profitable way, e.g. in interruptible DR programs, is important for the microgrid operators as well as for the overall concept of microgrids to be able to balance the initial investment costs.[230]

The key access to these questions is how microgrids can be incentivized best to leverage their infrastructure to support the macrogrid operation. This very question is at the core of the following analyses that will – based on a case example – determine if it is economically viable for a CERTS microgrid to dispatch its resources under existing DR incentive schemes. This analysis will be carried out for the newest and largest CERTS microgrid facility operational, actually the first large-scale real-life application of the CERTS concept, which had its grand opening at Santa Rita Jail in California in March 2012.[231, 232] Santa Rita Jail and its microgrid will be described in detail in the next chapter.

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228 (Lasseter et al., 2002, p. 10)

229 Whether this expectation is true, will be answered in sub-chapter 7.4.

230 For actual microgrid investment costs refer to chapter 4.4. and Appendix C.

231 (U.S. Department of Energy, 2010, p. 12)

232 However, until the new CERTS microgrid became operational extensive testing and developing was conducted at the CERTS microgrid laboratory test bed in Ohio. Without this test bed, the real-life CERTS application could not have been implemented. A short description of the test bed is given in Appendix B.

CHAPTER 4:
Santa Rita Jail

After previously describing the general setting of the California electricity market and introducing DR and microgrids in general, in section four, the case-specific part of the report commences and the facility under research will be introduced in detail.

In the first part of this section, Santa Rita Jail (SRJ), a facility hosting a modern microgrid and the facility under research in this report, is introduced.[233] The second chapter gives a detailed description of the various DER installed at SRJ to introduce the reader to the setting of the following analyses.[234] In the last two chapters, first the SRJ traditional internal grid structure is described[235], and then the microgrid specific infrastructure of the largest CERTS-based microgrid in the U.S., operational at SRJ,[236] is presented.[237] The detailed description of the power supply sources and the traditional and upgraded grid infrastructure is crucial to the understanding of the report at hand as the following analyses[238] are based on the specifics of SRJ to ensure meaningful and applicable results.

4.1. Campus Description

When discussing state-of-the-art microgrid installations, SRJ in Alameda County, California needs to be mentioned. SRJ was reopened after an extensive remodeling in 1989 on a 0.5 km^2 site 50 km east of San Francisco, California.[239] With about 4.500 inmates the jail is the third largest detention facility in the state of California and the fifth largest in the U.S.[240] SRJ is separated into 18 free-standing housing units that are grouped around two open-air yards. The administrative buildings as well as the general entrance are located between the left and right wing of inmate housing units. In the north-west corner, behind the employees' parking lot, the service buildings are located outside the jail's high-security area. The aerial photograph below gives a good initial overview of the large facility.

233 See chapter 4.1.

234 See chapter 4.2.

235 See chapter 4.3.

236 (Korosec, 2012)

237 See chapter 4.4.

238 For analyses refer to section 7.

239 (Dierckxsens, 2009, p. 4)

240 (Chevron Energy, 2009)

Figure 2: Aerial Photograph of Santa Rita Jail[241]

A more detailed view of the jail is depicted in the outline below.[242] The jail has three different security standards within the housing units. On the west end, housing units 1 to 4 and 6 to 9 are reserved for maximum-security detainees. In this area, small, mostly single cells are available for the prisoners. In the minimum-security area on the north-east end of the jail, in housing units 31 to 35, the inmates are situated in group cells. In the housing units 21 to 25, medium-security prisoners are housed in a mixture of smaller and larger group cells. All housing units have the same basic layout with the cells being located around a pond in the middle for day-use. The housing units all consist of two stories.

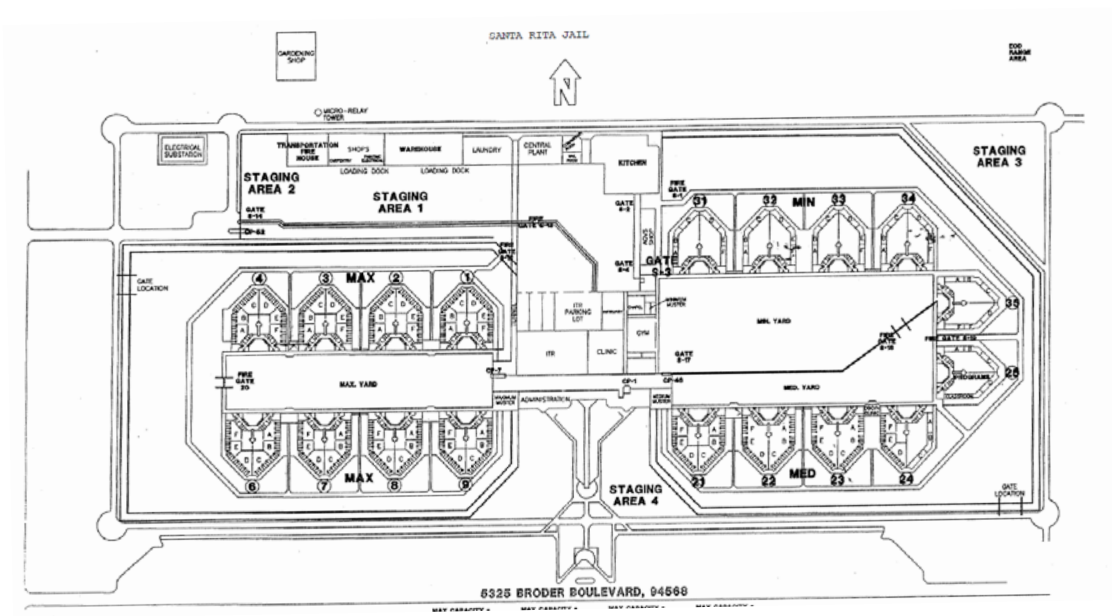

Figure 3: Floor Plan Santa Rita Jail[243]

SRJ is a one of the major electricity loads within the area.[244, 245] The jail consumes roughly 2.5 MW constant load and as the biggest facility under county governance makes up for 30 % of the

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[241] North is towards the top-right corner of the picture. (Scientific American, 2012)

[242] See Figure 3: Floor Plan Santa Rita Jail.

[243] Information provided by Alameda County.

[244] Apart from the size of the facility, this is also illustrated by, for example, the number of 12,000 meals that are being prepared and cooked centrally and electrically reheated upon arrival to the housing units at the jail every single day.

county's utility budget. Therefore, electricity costs are a major consideration for its operator, the Alameda County authority.[246]

4.1.1. Green Jail

To reduce electricity costs as much as possible, Alameda County, with its numerous private and public partners, has undertaken different measures in regards to energy efficiency and on-site generation.[247] The accumulation of these projects is the reason why SRJ is often referred to as the *Green Jail* in the press as well as in academic literature.[248]

Apart from the installation of several DER that will be discussed later on[249], different efficiency measures have been undertaken at SRJ. The two most important improvements are:[250]

- Air condition chiller replacement (2001)[251]
- Lighting retrofits (2009, 2010)[252]

These two projects in combination with a freezer upgrade completed in 2010 are expected to shave about 900 kW of the jails peak demand.[253]

4.2. Distributed Energy Resources and Electric Storage

The high demand for electricity at SRJ is supplied from a series of DER in combination with a connection to the PG&E distribution network. Last year, electric storage was installed to allow for further optimization of DER usage and grid supply. In the course of this chapter the different sources of electricity supplying SRJ are shortly introduced and described.[254, 255]

4.2.1. Photovoltaic

In 2002 a vast amount of PV arrays was installed on the roofs of most housing units of the jail. At the point of installation the PV system was the largest in the western hemisphere. The peak production of the three acres of panels is rated at 1.2 MWp. The panels are split into four groups and transfer their power to the jail through four separate inverters.[256] The panels are flat-mounted to the roof of the housing units. A picture of the flat-mounted panels as well as

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[245] (Dierckxsens, 2009, p. 4)

[246] According to Alameda County Energy Program Manager Matthew Muniz as quoted in (Ritchie, 2012).

[247] (DeForest et al., 2012, p. 2)

[248] For academic literature see (Marnay, 2012), for press releases see (PV Magazine, 2012).

[249] See Chapter 4.2.

[250] (DeForest et al., 2012, p. 2)

[251] See Appendix C for more detailed description.

[252] See Appendix C for more detailed description.

[253] (DeForest et al., 2012, p. 2)

[254] A detailed analysis of the generation profiles will follow in chapter 5.1.

[255] In 2012 a ground-mounted 275 kW sun-tracking PV array was installed. This installation is not part of this report, as the installation was not finished by the beginning of the analysis.

[256] PV panels from BP Solar as well as Astro Power were used.

discussion of the advantages and disadvantages of flat-mounting versus tilted-mounting is provided in the appendix.[257]

The installation of the panels was conducted in a joint project with the aforementioned AC chiller upgrade[258] as well as some minor energy efficiency measures. For the joint project the total cost of $ 9,000,000 were financed by loans from the CEC and the California Public Utility Commission. The project was expected to save up to 2,400,000 kWh annually and reduce the peak demand by roughly 30 %, which translated to expected savings of $ 410,000 per year. Over the 25 year lifetime the project was supposed to drive a net benefit of $ 15,000,000.[259]

4.2.2. Fuel Cell

After the PV project the next major energy project at SRJ was initiated in 2005 and completed mid 2006. In cooperation with Chevron Energy Solutions SRJ installed a 1 MW DFC1500, molten carbonate FC power plant with heat recovery cogeneration. The FC was installed to help cover the base load of the jail at lower costs and more energy efficiently, while the heat recovery unit was supposed to pre-heat the hot water for the domestic hot water system and thereby reduce the demand for natural gas. At the time of installation the FC was the first megawatt-class FC cogeneration plant in California and one of the largest in the U.S.[260]

The FC at the jail is a molten carbonate FC that operates at an approximate temperature of 1,200° Fahrenheit[261] and therefore requires a lengthy start-up process.[262] This is the reason why the FC is to be operated continuously, supplying the base load demand. By doing so, the FC is expected to generate around 8,000,000 kWh or around 50 % of the jail's annual load, which would produce annual electricity savings of $ 266,825.[263] The total costs of the project were $ 6,100,000 that could be reduced by $ 2,400,000 incentives from different sources. Chevron Energy Solutions calculated the net savings of the project to be $ 6,600,000 over the expected life time of 25 years.[264]

4.2.3. Wind Turbines

In 2010 SRJ installed even more renewable energy resources at its facility. In a small project, five wind turbines from Southwest Windpower were installed. The Skystream 3.7 models deliver 2.3 kWp.[265] As the electricity production is relatively small compared to the other DER as well as the overall load, no detailed data is available on the production of the wind turbines. Based on

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[257] See Appendix C.

[258] Described in chapter 4.1.1.

[259] Based on 2002 PG&E tariffs.

[260] (County of Alameda, 2006, p. 1)

[261] 649° Celsius.

[262] A brief description of the basic operation principles of FC is given in Appendix C.

[263] This is based on 2006 PG&E tariffs applicable to SRJ.

[264] (County of Alameda, 2006, p. 1 f.)

[265] (Wang, 2012)

the American Wind Energy Association (AWEA) annual energy rating of the turbines, an average output of 3,420 kWh per turbine can be estimated.[266]

As peak power as well as annual energy output of the wind generators only account for a very minor share of less than 1% of the maximum power consumption and total annual load, they will not be considered in the following analyses.[267]

4.2.4. Electric Storage

In the most recent energy project, SRJ installed a large electric storage onsite. The electric storage was one essential part of the larger microgrid project for SRJ. This paragraph gives an overview of the electric storage itself, while its role in the microgrid will be described later on.[268]

The installed electric storage has an energy capacity of 4 MWh and a power capacity of 2 MW. This high capacity is achieved through the connection of four 500 kW and 1 MWh Lithium Iron Phosphate batteries.[269] The Lithium Iron Phosphate technology is the first available rechargeable chemistry that is environmentally friendly and does not require the use of heavy metals or toxic electrolytes.[270] The battery is rated at 91.1 % round-trip-efficiency, while the decay is assumed to be 0.02 % per hour. During every-day operation the battery is not allowed to be discharged below 20 % state of charge to ensure availability of reserve capacity for unforeseen emergency situations.[271] The described storage technology is controlled by an S&C PureWave Storage Management System that controls the discharging and charging process.[272] The battery is able to be operated under the CERTS microgrid protocol[273, 274] and is located on-site in shipping containers as shown in the picture below.

Figure 4: Electrical Storage at Santa Rita Jail[275]

As mentioned, the battery was installed as part of the larger microgrid project and therefore the cost and savings of electric storage are hard to be broken out separately. However, roughly a

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266 For details on the AWEA rating see (AWEA, 2009).

267 0.35 % of peak demand and only 0.13 % of total annual load in 2011.

268 See chapter 4.4.

269 (Alegria, 2012)

270 (Enhanced Online News, 2012)

271 DER-CAM parameter assumption.

272 (S&C Electric Company, 2012)

273 More details regarding the integration of the battery into the microgrid is presented in chapter 4.4.

274 (Alegria, 2012)

275 (Alegria, 2012)

CAPEX[276] of $ 4,000,000 is attributed to the battery[277] and a lifetime of over 25 years is assumed.[278] Through this investment, the jail tries to achieve three main goals, i.e. the battery will allow to shift and store the onsite renewable generation, it will allow to conduct rate arbitrage for the electricity purchased from the grid,[279] and the battery serves as a quick responding back-up energy resource increasing the reliability of electricity supply within the jail.[280]

4.2.5. Diesel Back-up Generators

To be able to control over 4,000 inmates at all times a reliable power supply must be guaranteed. Due to the problems of the California grid mentioned previously[281] the jail has always been equipped with back-up generators. Currently, this back-up generation is provided by two 1.2 MW diesel generators.[282] Originally, these generators have been designed to supply electricity to the most relevant loads in case of an outage. Therefore, the generators were hard-wired to circuit A with the most relevant loads. When the first generator started, circuit A would be supplied right away. After the start of the second generator and the successful synchronization with the first generator, the medium relevant loads on circuit B would be connected step by step. In case of an outage the least important loads on circuit C would not be supplied.[283] Due to the numerous efficiency improvements, nowadays the back-up generators are able to cover almost all the load of the jail and allow for almost normal operation.

Since the microgrid with integrated electrical storage is operational, the generators are hardly needed, as outages can mostly be covered by the electricity of the battery and from other DER.[284] With the numerous DER and the electrical storage in place the diesel generators are only used to charge the battery during an extended outage. With an operational FC and some PV during the day, in combination with the electrical storage, the generators are only needed to guarantee electricity supply in longer outages. Due to the diesel generators being integrated in the microgrid concept, the jail is actually able to run self-sufficient for several days without any influence on operations.[285]

Although being relevant for the self-sustainability and security of the jail under extended outage situations, the generators will not be considered in the following analyses, as they were not used in 2011.[286] In addition, the back-up generators cannot be used for DR purposes due to legislation.

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[276] CAPital EXpenditure.

[277] (DOE Energy Storage Database, 2009

[278] (Enhanced Online News, 2012)

[279] Both these abilities have to be seen in connection with the microgrid project but could also be achieved if the battery was not part of a microgrid.

[280] This ability then clearly has to be viewed in close relation with the microgrid presented in chapter 4.4.

[281] See sub-chapter 2.1.2.

[282] (Ritchie, E., 2012)

[283] A detailed description of the different load priorities in the jail and the related circuits is given in sub-chapter 4.3.2.

[284] For details on the electrical storage please refer to sub-chapter 4.2.4. The SRJ microgrid, including the electric storage integration, is described in chapter 4.4.

[285] (Ritchie, E., 2012)

[286] Except for testing.

4.2.6. Grid Connection

In the past, the connection to the macrogrid at the PCC has been the main source of electricity for SRJ. With increased DER on-site generation, the grid demand has declined but is still a key parameter of the jail's electricity supply and has to be considered in close connection with the DER presented above. Therefore, the grid connection is presented at the end of this DER chapter.

Especially before the installation of the electric storage[287] and the start of the operational microgrid[288], the grid connection was essential to supply the demand not covered by the DER at all times.

Until 2011 the jail was not allowed to export electricity back to the grid. In case of an expected overproduction from PV and FC, the PV inverters or the FC had to be shut down. This was especially problematic for the FC, as a shut down and restarts takes up to hours and therefore results in significant additional lost savings. Since 2011 the jail is allowed to feed electricity back to the macrogrid in case of overproduction, which mitigates the aforementioned FC problems.[289] However, the jail is still not a net-metered customer[290] and is therefore not refunded for any exports to the grid.[291] SRJ is connected to the PG&E grid at 21 kV at the PCC.

4.3. Grid Layout

In this chapter the structure of the SRJ internal grid is described. In the first sub-chapter, the overall network is described basically as it has been operational since the reopening of the jail. Afterwards, the load-shed system with its different circuits will be discussed and ultimately the integration of the aforementioned DER into the traditional grid layout will be described.

4.3.1 Traditional Grid Layout

The basic layout of the internal grid today is still identical to the time of the reopening in 1989. Directly behind the PCC the voltage is stepped down from 21 kV PG&E distribution grid voltage to the internal jail distribution voltage of 12 kV at the main transformer. From the 12 kV main distribution loop, that spans the whole jail, the power is diverted to seven substations. At each substation the power is stepped down further to 480 V. The described high-level layout is depicted in the appendix.[292]

Behind each substation the electricity is distributed to different main control consoles connected to the substation with a 400 A main breaker. Each substation serves four to six main control consoles. From these consoles high voltage appliances, such as elevators or air compressors, are fed directly with a separate fuse. Smaller appliances including lighting, security equipment as well as plugs are served by switch bus panels that are fed from the main control console.

[287] See chapter 4.2.4.

[288] See chapter 4.4.

[289] As stated by Alameda County Energy Program Manager Matthew Muniz in a meeting with LBNL representatives on 4/24/2012.

[290] Net-metered basically means that the meter turns backwards when electricity is fed back into the grid and the customer only has to pay the differential of consumed and exported electricity.

[291] (Ritchie, 2012)

[292] See Appendix C.

Depending on the type of substation and main breaker circuit, between three and seven of these switch bus panels can be found behind a main breaker connection. In the appendix, the networks downstream from substation 1 and 2 are shown in detail.[293]

Substations 1 to 4 are structured very similar and, together, supply all inmate housing units. Substation 6 is located at the core of the facility close to the administration building and serves the core area and most of the administrative processes. Substation 7 and 8 are located in the service building on the north and supply electricity to different support processes needed within the housing units, e.g. HVAC or food cart operation, as well as to shops and facilities located in the service area such as laundry, kitchen, paint shop, firehouse, guard house etc. A detailed overview on the substations including locations, sub-circuits as well as served entities is given in appendix.[294]

4.3.2. Load Shed System

A basic grid layout, comparable to the one described above, can be found in most large industrial or even residential facilities. What differentiates the jail's internal grid is the load shed system that spans the whole network. Inherent to the operation of a jail is the fact that some loads are very critical and need to be supplied in the most reliable fashion to ensure inmate as well as staff and visitor security.[295] Other loads can be interrupted for a short while but should not be switched off for extended periods.[296] Finally, some loads increase the convenience of the operation but are not actually critical.[297] At SRJ the different priorities of loads have been implemented very comprehensively throughout the entire facility by the implementation of a load management system.[298] Basically, every load in the jail has been assigned one of the three load priorities, from loads directly connected to the main control consoles to a very granular distinction on split bus panels that allow assigning different priorities to loads connected to the same panel.[299]

Generally speaking, A loads include life and safety relevant loads. B loads consist of HVAC and lighting loads whereas C loads cover most non-critical plug loads, A/C chillers as well as more lighting.[300] This classification just covers the major shares. To be more specific, some critical lighting that has priority A exists, but the major share of lighting is on B and C. One can find A, B, and C lighting fixtures even within the same room. During normal operation all lights are on to provide proper luminosity. In the beginning of a blackout only some lights on the A circuit would be working to allow for basic orientation. With both back-up generators up and running

[293] See Appendix C.

[294] See Appendix C.

[295] At SRJ these loads are referred to as A loads.

[296] At SRJ these loads are referred to as B loads.

[297] At SRJ these loads are referred to as C loads.

[298] Manufactured and implemented by Honeywell.

[299] As visible in Line Diagrams. Line Diagrams provided by Alameda County are not included in this document due to confidentiality restrictions.

[300] Shown in Panel Schedules and Line Diagrams. Panel Schedules and Line Diagrams provided by Alameda County are not included in this document due to confidentiality restrictions.

B lights would be available providing a dimmed, but fairly acceptable lighting.[301] To provide a more detailed understanding of this lighting example and to give the reader a feel for how much lighting is within each priority group, the shares of connected lighting loads for each shed priority are given for each substation and at a whole jail level.

Share of Connected LIGHTING LOAD	Load priority A	Load priority B	Load priority C
Substation1	29%	14%	56%
Substation2	29%	20%	51%
Substation3	31%	20%	49%
Substation4	30%	0%	70%
Substation6	38%	17%	45%
Substation7	31%	0%	69%
Substation8	23%	0%	77%
WHOLE JAIL	**31%**	**12%**	**57%**

Table 6: Load Priority Shares for Lighting Load[302]

The key take-away from the graph above is the fact that throughout the whole jail facility 57 % of lighting is served under load priority C.

Beyond the described example for lighting, all other loads have one of the three load priorities assigned as well. Below, the shares of each load shed group for all loads within the jail are given to conclude this section.

Share of connected TOTAL LOAD	Load priority A	Load priority B	Load priority C
Substation1	24%	42%	34%
Substation2	34%	54%	29%
Substation3	18%	50%	32%
Substation4	16%	42%	42%
Substation6	14%	31%	56%
Substation7	7%	20%	73%
Substation8	24%	27%	49%
WHOLE JAIL	**15%**	**36%**	**50%**

Table 7: Load Priority Shares for Total Load[303]

[301] For details regarding the provision of back-up generation in case of a blackout please refer to chapter 4.2.5.

[302] Own analysis based on Panel Schedule information provided by Alameda County. The table provides information on the ratio of **connected** values. Actual consumption and power demand may differ. The Panel Schedules provided by Alameda County are not included in this document due to confidentiality restrictions.

[303] Own analysis based on panel schedule information provided by Alameda County. The table provides information on the ratio of **connected** values. Actual consumption and power demand may differ. The Panel Schedules provided by Alameda County are not included in this document due to confidentiality restrictions.

4.3.3. Distributed Energy Resources

The above described basic layout of the grid[304] has been enhanced by the installation of numerous DER over time described previously.[305] This paragraph will give a concise overview as to where the different DER have been connected to the SRJ traditional grid layout.

The **Photovoltaic** arrays are connected to the internal grid through four separate inverters.[306] The inverters are not directly linked into 12 kV loop but the power is back fed through the substations. The panels on housing unit 6, 7, 8, and 9 are connected to substation 2 with a 300 kW inverter. Panels on unit 21, 22, and 23 as well as on 24, 25, 34, and 35 are connected to substation 3 with a 225 kW inverter for each group. The panels on the roofs of building unit 31, 32, and 33 are connected through a 225 kW inverter to substation 4.[307]

When installed in 2006 the **Fuel Cell**[308] was connected to the 12 kV loop behind various power conditioning equipment. The operating power needed for the FC operation was also taken from this loop directly. With the installation of the battery and realization of the microgrid, the connection of the FC was altered.[309]

The **Wind Turbines** were installed in two different places adjacent to the jail facility.[310] Three windmills were installed on the west end next to housing units 4 and 6. These three turbines are connected to substation 2 via a 75 kVA transformer. The other two windmills are located on the north-west corner of the premises behind the service buildings and are connected to substation 7 via a 10 kVA transformer.

The **Diesel Back-up Generators**[311] are connected directly to the jail's 12 kV loop in parallel to ensure a minimum supply even if only one generator is able to start up. They are connected to the 12 kV loop at the same point at which the stepped-down supply from PG&E is fed in.[312]

The integration of the **Electric Storage** is not described in this chapter as it was installed as part of the microgrid[313] and is a core element of the microgrid architecture at SRJ. The following chapter will give detailed information on the microgrid project at SRJ.

4.4 Microgrid

In this separate chapter the biggest and most recent change to the electricity supply of SRJ will be described in detail. The installation and operation of a true microgrid at SRJ is the current culmination of the county's path to a modern and sustainable electricity supply. The microgrid

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304 As described in sub-chapter 4.3.1.

305 See chapter 4.2.

306 For details refer to chapter 4..3.3.

307 (Dierckxsens, 2009, p. 8)

308 For details regarding the FC please refer to chapter 4.2.2.

309 The new setup will be described in chapter 4.4.

310 For details regarding the wind turbines please refer to chapter 4.2.3.

311 For details refer to chapter 4.2.5.

312 See Appendix C.

313 The battery was never actually connected to the traditional i.e. pre-microgrid network.

project was finished with the official start of operation and the presentation to the public in March 2012.[314]

In this chapter, at first the general goals of the microgrid project will be outlined. Afterwards, the capabilities that are needed to achieve the goals will be derived and the needed new and upgraded equipment will be presented.

4.4.1. Goals

In cooperation with private and public partners under the guidance of Chevron Energy Systems, Alameda County's primary goal for the microgrid project was to demonstrate the commercial implementation of a CERTS microgrid in a large scale facility proving the CERTS concept.[315] At a public facility the project shall demonstrate the functionality and potential of a true microgrid in a real-life application, especially in combination with the existing DER onsite and the – as part of the project – installed electric storage.[316] This cutting edge approach is what makes this project interesting not only for industry partners[317] but also for research facilities such as LBNL. The project will provide usage data from a working microgrid and thereby supply the data-base for trendsetting research with a clear practical orientation.

The second major goal of the project was the full system integration of the renewable and clean DER at SRJ. The integration within a microgrid will allow for better utilization and control of the different DER.[318] This is especially important as before the implementation of the microgrid and the installation of the electric storage the DER output would sometimes exceed the jail's demand and as the jail is not net-metered, the fuel cell needed to be shut down to avoid over-production. Also, with the system integration of the existing DER and the battery buffer, the jail is now able to install further, new DER and continue to promote renewable energy production. Actually, after the completion of the microgrid, the jail started installing additional 275 kW of sun-tracking PV arrays. This installation would not have been possible without the advanced management capabilities of the microgrid.[319, 320]

Another important goal of the microgrid project was to increase the reliability of the electricity supply. With its need for a secure and reliable power supply for its critical operations, the jail has always had troubles with electricity supplied by PG&E. Although major outages have not occurred recently, the quality of the power supply caused problems at SRJ and affected operations. Frequent voltage swings also caused problems with the operation of the FC as the operating voltage needs to be very stable. Swings in the distribution network's voltage and frequency caused numerous outages of the FC and thereby affected overall costs negatively.[321]

[314] (Lawrence Berkeley National Laboratory, 2012)

[315] (Alegria, 2012)

[316] (County of Alameda, 2012)

[317] For example S&C Electric Company or SatCon Power Systems.

[318] (County of Alameda, 2012)

[319] (Ritchie, 2012)

[320] The 275 kW tracking PV will not be considered in this report as by the time the data-analysis was finished, no data was available on the output of this unit.

[321] As stated by Alameda County Energy Program Manager Matthew Muniz in a meeting with LBNL representatives on 4/24/2012.

Goal of the microgrid is to ensure 24/7 reliable power supply with high quality power to SRJ even if the macrogrid is under peak load stress.[322]

Another set of goals for the microgrid project was driven by the local utility. PG&E wants to leverage the microgrid at SRJ, of one of its largest customers in the region, to improve local grid stability as well as power quality and reliability in the network around the jail. They aim on doing so by finding ways to use the dispatchable DERs at the jail not only for the best benefit of the jail but also for the purpose of supporting the local grid. Research, related to this topic, will also have to deal with the question of how the operators of SRJ can be either forced or incentivized to dispatch some of their resources for the good of the local grid. As a first tangible goal in this larger set of goals, the microgrid at SRJ is to reduce the load on the PG&E distribution feeder by 15 %. Reaching this goal would allow PG&E to postpone expensive investments to the feeder infrastructure.[323, 324]

Finally, closely related to the previous set of goals, SRJ is also hoping to be able to take part in ancillary services, DR as well as energy price arbitrage by means of the microgrid.[325] Using the electric storage as part of the microgrid SRJ can purchase energy during off-peak times when the kWh-price is low and then use the stored energy in combination with the supply from the onsite DER during on-peak hours when kWh-prices as well as kW-prices are significantly higher. By doing so, the jail first and foremost reduces its electricity costs but from a more general perspective also supports stable grid operation. Utilities put time-of-use tariffs into place to shave off the typical mid-day peak in electricity consumption and motivate customers through price-differentiation to shift their load to the morning and night hours.[326] By using its microgrid for energy price arbitrage, it follows the incentives set by the utility and thereby supports grid stability.

While TOU tariffs try to mitigate the daily peak, DR programs focus on the highest peak days during the summer. Reliable participation in DR programs helps the local grid operator to maintain stable operations during critical peak times and therefore finally reduces the total cost of energy supply.[327] Due to the large amount of onsite generation and controllable load/supply by the battery the participation in these programs could drive significant economic advantages for SRJ. The identification of the saving potentials under different DR programs in combination with TOU structured tariffs is, as previously mentioned, the purpose of the report at hand.

4.4.2. Capabilities

To achieve the above-described goals, Chevron Energy Systems defined a list of capabilities for the microgrid. The core of the whole microgrid project revolves around the ability of the microgrid to island seamlessly from the grid. Therefore, the core capability defined is a

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322 (County of Alameda, 2012)

323 Please see (Alegria, 2012) and (County of Alameda, 2012).

324 This goal is in detail addressed in (DeForest et al., 2012).

325 (County of Alameda, 2012)

326 A typical cooling-driven load profile, as it is common in California, is presented in chapter 5.3.3. For German load profiles, especially industrial, please refer to (Thiemann, 2011).

327 This is discussed in more detail in chapter 3.1.

seamless islanding ability at the PCC in 8 ms or less. Only with the capability to island that fast it can be assured that all generation and loads are kept online during the switching period. Especially interesting in this context is the ability of the microgrid to island while the DER are still producing electricity. In a normal back-up generation scenario the backup generation comes online when a grid disturbance is detected and after the back-up generators are online the disconnection from the grid is made. However, in the case of the jail the issue is more complicated, as the islanding has to happen while the DER are continuously producing electricity. This complexity is tackled by a frequency and voltage control using the battery under the above-described CERTS protocol.[328]

During an extended outage of the utility power supply the microgrid should also have the ability to work without any disturbance. To achieve the goal of 24/7 reliable and high quality power supply even during extended outages, the microgrid also has to have the capability to not only control voltage and frequency under battery usage but must also be able to coordinate with the diesel backup generators in CERTS mode. During an extended outage, the generators will come online to recharge the battery and feed demand directly. A secure and reliable power supply will be ensured by the CERTS protocol.

In order to influence the utility feeder peak load and optimally mitigate the peak, the microgrid should also have the capability of a bidirectional power flow at the PCC. This ability could be used in a future scenario to supply electricity back to the grid during peak hours.[329]

The last capability is the ability to control the power flow at the PCC. This capability supports the goal of energy price arbitrage and participation in DR programs. Only with the ability to control the flow at the PCC, SRJ has the option to reduce its demand from the grid and instead use stored or self-generated electricity to supply its loads.[330]

4.4.3. Components

Although the technical implementation of the microgrid is not at the core of this analysis, a short overview of the upgraded and new components will be given and the new layout will be discussed. The below depicted single line diagram gives an overview of the general layout of the new microgrid.

[328] Regarding the CERTS protocol please refer to sub-chapter 3.3.3.

[329] This capability is needed more with a long-term perspective because as of now the jail is not on a net-metered tariff and therefore is not refunded for the export of electricity back to the grid. For the jail, the support of the local grid obviously would need some kind of incentive that is yet to be figured out. Nevertheless, the bidirectional flow capability at the PCC allows SRJ to export electricity back to the grid in case of overproduction. This non-refunded export might make economic sense as the alternative is to shut down the FC that takes several hours, even up to days, to be back at full output

[330] Discussion of capabilities based on (Alegria, 2012).

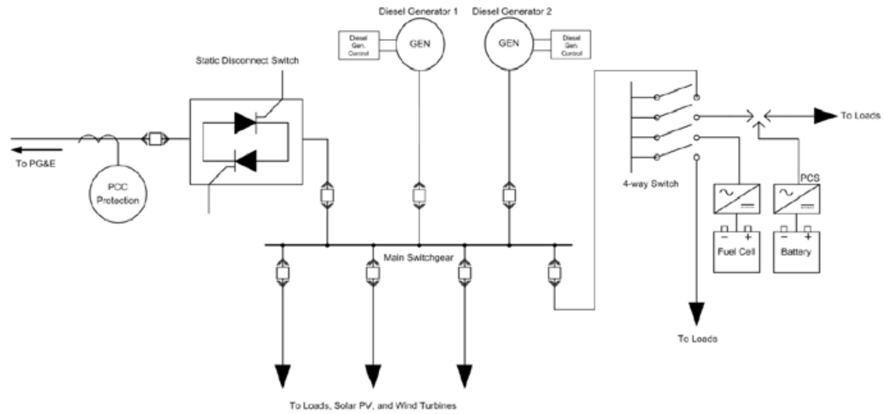

Figure 5: Main single line diagram Microgrid[331]

Starting from the left of the line diagram, the PCC protection scheme was upgraded to match the new requirements. At the 21 kV side of the transformer, conventional protective equipment is still installed to conform to PG&E's interconnection requirements. Downstream from the transformer on the 12 kV voltage level a static disconnect switch was installed. This static disconnect allows for the synchronization across the breaker and ensures a smooth islanding and re-connection to the grid. As shown on the top of the picture above, the diesel generator control system was upgraded in order to function under the CERTS protocol. On the very right hand side of the picture the integration of the battery into the microgrid is shown.[332, 333]

In addition to these changes shown in the picture, three major alterations have been made. First, a 12 kV 900 kVAR reactive power compensation was installed to ensure the correct ratio of real to apparent power.[334, 335] Second, the load shedding system was upgraded to better manage and control the shed of distinct loads. Basically, the system described before is still in place and the distinction into A, B, and C circuit is kept as before. However, after the upgrade, the load shedding system does not shed loads directly when the utility power goes out. In microgrid islanding mode the loads will stay online until a critical state-of-charge of the battery is reached before load shedding starts. Also, a computer controlled shedding of loads independent from the supply situation is now possible to allow for load shed under DR programs or for economic benefit.[336] The third alteration was the installation of a Distributed Energy Resource Management System (DERMS). This system estimates and measures the output of the different sources as well as the demand for upcoming time periods. The power flow at the PCC is controlled based on DERMS data. DERMS stores 15-minute data at numerous points of the microgrid and will allow for an even more detailed analysis in the future.[337, 338]

331 (Alegria, 2012, p. 8)

332 (Ibid., p. 6)

333 For details on electric storage please refer to chapter 4.2.4.

334 (Alegria, 2012, p. 6)

335 Large amounts of installed PV tend to cause problems with real to apparent power ratio. For details refer to (von Appen, 2011).

336 (Alegria, 2012, p. 16 f.)

337 (Alegria, 2012, p. 11.)

An overview of the costs and funding of the microgrid project is given in the appendix.[339]

[338] DERMS only collected data from March 2012 on and LBNL only obtained access to this data in late 2012. Therefore, the analyses in the report at hand are based on non-DERMS data.

[339] See Appendix C.

CHAPTER 5:
Generation and Load Analysis

In section five of the report at hand the generation at and load of SRJ will be analyzed for the years 2003 through 2011, with a clear focus on supply and demand data for the year 2011. In the first chapter of this section the relevant generation resources, namely PV and FC, as well as the amount of power procured from the grid will be analyzed to give the reader a basic understanding of DER behavior.[340] Afterwards, a short introduction to Building Energy Simulations (BES) will be given and the eQuest based BES model of SRJ will be described.[341] In the last chapter, the actual load will be juxtaposed to the model loads and further detailed analyses of the modeled loads from eQuest will be carried out.[342]

5.1. Generation and Total Load Analysis

To support the following analyses extensive amounts of raw generation and load data has been collected from Alameda County, organized, and cleaned. The data consists of 15-minute interval, actual and average power values for the PV arrays, the FC power output as well as the electricity supplied from PG&E. The addition of these three input factors will serve as total load for SRJ. The evaluated data covers the years 2003 to 2011 and is complete for all 15-minute values.[343]

In the following sub-chapters first the output of PV and FC will be analyzed for the years 2003 to 2011.[344, 345] Afterwards, the grid consumption and the total jail load will be discussed.[346] Concluding, generation and load for 2011 will be presented in a joint analysis to point out interdependencies.[347]

Assumptions

In order to handle the vast amount of data and to be able to carry out the analyses described in the following chapters[348], two simplifications were made. First, wind turbine output is considered negligible as discussed above.[349] Second, diesel back-up generation output will not be considered. This assumption is justifiable as the back-up generators are not a standard source of supply but are only used if the macrogrid shows disturbances. The back-up

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[340] See chapter 5.1.

[341] See section 4.

[342] See chapter 5.3.

[343] An overview of the data manipulation carried to create a consistent data-base is show in Appendix D.

[344] Respectively from 2006 to 2011 for FC as it was not installed before 2006.

[345] See sub-chapters 5.1.1. and 5.1.2.

[346] See sub-chapter 5.1.3. and 5.1.4.

[347] See sub-chapter 5.1.5.

[348] See chapter 5.1. and 5.3. and section 7.

[349] See sub-chapter 4.2.5.

generation was not used in 2011.[350] Also, with the installation of the microgrid, the relevance of the diesel generators will be further diminished.

5.1.1. Photovoltaic Output

This sub-chapter will discuss the performance and output of the PV arrays at SRJ.[351] As described above, the PV arrays at SRJ were installed in 2002 and are, therefore, present during the whole data analysis period. The extensive amount of real-life data allows for an insightful analysis of the array performance. To obtain a first overview, the graph below shows the monthly output of the PV arrays for the years 2003 to 2011.

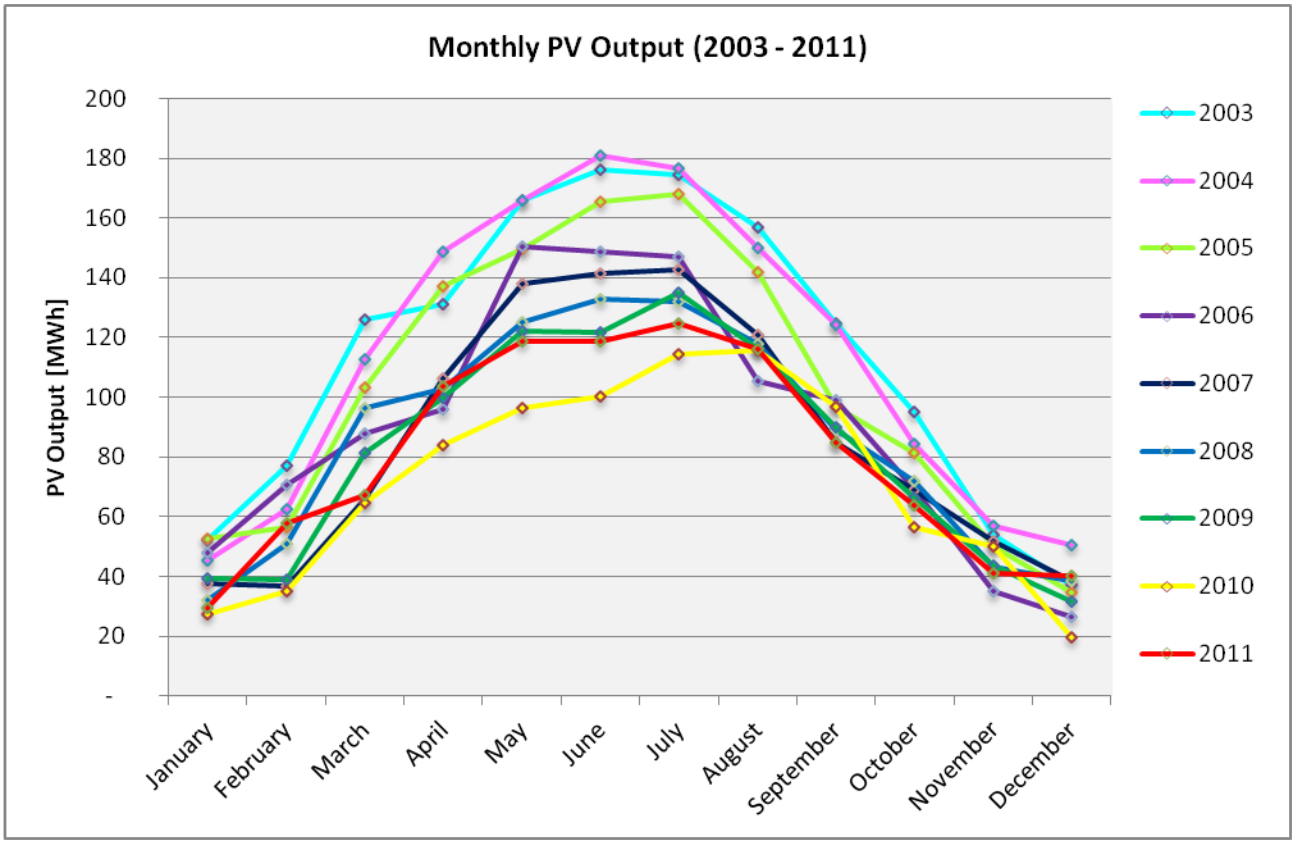

Figure 6: Monthly PV Output (2003 - 2011)

First, all curves describe the same general behavior. In all years, the highest production is observed in the summer months. The steepness of the curve, i.e. the difference between winter and summer output, was analyzed in an earlier report on the jail and it was shown that the flat mounting of the arrays[352] leads to a higher output during summer months and a lower winter output compared to a tilted mounting.[353]

[350] Except for testing.

[351] Technical details or the connection of the PV arrays to the internal grid are not detailed here. For such information please refer to sub-chapters 4.2.2. and 4.3.3.

[352] See Appendix C.

[353] A typical mounting angle of ~38° was the basis of that analysis (Dierckxsens, 2009, p 8).

The second insight from the analysis of the PV output above is the continuous deterioration of the PV output. Over the eight years observed, the total output sank by almost 30 %. In some years the annual deterioration was as low as 1 %[354] while other years show a decline of almost 13 %.[355, 356] Also remarkable is that the total output picked up in 2011. While the fluctuation in output is influenced by different weather situations in different years, the overall deterioration of output can be explained through soiling of the arrays. Soiling means the gathering of soil, dust and other dirt on top of the arrays that reduces the transparency. If the arrays are installed in a tilted way, less dust actually gets stuck and during rain, the self-cleaning is more substantial. Especially for the jail the soiling effect must be considered as California usually sees little precipitation and the jail is located within a desert-like setting. In the SRJ setting, an annual decrease in output due to soiling can be assumed to be 5 %.[357] Based on the 2003 output value and assuming a 5 % annual decrease, the expected output in 2011 would have been 908 MWh, which is short of the actual output in 966 MWh. Concluding, the degeneration of the output can be explained by soiling.[358, 359]

While the continuous annual deterioration can be explained, the starting point of the deterioration, the output in the first year after installation, is only 1,370 MWh, clearly falling short of the expected 2,400 MWh anticipated at the point of installation.[360] A detailed analysis of the poor performance carried out in 2009 gave a detailed explanation for this poor performance.[361] The underperformance of the PV is not only evident in the annual energy view but also from a daily power output view. A detailed discussion of this effect is given in the appendix.[362]

5.1.2 Fuel Cell Output

The FC, as outlined above[363], was installed in April 2006. Thus, the generation data is only available from this point on. The graph below is the equivalent to the graph previously presented for PV.[364]

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354 From 2003 to 2004 and from 2007 to 2008.

355 From 2005 to 2006 and from 2009 to 2010.

356 This can also be influenced by different weather situations and a resulting different total solar insulation in the different years. This could be analyzed by looking into weather data of the area or output of PV panels nearby. However, these types of analyses were not conducted as they would be beyond the focus of this report.

357 (Dierckxsens, 2009, p. 8)

358 A non-soiling, technical deterioration of the actual arrays is assumed to be less than 0.5 % per year and therefore neglected in this analysis. See (Wirth, 2012).

359 No detailed analysis of the weather influence on output is conducted here. For more detailed analyses see (Dierckxsens, 2009)

360 For more details see sub-chapter 4.2.1. Although, the PV installation was conducted in a combined project with the AC chiller replacement and minor efficiency measures the panels were still expected to provide significantly over 2 GWh per year.

361 The analysis showed that three of the four inverters work within tolerance of the expectation, while the inverter of the panels on housing unit 24, 25, 34, and 35 does not function properly. For details on connection see sub-chapter 4.3.3. The report states that these panels were inspected and it was found out that some of the panels were "engineering samples", not expected to be commercially used; some of the panels were even broken. The underperformance was accounted to the poor quality of the panels. (Dierckxsens, 2009, p. 8 ff.)

362 See Appendix D.

363 See chapter 4.2.2.

364 See Figure 6: Monthly PV Output (2003 - 2011).

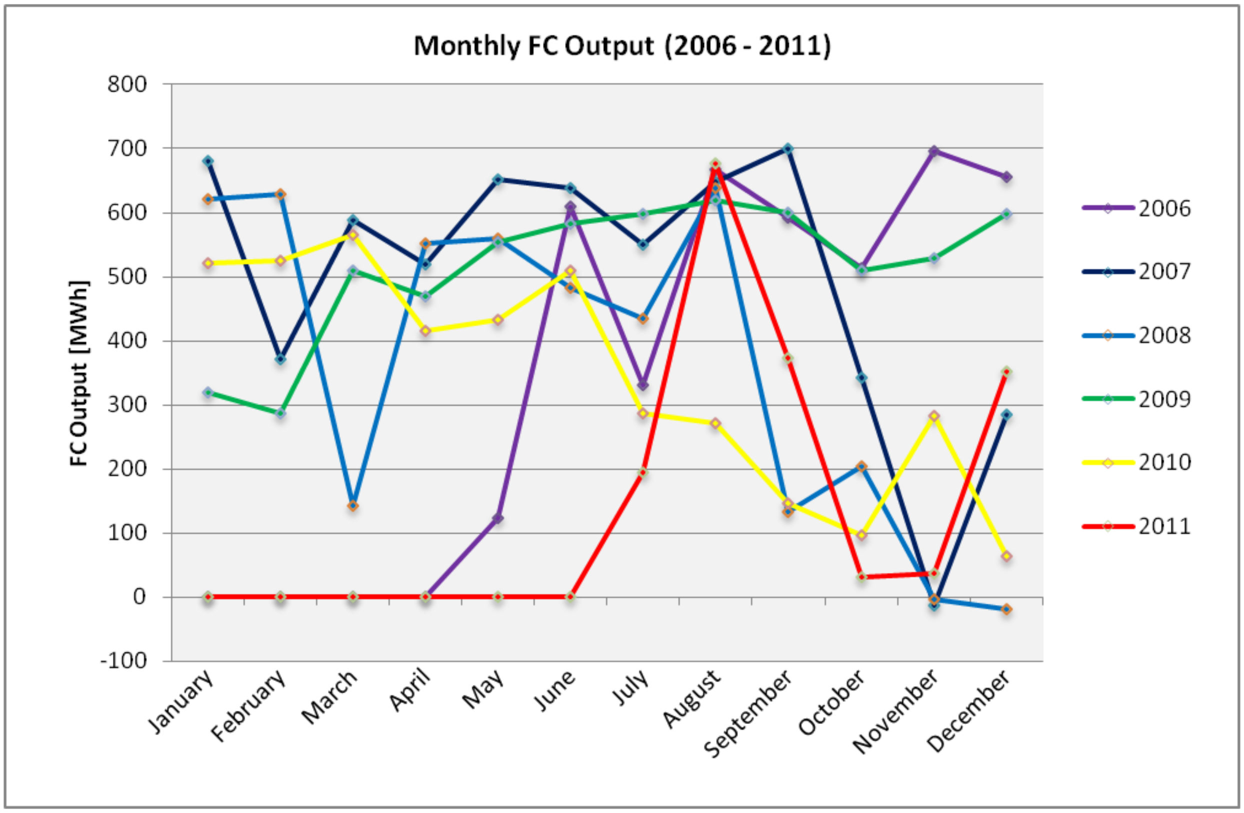

Figure 7: Monthly FC Output (2006 - 2011)

Each line in this graph represents the monthly FC electricity production for one year. The purple curve picks up in April respectively May after the installation of the FC in 2006. From this point on, all lines should be basically flat at 720 MWh monthly electricity generation.[365] However, as is visible, the FC did not meet its expectations. The output goes up and down and the only somewhat stable output can be found in the second half of 2009 and the beginning of 2010. Especially in 2011, the year under evaluation, the FC was completely switched off for the first half of the year due to an extended maintenance period. Then, for one month, the production recovered to its expected level in August before it turned back to its volatile behavior.

In the beginning, the high amount of trips of the FC was caused by faulty technology as well as unreliable supply voltage. Moreover, the actual cell stacks have been replaced numerous times. The last big maintenance was performed in the first half of 2011 and has not yet shown any effect. It must be clearly stated that the FC cannot be considered a reliable source of supply for SRJ. Based on this data it can be said that the FC project is not yet, after five years, actually completed. However, it still serves as a helpful and instructive research resource for larger FCs in general.

[365] 1 MW constant output over 30 days with 24 hours.

The FC was expected to generate over $ 250,000 annual net energy savings. The actual net benefit of the FC in 2011 is close to zero and even negative in some months. A detailed discussion of the monthly net benefits of the FC is given in the appendix.[366]

Due to the eminent and long lasting performance issues and due to the fact that the FC only contributed significant energy in one month during the year 2011, the FC will not be considered in the following analyses. For the year 2011 the FC production will, for the purpose of the analyses[367], be replaced with grid electricity.

5.1.3. Grid Consumption

After the presentation of the two major DER onsite, the grid consumption over the last years will be reviewed in more detail. The grid consumption covers the remaining difference between production of PV and FC and the total jail electricity load. The grid consumption was measured in 15-minute intervals throughout the years 2003 to 2011 at the PCC. The graph below shows the grid consumption by year in monthly resolution.

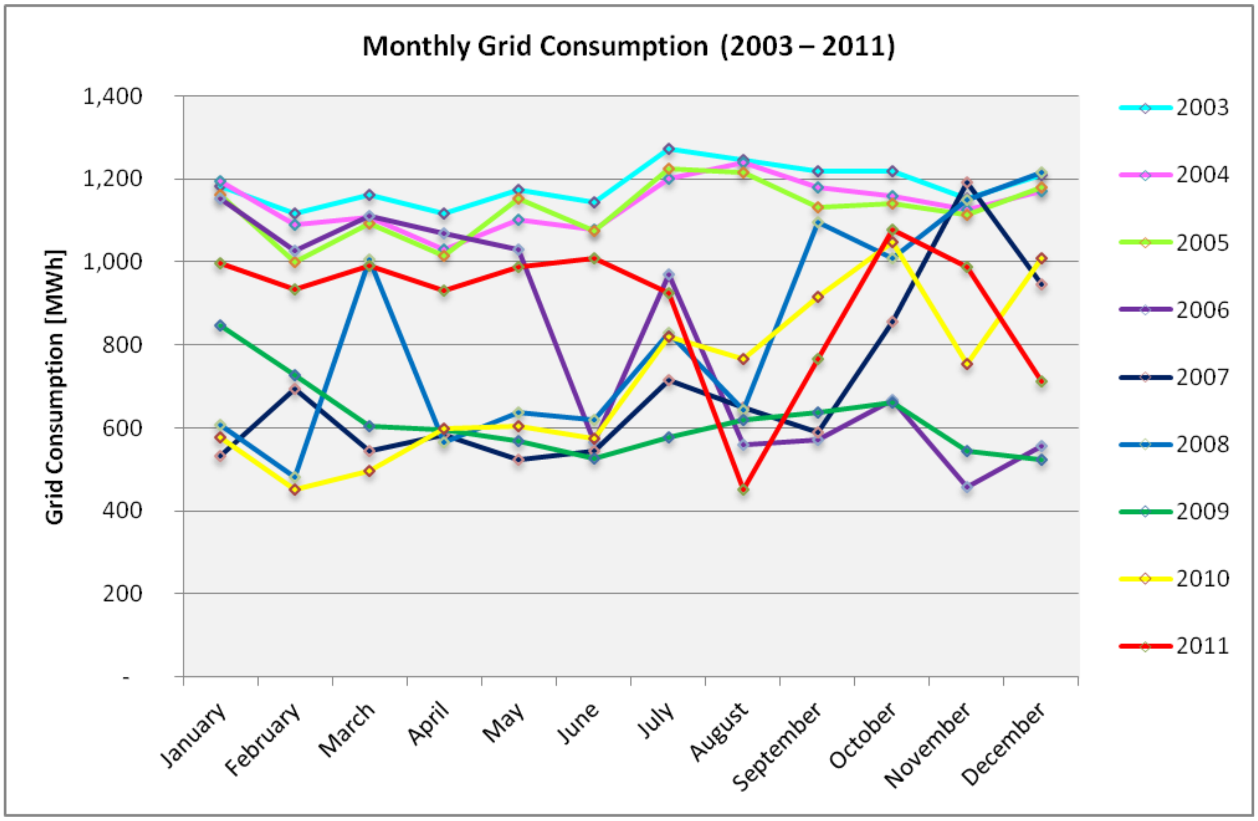

Figure 8: Monthly Grid Consumption (2003 - 2011)

The years 2003 to 2005 show higher grid consumption as the FC was not yet installed.[368] In the following years the effect of the malfunctioning FC can be clearly seen in the up and down ticks

[366] See Appendix D.

[367] In section 7.

[368] Although the FC did not perform as expected, it still contributed some electricity that, in result, did not have to be purchased from the grid.

of the grid consumption. The diagram also illustrates how the grid consumption was expected to behave after the installation of PV and FC. As pointed out before[369], the FC worked relatively well in most of 2009 and the beginning of 2010. This is represented in the grid purchases by significantly lower consumptions during these times. Also, the aforementioned good FC performance in August 2011 sticks out with one of the lowest summer month grid consumption over the observed period. This demonstrates even more clearly how the FC affects electricity costs.[370]

All grid purchases are charged for by the standards of the E20 tariff presented above.[371] As the grid consumption is not only influenced by the production of the DER but also by the behavior and development of the jail load, the load will be further analyzed in the following sub-chapter.

5.1.4. Total Jail Load

The total load of the jail can be assumed as the addition of PV and FC output and grid consumption[372]. This chapter will only present and analyze the total load of SRJ as the existing data[373] does not allow for a more granular analysis of the load as no measurements have been taken and recorded on a substation level.[374, 375] The total load on a monthly resolution is displayed in the line diagram below.

[369] See sub-chapter 5.1.2.

[370] The grid consumption is not only influenced by the FC behavior but also by the PV output. However, the variation in PV output between months and especially from year to year is negligible in comparison to the changes in FC output. Also, the grid consumption is influenced by the total load of the jail that will be presented and discussed in sub-chapter 5.1.4.

[371] See sub-chapter 3.2.1.

[372] This assumption covers the vast majority of the loads. Neglecting wind and losses can be considered acceptable at this early stage of analysis.

[373] Provided by Alameda County.

[374] As no actual load measurements existed for the jail it is assumed that the energy supply equals the load of the jail and no losses occur within the facility. Or put in another way: The losses are considered as part of the total load and not broken out in detail.

[375] However, a model based analysis will be conducted in chapter 5.3.

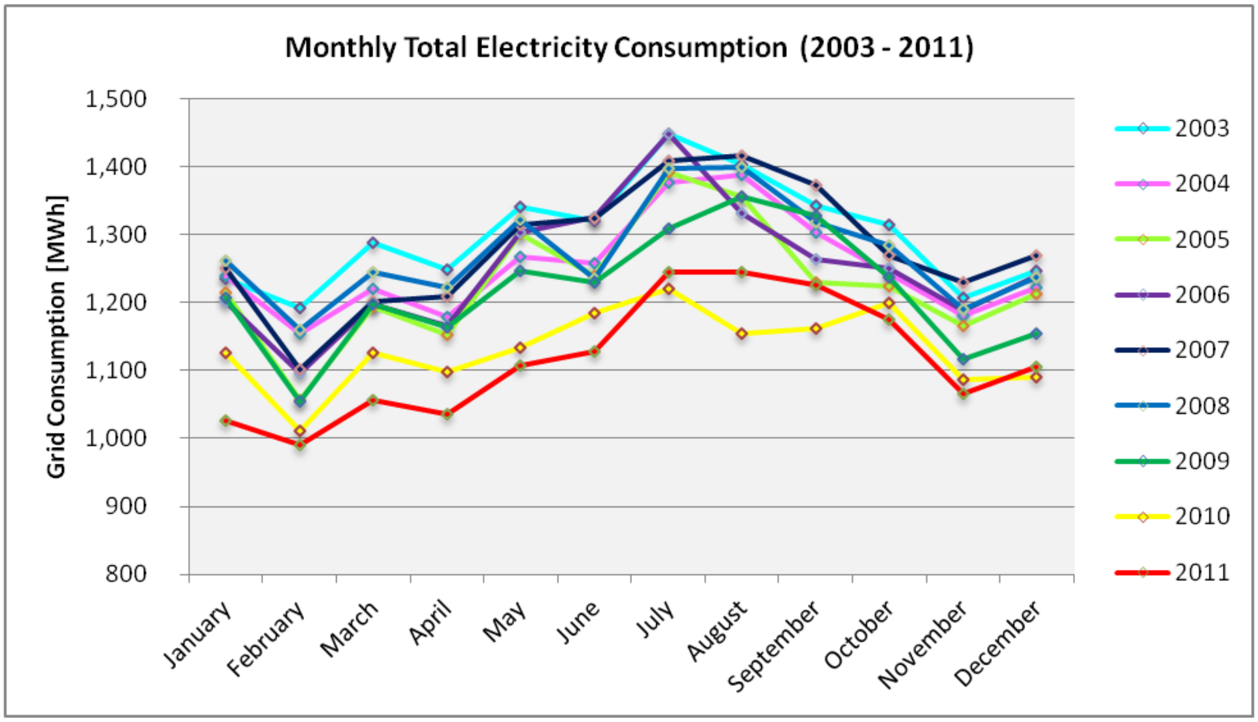

Figure 9: Monthly Total Electricity Consumption (2003 - 2011)

It can be observed that all years from 2003 to 2011 show the same basic shape: total loads in summer are higher than in winter. The cause for this is the higher summer cooling load that is served electrically.[376] The diagram demonstrates how the total load of the jail has been lowered consistently over the last eight years. In total,[377] the jail achieved an electricity consumption reduction of about 16 %.[378] The line diagram depicts that 2010 and 2011 have higher savings in consumption than previous years. These h savings occurred in the years of the lighting retrofit project[379]. The total load is obviously also influenced by external factors such as weather conditions[380] or changes in the operational behavior. Between 2008 and 2011, however, the load was lowered by 1.9 GWh, of which around 1 GWh per year can be accounted to the lighting retrofit.[381]

To give the reader a deeper understanding of the total load behavior, the load curves of two select days are displayed with a 15-minute resolution below.

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[376] See chapter 5.3.3.

[377] From 2003 to 2011.

[378] Own analysis based on SRJ data.

[379] As described above.

[380] Cooling and heating.

[381] In a more detailed load analysis it would be interesting to determine if the remaining load reduction is due to changing weather situation of if changes in operational behavior can be observed. At this point, this is beyond the scope of this report, especially due to the lack of reliable data. Since March 2012 DERMS collects and stores more detailed data and might allow for more detailed analysis in the future.

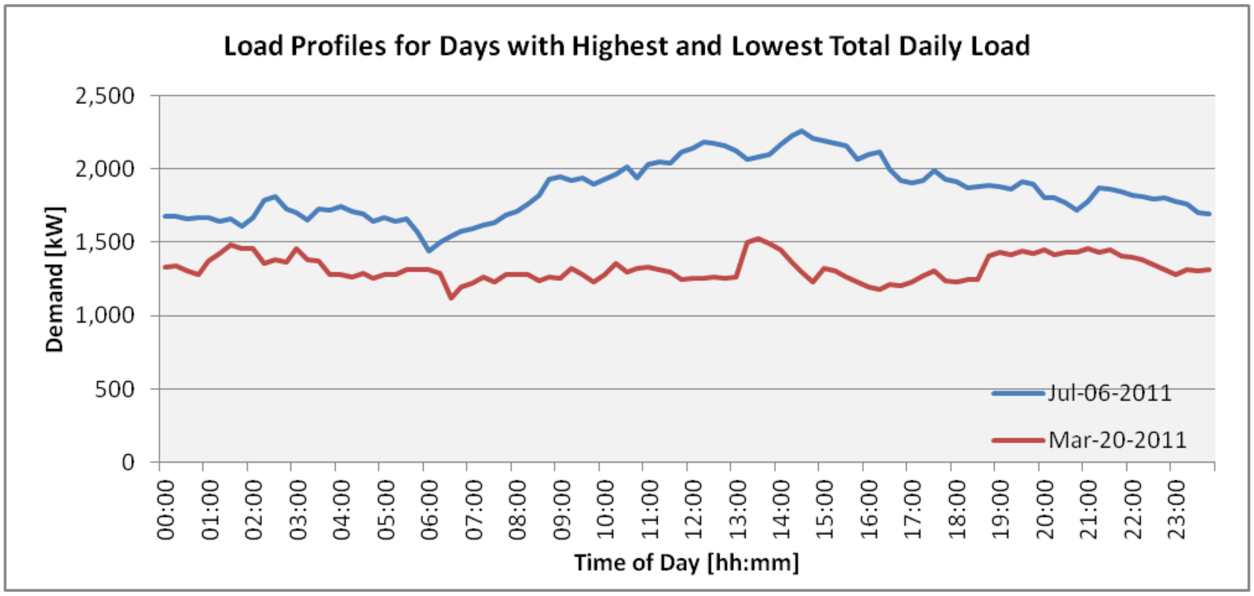

Figure 10: Load Profiles for Days with Highest and Lowest Total Daily Load[382]

The blue line represents the day of the highest total daily load in 2011, 6th of July 2011, while the red line represents the day with the lowest daily consumption in 2011, 20th of March 2011.[383]. As shown before on a more aggregated level, the consumption during summer is higher than in winter or early spring. While the load in March is relatively flat throughout the day, the summer load clearly shows a peak during mid-day. The cause of this peak will be analyzed based on a BES in the next chapter.[384]

5.1.5. Summary 2011

The previously separately conducted analyses of DER generation, grid consumption and total load are brought together below in one summarizing graph to conclude this part of the analysis and give the reader a better overview of the interdependencies of generation and load. This summary is only presented for the year of 2011 as this is the focus of the following analysis.[385] The scatter displays the measured 15-minute power values for FC and PV output, grid purchases, as well as the total load[386].

[382] Own analysis based on SRJ data.

[383] Actually, six days within 2011 show a lower load, but the data of these days show some abnormalities and are therefore not picked for this representation.

[384] See chapter 5.3.

[385] See chapter 7.

[386] Actually, to ensure legibility only every 8th value was displayed in the graph, which means that one value is shown for each two hour period.

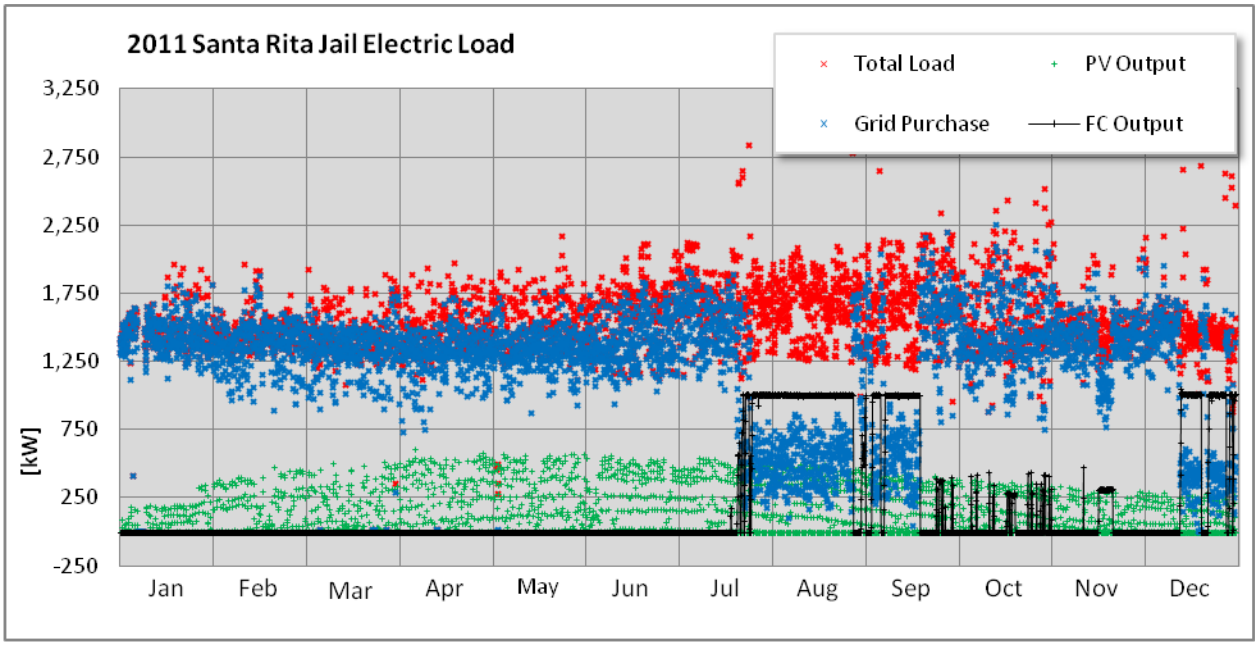

Figure 11: SRJ Electric Load (2011)

The diagram shows how the PV output picks up during summer. Numerous green dots on the x-axis represent the non-existing PV output at night. The black dots[387] represent the performance of the FC and depict that operation was very poor in 2011. Even in August and the beginning of September, when the performance looked somewhat acceptable in the monthly view, outages occurred. These outages caused high grid purchases in the respective months, which caused high demand charges for the relevant months and, thereby, basically eliminated all demand charge savings. The blue points in the graph signify the grid purchases that went down during the rare times that the FC worked properly. Finally, the red dots represent the total load. The increased spread, causing more problems for the macrogrid operator, is caused by the FC. The limited number of outliers on the top of the graph is caused in the moments when the FC faults.

After this summarizing analysis of the generation and load data for 2011, a more detailed model-based analysis of the load will follow[388] after the concept of BES has been introduced.[389]

5.2. Building Energy Simulation

As described above, the measured data does not embrace any disaggregated load information and, therefore, a detailed analysis of the load must be based on a different source. This source will be a detailed BES model of SRJ.

Before the more detailed load analysis will be presented based on the BES model of SRJ, the general concept of BES will be introduced in the following. After outlining what BES entails[390],

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[387] The points appear as a line due to the high resolution.

[388] See chapter 5.3.

[389] See chapter 5.2.

[390] See sub-chapter 5.2.1.

this general introduction will focus on the presentation of the modeling engine and the program interface, which the existing SRJ model is based on.[391, 392]

5.2.1. General Concept

In this sub-chapter, the general concept of BES will be presented, starting with a detailed definition:

"*Building energy simulation is an analysis of the dynamic energy performance of a building using computer modeling and simulation techniques. […] An energy simulation tool models the thermal, visual, ventilation and other energy consuming processes taking place within a building to predict its energy and environmental performance. During its calculation process, it takes into account the external climatic factors, internal heat sources, building materials and systems to accurately model the building.*"[393]

As approximately 30 % of our primary energy is consumed by and within buildings,[394] BES has been a topic of high relevance within the research community for the past 50 years.[395] HVAC and lighting make up for the major consumers within a building and BES are developed to help building engineers and architects to outline and optimize these systems in an energy efficient way. In every building, the total energy performance is not only determined by the efficiency of each of these systems, i.e. the ventilation fans, but the total energy consumption is heavily influenced by the combined performance of the different systems. Within larger buildings, these complex and dynamic interferences cannot be optimized manually but need detailed analysis support based on computer simulations. That is, at the core, what BES is used for.[396] A short description of the past development of BES and the most relevant applications nowadays is given in the appendix.[397]

In the following, one of the most established detailed design engines, DOE-2, will be described in more detail as this engine is underlying the SRJ BES.

5.2.2. DOE-2 and eQuest

The BES model of SRJ has been laid out in eQuest, a program based on the DOE-2 engine. To obtain a better understanding of the possibilities and the underlying system structure, first, DOE-2 will be described in detail in the following. Afterwards, the eQuest program will be presented briefly.

DOE-2

DOE-2 performs a simulation of a building's electricity and gas consumption on an hourly basis and is able to derive energy costs based on the descriptions of climate, architecture, materials, schedules of operation and HVAC equipment details. DOE-2 development has been sponsored

[391] See sub-chapter 5.2.2.

[392] For an overview on other programs and modeling engines available in the market please refer to (Drury et al., 2008) and (Tiazhen Hong et al., 2000).

[393] (Rallapalli, 2010, p. 8)

[394] (Tiazhen Hong et al., 2000, p. 1)

[395] (Drury et al., 2008, p. 1)

[396] (Tiazhen Hong et al., 2000, p. 1)

[397] See Appendix D.

by the DOE and is widely used in the U.S. and over 40 countries around the world. DOE-2 has been developed by the Simulation Research Group of LBNL and its first working version was already released in 1979.[398, 399] During the first ten years after its introduction, DOE-2 has achieved an estimated $ 11,000,000,000 of energy cost savings in the U.S. Users have reported an average of 22 % energy savings through the use of DOE-2.

A detailed description of DOE-2 capabilities and the program flow, including the most relevant sub-programs, is presented in the appendix.[400]

As mentioned above, the DOE-2 engine is widely used. One of the reasons for the wide spread use and the long existence of the different versions of DOE-2[401] is the trust of users in the validity of the result. During its lifetime, DOE-2 has undergone theoretical evaluation by research institutes and universities. Even more important, the simulation results of real-life projects have been compared to actual thermal and energy consumption measurements of the described buildings. These comparisons were conducted for numerous buildings and settings and ensured continuous improvement of the engine.

Nevertheless, due to the time-consuming and error-prone input and output format, other programs were needed to allow for a more user-friendly application of the DOE-2 engine. One of these programs will be described below.

eQuest

While DOE-2 is available since over 30 years to determine energy building consumptions, it has always been complicated to apply. Thus, it required well-trained and expensive personnel to be operated, which caused high project costs and limited application of DOE-2[402]. In order to circumvent these issues, eQuest[403] was developed. Based on DOE-2[404] the engine was expanded to create the eQuest program. eQuest is a user-friendly, easy to use BES tool that obtains high quality results from a DOE-2 engine and combines these with user-friendly input options and graphical output displays.[405] Based on its DOE-2 engine, eQuest performs simulations at an hourly resolution and takes walls, windows, glass, people, plug loads, ventilation, fans, pumps, chillers, boilers and other energy consuming appliances into consideration. eQuest also allows the user to create numerous simulations simultaneously and view the results in direct comparison. eQuest enhanced DOE-2 capabilities with regards to tariff structures and costs

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398 (Drury et al., 2008, p. 5)

399 Although it was introduced over 30 years ago, DOE-2 is still relevant and used. While research more and more switches to more elaborate and capable programs, industry practitioners still use DOE-2 engine extensively. For a comparison of DOE-2 based programs versus newer programs refer to (Rallapalli, 2010).

400 See Appendix D.

401 Currently, DOE-2.2 is the latest version published. Most likely this will also be the last version as the D.O.E cut its funding for this project.

402 (Rallapalli, 2010, p. 23)

403 eQuest stands for Quick Energy Simulation Tool.

404 (Version 2.2)

405 (Rallapalli, 2010, p. 4)

estimations, daylighting, and lighting system control and the automatic implementation of energy efficiency measures.[406]

During the development of eQuest, the outmost attention was paid to ensure that different users would be satisfied with the program. Therefore, eQuest is easy to apply, yet gives the option to dive deep into any imaginable detail. This allows for the program to be applied at early design stages with less specific information to obtain directional results as well as during the final layout or a retrofit that requires detailed input and accurate results. This structure makes the program usable for professional engineers with an energy building background as well as for architects or facility managers with less profound BES knowledge.[407] This stretch over different user groups is achieved by the use of three wizards that guide the user during the modeling, analysis, and modification process. These wizards are described briefly in the appendix.[408]

5.2.3. SRJ eQuest Model

In 2006, an eQuest model of SRJ was developed by a subcontractor of Chevron Energy Solutions. The building model was made available to all project partners including LBNL.

The building model was originally commissioned to be able to evaluate energy efficiency and economic improvement opportunities.[409] The model is extensive and includes all inmate housing units as well as the administration area between the two wings.[410] The model itself consists of 19,000 lines of code and incorporates 3,000 different components such as walls, windows, HVAC equipment etc. Within the model, every inmate housing unit is separated into five "zones", which are treated as a uniform area for the purpose of the simulation of heat and cooling loads. These zones are the left and right side cells on the outside. First and second floor cells are represented by different zones, adding up to four zones for the cells plus one zone for the open, two story-high ponds in the middle of each housing unit. The administration area is separated into four zones, which gives a total of 94 zones for the whole campus.[411] A graphical 2-D representation of the model from eQuest is shown below:

406 (Ibid., p. 22 f.)

407 (Rallapalli, 2010, p. 23 f.)

408 See Appendix D.

409 The data set of the model entails one base model and six adaptations of this base version that were used to determine different energy efficiency measures. In addition, the data includes one model named "adjusted baseline" representing a fine-tuned version of the base model. This model-version has been improved based on actual usage data and, consequently, is closest aligned to the actual jail consumption. The "adjusted baseline" model will be the foundation of the following analysis. Between existing and "adjusted baseline" an increase in model consumption occurred due to the adaption. However, the model was still significantly underestimating consumption compared to actual consumption in 2006. More detailed information on the usage of the models could not be obtained as the subcontractor, who produced the models, passed away in the meantime and no detailed documentation was available.

410 Service building is not incorporated.

411 Model data is included in data package.

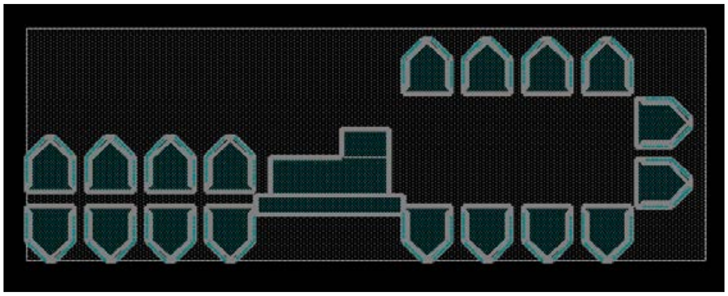


Figure 12: eQuest Model - 2-D view

Beside the architectural representation of the building shell, the model also includes information on the water-side and air-side HVAC equipment installed at the jail.[412] Apart from the equipment, the model also specifies the operation of the jail and, therefore, includes annual, weekly and daily schedules for occupancy, lighting operation, HVAC temperature set points, electricity tariff information etc.

In this project, the model will first be checked regarding its alignment with the 2011 actual electricity consumption and will then be used to obtain a better understanding of the load drivers within the jail.[413]

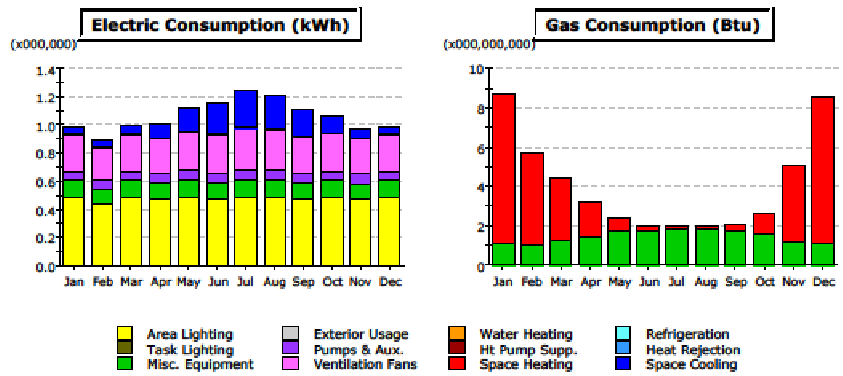
Model Output

To provide a better understanding of the output of the eQuest model, the basic results page is shown below.

[412] A detailed discussion of this equipment is not within the scope of this project but detailed information on the equipment is incorporated in the model data available in the data appendix to this project.

[413] The model is used as a tool to compensate the shortfall of disaggregated electricity consumption data behind the PCC. Once DERMS is fully functional and a year-long data set could be obtained on a more granular level the model loads should be compared to the actual consumption split and the analyses might need to be fine-tuned.

Project/Run: Santa Rita County Jail (Adj Baseline) - Baseline Design Run Date/Time: 10/28/12 @ 22:25



Electric Consumption (kWh x000,000)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Space Cool	0,05	0,05	0,06	0,09	0,17	0,22	0,27	0,24	0,19	0,13	0,06	0,05	1,58
Heat Reject.	-	-	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	-	0,01
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-
Space Heat	0,01	0,01	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,01	0,01	0,04
HP Supp.	-	-	-	-	-	-	-	-	-	-	-	-	-
Hot Water	-	-	-	-	-	-	-	-	-	-	-	-	-
Vent. Fans	0,26	0,23	0,26	0,25	0,27	0,27	0,29	0,28	0,26	0,26	0,25	0,26	3,14
Pumps & Aux.	0,07	0,06	0,07	0,07	0,07	0,07	0,08	0,08	0,07	0,07	0,07	0,07	0,85
Ext. Usage	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Equip.	0,12	0,11	0,12	0,11	0,12	0,11	0,12	0,12	0,11	0,12	0,11	0,12	1,38
Task Lights	-	-	-	-	-	-	-	-	-	-	-	-	-
Area Lights	0,49	0,44	0,49	0,47	0,49	0,47	0,49	0,49	0,47	0,49	0,47	0,49	5,73
Total	0,98	0,89	1,00	1,00	1,12	1,15	1,24	1,21	1,11	1,06	0,97	0,98	12,72

Gas Consumption (Btu x000,000,000)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Space Cool	-	-	-	-	-	-	-	-	-	-	-	-	-
Heat Reject.	-	-	-	-	-	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-	-	-	-	-	-
Space Heat	7,72	4,66	3,16	1,78	0,68	0,26	0,20	0,22	0,36	1,11	3,91	7,49	31,55
HP Supp.	-	-	-	-	-	-	-	-	-	-	-	-	-
Hot Water	-	-	-	-	-	-	-	-	-	-	-	-	-
Vent. Fans	-	-	-	-	-	-	-	-	-	-	-	-	-
Pumps & Aux.	-	-	-	-	-	-	-	-	-	-	-	-	-
Ext. Usage	-	-	-	-	-	-	-	-	-	-	-	-	-
Misc. Equip.	1,06	1,03	1,26	1,41	1,69	1,74	1,81	1,81	1,71	1,58	1,18	1,06	17,34
Task Lights	-	-	-	-	-	-	-	-	-	-	-	-	-
Area Lights	-	-	-	-	-	-	-	-	-	-	-	-	-
Total	8,78	5,68	4,43	3,19	2,38	2,00	2,01	2,02	2,07	2,68	5,09	8,56	48,89

eQUEST 3.64.7130 Monthly Energy Consumption by Enduse Page 1

Figure 13: eQuest results TMY

In this output overview, the modeled electricity and gas[414] consumption for SRJ are presented on a monthly basis.[415] Based on the simulation of the building loads and equipment, the model provides information on the major electricity loads. It can be seen from these results that cooling, ventilation, pumps and lighting consume the major shares of electricity. It can also be noted that the total load is higher in summer, as was also observed in the actual total jail load before.[416] Previously, one could only assume what the driver for this incline in total consumption over the summer is, but the aggregated total load would provide no detailed information. Now, the model shows that the increase in summer can almost be exclusively

[414] The gas consumption is only shown in this overview for the sake of complete representation of the results.

[415] The gas consumption will not be discussed within this report. Nevertheless, it should be a topic of further research at SRJ.

[416] See sub-chapter 5.1.4.

assigned to space cooling loads, i.e. the operation of air conditioning chillers. This type of insights is what the eQuest model is expected to deliver in this project. Different from the typical usage of BES in the design stage or application of more energy efficient equipment, the model will solely be used to provide a better understanding of the structure of the jail's consumption.

In order to ensure that the insights generated from the model are somewhat trustworthy and that the model actually mirrors the jail's behavior, the model output is compared to the actual monthly consumption in 2011 in the graph below:

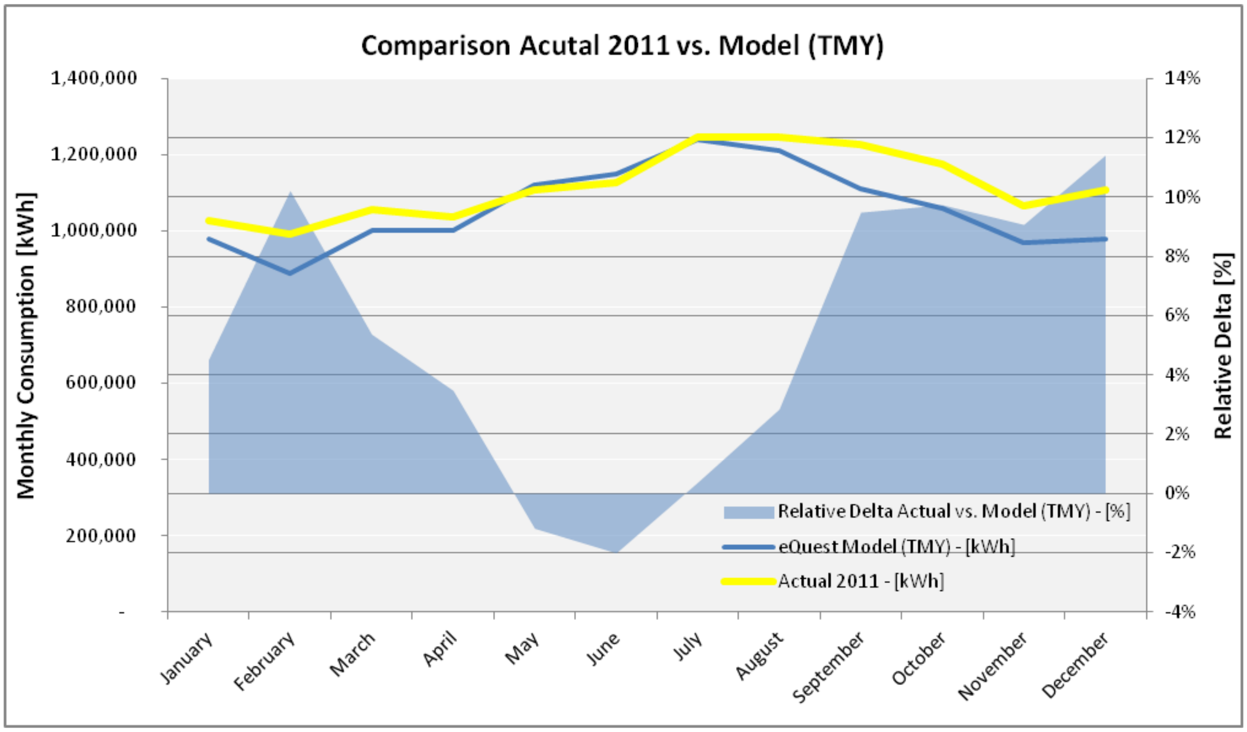


Figure 14: Total Load Comparison (Actual versus Model TMY)

Over the whole year, the deviation between model and actual consumption in 2011 was 5.13 %. The major share of this discrepancy over the year is clearly contributed during the winter months. While the maximum monthly deviation with almost 12 % underestimation of the model is reached in December, eQuest overestimates consumption during summer only slightly with about 2 % in June. In general, it can be said that by the standards of BES, the model can be considered well aligned as in BES a closer alignment is hard to achieve.[417] Hence, the SRJ model can be considered acceptably aligned with the actual building behavior.

However, it is intriguing that the model is very well aligned during some parts of the year while during the rest of the season the error seems to be significantly higher. A calibration of the

[417] For example, in 2008 ACEEE calculated energy savings based on different BES and compared the results to actual savings in actual buildings. Over half of the projects researched showed a deviation of more than 25 %. (Frankel, and Turner, 2008) In other cases, a professionally designed model could even deviate by two-fold from the measured consumption of the actual building. (Norford et al., 1994)

model to actual 2011 consumption data would be significantly easier if the model mirrored the general load shape over the year. An adaption of the model is conducted in the following.

Weather Data Modification

The difference in deviation could be caused by differences in the model weather input data versus the actual weather in 2011. The model bases its calculation on a weather dataset called a Typical Meteorological Year (TMY)[418] and is actually not set up for the input of a specific year's weather information.[419] However, after multiple conversions 2011 weather data was integrated into the model. A detailed description of the process to replace the TMY 2 weather information with specific weather information for 2011 is given in the appendix.[420] With this new weather information, a new simulation run of eQuest was conducted and the results are presented – in comparison to the previous results and the actual consumption – in the graph below:

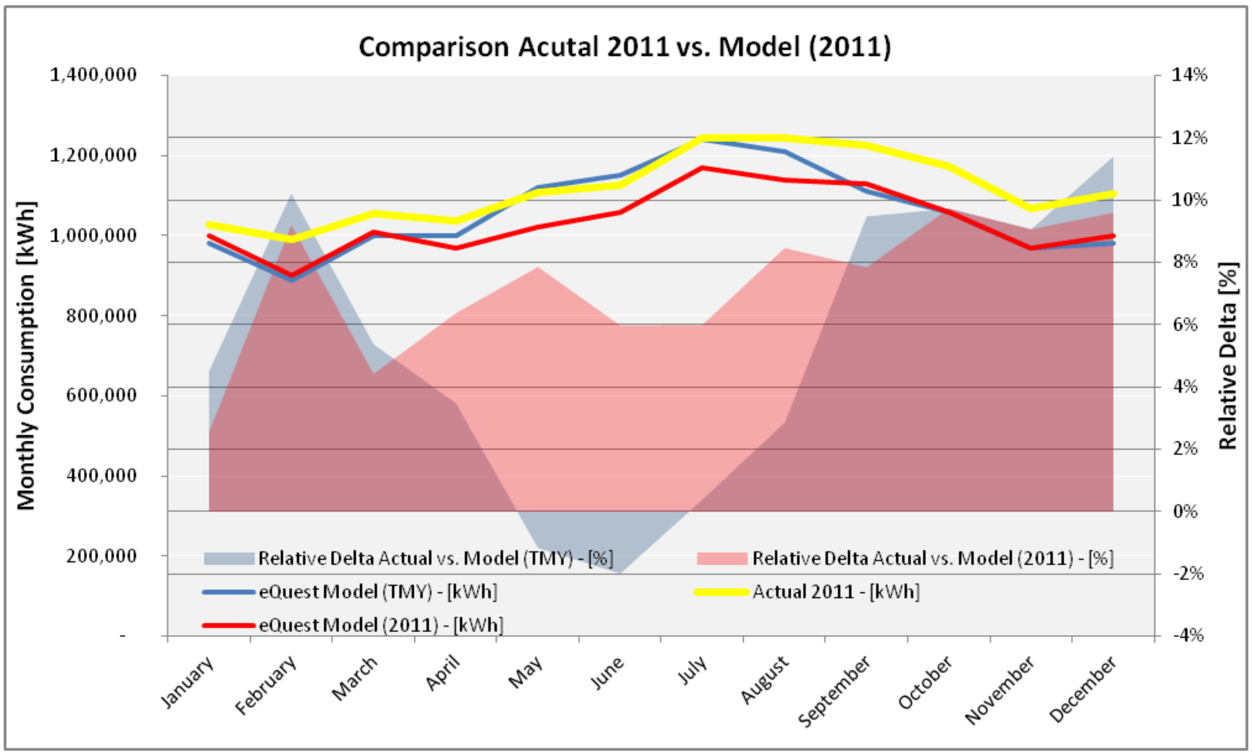


Figure 15: Total Load Comparison (Actual versus Model TMY and Model 2011)

It can be seen that the different weather information clearly changed the behavior of the system and especially the load in summer. The total deviation between model and actual consumption increased slightly to 7.29 %, which is mostly due to a higher offset in the summer months. However, the major problem has previously been that the model overestimated in summer and underestimated in winter. By using more realistic weather input data, the shape of the annual

418 The provided model used the outdated second version of the TMY although TMY3 is already available to al users.

419 This restriction is due to the fact that eQuest is intended to be used for building design and optimization. In these fields a typical year is more relevant and helpful than one specific year. For the case of this scenario, however, the specific data from 2011 is more relevant, as also the year's specific load is used. Also, averaged data-sets tend to underestimate peaks, which would distort the results of the following analyses.

420 See Appendix D.

load curves are more parallel and can, thus, be more easily calibrated in a next step. It can be concluded that the model is not yet perfectly calibrated to the actual jail but by using more accurate weather information it at least shows the same behavior for the monthly total consumption with a slight, but not consistent underestimation.

Calibration

The accuracy of BES of existing buildings is usually improved by a calibration process that compares the results of the simulation to historic usage data. If the comparison shows relevant deviation, the model is modified and adapted to be better aligned to the actual consumption behavior. Literature provides guidance on the calibration process, which is also defined in different official guidelines.[421] An actual calibration will not be conducted for this model as it is clearly beyond the scope of this work.[422] Nonetheless, to achieve a better alignment of model and actual 2011 usage, the output of the eQuest model using 2011-temperature TMY3 weather information will be upscaled by factor 1.05.[423] The upscale factor of 5 % was chosen as it lowers the total annual difference in consumption to 2.65 % without causing significant overestimation of the load on a monthly basis. Especially for the more relevant summer months, the model should not overestimate the consumption to ensure that the results of the analysis do not overpromise and can actually be achieved in reality.[424] The comparison of the *calibrated* to the previous model and the actual consumption is shown below:

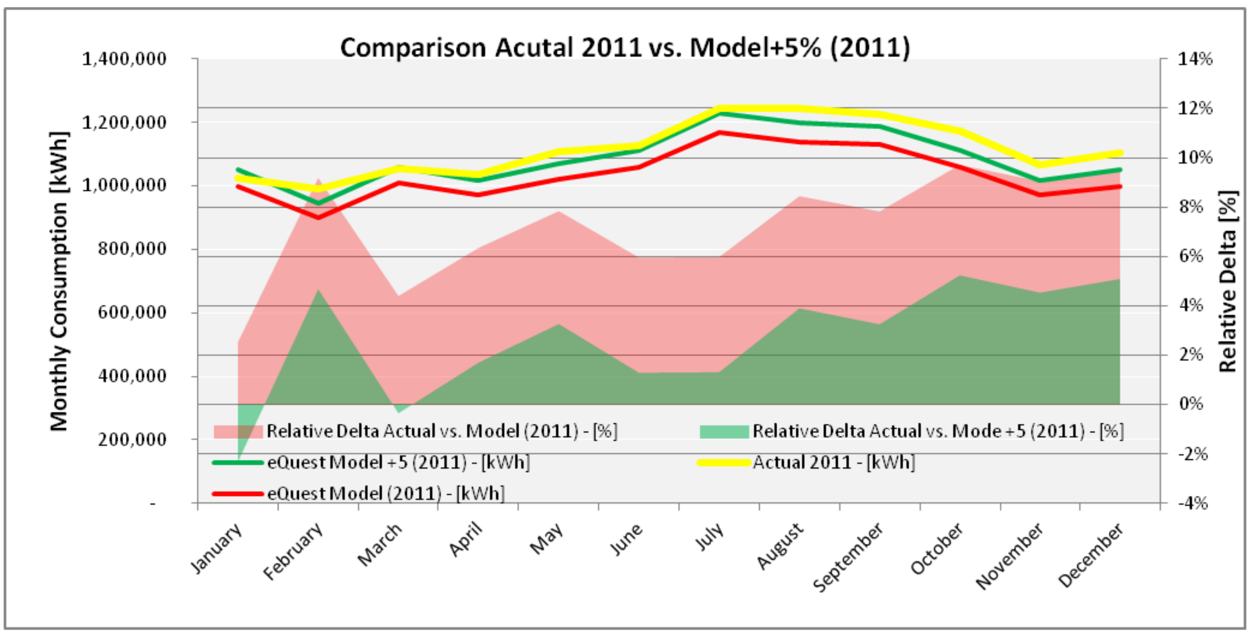


Figure 16: Total Load Comparison (Actual versus Model+5% 2011)

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[421] (Pan, Y., 2006))

[422] This calibration involves the in-depth knowledge of the developed model as well as the building structure and extensive BES experience. A calibration of the eQuest model for large facilities such as SRJ would already be a report of its own and can, therefore, not be conducted in this DR-focused report. In addition, the level of detailed information on the HVAC systems and the building shells is currently not available for SRJ.

[423] This simplification is justified by the amount of work an actual calibration would cause.

[424] Other upscale factors could have been chosen but due to the uncertainty inherent in building energy simulation the effort to determine a slightly better factor would not have paid off.

With a deviation of not more than 5 % on a monthly basis, this model is well within the standards of actually calibrated BES results for electricity consumption presented in the literature.[425]

5.3. Model-Based Detailed Load Analysis

In this chapter the output of the model will be analyzed in more detail. First, the output will be presented for smaller time steps, i.e. daily and hourly time steps, and the alignment to the actual load will be discussed briefly.[426] Afterwards, the lighting and cooling load will be discussed thoroughly as these loads will be used in the DR analysis.[427]

5.3.1. Total Load

In this sub-chapter the model output will be compared to the actual load in smaller time steps. Previously, the model was only compared to the actual consumption in monthly aggregations. After achieving a good alignment on this level, the adjusted model output will be juxtaposed to the actual consumption on daily aggregation and then finally on an hourly basis. The actual consumption is measured in 15-minute time steps but the BES model only delivers hourly output, therefore this is the smallest possible unit for comparison.[428]

Daily Time Steps

For the evaluation of the daily alignment all summer months have been analyzed and in the following one exemplary month, the month of June, is presented.[429]

[425] For example on calibration results see (Carriere et al., 1999).

[426] See sub-chapter 5.3.1.

[427] See sub-chapters 5.3.2. and 5.3.3.

[428] eQuest always calculates the hourly values while the monthly and daily values are obtained by summation of the hourly values.

[429] Two other exemplary summer months (May and October) are presented in Appendix D. June was chosen as it represents a somewhat average behavior by neither being the worst nor the best aligned month in 2011.

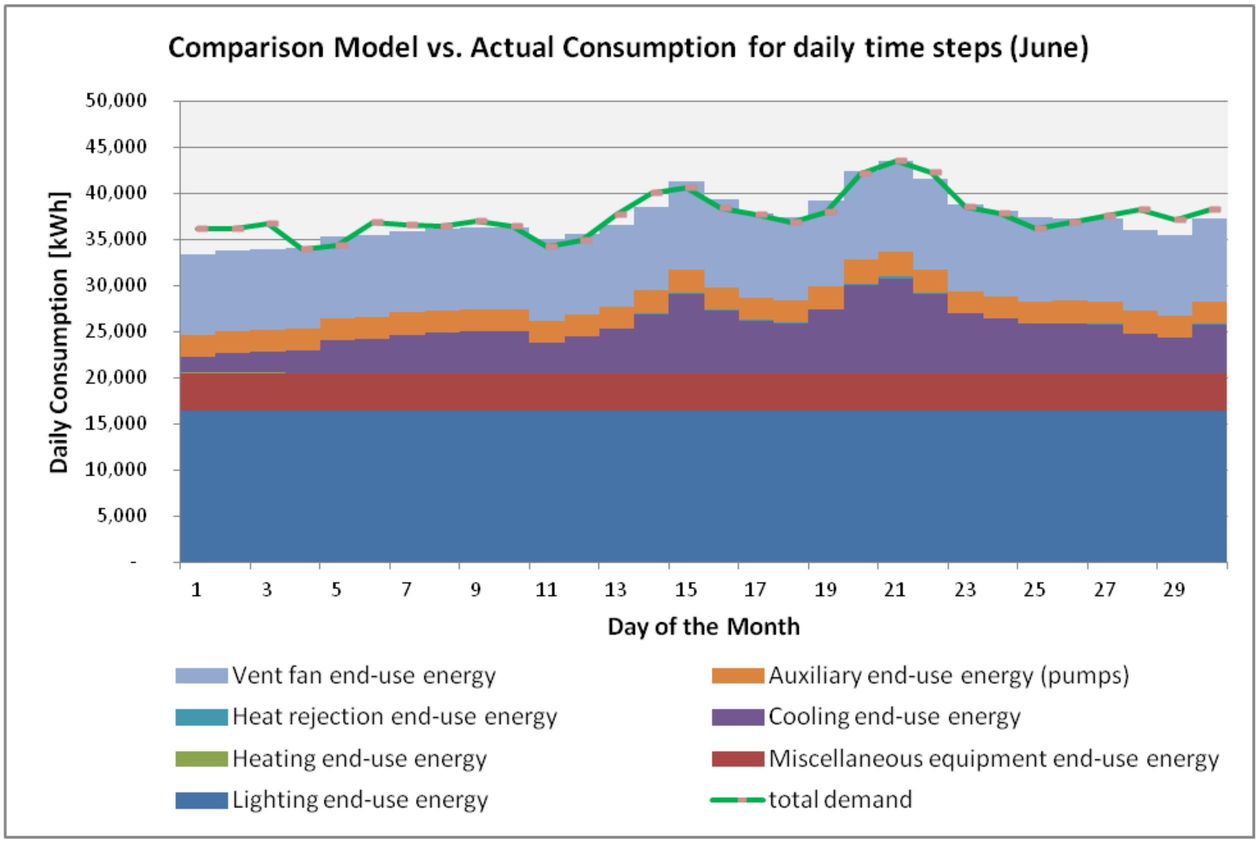

Figure 17: Model versus Actual Consumption (Daily Time Steps)

The stacked areas in the diagram above represent the model output while the green line shows the actual consumption in June 2011 derived from 15-minute measured interval data. This diagram shows that the model follows the actual consumption quite well. In the second half of the month, the load curve shows two peaks that seem to be driven by high temperatures. It can be seen that the model mirrors this increase in outside air temperatures by a significant increase in cooling end-use energy. The two predominant peaks of the load curve are very well represented by the model data, based on the adjusted 2011 temperatures that are used as an input to the model. The other energy end-uses such as lighting are constant on a daily level.

Hourly Time Steps

In a next level drill down from monthly, over daily to finally hourly time steps, one week in June[430] is presented below.

[430] 06/13/2011 – 06/19/2011.

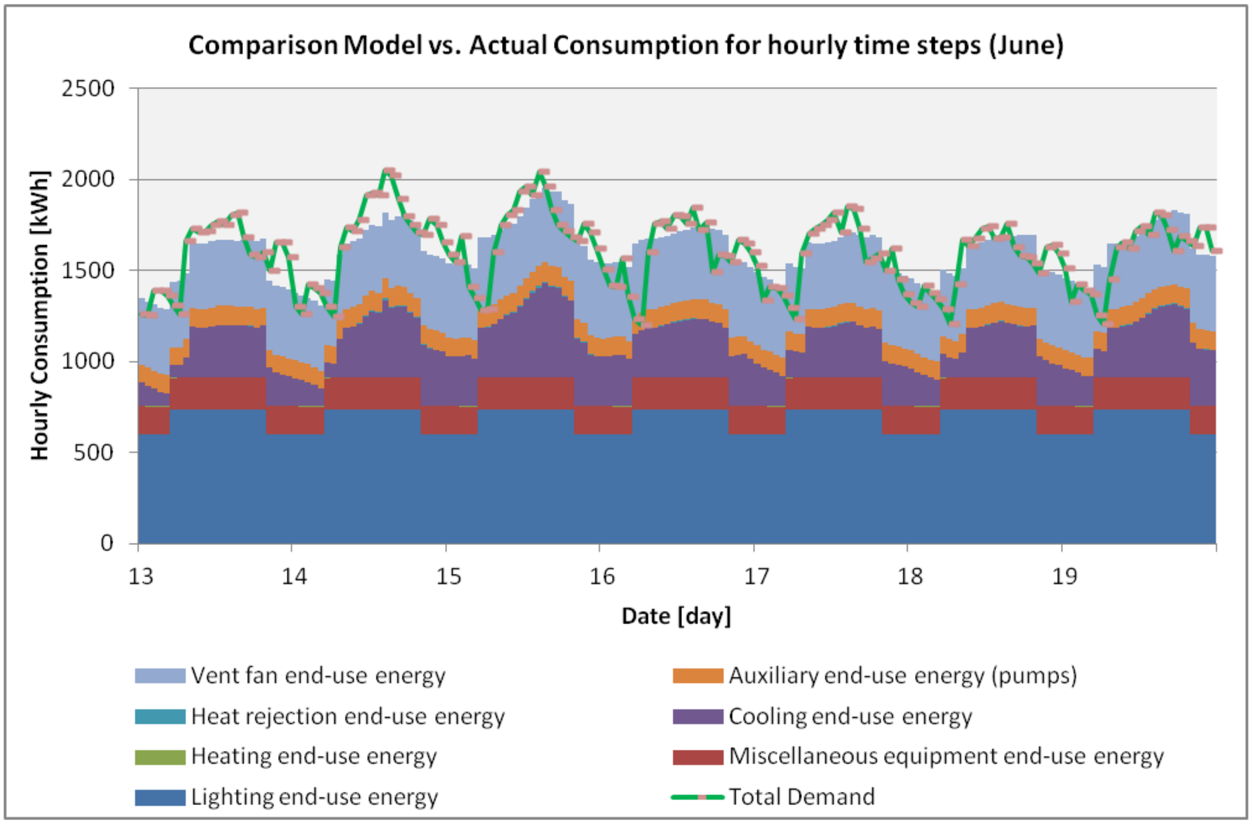

Figure 18: Model versus Actual Consumption (hourly time steps)

In this most granular view of the data, a higher deviation between actual consumption and model output can be observed. It seems that the model is not able to perfectly reconstruct the consumption on an hourly basis. The model seems to not mirror the daily maximums and minimums exactly as they occur. However, the general load shape of the consumption is represented in the model output and as the mid-day peaks are slightly underestimated and the night-time minimums are slightly overestimated this error evens out on a daily basis. This also explains the fact that the previous view with daily time steps showed a better alignment. For the purpose of this analysis, however, the alignment of model output and actual consumption on an hourly time step basis is considered sufficient.

In the following, the lighting and cooling load will be reviewed in more detail as these loads are relevant for the identification of load shed and shift potential presented later on.[431]

5.3.2. Lighting Load

The lighting load in the jail – as modeled by eQuest – has the same shape every day of the year. The daily lighting load shape is presented below.

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[431] See chapter 5.4.

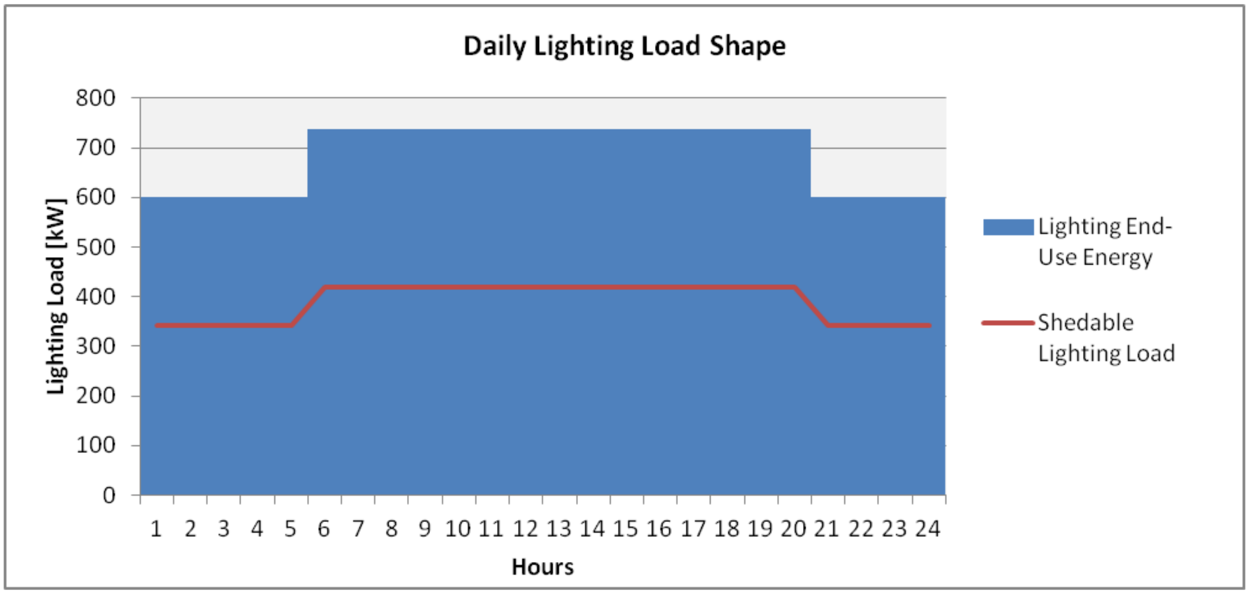

Figure 19: Daily Lighting Load Shape (including shedable share)

The lighting load is clearly structured. During the daytime hours from 6 am to 8 pm 738 kW are used constantly for lighting purposes. During the early morning, evening, and night and the load is reduced to 601 kW. The increased demand for lighting during the daytime may seem counter-intuitive but can easily be understood when recalling that the facility under research is a jail. To explain the lighting specifics of a jail, the figure below shows the 3D-representation of the eQuest model building shell.

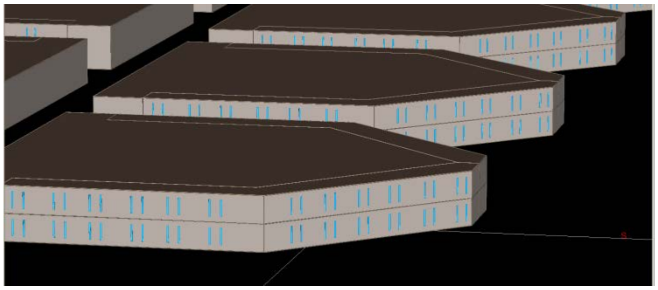

Figure 20: eQuest Model - 3-D view

The building shell is modeled closely after the actual facility and shows how small the windows of the facility are. Also, there is no daylighting in the roof as most roofs are covered with PV arrays anyway.[432] At night, the jail only needs to maintain some basic lighting as the inmates are locked in their cells. During daytime, however, more areas of the jail are used and need to be illuminated. Due to the small windows very little natural light can be used within the jail, leading to an increased demand for lighting during daytime. The small amount of window area is also the reason why there is no difference in artificial lighting demand between summer and winter season. Usually, during summer months, the longer daylight period would lower the

[432] See sub-chapter 4.2.1

demand for lighting compared to winter in residential[433] as well as in office buildings.[434] Even if the demand for lighting was slightly lower in some areas in some moments in summer this savings potential cannot be tapped easily due to another specific characteristic of the jail. Different from office buildings and especially residential building, the inmates have no individual control over the lighting and cannot turn off the light when they feel their cell is sufficiently lit by outside light.[435] Concluding, the present lighting load profile and its uniformity over the whole year can be considered reasonable in the specific setting of SRJ.

Every day SRJ uses 16 MWh of electricity to provide lighting. That sums up to about 6 GWh annually.

5.3.3. Cooling Load

The cooling load is calculated in eQuest depending on outside and inside temperatures[436] as well as the air flows in the building and the operation of the HVAC equipment. Also, the building shell and insulation of the exterior and interior walls plays an important role.

Cooling loads vary significantly form one day to another, as the overview of cooling loads for every day of the month of September shows in the graph below:

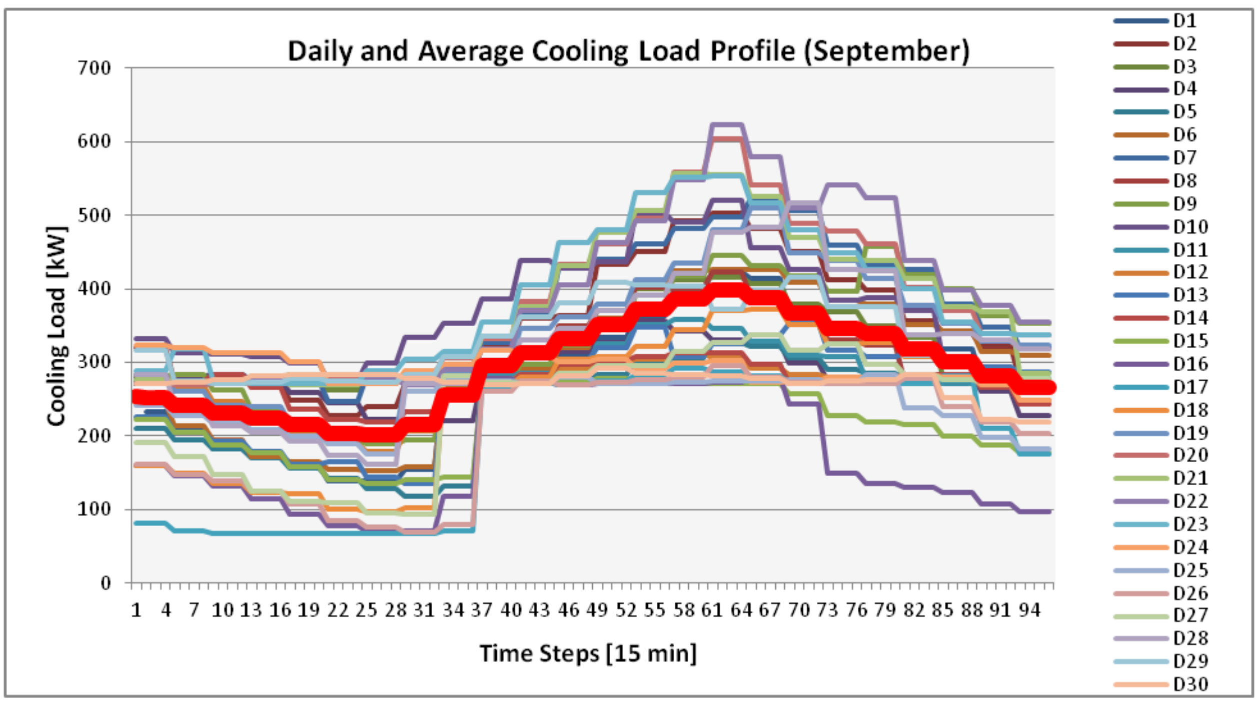

Figure 21: Daily and Average Cooling Load Profiles (September)

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[433] In residential buildings, for example, the consumption can be four times higher in winter. (Bartlett, 1993, p 3) However, due to the very small windows this effect is minimized.

[434] The classification of the jail in standard building types is difficult as it serves as a residence for its inmates but inmates do not leave during the day as it s the case in a normal residential home.

[435] Such control could be implemented centrally but due to the small windows it is very doubtful that such measure would be economically viable.

[436] And additional weather information such as solar irradiance.

The graph shows the variation in daily cooling demand as well as the fact that cooling load is at his high during mid-day or early afternoon and at its minimum in the early morning hours. The average cooling load for September is depicted by the red line graph.

Due to this day-specific behavior of the cooling load a general discussion of the load behavior cannot be conducted.[437] Therefore, the following analyses[438] will always be based on the day's specific load profile that has been precisely[439] determined by the eQuest BES model.

5.4. Load Shedding and Shifting

In this final chapter of section five, the previously presented information will be leveraged to derive an estimate of load shed and shift potentials at SRJ. For the purpose of the participation in DR programs, load shedding and shifting is of high relevance as it can help SRJ to lower demand during peak times to support macrogrid stability and save electricity costs. In the next part, estimates of loads, which can be shed during certain times, will be derived.[440] Afterwards, one option for load shifting at SRJ will be presented and quantified.[441]

5.4.1. Load Shedding through Lighting Shed

As outlined before, DR in this report[442] basically means that customers lower their demand during critical times on the macrogrid referred to as DR events. During these events the customer is asked or obliged to lower its demand from the microgrid either instantaneously or during certain times of the event day[443]. Load shedding is one way a customer can influence its own load. Load shedding means to switch of some loads for DR purposes without compensating this lowered demand before or after the DR event. For example, switching off production machinery during peak times is not exactly load shedding as the company will run its machines longer or harder in order to produce the desired output of goods. A good opportunity for actual load shedding is the shedding of lighting.[444] During peak times, light lighting can be shed without causing "catch-up" effects after the end of the DR event. After lowering lighting for a certain period of time people will typically not demand more illumination to compensate for the dimmed period. All studies in this field of light shedding always discuss – in various ways – the reaction of occupants to lowering the lighting from a standard level and going back to that level after the event without any compensation for the previous dimming.[445]

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[437] Providing one daily profile for all days of the year, as under 5.3.2, is not possible.

[438] Especially for precooling, introduced in sub-chapter 5.4.2.

[439] Within model accuracy. See sub-chapter 5.3.1. for details.

[440] See sub-chapter 5.4.1.

[441] See sub-chapter 5.4.2.

[442] See sub-chapter 3.1.1.

[443] Depending on DR program. See chapter 3.2.

[444] (Dillouie, 2009)

[445] See literature review in (Newsham, 2006).

Shedable Load

As discussed previously, the total load, including lighting, at SRJ is served by three different circuits A, B, and C.[446] It has been discussed that the light on circuit C is not essential to the jail operation and could be shed for *certain times*[447], e.g. during a DR event or in periods of very high consumption. Although research suggests that a smooth dimming of lights is less likely to be detected by occupants[448], this option will not be discussed within this report, as, momentarily, SRJ does not have the option of dimming its lights centrally controlled. However, as discussed above[449], one room or area within the jail will typically have lighting fixtures connected to A, B, and C circuit. Switching off lighting on circuit C will, therefore, be most likely detected by occupants but all relevant rooms and areas will still be sufficiently lit to ensure basic occupant comfort and - even more important - secure jail operation.

It was identified previously that 57 % of lighting in the jail is served through circuit C and can, thus, be used for DR purposes without affecting security or jail operation.[450] This 57 % is the share of lighting fixtures in watts that are connected to circuit C, not the actual consumption from lighting on circuit C.[451] As the different circuits A, B, and C are only of relevance in case of a grid disturbance it can be assumed that the operational scheme of lights on circuit C does not differ from lights connected to circuit A or B under non-emergency and non-disturbance conditions. Hence, the assumption is made that also 57 % of the jail's electricity consumption for lighting is consumed by fixtures connected to circuit C.

As no detailed actual measurements on lighting electricity consumption are available, the previously discussed eQuest model will be leveraged to translate the 57 % connected load share into actual energy consumption. In combination with the model-based lighting consumption it can be concluded that during the time from 6 am to 8 pm 419 kW of lighting load could be shed for certain times. From 9 pm to 5 am, 341 kW are theoretically available for load shedding.

At first sight, shedding over 50 % of lighting for DR purposes may seem as a major impact for occupants but it should be noted that research showed that occupants did not even realize light shedding of around 20 % of the original output.[452] Depending on the initial lighting level, study participants allowed a reduction of up to 60 % before they increased the lighting level again.[453] This shows that reductions in lighting of around 50 % are not as substantial or critical as the cheer figure might suggest.

[446] See sub-chapter 4.3.2.

[447] The vague term of *certain times* is used in this paragraph as first the shedable load shall be introduced. For how long the load shed can occur, i.e. what *certain times* means precisely, will be discussed in the next paragraph.

[448] (Newsham, 2006, p. 5)

[449] See sub-chapter 4.3.2.

[450] See sub-chapter 4.3.2.

[451] As mentioned previously no detailed information is available on detailed internal jail demands.

[452] (Kryszczuk and Byce, 2002)

[453] (Tenner et al., 1997). The study used linear dimming of lighting to a certain level and not for a sharp on/off scenario of some lamps. Nevertheless, the total value of accepted decrease in luminance may be used to put the reduction at SRJ in perspective and support the validity of this approach.

Shedding times

However, it must be stated that mood, comfort, and satisfaction of people is positively influenced if they experience luminous conditions closer to their preferred level.[454] Therefore, shedding the lighting on circuit C continuously should not be considered for now.[455] Consequently, the aforementioned *certain times* for light shedding must be specified in more detail. For the purpose of this analysis, a daily as well as a monthly maximum of hours for lighting shedding will be incorporated into the optimization. As the actual influence on occupant comfort is very specific, depending on individual preferences as well as the building scenario, this report will research the savings potential for one daily and monthly maximum shed scenario.[456] A daily maximum will be set to two hours as an initial point of analysis. As lighting shedding should be a measure during DR events, the monthly maximum should be set in such way, that lighting shed can be executed[457] at each DR event day. At the maximum, in September 2011, four event days were called and, therefore, the monthly maximum will be set to eight hours per month.[458]

To ensure a focused analysis no additional daily and monthly maximum lighting shed scenarios have been evaluated for now. However, it might make sense to assess further set ups in the future to determine how savings potentials develop alongside the change of daily and monthly maximum lighting shed levels. It will be shown later on[459] that the optimization tool was set up in this project in such way that other daily and monthly maximum levels can be evaluated without any additional programming effort.[460]

5.4.2. Load Shifting through Precooling

After discussing the concept of load shedding previously the concept of load shifting will be introduced briefly. Load shifting in this context is not supposed to be a permanent measure that will take place every day but shall be seen as a measure of DR, meaning that it occurs in reaction to called DR events under the various programs[461]. Load shifting can be defined as "*a shift in the demand curve, brought about by consuming electricity at a different time […], which can be achieved by utilizing thermal energy storage such as […] building thermal mass.*"[462] Using building thermal mass to shift load is usually referred to as Precooling (PC) and means to use the HVAC system of a

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[454] (Newsham, 2006, p. 9). Also, it is assumed that the standard lighting level at SRJ is close to the preferred lighting level of occupants and staff.

[455] This report especially does not consider this option, as the permanent reduction of lighting at SRJ would be an energy efficiency measure and not a DR measure that is at the core of this report.

[456] Once savings potentials have been identified in this report, SRJ can conduct internal studies to evaluate the influence of lighting shed on their occupants. Once the savings and the non-monetary costs are determined an educated decision can be made by SRJ management whether and if yes, under which limits, lighting shed should be evaluated in more detail.

[457] This is limited by the daily maximum.

[458] Meaning to allow for lighting shed of two hours in four DR events per month.

[459] In sub-chapter 6.2.3.

[460] To allow for a more detailed evaluation of lighting shed after the conclusion of this project, the optimization infrastructure has been set up in such way that the limits for lighting shed can be changed within the Excel user interface with two clicks. See chapter 6.2. for description of Excel user interface.

[461] See definition of DR in sub-chapter 3.1.1.

[462] (Yin et al., 2010)

building to cool the air and building structure during *off-peak* periods and during the following *on-peak* period the temperature set points are increased and the cool structure helps to reduce heat gains to the air. This results in lower *on-peak* electricity consumption in exchange for increased consumption during *off-peak* periods. This strategy can provide load shifting potential without the installation of additional systems[463] and can therefore be implemented with minimal upfront investment costs.[464] PC is especially applicable to buildings with heavy thermal mass and is therefore interesting to be evaluated for SRJ with its massive prison walls and very limited window surface.[465]

To perform a very accurate evaluation of the PC potential for load shifting within a specific building it would be necessary to adapt the HVAC system set points and observe the changes in cooling load behavior. This can either be done by actually changing the set points of the system and measuring the consumption of the HVAC system or by leveraging a detailed BES model.[466] Unfortunately the limitations of this DR focused project did not allow for the installation of measuring equipment at SRJ. It was then attempted to use the previously described eQuest model to obtain the changed cooling loads under a PC scenario. However, detailed research and discussions with numerous experts led to the conclusion that the underlying DOE-2 engine does not allow for an accurate estimation of PC potentials as the thermal mass in the building is not considered correctly. Due to these doubts regarding the accuracy of the results it was decided to not use the eQuest model for PC evaluation. Instead, a literature review was conducted to derive good estimates for PC load profiles. These profiles will then be used to be able to analyze underlying principle and mechanism in relation to the various DR programs and the microgrid DER and infrastructure and to get an initial estimate of the savings potential of PC at SRJ. A more detailed analysis of the PC potential would be beyond the scope of the project but could be conducted by LBNL in the near future in a separate project that will detail the results of this initial analysis.[467]

Literature Review

The first finding derived from literature review is the fact that the accurate evaluation of the PC potential requires a either a very accurate BES model[468] or extensive installations of measuring equipment[469] that take the building structure as well as orientation into account. In addition, measurements need to be taken over a prolonged period of time to ensure that different weather situations are accounted for. This finding supports the decision to conduct an initial estimate

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[463] Such as electrical storage or ice storage tanks.

[464] (Braun et al., 2002).

[465] (Xu, 2010)

[466] Leveraging a BES model would mean to adapt the temperature set points within the model and compare the resulting, simulated cooling loads to a no-PC scenario.

[467] Currently LBNL is working on a detailed BES model of SRJ in EnergyPlus, a BES program that has detailed and verified PC functionalities. In this future effort the DER-CAM PC functionality developed for the report at hand will be leveraged.

[468] Beyond the level of detail in the existing eQuest model.

[469] Load and temperature control.

based on literature-based PC profiles. The estimates provided in this project will then support the decision regarding the further pursuit of PC - or its more detailed evaluation - at SRJ.[470]

However, when discussing PC it is relevant to consider and control the occupant comfort at all times. This is especially relevant at SRJ with its special use case with residential, commercial, and even industrial usage. Usually, PC is conducted for commercial buildings that are not occupied over night and therefore can be cooled below the comfort zone. Going below the comfort level is not possible at SRJ but nonetheless additional cooling, down to the lower boundary of the comfort zone, is possible. Comfort zones are defined around 69 °F to 77 °F.[471, 472] Observing these limits, different studies showed a large number of slightly diverting effects on the resulting cooling load depending on numerous influencers.[473] However, for settings that can be vaguely compared to SRJ these universal findings could be derived:

- Energy consumption during the cooling period at night can be about twice as high when applying PC compared to no-PC cooling load.[474]
- During peak times the reduction in cooling load is in the order of 10 % to 20 % compared to no-PC energy consumption.[475]
- The energy penalty, i.e. the increase in total cooling energy consumed over the PC day, is in the order of 5 %.[476, 477]

Based on these findings two PC scenarios have been developed that will be presented in the following paragraph.[478]

Precooling Scenarios

Apart from the amount of increase and decrease in cooling load due to PC the timing of these periods must be determined. For this evaluation it is assumed that the decrease in consumption is to occur during *on-peak* period, which is reasonable as the highest charges apply during this period and therefore PC would definitely be set up at SRJ in such way that load during this period is minimized i.e. shifted away from this period. The increase in load due to PC is assumed to be during the *off-peak* period, while during *mid-peak* the load remains unchanged compared to the no-PC scenario. This would basically mean that during *off-peak* additional cooling occurs and then, during the first *mid-peak* period of the day the cooling reserve is kept at a constant level before being used during *on-peak*. During the second *mid-peak* period of the day the slightly increased temperature levels that were reached during *on-peak* are kept constant

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470 See (Peng, 2006) for specific evaluation and (Motegi, 2007) for broader discussion.

471 20.5 °C to 25 °C.

472 (Keeney, 1997)

473 Building structure, building orientation, building materials, occupancy level and schedules, climate zone, etc.

474 (Xu, 2005)

475 (Henze, 2006)

476 Mainly due to losses.

477 (Henze, 2006)

478 As discussed above, these scenarios do not claim to be realistic PC scenario at SRJ. However, they will be used as an approximation to get a first estimate of the PC potential.

again[479] and are brought down again once the *off-peak* period begins in the evening of the day. This is also in accordance with the literature review presented above.

The two derived scenarios are named PC-I and PC-II. PC-I is the soft PC scenario. In this scenario the cooling load of the specific day, at which PC is determined to be optimal by the optimization, is increased by 20 % during *off-peak* while it is decreased by 10 % during *on-peak.* For the average of the daily cooling load profiles in September PC-I results in an increase of 4 % in the total daily cooling energy consumption.[480] PC-II is the scenario, where more or stronger PC occurs. The reduction during *on-peak* is assumed to be 20 % while the related increase during *off-peak* is 50 %.[481] For the average daily cooling load profile of the month of September this leads to an energy penalty of 12 %.[482, 483] The DER-CAM optimization will determine if PC-I or PC-II is more useful to use on a specific day and calculate the resulting costs based on its choice.

The cooling load profiles that are the basis for the calculation of the altered PC cooling profiles are taken from the aforementioned eQuest model.[484] In the DER-CAM implementation the cooling load is broken out from the total electricity load, which results in no change in optimization behavior or results as long as no PC occurs. If PC is enabled and determined to be optimal for one specific day, the original cooling load profile for that day is replace with the chosen PC cooling load profile,[485] which is calculated based on that specific day's original cooling load.

Limitations

As mentioned above, PC is not considered within this report as a measure to change every day's load profile but evaluated in connection with the occurrence of DR events. As the maximum amount of DR event days ever occurring in 2011 was four, the maximum days that PC can be applied on is set to four days for all following evaluations of PC. During these four days either PC-I or PC-II can be applied without any further limitations.[486, 487, 488]

Furthermore, PC will only be evaluated in summer months (May through October), as during the summer the cooling load is higher than in winter and therefore the savings potential is

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479 No increase in cooling load during this period.

480 For a different cooling profile on a different day, with a different cooling load profile, the increase in total cooling load might vary, but the order of magnitude, especially in comparison to PC-II, will still be valid.

481 The over-proportional increase of the *off-peak* cooling load is to mirror non-linearity in the thermodynamics of the building and the HVAC system as well as additional losses.

482 For a different cooling profile on a different day the increase in total cooling load might vary, but the order of magnitude, especially in comparison to PC-II, will still be valid.

483 The daily and average cooling load profiles as well as the PC-I and PC-II scenario based of the average cooling profile are shown in Appendix D.

484 Although the model does not have trusted PC capabilities it is totally trusted for its ability to determine daily cooling load profiles that vary for each day depending on occupancy schedules and detailed weather information.

485 PC-I or PC-II, not a combination of both.

486 This means that in one specific month four times PC-I can occur or four times PC-II or any ratio of mixture between those, as long as the maximum number of four days is not exceeded.

487 Also, one PC day can only have one of the two PC profile, never a combination of those two.

488 This limitation will be varied in the next version of the report to determine a potential sweet spot of precooling days per months from a savings perspective.

expected to be higher. In addition the difference in pricing between *off-peak* and *on-peak* is smaller in winter (see chapter on TOU tariff) and therefore, even with identical cooling loads the same amount of load shifting would result in fewer savings.

Concluding, it should be stated that PC is only evaluated under DR tariffs and programs that have a day-ahead notice, as the first load reduction can occur the earliest about twelve hours after the notification[489]. PC is therefore not evaluated under BIP.

[489] Time from beginning of the day (midnight) to beginning of the *on-peak* period.

CHAPTER 6: DR-DER-CAM at Santa Rita Jail

For more than the past ten years LBNL's microgrids group has been developing the Distributed Energy Resources Customer Adaption Model (DER-CAM) as one of its major contributions to the discussion of DER grid integration through the concept of microgrids. The aim behind DER-CAM is to develop and continuously refine a tool that is capable of modeling energy related investment decisions from the customer's side and help explore the complex economics that occur when numerous DER are combined under different tariff scenarios within a microgrid. In this setting DER-CAM is able to find the optimal combination of DER with minimal energy costs and/or greenhouse gas emissions as well as the optimal operation schedule for the equipment determined optimal or available at an existing site.[490]

DER-CAM is a Mixed-Integer Linear Program (MILP) written and executed in the General Algebraic Modeling System (GAMS).[491]

In the first chapter of section six an introduction will be given to the DER-CAM optimization in general, including a description of the modeling environment, the overall model and the specific version of the model used in this project. In the second chapter, then, the extensions made to DER-CAM to be able to evaluate DR potentials at SRJ under PG&E's DR tariffs and schedules will be presented. The version of DER-CAM embracing all additions and alterations made during this project will be referred to as DR-DER-CAM, Demand Response Distributed Energy Resources Customer Adaption Model.

6.1. Distributed Energy Resources Customer Adaption Model

In this first chapter, GAMS will be briefly presented to the reader, as it is the underlying system the different versions of DER-CAM are based on and executed in. Afterwards, a general overview of the DER-CAM model will be given before detailing the version of the model that was used to assess the DR potential at SRJ.

6.1.1. General Algebraic Modeling System and CPLEX

All versions of DER-CAM are developed and run in the mathematical modeling system called GAMS. This system was especially developed to solve complex and detailed mathematical programming problems of linear, non-linear, mixed integer and mixed integer non-linear character. GAMS is considered user-friendly due to its syntax and its logical construction of problems. Both syntax and structure of problems is closely aligned to mathematical notation and can, therefore, be understood without extensive studies of the programming language. Under GAMS, all sets, parameters, tables, scalars, variables, objective functions and the main objective function can be declared in a mathematical fashion. For the input and output an interface to MS Excel is available, which broadens the scope of application and allows for an

490 (Siddiqui et al., 2001) and (Marnay, 2001).

491 (de Celis Gutiérrez, 2012)

easy pre-processing of the input data and a comfortable post-processing and user-friendly display of the obtained results.[492]

For the implementation of DER-CAM, CPLEX was chosen as a solver technology. CPLEX is a combination of the programming language C and the simplex algorithm. CPLEX was developed by IBM[493] and nowadays has a wide-spread commercial application. IBM especially markets this solver as very stable and able to run under various environments. To find the optimal solution for a given objective function in a reasonable amount of simulation time, CPLEX uses the branch-and-bound method.[494]

6.1.2. DER-CAM

As stated before, DER-Cam is an optimization tool for energy economic analysis of microgrids. The aim of DER-CAM is to find the cost minimal set up for energy services or to determine the potential for greenhouse gas emission reduction by defining either the optimal combination of DER for a given load scenario or the optimal operating schedule for a given DER setup. In past projects DER-CAM was used to evaluate diverse settings for institutions such as hospitals, jails, military facilities or university campuses. In some of these projects also the economic benefit of using innovative technologies such as Plug-In Electric Vehicles has been analyzed using DER-CAM.[495] The key contribution of DER-CAM to the academic discussion is the ability to simulate different DER technologies as well as electric storage at the same time, their interaction based on time steps as low as 15 minutes, the related investment, maintenance and operation costs as well as the resulting greenhouse gas emissions. DER-CAM also considers the option to purchase electricity from or sell to the grid, if this is reasonable to achieve lower total electricity costs.[496] The complexity with its numerous inputs, adaptive objective functions and multiple outputs handled by DER-CAM is depicted in the graph below.

492 (von Appen, 2011, p. 47)

493 The product is called IBM ILOG CPLEX Optimizer.

494 (IBM, 2012)

495 (Momber et al., 2010)

496 (von Appen, 2011, p. 42)

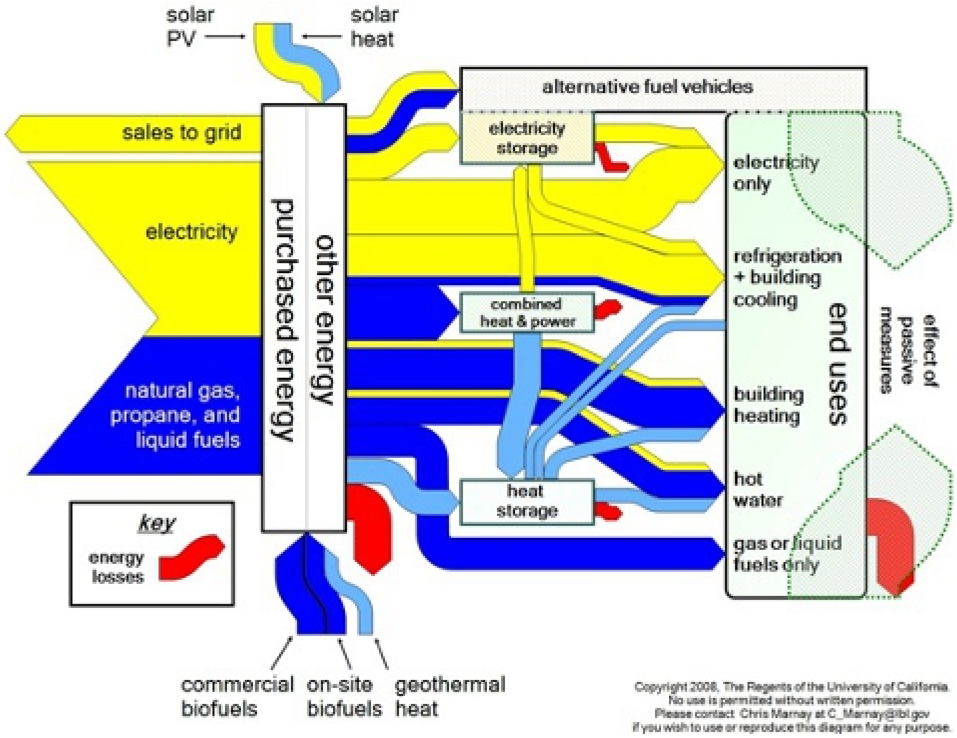

Figure 22: DER-CAM Energy Flows

Under DER-CAM the energy demand is defined through five end use consumptions shown on the very right hand side. The demand needed for electricity, refrigeration, building cooling, building heating or hot water is supplied by purchases from the electricity and gas grid as well as provisions from DER such as PV or solar panels.[497] The points of interconnection of the different energy flow arrows symbolize possible connection and transformation points that DER-CAM can model, if relevant in the scenario under evaluation. The small red arrows symbolize losses in the energy conversion and usage process that can be accounted for by DER-CAM whereas the dotted arrows on the very right hand side visualize energy efficiency measures that can be evaluated by DER-CAM.[498]

The figure below shows the most relevant input and output categories that are implemented in DER-CAM.

[497] Or FC, not shown in the picture, as it is not considered in the analysis.

[498] (Beer and Momber, 2010)

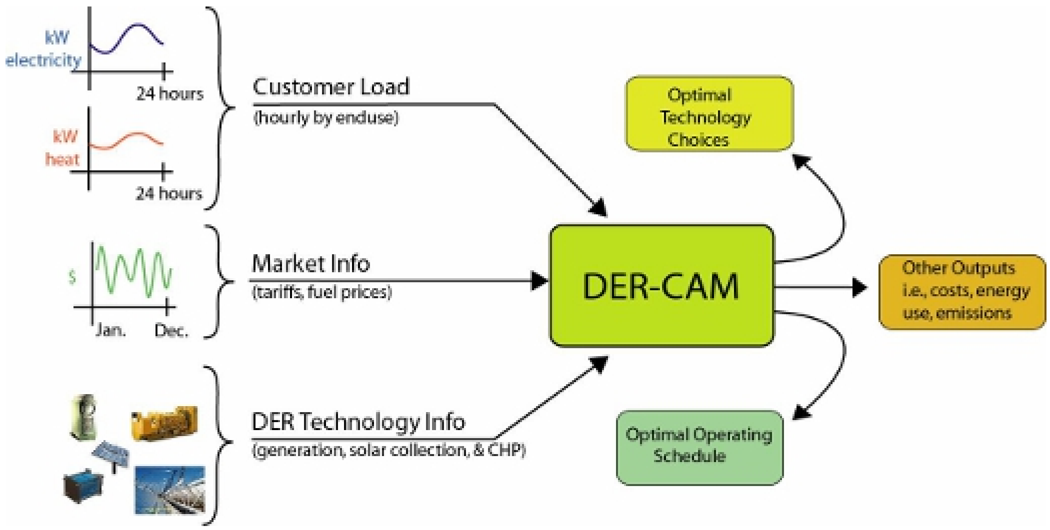

Figure 23: DER-CAM Input and Output Scheme

Starting from the top left corner of the depiction, first the customer load profiles for end-uses such as space heating, hot water, gas, cooling and electricity only demands must be specified. Afterwards, the market info needs to be detailed, which mainly refers to the customer's electricity tariff[499], natural gas prices or any other relevant price information. The electricity tariffs can be specified in much detail including monthly contract fees, daily or monthly demand and energy charges. All these tariff components can be differentiated for different TOU periods as well as for different months, i.e. summer and winter season. The DER Technology Info includes financial information as well as technical information on the equipment under evaluation. Some of this information is relevant for the investment evaluation only[500], while other information[501] are relevant for both, investment and operation analysis.[502] The main categories of output are the optimal technology choice, the optimal operating schedule as well as the resulting costs and emissions.

The described capabilities of DER-CAM are grouped into two different versions that allow for a more user-friendly and more tailored application:[503]

- *Investment & Planning DER-CAM*: Based on observed load profiles the optimal investment decision for DER equipment is made for a specific site minimizing total costs and/ or greenhouse gas emissions
- *Operations DER-CAM*: Based on the specification of the site and the installed DER equipment this version can predict the load shapes for the next seven days[504] that are then used as an input to find the optimal operating schedule of the installed DER for that

[499] Or additional DR programs.

[500] Such as capital costs, lifetime, or operation and maintenance costs.

[501] Such as heat to power ratio, conversion efficiencies, plant sizes, technical constraints.

[502] (Lawrence Berkeley National Laboratory, 2011)

[503] (Stadler et al., 2011)

[504] If load profiles are obtained from a different source they can also be read into the optimization.

upcoming week.[505] The operation schedule can also be optimized for minimal cost and/ or minimal greenhouse gas emissions.

In the following, Operations DER-CAM (O-DER-CAM) will be presented in more detail as the following analyses will be carried out in O-DER-CAM.

6.1.3. Operation DER-CAM

As O-DER-CAM is used to conduct the analyses in this report it will be discussed in more detail in the following paragraphs. First, the specifics of O-DER-CAM in comparison to the more general description of DER-CAM presented above will be outlined. Afterwards, the input and output infrastructure will briefly be discussed to enhance the understanding of the O-DER-CAM analysis process.

Capabilities

O-DER-CAM is laid out to perform week-ahead optimizations and determines operating schedules for the DER equipment of the microgrid under evaluation. As an input to O-DER-CAM all DER can be specified in detail and complemented with detail weather forecasts so that O-DER-CAM can create a forecast of the load profile for the following week. Alternatively, the load forecast can also be calculated externally and directly entered into O-DER-CAM to circumvent the detailed specification of the DER equipment. For ex-post evaluations using historical load profiles, these can be treated as 100 % correct forecasts and read-in the same way. When using historical load data, no weather information or occupancy levels are needed but it is still important to provide accurate tariff schedules and detailed technical information regarding the schedulable resources, such as batteries. O-DER-CAM provides, based on either internal or external forecasts or historic load profiles, the optimal operation schedule for controllable resources and determines how much electricity should optimally be purchased from or sold to the grid.

The O-DER-CAM version in this report will be supplied with historic load profiles and be based on a version of O-DER-CAM that generates detailed charging and discharging schedules for electrical storage. When determining the optimal operation schedule, the optimization takes the tariff structure[506] as well as the very specific load shape of the week under evaluation into account. The resulting load shape relevant for the optimization might be influenced by the output of other DER in the microgrid.

The objective function of O-DER-CAM aims at reducing total energy costs either financially or economically[507] while ensuring that at every 15-minute time step, the energy balance of supply and demand zeros out.[508, 509]

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505 The optimization of the operating schedule requires the existence of schedulable resources such as thermal or electric storage.

506 Demand and energy charges.

507 Greenhouse gas emissions.

508 Specific objective function will be presented in the following sub-chapter.

509 (de Celis Gutiérrez, 2012)

Infrastructure

In the following, a brief overview is given on the infrastructure that forms the O-DER-CAM optimization tool apart from the core GAMS file and its interaction. The picture below presents this for a generic version of O-DER-CAM, which is not yet specific to the application at SRJ.

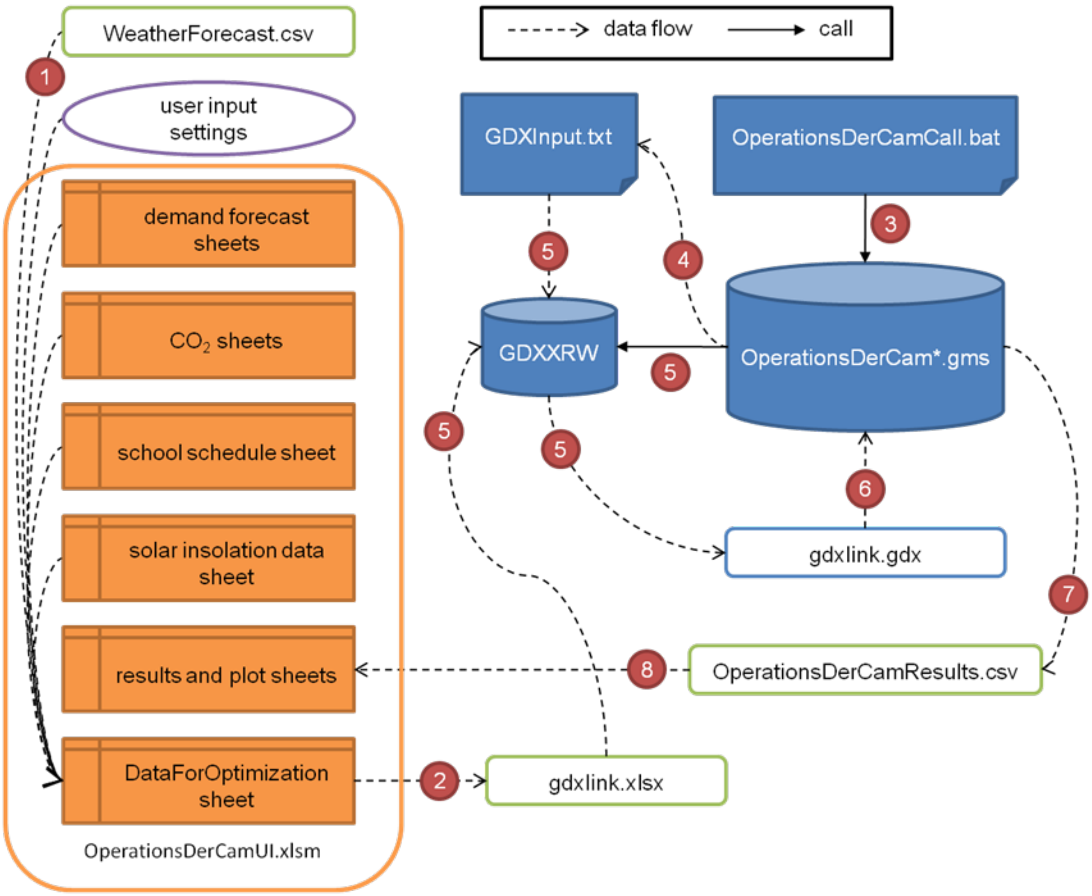

Figure 24: DER-CAM Excel Infrastructure

The *OperationsDerCamUI.xlsm* is the basis for the in- and output. The different rectangular boxes in the rounded orange box represent different sheets within the Excel file. Basically, only the *results and plot sheet* and the *DataForOptimization sheet* are identical for all versions of O-DER-CAM. All other sheets are used to ease input and support better manageability of the inputs. As indicated by the dashed arrows, all the other sheets result in the *DataForOptimization* sheet and are adapted based on the specific use case and the needed inputs. Once the *RunGAMS* macro in the *OperationsDerCamUI.xlsm* is clicked, the optimization starts.

Since the GAMS utility GDXXRW cannot read from *.xlsm* files, all of the information on the worksheet *DataForOptimization* must be transferred to a *.xlsx* file. The macro opens *gdxlink.xlsx*, which contains cells linked to *DataForOptimization*, and data is transferred to the .xlsx file. The macro then saves and closes *gdxlink.xlsx*. The macro next uses a Windows API call to run a batch file named *OperationsDerCamCall.bat*, which in turn executes GAMS to compile and solve the optimization model *OperationsDerCam.gms*. *OperationsDerCam.gms* contains references to particular spreadsheet cells, specifying locations of data and set members to be used in the optimization. It is easier to organize these references in the *.gms* file if GAMS is to write them to a text file first. When GAMS compiles the *.gms* file, a new text file containing the cell references and named *GDXInput.txt* is created. When GAMS compiles the *.gms* file, data is loaded into declared parameters using the GAMS utility *GDXXRW*. The call to *GDXXRW* is written in the *.gms* file along with the appropriate arguments for data source and instructions. Using *gdxlink.xlsx* as the data source and *GDXInput.txt* as instructions, *GDXXRW* creates *gdxlink.gdx*, which holds data in a format that GAMS can read. When GAMS compiles the *.gms* file, *GDXXRW* statements in the *.gms* file are used to load data from the *.gdx* file into the optimization model for each parameter. Once the optimization has finished, a results file named *opsdercamresults.csv* is written by GAMS. The macro *RunGAMS* opens opsdercamresults.csv, copies all of the results data and pastes them to the *Results* sheet within *OperationsDerCamUI.xlsm*. The macro then shows the user the *ResultsPlots* sheet, which contains a plot of the electricity generation and usage balance over the next week.

6.2. Operations DER-CAM for Demand Response at Santa Rita Jail

In this chapter the O-DER-CAM version developed during the SRJ DR project will be described in detail. After providing the high-level objective function and the most relevant constraints in this introduction, the first sub-chapter will present the alterations made to be able to run year-long instead of weekly simulations in an automated fashion. In the second sub-chapter the extensions made to O-DER-CAM to include DR programs will be presented very briefly and finally, in the third sub-chapter, the extensions made to implement load shift and shed in a way that it can be evaluated under the different DR tariffs and programs will be depicted.

In the analysis of the DR potential at SRJ, the sole focus lies on electricity; natural gas is not included in the evaluation. Therefore, the objective function is as simple as:

$Min \rightarrow TotalEnergyCosts$

In addition, all equipment is already installed on-site. Thus, investment costs are not considered. Finally, the evaluation of the DR potential is conducted under the assumption of perfect knowledge of the resulting load profile[510] for the full month, i.e. historic load data will be used. As a result, the forecasting module of O-DER-CAM will not be used. Instead, the power requirement will be directly keyed into the optimization. Due to these simplifications it can be stated that:

$$TotalEnergyCosts = ElectricTotalCost \qquad (Eq\ 6.1)$$

$$ElectricTotalCost = ElectricTOUCost + ElectricDemandCost \qquad (Eq\ 6.2)$$

In the equation above, the *ElectricTOUCost* are the sum of the electricity consumed during the different TOU periods multiplied by the respective energy charge. The *ElectricDemandCost* is calculated accordingly, with the single addition that the highest demand multiplied by the monthly maximum demand charge is added to this sum.

The most relevant constraint considered in the optimization is:

[510] Total Load – PV Generation.

$$ElectricityConsumed_{t,d} = ElectricityProvided_{t,d} \qquad \forall(d,t) \qquad \textit{(Eq 6.3)}$$

d being the day and t the time step, this means that the energy balance must be observed at every time step of every day. The two sides of this equation are defined as following:

$$ElectricityConsumed_{t,d} = ElectricNonCoolingLoad_{t,d} + ElectricityForCoolingLoad_{t,d} + ElectricityForBattery_{t,d} \qquad \forall(d,t) \qquad \textit{(Eq 6.4)}$$

$$ElectricityProvided_{t,d} = Electricity\_Purchase_{t,d} + Electricity\_Photovoltaics_{t,d} + ElectricityFromBattery_{t,d} \quad \forall(d,t) \qquad \textit{(Eq 6.5)}$$

These two formulas do have more elements to them but have been reduced to the ones relevant in the report at hand. For the electricity consumption, cooling and non-cooling load have been separated to allow for the later implementation of PC. Basically, all loads, except for cooling, are aggregated under *ElectricNonCoolingLoad*.[511] *ElectricityForBattery* refers to the electricity used for charging the electric storage whereas *ElectricityFromBattery* refers to the electricity made available for consumption when discharging the electric storage. *Electricity_Purchase* is the purchase from the PG&E grid.[512]

6.2.1. Extension to automated year-long optimization

The extension from a week-long to a year-long optimization was conducted in two steps, with significantly different characteristics.

Extension from week-long to month-long optimization

Previously, all evaluations in O-DER-CAM have been conducted on a weekly basis. This is fine for the calculation of the energy charges but causes inaccuracies with respect to demand charges. In the week-long version, demand charges were calculated using the monthly charges and then divided by four[513]. However, demand charges, in reality, are calculated for a full month and take the highest consumption into account for a full month. As the peaks[514] most likely differ from week to week, the week-long version would systematically underestimate the demand costs. In addition, the optimization would set the optimal demand levels based on the first week of the month only, which might not be optimal for the full month.[515]

To extent the optimization from a week to a month, the input and output infrastructure had to be adapted and new sheets were created to be able to handle the data input.[516] The output

[511] Loads could further be segmented – if needed – at any time.

[512] *Electricity_Photovoltaics* are shown in the equation to avoid confusion by the lack of it. However, it is actually not needed in this version of O-DER-CAM as *ElectricNonCoolingLoad* is already reduced by the output of the PV arrays before fed into the optimization. As the PV output is deterministic, running it through the optimization would only increase simulation time without any relevance to the results.

[513] Assumption: Four full weeks in a month.

[514] Total peak and peaks in TOU periods.

[515] Looking at weeks instead of months can be more reasonable when working with load forecasts, as those might be more accurate one week in advance compared to looking at a full month. However, as this evaluation is conducted under the assumption of perfect knowledge of the load profiles this argument is not applicable for the analyses in this project.

[516] Load, DayofMonthList, MonthList.

sheet[517] was adapted as well to show the energy balance of the full month and to account for numerous minor changes. The GAMS code had to be changed slightly throughout the whole code, but the structure was not altered. Therefore, no detailed equations are presented here.

All months are assumed to have 30 days in total. By using the month-long version it is also implied that the billing cycle, which is the period for which the demand charges are calculated by PG&E in reality, equals the calendar month.

Extension from month-long to year-long optimization

Extending the simulation from a monthly version to an automated simulation of a full year needs to be done through a different approach. As the billing and especially the calculation of demand charges is done on a monthly level, it is of no help to further expand the horizon of the GAMS code itself. Instead, the different months can be optimized separately but the infrastructure needs to be adapted so that the twelve months of the year can be simulated in a row and without human interaction.

This was done by adapting the input infrastructure in such a way that references would pick the correct loads and schedules depending on the selected month. After doing so, an Excel macro was developed to control the change of the different months in the input data and to call the *RunGAMS* macro for each month. Once the simulation of one month is finished, the new macro ensures that the results are saved and not overwritten by next month's results. The output infrastructure was also adapted to be able to gather the results of numerous simulations run in a row.

The result of the year-long optimization is a detailed display of monthly cost elements and demand levels, which are aggregated to an annual cost overview. Depending on the accuracy level of the optimization and the selected scenario, the year-long optimization takes between 15 minutes to two hours for a full run.

6.2.2. Extensions for DR tariffs and programs

In the following, the extensions for the new DR tariffs and programs will be presented. For the sake of a focused presentation, a mathematical formulation of the code will also be given if relevant parts of the code have been altered.

PDP

PDP could be implemented in DR-DER-CAM without major changes to the structure of the program code, however, requiring numerous detailed changes. Within the code itself, the TOU time periods had to be extended by the additional PDP event period for the calculation of the energy costs. Different to the existing TOU periods, it had to be ensured that the energy charges during the PDP event period are multiplied by the PDP event energy charge, while the calculation of the demand charges had to remain unchanged and demand peaks during PDP events have to be evaluated as normal *on-peak* demand.

In the input infrastructure, the rates had to be changed and the tariff schedules had to be extended by a PDP event type day that was not known before. In addition, the PDP event days

[517] ResultsPlot.

had to be entered and automatically adapted to ensure DER-CAM would apply the correct tariff schedule on the event day to allow for a smooth year-long simulation.

DBP

To be able to evaluate DBP within DR-DER-CAM, a new section had to be added to the GAMS code that will be presented in mathematical formulation.

First, the potential reduction is calculated for all time steps of the month in accordance with the program definition:

$$DBPRedAll_{t,d} = TenDayAvg_{t,d} - Electricity\_Purchase_{t,d} \qquad \forall(d,t) \qquad \textit{(Eq 6.6)}$$

The ten-day average is calculated outside the optimization based on previous runs of the identical load shape without occurrence of DBP events and then read into GAMS.[518]

In a next step, the potential load reduction matrix *DBPRedAll* is set to zero for all non-DBP event time steps by multiplying it with the binary *DBPevent* matrix[519] that is zero for all time steps except event time steps:[520, 521]

$$DBPRedEvent_{t,d} = DBPRedAll_{t,d} * DBPEvent_{t,d} \qquad \forall(d,t) \qquad \textit{(Eq 6.7)}$$

Afterwards, the event load reductions are added up for the month under evaluation, multiplied by the DBP incentive level[522] and integrated into the objective function:

$$DBPRedSum = \sum_{t=1}^{96} \sum_{d=1}^{30} DBPRedevent_{t,d} \qquad \textit{(Eq 6.8)}$$

$$DBPSavings = DBPRedSum * DBPIncentive \qquad \textit{(Eq 6.9)}$$

$$TotalEnergyCosts = ElectricTotalCost \text{ - DBP savings} \qquad \textit{(Eq 6.10)}$$

The read-in of the ten-day averages as well as the DBP events has been automated in Excel depending on the active month to allow for year-long optimization. A detailed representation of the code, including read in and results plot, is included in the appendix.[523]

BIP

For the implementation of BIP in DR-DER-CAM some more extensive changes to the existing structure had to be conducted. To account for the different BIP BRL and to ensure that enough energy is available in the battery[524], the electric storage constraints had to be edited. For days with no BIP event it is defined:[525]

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[518] This approach ensures that DER-CAM does not alter the ten-day average to generate higher savings because this would not be possible as the ten-day average is determined in reality, before the event is known. Refer to discussion on similar issue under BIP analysis.

[519] Read-in from Excel.

[520] 1 for these.

[521] This two step approach is essential to ensure compliance with the linearity constraint of the optimization.

[522] Read-in as a scalar.

[523] See Appendix E.

[524] See chapter 7.4.

[525] BIP days are read in as a 30*1 binary matrix.

$$ElectricityInBattery_{t,d} = BatteryCapacity * MinimumSOC + BIP\_BRL \qquad (Eq\ 6.11)$$

For BIP event periods and the remainder of the day the BIP event is called on, the restriction on the battery is set to its standard value:[526]

$$ElectricityInBattery_{t,d} = BatteryCapacity * MinimumSOC \qquad (Eq\ 6.12)$$

During a BIP event[527] the following restriction is applied to the electricity purchases:

$$ElectricityPurchase_{t,d} = FSL \qquad (Eq\ 6.13)$$

After ensuring that the energy balances are set up to comply with the BIP regulations, the incentive for such behavior must be calculated. The PLR for summer is, therefore, calculated as follows:[528]

$$PLR = \left(\sum_{t=1}^{96}\sum_{d=1}^{30} ElectricityPurchase_{t,d}^{on-peak} / \sum_{t=1}^{96}\sum_{d=1}^{30} timesteps_{t,d}^{on-peak}\right) - FSL \qquad (Eq\ 6.14)$$

The PLR is then integrated into the objective function together with the read-in BIP incentive:

$$TotalEnergyCosts = ElectricTotalCost - PLR * BIPIncentive \qquad (Eq\ 6.15)$$

The FSL, that is the key user-input for the optimization of BIP participation, is read-in from the Excel input infrastructure. As the calculation of the FSL differs depending on different sub-scenarios that will be introduced later on[529], the presentation of the FSL determination will be shifted to the BIP BATTERY scenario. Separating the calculation of the FSL from the presentation of the GAMS, implementation is also reasonable as the FSL can be chosen by the customer without any constraints. This means the above presented code is the implementation of the BIP schedule in DR-DER-CAM and the later presented calculation of the FSL is not actually part of the BIP schedule. Thus, it is presented alongside the different BIP sub-scenarios.[530]

The read-in of the BIP events and event days has been automated in Excel depending on the active month to allow for year-long optimization. A detailed representation of the code, including read-in and results plot, is included in the appendix.[531]

6.2.3. Extension for Shed and Shift loads

In the following paragraphs, the additions and changes made to DR-DER-CAM to implement load shedding through lighting shed and load shifting through precooling will be outlined briefly.

[526] Minimum SOC is 20 %.

[527] That is read in as 30*96 binary matrix.

[528] For winter accordingly with *on-peak* replaced by *mid-peak.*

[529] See sub-chapter 7.4.1.

[530] See chapter 7.4.

[531] See Appendix E.

Lighting Shed

As outlined before, lighting shed is restricted by the total amount of time steps that can be shed per day and per months. These limitations are implemented in the GAMS code as following:

$$\sum_{t=1}^{96} LS\_event_{t,d} \leq LS\_dailyMax \qquad \forall d \qquad \textit{(Eq 6.16)}$$

$$\sum_{t=1}^{96} \sum_{d=1}^{30} LS\_event_{t,d} \leq LS\_monthlyMax \qquad \forall d \qquad \textit{(Eq 6.17)}$$

LS_dailyMax and *LS_monthlyMax* are read-in from Excel as scalars. *LS_event* is a 30 by 96 binary matrix that serves as a variable and is filled by the tool as optimal. Afterwards, this matrix is connected with the load shed potential for each time step of the month that is fed into the optimization under the name *LS_Profile:*

$$LS\_Savings_{t,d} \quad = LS\_Profile_{t,d} \quad * \; LS\_event_{t,d} \qquad \forall(d,t) \qquad \textit{(Eq 6.18)}$$

LS_Savings is then integrated into the equation that determines the total electricity consumption:

$$ElectricityConsumed_{t,d} = \; ElectricNonCoolingLoad_{t,d} + \; ElectricityForCoolingLoad_{t,d} + ElectricityForBattery_{t,d} - LS\_Savings_{t,d}$$

$$\forall(d,t) \qquad \textit{(Eq 6.19)}$$

A detailed representation of the code, including read-in and results plot, is included in the appendix.[532]

Precooling Shift

For the implementation of precooling in DR-DER-CAM, the cooling load determined from the eQuest model is subtracted from the total load and fed into the optimization as a separate load. In addition, three binary variables are defined for each day that precooling occurs: One to indicate a day without precooling, one to indicate a day with PC-I precooling, and one to indicate a day with PC-II precooling. For each day only one of the three binary variables can be one.

$$BiPreCoolNo_d + BiPreCoolOne_d + BiPreCoolTwo_d = 1 \qquad \forall(d,t) \qquad \textit{(Eq 6.20)}$$

In addition, the total number of days that precooling can be used on, is limited to four:[533]

$$\sum_{d=1}^{30} BiPreCoolOne_d + \sum_{d=1}^{30} BiPreCoolTwo_d \quad \leq \; 4 \qquad \textit{(Eq 6.21)}$$

Afterwards, the resulting cooling load after optimizing the usage of PC is calculated:

$$CoolingLoadPC_{t,d} = OriginalCoolingLoad_{t,d} * BiPreCoolNo_d + PreCoolOneLoad_{t,d} * BiPreCoolOne_d + PreCoolTwoLoad_{t,d} * BiPreCoolTwo_d \qquad \forall(d,t) \; \textit{(Eq 6.22)}$$

This resulting *CoolinLoadPC* is inserted into the equation for electricity consumption and replaces the *OriginalCoolingLoad:*

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[532] See Appendix E.

[533] See discussion under sub-chapter 5.4.2.

$$ElectricityConsumed_{t,d} = ElectricNonCoolingLoad_{t,d} + CoolingLoadPC_{t,d} + ElectricityForBattery_{t,d}$$

$$\forall(d,t) \qquad \textit{(Eq 6.22)}$$

Cooling load as well as precooling profiles P-I and P-II are read-in from Excel. A detailed representation of the code, including read-in and results plot, is included in the appendix.[534]

[534] See Appendix E.

CHAPTER 7: Analysis of Demand Response Potentials

This section of the report will present the results of the analyses carried out under the previously presented DR-DER-CAM.[535] Along with descriptions on how the analyses were carried out, the results are presented and discussed in detail. This section will also highlight especially relevant results as well as limitations to be considered in future analysis and the practical implementation of DR at SRJ.

This analysis section is clustered into four main chapters along the relevant tariffs and DR programs under research in this report.[536] Each tariff or DR program forms one case in the analysis, starting off with the standard TOU tariff under schedule E-20.[537] Following, the participation of SRJ in PDP will be evaluated. Afterwards, the combination of PDP with DBP will be analyzed and, finally, the report will go into detail on partaking in PDP and BIP simultaneously. The two actual DR programs DBP and BIP[538] are analyzed in combination with PDP instead of the standard E-20 TOU tariff, as PDP is getting more relevant in the market and might become the standard tariff for industrial customers – without the possibility to opt out – sooner or later anyway.[539, 540]

In each of the four cases will be segregated into scenarios. Each chapter starts off with an analysis of the 2011 consumption of the jail without leveraging the battery or any other schedulable resource such as lighting shedding or pre-cooling. Afterwards, the usage of the battery will be evaluated. In the next two sub-chapters the potential of lighting shedding and pre-cooling will be presented. The evaluation on lighting shedding and pre-cooling will embrace the usage of the battery.[541] In total, 12 scenarios will be evaluated. The table below shows the analyzed scenarios and gives a quick reference to the sub-chapter of the analysis.

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[535] See section 6.

[536] See chapter 3.2.

[537] Current SRJ tariff. See sub-chapter 3.2.1.

[538] See chapter 3.2 for differentiation between tariff and DR program.

[539] See chapter 3.1.2.

[540] In addition, the following analyses will prove, that the participation in PDP is beneficial for SRJ under any circumstances evaluated and can therefore be considered the "improved base-case" for these analyses.

[541] Although methodically it would be more stringent to first present the potential of lighting shed and pre-cooling without the usage of the battery, this step will be dropped in the analysis as the battery is installed at SRJ anyway since this year (See chapter 4.4. and 4.2.4) and most definitely will be used to minimize electricity costs. An analysis leaving out the electric storage would, therefore, not be of any practical relevance. Dropping this first step also allows to better focus on the more complex analysis of the DR programs DBP and BIP under the more relevant battery scenarios. However, the FIXED DEMAND case is still presented for TOU and PDP as it will help the reader to grasp the overall concept of the analyses, the tariff structures, and, in addition, it will be interesting to determine how much electricity costs can be offset by the battery in general and if the electric storage proves to be financially viable. Financial viability of the electric storage has not been a key point of concern when the battery was installed as the whole SRJ microgrids project is still considered a research project. Therefore it will be interesting to evaluate if the electric storage is reasonable under real-life market conditions.

	Fixed Demand	Battery	Load Shed	Load Shift
TOU	7.1.1.	7.1.2.	7.1.3.	7.1.4.
PDP	7.2.1	7.2.2	7.2.3.	7.2.4.
DBP	-[542]	7.3.1.	7.3.2.	-[543]
BIP	-[544]	7.4.1.	7.4.2.	-[545]

Table 8: Overview of Scenarios

For each and every one of these scenarios as well as for any additional annual costs given under sub-scenarios, the whole year is simulated month by month with DER-CAM for all 34,560 15-minute time steps.[546] Even if only one exemplary day is presented or only a total annual cost figure is given, the underlying analysis considered the behavior during every day of the year in detail.

Additionally, before starting off the detailed presentation of the results, it shall be remarked that the presentation of the analyses focuses on the summer months May through October. Most DR events occur during the summer months only and the majority of the DR programs are even limited to event occurrences during the summer period. In addition, in underlying TOU and PDP tariffs the highest charges for demand and energy during the *On-peak*[547] period only occur in summer. Winter does not have *on-peak* periods and the whole daytime[548] is considered *mid-peak*[549].[550]. Due to this tariff structure the difference in rates is not as steep in winter as it is in summer. Thus, the summer analysis is considered more relevant as a steeper grade between different times of the day also provides more arbitrage potential that can be tapped through optimized scheduling.

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[542] Although methodically it would be more stringent to first present the potential of lighting shed and pre-cooling without the usage of the battery, this step will be dropped in the analysis of DBP AND BIP as the battery is installed at SRJ anyway since this year and most definitely will be used to minimize electricity costs. An analysis leaving out the electric storage would, therefore, not be of any practical relevance. Dropping this first scenario also allows to better focus on the more complex analysis of the DR programs DBP and BIP under the more relevant battery scenarios. However, the FIXED DEMAND case is still presented for TOU and PDP as it will help the reader to grasp the overall concept of the analyses, the tariff structures, and, in addition, it will be interesting to determine how much electricity costs can be offset by the battery in general and if the electric storage proves to be financially viable. Financial viability of the electric storage has not been a key point of concern when the battery was installed as the whole SRJ microgrids project is still considered a research project. Therefore it will be interesting to evaluate if the electric storage is reasonable under PDP and TOU. The additional participation in DBP and BIP slightly affects the viability evaluation of the battery, but does not change the key finding to an extent that it would be worth discussing in this study.

[543] This scenario is not presented as the participation in DBP did not change the scheduling of precooling at all and the resulting costs only changed marginally. Discussing this scenario would not result in any new insights, neither related to DBP nor regarding the usage of precooling.

[544] See previous footnote.

[545] Precooling is not evaluated under BIP as the short event notice of precooling does not allow to use precooling during BIP events. Precooling could still be used for the underlying PDP events, but conducting this analysis did not result in any relevant new insights, neither related to BIP nor to precooling. Also, costs only changed very marginally and therefore this scenario is not presented in the report at hand.

[546] See sub-chapter 6.2.1 regarding assumptions made for the implementation of a year-long optimization.

[547] Also referred to as *peak* period above.

[548] 8:30 a.m. to 9:30 p.m.

[549] Also referred to as *partial-peak* above.

[550] See sub-chapters 3.2.1 and 3.2.2.

It shall also be mentioned that the following analyses are all carried out under the assumption of full certainty regarding consumption behavior and DER output. This assumption represents the current state-of-art of DR-DER-CAM.[551] Although all inputs are fixed and known to the optimization program before the start of the month's optimization, it was ensured during the implementation of the DR extensions that the optimization does not imply a change to the standard behavior due to a DR event before the DR event notification would be issued in real life. Summarizing, this means that the following analyses assume that SRJ is able to perfectly forecast its own load and DER output but does not have any knowledge of upcoming DR events prior to the official notification by PG&E.[552]

In the following analyses all loads are based on actual 2011 consumption[553] and also the actual PV generation of 2011 is used.[554]

7.1. E-20 Time of Use

The detailed analysis of SRJ's DR potential is kicked off with an analysis of the current tariff that SRJ is served under to use the results of this scenario as the benchmark afterwards. Unfortunately, the real billing data cannot be used to form the base case as the electricity consumption and costs have been significantly influenced by FC failures as explained above.[555] Due to these limitations the analysis of the E-20 TOU tariff will serve as a base case and an introduction to the different schedulable load influencers. In the first sub-scenario electric storage and any other form of load influence are disabled. Afterwards, battery, lighting shedding and load shifting will be introduced subsequently.

The analyses will identify the potential cost savings that SRJ can generate from using its electric storage, its load shedding and load shifting capabilities and the combination of those three influencers without being involved in any kind of DR tariff or program. This detailed base case ensures that later on benefits of partaking in a DR program can be clearly distinguished from the savings that e.g. load shedding can generate under the current, standard TOU tariff as well.

Before diving deep into the analysis, it is of outmost importance for the reader's understanding to recall the structure and rates of the TOU tariff, especially as the basic tariff structure is underlying to all other scenarios as well. For doing so, please refer to the TOU tariff presentation above.[556].

7.1.1. Fixed Demand

In this analysis the demand of the jail is considered totally fixed, meaning that the battery will not be used to shift load and load shedding or shifting opportunities are disabled. This is the

[551] However, parallel to this project the microgrids group of LBNL is undertaking efforts to be able to integrate uncertainty in DER-CAM.

[552] The assumption of full certainty will be further discussed in section 8.

[553] Actual consumption plus FC generation, as FC is not considered in analysis. See sub-chapter 5.1.2.

[554] As discussed under 5.1.1.

[555] A scenario analysis including the actual FC consumption as well as a perfect FC production is carried out for the most viable DR option at the end of this chapter.

[556] See sub-chapter 3.2.1.

base case that is closest to the actual consumption of the jail in 2011[557] and means that the jail basically supplies all its demand by the installed PV and its connection to the PG&E grid. As no variables are available to be optimized in this run, DR-DER-CAM is used to calculate the cost of electricity for 2011 for the given demand and the given PV generation.

Energy Balance for Exemplary Day

To illustrate the result of the optimization and to familiarize the reader with the graphical results presentation used throughout the following analyses one exemplary summer weekday is presented and described below. Although only one day is presented for this case, it shall be noted that a likewise display of consumption and generation is available for all other days of the year as well.

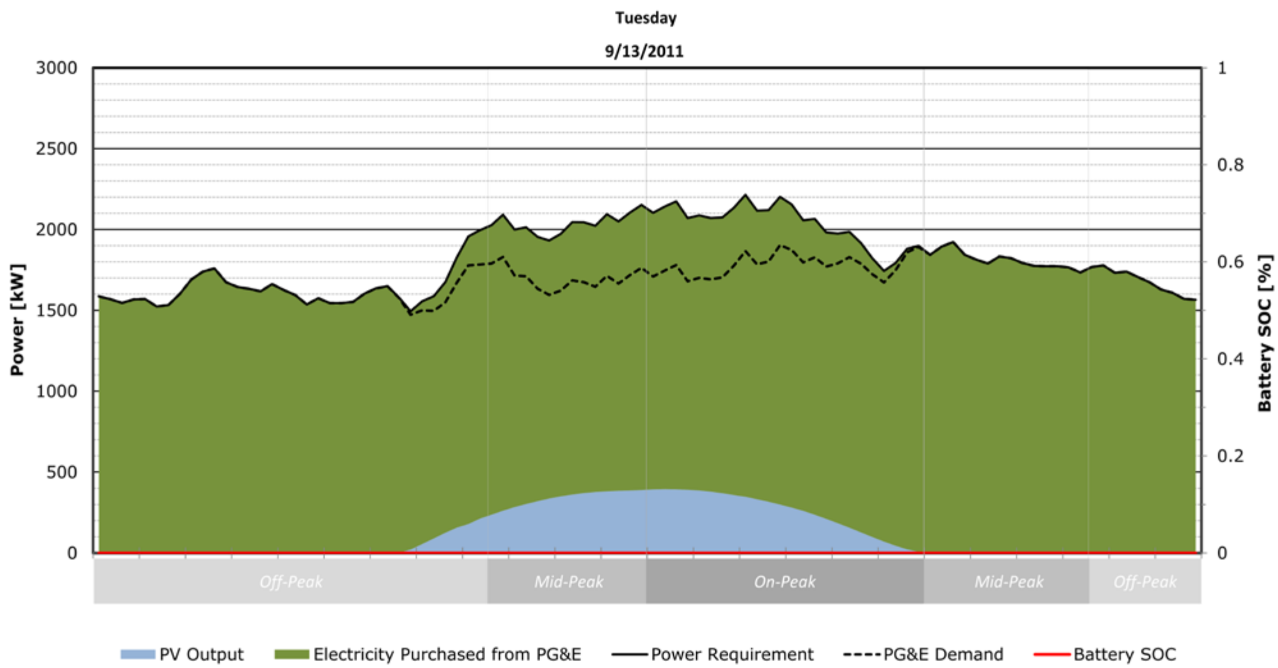

Figure 25: Electricity Balance SRJ - TOU FIXED DEMAND

The graph above shows the consumption analysis for SRJ on the 13th of September 2011. In this graph the black line represents the power requirement of SRJ in 15-minute time steps for the full 24 hours of the day. This is basically the aggregated consumption of all loads at SRJ. The blue area at the bottom shows the generation of the PV. The shape of the solar generation indicates that this day was a perfect bluebird day at SRJ and no passing clouds limited the PV generation.[558] Above the blue area is the green area, representing the electricity that SRJ consumed from the PG&E grid. The dotted black line during mid-day indicates the actual PG&E demand at each time step. During the day the dotted line deviates from the solid line –

[557] Except for no consideration of FC output.

[558] The peak exactly at mid-day is caused by the flat mount of the arrays that provide the highest output of electricity when the sun is at its highest point, which is around mid-day during summer.

the power requirement or total load of SRJ – because some of the SRJ load is covered by the PV output. The blue area and the integral between the dotted and the solid line are exactly identical and if one switched the stacking order of the blue and green parts, the area between the dotted and the solid line would be exactly filled by the blue PV output.[559] For the following analyses it is important to bear in mind that the relevant line for the electricity costs is the dotted line, which is overlaid by the solid line in the morning and evening. The dotted line represents the actual PG&E demand and the highest peaks of the dotted line during a month are what drive demand charges. The energy charges, however, are equivalent to the green area in the diagram, multiplied by the different rates in the different TOU periods. To support the understanding of the consumption, especially in later battery scenarios, the TOU periods are indicated below by the grey bar below the diagram and the small vertical lines going up into the diagram itself represent the thresholds between the different TOU periods.[560]

Cost Analysis

In this fixed scenario under the TOU E-20 tariff the total costs of electricity supply add up to $ 1,447,368. Of this, $ 1,001,706 is caused by energy charge and the remaining $ 445,369 by demand charge. With 53 % most of the energy charge is attributed by *off-peak* energy. As *off-peak* has the lowest energy charge this might be surprising at first sight but recalling how much of each day and the whole weekends and holidays are *off-peak*, one can understand that these times add up. For the demand charge the biggest contributor with 53 % is the *monthly maximum* charge.[561] This means that for the majority of months the highest peak has not been during *on-peak* times.[562] It can be concluded that the resulting SRJ demand from PG&E, when including on-site PV generation, is rather flat and does not have any significant mid-day peaks. This can also be seen by the more or less horizontal orientation of the dotted line in the above presented diagram.[563]

To enhance the understanding of the contribution of energy and demand charges over the year, the graph below presents the energy and power/demand costs on a monthly basis for 2011. The green line indicates the total monthly costs.

[559] Actually switching the stacking order of PV and Grid Consumption to simplify this energy balance is not reasonable as in later – more complex – scenarios the presented stacking order has been proven to be more intuitive.

[560] Instead of displaying single hours or times on the x-axis the TOU periods are symbolized by the grey bar as they are more meaningful for the analysis than the actual times. Small tick marks directly above the grey bar indicate one hour.

[561] The equality of the figures in this case is random and does not indicate any kind of connection.

[562] This observation was not made in the earlier analysis because before the total load was evaluated by itself. In this scenario, however, the PV production is included and helps to lower the demand especially during the day hours.

[563] See Figure 25.

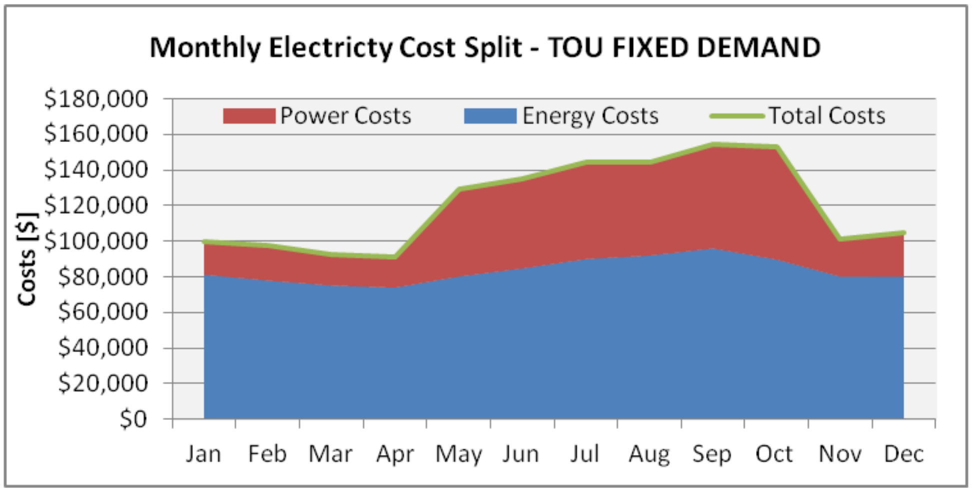

Figure 26: Monthly Electricity Cost Split - TOU FIXED DEMAND

The blue area, indicating the electricity costs, shows a slight increase in costs over the summer, which is mainly due to higher energy charges in summer.[564] The eye-catching part of this diagram, however, is the fact that the power charge is much higher in summer than in winter. In summer the demand charge accounts for 39 % of total electricity costs. Although the *monthly maximum* demand charge remains unchanged for summer and winter, the *mid-peak* demand charge is increased by a factor eleven from winter to summer. In addition, the high *on-peak* demand charge only applies in summer. This finding affirms the previously made choice to focus the analyses on the summer months.

Peak Demand Analysis

The higher rates during summer definitely cause increased power costs during summer to some extent but to be able to identify how much of the increase in demand charge is driven by the tariff structure and how much by an actual increase of peak demands in summer a peak demand level analysis is needed. The diagram below shows the *monthly maximum*, *on-peak*[565], and *mid-peak* demand peaks.

[564] While the jail load increases during summer the increase is almost fully compensated by the higher PV output in summer months, leaving total grid consumption almost stable over the course of the year. See chapter 5.1. for details.

[565] Only relevant in summer.

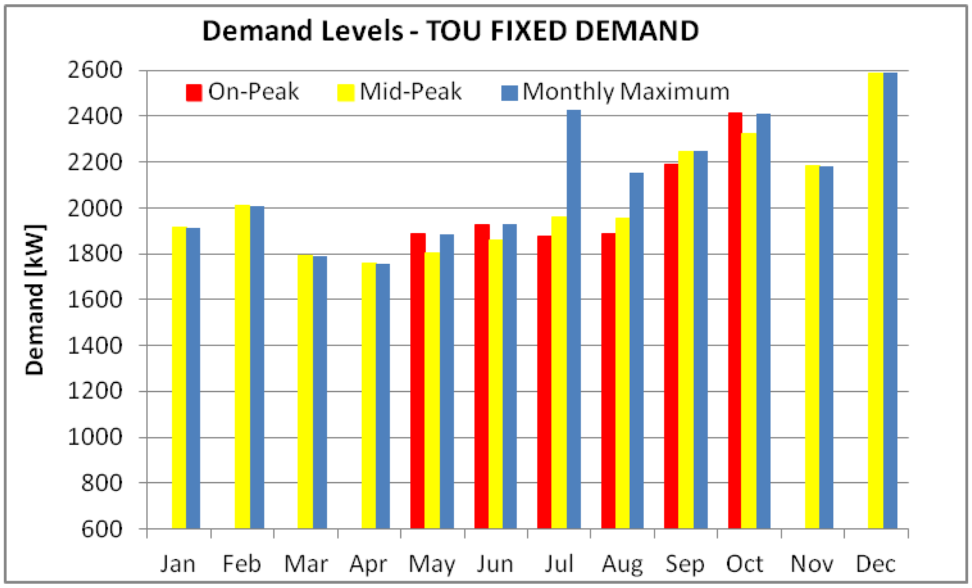

Figure 27: Demand Levels - TOU FIXED DEMAND

It can be concluded from the diagram that the significant increase in power costs between summer and winter is mainly driven by the changed rates and not by the total demand peak. Especially the high peak in December does not influence the resulting power costs.[566] Nevertheless, it can be seen that a certain alignment of *on-peak* maximum demand with the total power costs is evident during summer. The extreme outlier in September for the *on-peak* maximum demand is in line with the highest monthly power costs in September.[567]

Especially for summer, the diagram also supports the argument that for the majority of months the *monthly maximum* peak did not coincide with the *on-peak* periods, indicating a rather flat grid consumption.[568]

Conclusion

This sub-chapter should have given the reader a basic understanding of the structure of electricity costs and its key drivers at the jail, when not interfering by using electric storage or load shedding or shifting. It was determined that during summer the demand charges are an important cost driver to be considered. Also, it was determined that SRJ's PG&E demand is rather flat and shows no relevant mid-day peak.

7.1.2. Battery

In the second scenario the battery is enabled. All previous parameter such as load shape and PV generation output as well as the E-20 tariff rates remain unchanged. Now, for the first time, DR-DER-CAM is actually conducting an optimization in such a way that the charging and discharging is controlled by the optimization tool to find the lowest possible energy costs for SRJ. There are no restrictions to how the battery can work except for the charging and

[566] Compare to Figure 27.

[567] $ 58,250.

[568] In winter this dependency is significantly weakened by the low mid-peak demand rate.

discharging efficiencies, the decay and the energy and electricity limits of the battery[569]. The electricity costs will, in the following analysis be compared to the costs under the scenario presented before that does not include the usage of the battery to determine the amount of savings the battery can generate for SRJ.

In the analysis of this scenario, the demand-setting day for September will be presented. A non-demand-setting day is discussed in the Appendix.[570]

Energy Balance for Demand-Setting Day

The first day shown and discussed is the 20th of September 2011 that is the relevant Demand Setting day for September.[571]

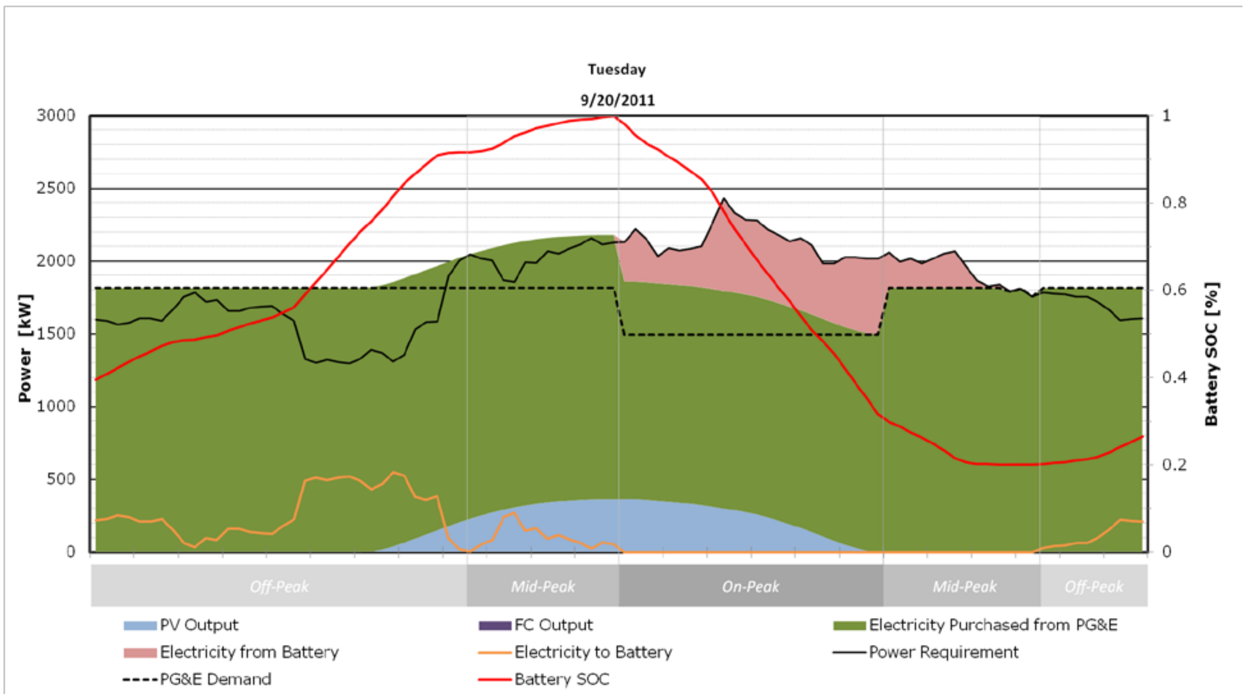

Figure 28: Electricity Balance SRJ - TOU BATTERY

The above diagram is the exact same representation of the energy balance at SRJ for a single day as the one already shown for the *FIXED DEMAND*[572]. However, now the battery usage is added to the diagram increasing the complexity of the depiction. One can still clearly identify the known elements; the blue and green area representing the PV generation output and the electricity purchased from PG&E respectively. Also discussed before was the solid black line that remains unchanged between the no-battery and the battery scenario as using the battery does not influence the total consumption of SRJ. The last part of the diagram that was already

[569] See chapter 4.2.4.

[570] See Appendix F.

[571] Although it might have been reasonable to choose identical days for representation in the different scenarios to prove such points as the unchanged power requirement, different days were chosen between these two scenarios. The reason for this is that the author gave higher priority to picking the days of the year that best characterize the points worth discussing under the different scenarios rather than looking at identical days throughout the whole analysis section.

[572] See Figure 25.

discussed previously is the dotted line representing the actual load of SRJ served by the PG&E grid. This dotted line is relevant for determining the costs of electricity. To recall, previously the dotted line did only deviate from the solid line during mid-day as the PV output lowered the consumption from the grid. Now the dotted line is also influenced by the behavior of the battery, which is shown in the diagram by three different elements. First, the SOC is represented by the red line, which is actually plotted to the secondary axis on the right-hand side of the diagram and measured in percentage of the total battery capacity. 100 % equals to a full charge of 4 MWh. Although this is not clearly visible in this diagram, the SOC is restricted to never be below 20 % at any point of time.[573, 574] The second part describing the battery behavior is the orange line that describes the electricity going into the battery, i.e. the charging. This line is plotted to the primary axis on the left hand side.[575] The last part of the battery behavior representation is the electricity taken from the battery to supply the jail load, i.e. the discharging. This is represented in the diagram by the pink stacked area.[576, 577]

After previously determining what line describes which part of the SRJ energy balance in this paragraph the interconnection between the different energy resources and loads will be pointed out. It can be seen that during the morning hours the battery is charged while ensuring a flat demand from PG&E. During the morning hours the demand from PG&E exceeds the power requirement of SRJ. The green area then starts to climb over the dashed line in the late morning as PV production starts to pick up. The relation can be seen, as the shape of the blue PV output area is mirrored in the outline of the green area during the morning mid-peak period as well. During the on-peak period the discharging of the battery starts and the power requirement is served by electricity from the battery, by PG&E supply and PV output as can be seen from the stacked areas below the solid line. In the late night, before midnight, the charging of the battery starts over again – preparing for the next day – and again the area under the orange line is equivalent to the integral between the dashed and the dotted line.

In this paragraph the underlying reasons for the structure of the energy balance presented above in figure 28 will be explained. First, it must be said that the energy balance of the presented day cannot be analyzed by itself but must be seen in connection with all the other days of the month of September. However, the 20th is chosen for discussion, as it is the most significant day of the month, the demand-setting day, as it shall be called in this report. The demand-setting day is

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573 See sub-chapter 7.2.2. for clearer visualization of this effect.

574 See sub-chapter 4.2.4.

575 Although electricity consumptions are usually shown as stacked areas, the electricity going into the battery is shown as a line graph because it does not represent a source of electricity as the PV output, the consumption of the grid or the electricity taken from the battery, but rather a usage of the electricity. During the night and early morning hours for example, the battery is charged, which is visible by the fact that the orange line is above zero. However, this electricity is taken from the grid and would, therefore, be double-counted if it were also shown as a stacked area

576 In contrary to the electricity going into the battery, which is not a source of electricity but rather a usage specification, the electricity taken from the battery is used to serve the jail load and can be considered a source of electricity. Thus, it is shown as a stacked area, like the PV output and the consumption from PG&E grid.

577 If a line, such as the dotted line for demand goes up or down with a steep grade, but not perfectly vertical, one has to bear in mind that the resolution of the used data is only 15 minute time steps. With a higher data resolution the transitions would be even steeper and if they were to occur at the border of a TOU period, be perfectly aligned with the grey TOU period indicator.

characterized by the fact that all battery capacity available is used to keep the demand levels[578] at the optimal level. Depending on the total load structure of the month[579] and the characteristics of the battery[580] the DER-CAM optimization tool uses the battery in such way that the total electricity costs are minimized. This is achieved by ensuring a flat demand throughout the different TOU periods to avoid high demand charges caused by peaks that might only last for one or a few time steps. This effect can be clearly seen in the diagram above. During the *off-peak* and *mid-peak* in the morning the battery is charged but in such way that the resulting demand from PG&E is at a flat level. Then, during the on-peak period, the battery energy is used to reduce the *on-peak* demand level and also keep it on a certain level. The resulting *on-peak* demand is lower than the chosen off- and mid-peak demand levels as the charge for on-peak demand is higher. In the second *mid-peak* period of the day some battery capacity is used to maintain the mid-peak demand level set before. In the end of the day the charging of the battery begins again with consideration of the before chosen *off-peak* demand level. As mentioned before, the setting of the demand levels is not done by the program for this demand-setting day only but taking the SRJ load shape of the whole month under evaluation into consideration. A lower demand during *on-peak* periods would obviously result in a higher demand during *off-* or *mid-peak* periods. Within this complex scenario the optimization tool finds the optimal demand levels for all three periods and ensures that they are maintained throughout the whole month. In addition to this, the charging and discharging efficiencies as well as the battery decay are also considered by the optimization.[581] When charging the battery during *off-* and *mid-peak* and discharging mainly during *on-peak* periods obviously also energy costs are lowered as the battery is charged at a lower rate per kWh than the rate of the *on-peak* energy that is offset when discharging the battery. However, the existence of one demand-setting day per month[582] proves that the demand charges are the key driver for the usage of the battery. The demand levels that can be maintained on the demand-setting day can and are also maintained throughout the rest of the month. During the weekend and holiday days, which are off-peak all day long, the battery is not leveraged.[583] Which day is the critical demand-setting day cannot be intuitively determined by e.g. the highest *on-peak* demand during the month but depends on the detailed shape of the load throughout the peak periods as well as the *mid-* and *off-peak* periods. Furthermore, the amount of PV output available, which lowers the resulting load, plays into this.

Cost Analysis

For the battery scenario under TOU the total costs add up to $ 1,319,246, with energy costs of $ 989,473 and power costs of $ 329,774.

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[578] Total demand, mid-peak demand, and on-peak demand.

[579] Load requirement minus PV Output.

[580] See sub-chapter 4.2.4.

[581] The efficiencies and the decay result in the fact that during winter months the battery capacity is not always fully leveraged as this would not be optimal due to smaller difference in demand charges between the different periods.

[582] In summer.

[583] Only if load peaks would drive up the total month max demand charge, the battery is used to ensure that the determined demand level is not exceeded. Nevertheless the load shapes on the weekends also influence the optimal load levels, even though with a low priority as the related charges are low compared to *mid* and especially *on-peak* charges.

The total costs compared to the previous *FIXED DEMAND* scenario are lowered by 9 %. These savings are almost exclusively attributed by savings from power charges. Power charges decreased by 26 % in this scenario compared to no battery usage. Energy charges only went down by 1 %. This again highlights the point that, under the optimal scheduling of DER-CAM, the battery usage is driven by demand charges and tries to lower these. Although energy charges are offset during non-demand-setting days, it must be kept in mind that during charging, discharging and storage, energy is lost due to technical inefficiencies and decay. While some savings of energy charge are achieved during non-demand-setting days, these are almost totally compensated by the additional energy that must be purchased from PG&E due to the inefficiencies and decay. The higher amount of savings in power demand leads to a changed ratio of energy to power charges of now 75 % to 25 %[584]. The monthly cost split for this scenario is provided and discussed in the appendix.[585]

Peak Demand Analysis

The effect of including the battery in the electricity supply structure can most clearly be seen when looking into more detail into the monthly demand levels presented in figure x below. This representation is equivalent to figure 27 shown for FIXED DEMAND.

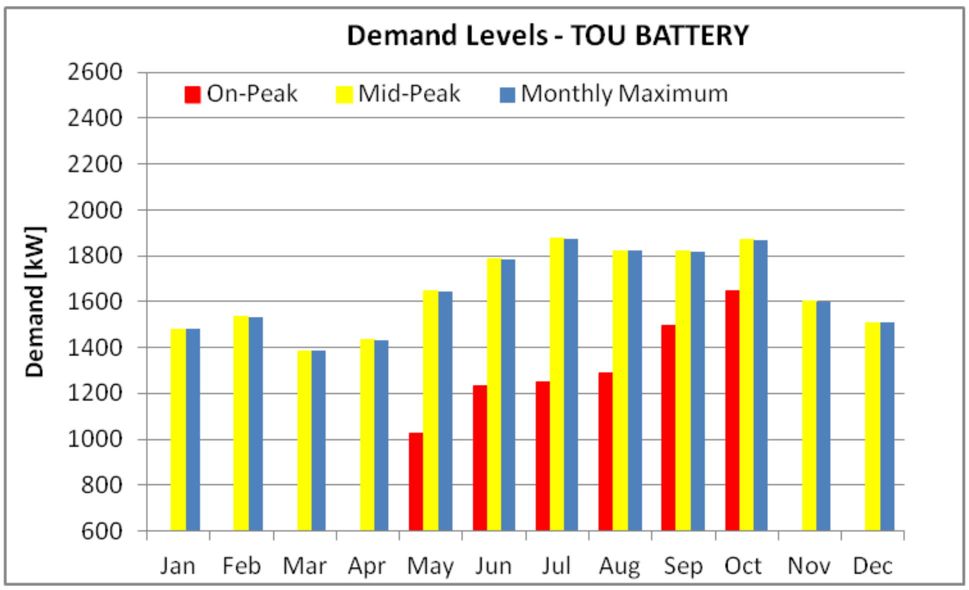

Figure 29: Demand Levels - TOU BATTERY

The graph shows, compared to FIXED DEMAND, how the battery is used to better align the different demand levels and lower them altogether to save on power charges. While in the original load under the previous scenario the monthly max demand would sometimes occur during off-peak periods these spikes have been flattened so that now the monthly max demand is never higher than the mid-peak demand. This is very nicely illustrated by the flat demand in the first *off*- and *mid-peak* period in the energy balance of the demand-setting day[586]. Over the full

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584 Previously 69 % to 31 %.

585 See Appendix F.

586 See Figure 28.

year the average of the monthly total monthly maximum demand was lowered by 387 kW and the mid-peak by 462 kW by using the battery. The most significant change, however, was made to the on-peak maximum demands. As during this period the highest demand charges apply, the battery was leveraged to lower these the most. In graph 27 above[587] the on-peak was mostly somewhere close to the total maximum of the month. In graph 29 above, the *on-peak* maximum demand is always significantly lower than the *monthly maximum* demand of the month. On average, the *on-peak* demand has been lowered by 708 kW per month.

Conclusion

It can be concluded that the optimal battery scheduling focuses primarily on reducing the different demand levels and amongst those mainly the one with the highest peak demand, the on-peak maximum demand. To do so, the optimization tool determines a demand-setting day at which all battery capacity is used to keep the identified optimal demand levels. During all other days, the optimization uses the additionally available battery capacity to lower energy costs slightly. In 2011 using the battery under TOU tariff E-20 generates savings of $ 128,122.

To compare these savings to the total investment costs of the battery of $ 4,000,000 the avoided negative cash-flow from the aforementioned annual electricity cost savings[588] is discounted over the expected life-time of the battery of 25 years.[589, 590] The resulting net present value (NPV) of the investment is $ -1,640,871, meaning that under today's E-20 tariff rates and structure the installation of the electric storage at today's costs is not financially viable.

Nevertheless, the battery will be included in the following analyses as it is installed at SRJ and, therefore, will be used. The following "battery scenarios" will also determine the savings generated by the battery itself and the resulting NPV will be presented to determine if the battery can be brought to break even by taking part in DR programs or to be able to at least prove under which scenario the battery gets closest to a financial viability.

7.1.3. Lighting Shed

In the third scenario the previously described lighting shed[591] is added to the analysis. The electric storage is installed at SRJ and will certainly be used to reduce electricity costs. Therefore, in this scenario, the lighting shed will be evaluated in combination with the battery, as presented in the previous sub-chapter. Initially, the lighting shed was introduced based on the idea to reduce load in reaction to DR events. Nevertheless, lighting shed will now be evaluated under the E-20 TOU tariff to be able to compare total electricity costs between E-20 and PDP correctly and evaluate the savings potential of lighting shed without DR.

The DER-CAM optimization tool will be used to optimally schedule the battery charge and discharging in combination with the available lighting shed. As discussed above, the lighting

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[587] See Figure 27.

[588] Tariff structure and rates are assumed to be fixed. This might not be realistic, but the only reasonable assumption as forecasting tariffs rates and structures over 25 years that will heavily depend on economic growth and the success of the paradigm change in the electricity market.

[589] See chapter 4.2.4.

[590] Assumed risk-free discount rate of 3 %.

[591] See sub-chapter 5.4.1.

shed available is 341 kW in the time before 6 a.m. and after 9 p.m. and 419 kW in the time between. Lighting shed is limited to a maximum of 2 hours per day and a maximum of 8 hours in total per month. This limit is essential as the lighting shed does not have any costs associated in the DER-CAM optimization. A reduced lighting, however, might cause inmate and staff discomfort and, thus, these limits were chosen before.[592]

Energy Balance for Exemplary Day

In the following paragraphs the demand-setting day for the month of September will be presented and discussed. The demand-setting day is still the 20th of September, which is advantageous to the presentation as the differences can be more easily visualized.[593] Below the energy balance for the 20th of September is shown.

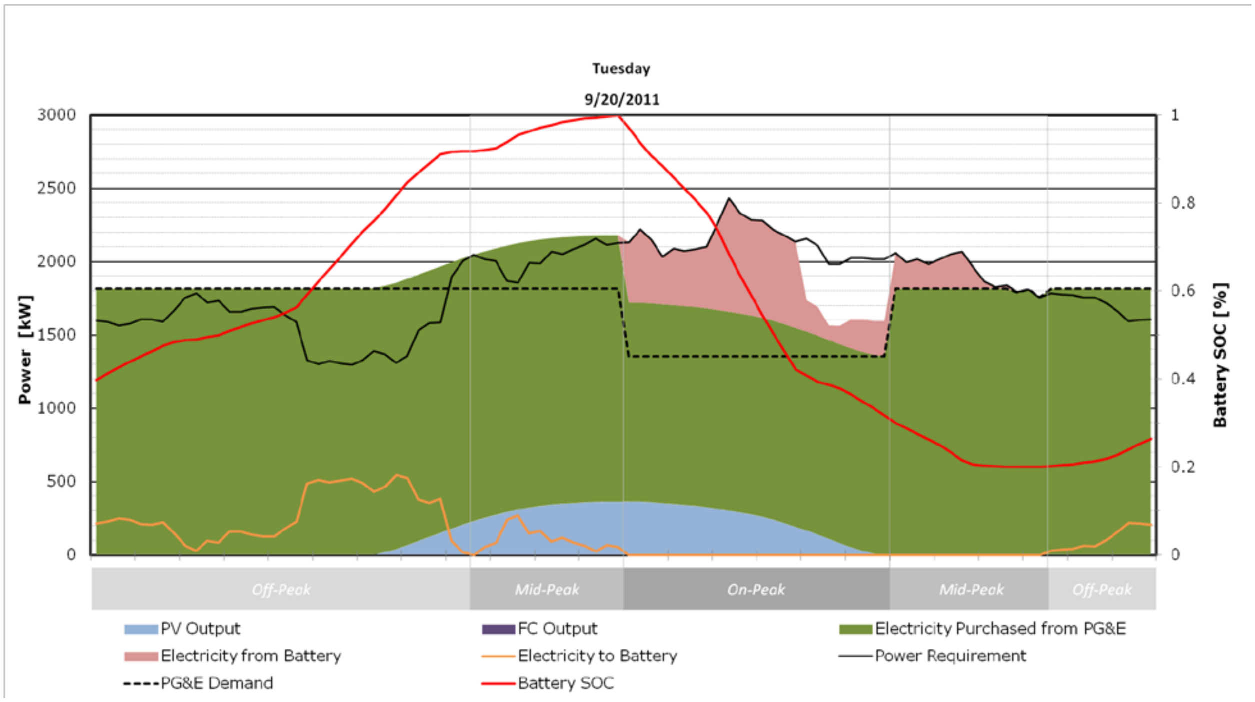

Figure 30: Energy Balance SRJ - TOU LIGHTING SHED

The elements of the diagram remain basically unchanged compared to the previous scenario. The only new element to the diagram is the blank area at the end of the on-peak period, whichrepresents the lighting shed. It can be seen that the addition of PV output, PG&E consumption and battery discharge does not add up to the solid black line of power-requirement as it usually does at times when the battery is discharged. To not further complicate the depiction of the energy balance the lighting shed area is left blank as this intuitively shows that the SRJ demand was lowered and the switched of lighting load does not

[592] See sub-chapter 5.4.1.

[593] Nevertheless, it should be kept in mind that in this altered scenario the demand-setting day could have been another day, meaning that on the 20th battery capacity would still be available to reduce energy costs as described before.

need to be supplied.[594] The height of the blank area shows the amount of lighting shed chosen by the optimization.[595]

On the demand-setting day the full lighting shed of 419 kW is used over the maximum allowed time of two hours. The lighting shed is scheduled at the very end of the on-peak period, because most savings can be generated during this time period as the highest charges for demand and energy apply. The reason for the lighting shed being scheduled at the very end of this period is the decay of the battery. Energy stored in the electric storage decreases over time.[596] First the energy from the battery is used to level demand and offset electricity costs and then, for the last two hours of the on-peak period, the lighting shed is leveraged.

Also, it must be mentioned that the demand levels in off- and mid-peak have been slightly changed and the on-peak demand level has been more substantially lowered compared to the previous scenario. This was possible, because the battery capacity can be used to set a lower level of on-peak demand by using the lighting shed potential during the on-peak period. As this level can be maintained on the demand-setting day, it can also be maintained throughout the rest of the month and thereby generate savings from a lowered on-peak demand charge.[597]

For this scenario no non-demand-setting day is discussed in detail as the behavior does not change significantly compared to the battery scenario.[598, 599]

Cost Analysis

For the lighting shed scenario under TOU the total annual electricity costs add up to $ 1,302,071, with energy costs of $ 985,425 and power costs of $ 316,646. Compared to the battery scenario, the inclusion of lighting shed generated savings of $ 17,175 or 1.3 % of total costs. With $ 13,128 the vast majority of these cost savings comes from savings in power charges.

Of the total cost savings, 82 % are achieved during the summer season. Of the total annual demand savings, 89 % are contributed during summer, while only 60 % of the total energy savings are accumulated in the summer months. The amount of summer energy savings of $ 2,467 is almost exactly the amount that is obtained when multiplying the monthly maximum load shed potential of eight hours with the maximum load shed capacity of 419 kW and the summer electricity on-peak price.[600, 601] This suggests that all lighting shed in summer occurs during on-peak periods only.[602] The high share of summer demand savings is caused by the fact

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[594] Filling in the blank area would suggest that the lighting shed can be considered a source of electricity, such as the battery discharge, PV and grid consumption, which is not true. Therefore the blank area represents the lighting shed and does not indicate an under-supply situation.

[595] This amount can be more easily quantified if grid lines are visible in the background, which also supports the argument for not filling in the lighting shed area.

[596] See sub-chapter 4.2.4.

[597] The savings will be discussed in more detail in the detailed cost analysis.

[598] Refer to 7.1.2.

[599] Except for the lowered demand levels.

[600] See sub-chapter 3.2.1.

[601] The fact that the actual savings is by $ 5 larger than the result of the described of the multiplication is due to the fact that battery decay could be avoided by lighting shed.

[602] If this assumption holds true will be evaluated below in the lighting shed distribution analysis.

that during summer months lighting shed can be used to lower the high on-peak demand charges, while during winter months the significantly lower power charges only provide a smaller savings potential for the identical amount of load shed available in every month. The influence of lighting shed on the different demand levels will be evaluated in more detail in the following paragraphs.[603]

Peak Demand Analysis

The general structure of the demand levels is still identical to the previous scenario. The highest total demand always occurs at *mid-peak* and *on-peak* demand levels are noticeably lower. The detailed analysis showed that *monthly maximum* demand and *mid-peak* demand levels have decreased on average by 11 kW and the *on-peak* demand level[604] was reduced by 142 kW per month on average. This explains why the majority of demand savings is contributed in the summer season, as it was mentioned in the cost analysis before.

A graphical representation of demand levels as shown in the previous two scenarios is included in the appendix.[605]

Lighting Shed Distribution Analysis

After the standard analyses that have also been conducted for all previous scenarios, another lighting shed specific analysis is added to better understand how the optimization tool leveraged the given lighting shed potential to find the cost minimal schedule for battery and load shedding.[606]

First, the times at which lighting shed is scheduled will be evaluated. In the analysis of the demand-setting day it was already determined that the light shed in that most critical day of the month occurred in the last two hours of the on-peak period. To be able to evaluate how the lighting shed potential is distributed on non-demand-setting days the graph below displays the number of time steps[607] in which lighting shed was used over the hours of the day.

[603] The overview on annual demand and energy charges presented in the previous scenarios is left out in this scenario as due to the small amount of savings, the changes are hardly visible in the aggregated format.

[604] Only occurring in summer.

[605] See Appendix F.

[606] This analysis will be restricted to summer months in accordance to the focus of this report.

[607] 15 minute time steps.

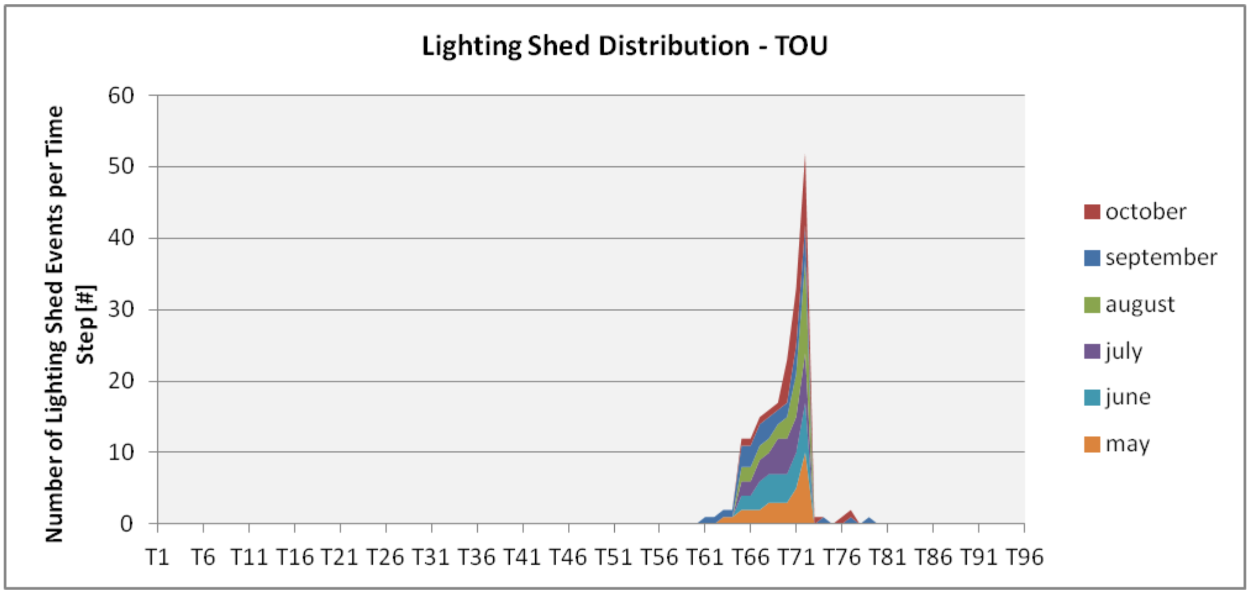

Figure 31: Lighting Shed Distribution - TOU

The figure shows that most lighting shed is used at the very last time step before the end of the on-peak period with a total of 52 time steps with lighting shed. Absolutely no lighting shedding occurred before 3:15 p.m. during the whole summer. Slightly above 3 % of the time steps in which lighting shed was determined to be optimal in the summer of 2011 did not occur in the on-peak period but in the beginning of the second mid-peak period of the day. These outliers are caused by significantly above average power requirements at these times on very select days.[608]

This analysis shows when lighting shed is used but did not give any information on the duration of the lighting shed. As determined, the maximum amount of lighting shed per day is two hours. Though, it is to be determined if the optimal solution means to always use two hours of lighting shed in a row or if lighting shed is used more selectively and for shorter periods as well. The two graphs below show the durations of the lighting shed events in 15-minute intervals on the x-axis.[609] The graph on the left-hand side shows the number of lighting shed events for each duration from 15 minutes to two hours. The graph on the right-hand side includes the duration of the event in the y-axis information and displays the total time of lighting shed events for the eight different durations.

[608] For example on 9/28 and 9/21.

[609] This is the resolution the optimization tool works with.

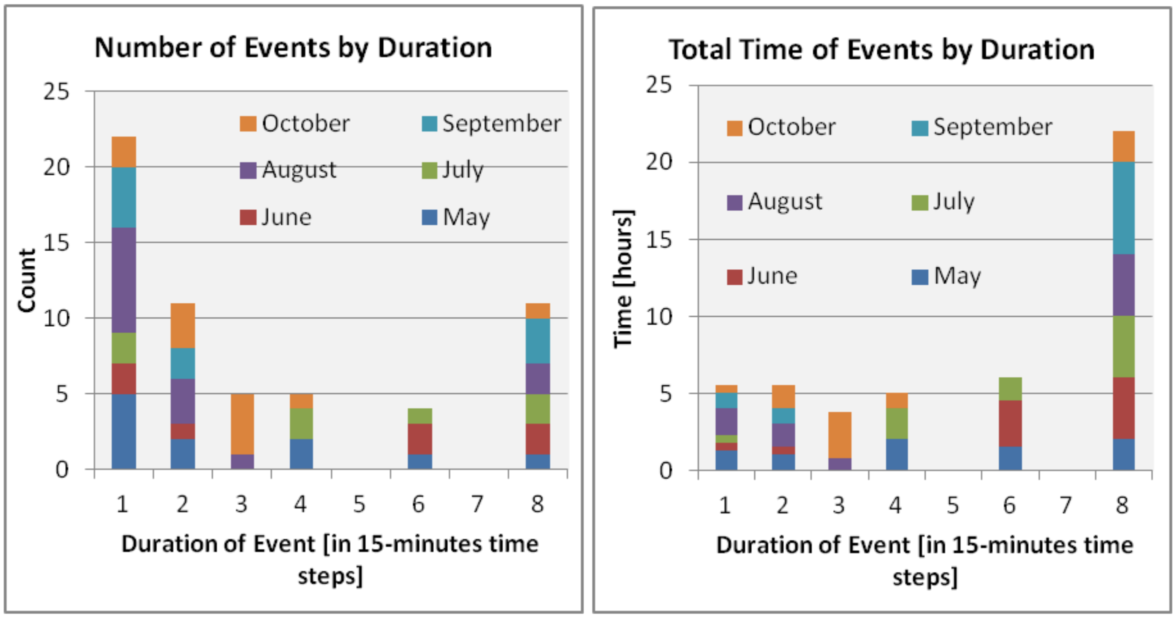

Figure 32: Lighting Shed by Duration of Event - TOU

From the left-hand graph it can be concluded that most lighting shed events last only one time step. Also, the number of events lasting two time steps and the number of events lasting eight time steps is at almost equal levels. The high number of lighting shed lasting for a single time step shows that the scheduling of the lighting shed is not trivial and is best done by a DER-CAM optimization. A more detailed analysis of the results showed that the single time step lighting shed events are not used to cut of extreme peaks as most peaks in the SRJ load shape last longer than one time step. In the optimal solution the single time step events are spread over the whole on-peak period by the optimization tool to ensure the lowest possible costs. For the two hour lighting shed events it can be remarked that every month has at least one two hour lighting shed event. This is in line with the presentation of the demand-setting day above of which every month has one. Surprising, however, is the fact that in some months one, and in September even two, two hour lighting shed events occur. Detailed analysis of the results showed that the days these events were scheduled were very close to being demand-setting days, meaning that the specific load structure only allowed for a very minimal energy reduction in the beginning of the on-peak period because almost all schedulable capacity is needed to maintain the optimal demand levels. The energy dumb in the beginning of these very select days exists, but is always smaller than 104.75 kWh and, therefore, the lighting shed cannot be reduced to seven time steps.[610, 611] The right-hand diagram puts the information from the left-hand diagram into perspective by showing the total time of lighting shed events, instead of only the number of events. This shows that most lighting shed, by total time,[612] is clearly scheduled to happen in two-hour events. Also, the high number of single time step lighting sheds is put into perspective as all durations that occur[613] except the two-hour load shed account for around five

[610] In September for example these days are the 22nd and the 23rd.

[611] 104.75 kWh is the amount of energy that is saved by lighting shed during the day in one time step.

[612] Total time looks at the number of lighting shed time steps instead of just at the number of events.

[613] Not including 5 time steps and 7 time steps.

hours of load shedding in the whole summer. Finally, the underlying data of both graphs proves that the total available lighting shed per month of eight hours or 32 time steps was used in every summer month.

Conclusion

Summarizing, for the scenario using battery and lighting shed potential under the E-20 tariff, the battery behavior remains unchanged compared to the battery-only scenario. All lighting shed potential is used by the optimization, mostly during the *on-peak* period with a clear orientation towards the end of the on-peak period. The daily maximum of two hours is used on demand-setting days and days that behave almost like demand setting days.[614] Numerous short lighting shed events are scheduled by DER-CAM to ensure the cost-minimal solution but no clear pattern for the distribution of these short i.e. single time step lighting sheds can be determined.

The demand levels could be lowered altogether with the highest impact on the on-peak demand level. The total savings generated by the inclusion of lighting shedding compared to the battery only scenario for 2011 are $ 17,175. The major share of these savings[615] comes from reductions in demand charges. More than 80 % of the total electricity savings achieved through lighting shedding are contributed during summer months, which, thus, should be the focus of lighting shed activities.

7.1.4. Precooling Load Shift

In this scenario the potential for PC under TOU tariff will be evaluated. Although it was determined above[616] that PC shall be used in conjunction with DR only, this base case is needed to determine how savings from PC are affected by changing from the current tariff that the jail is currently served under to a dynamic pricing tariff.

In *TOU PC* the usage of the battery will be enabled, for the same reasons mentioned under *TOU LIGHTING SHED*[617]. However, lighting shed capabilities will not be enabled in this scenario, as PC shall be evaluated by itself without having lighting shed interfere with the results. Also, there will be no joint analysis of electric storage, lighting shed and PC, as SRJ management is mainly interested in determining if the pursuit of lighting shed or PC is more reasonable in general[618] and in conjunction with DR specifically.[619, 620] Concluding, all parameters and settings under *TOU PC* – except for the addition of the PC functionality[621] – are equal to what was discussed and used under *TOU BATTERY*.

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614 In which only very little excess capacity of schedulable resources is left to offset electricity costs after ensuring that the optimal demand levels are not exceeded.

615 76 %.

616 See chapter 5.4.2.

617 See chapter 7.1.3.

618 Evaluation under TOU.

619 PDP, DBP. No comparison possible for BIP due to short notification time.

620 A joint analysis could, however, be evaluated in the future, once the more precise EnergyPlus PC profiles become available. See discussion under 5.4.2.

621 See chapter 6.1.2.

As outlined in the description of PC above[622] the focus of the analysis slightly differs from what was presented under *BATTERY* and *LIGHTING SHED*[623]. While lighting shed was evaluated in much detail, the analysis of PC is at a more conceptual level, will identify underlying mechanisms and give a first estimate of associated savings potential. To account for the changed priorities, the structure of the presentation of the analysis will differ slightly from what was presented above. After discussing an exemplary energy balance, the key findings will be outlined, before finally stating the resulting costs and savings. A detailed discussion of peak demand behavior is skipped at this early stage of analysis and also the numerical evaluation of the distribution of the PC days will not be presented in detail,[624] but the most relevant observations will be mentioned in the discussion of the findings.

Energy Balance for Demand-Setting Day

To start of the discussion the energy balance for the demand-setting day in September is presented:

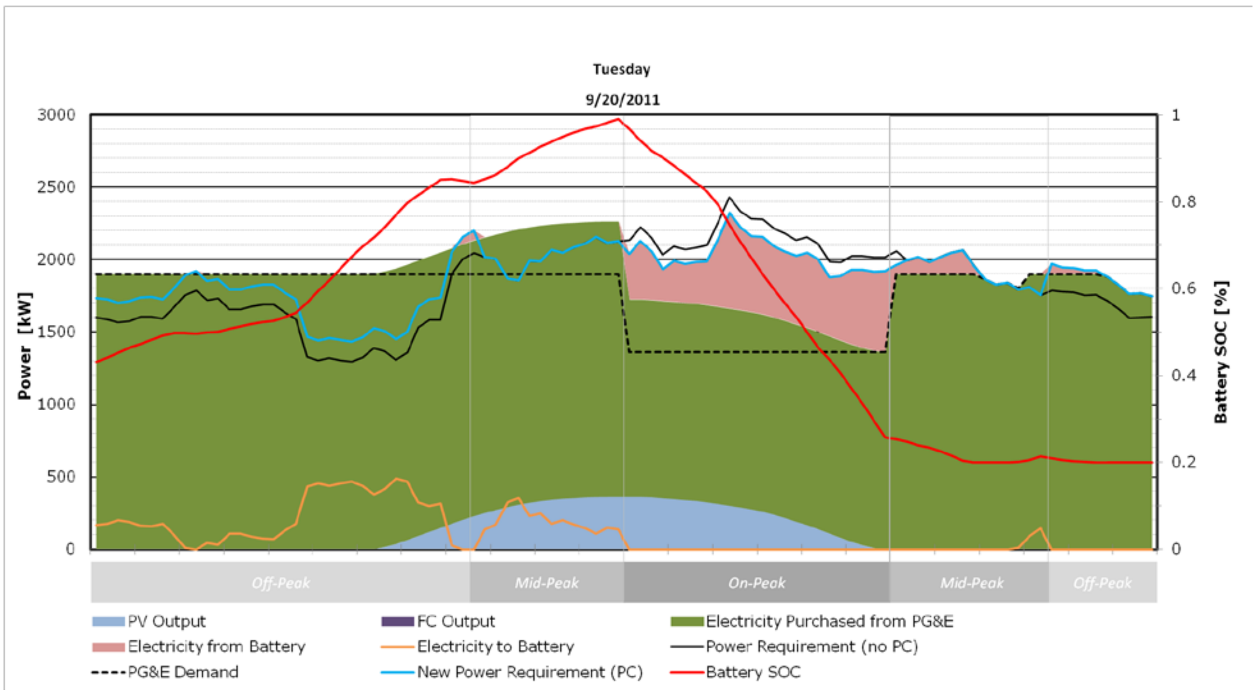

Figure 33: Energy Balance SRJ - TOU PC

The demand-setting day in September is still the 20th.[625] In addition to the presentation under *TOU BATTERY*[626] the energy balance contains one more line graph, in turquoise. This line represents the power requirement under PC, while the solid black line still represents SRJ's

622 See chapter 5.4.2.

623 See chapter 7.1.3.

624 As done in the lighting shed distribution analysis under chapter 7.1.3.

625 As under *TOU FIXED DEMAND*, *TOU BATTERY*, and *TOU LIGHTING SHED*.

626 See Figure 28.

original power requirement with unchanged cooling load.[627] For 26 days of the months[628] the turquoise and the black line will be exactly identical for the whole day. However, on each day that DR-DER-CAM schedules PC for, the turquoise line will deviate from the solid line accounting for the changes in cooling – and therefore total – load during *off-peak* and *on-peak*. It can be seen that on September 20th the load in the morning and evening was increased due to PC. Actually, at the very end of the first *off-peak* period and at the beginning of the second *off-peak* period the battery needs to be discharged for a short period of time to be able to maintain the optimal demand level. This effect was not observed on the comparable days under *TOU BATTERY*. During *on-peak* it can be seen how the demand is lowered, which is the actual aim of PC. The chosen optimal PC profile on the 20th of September is PC-II.[629]

The optimal battery charging and discharging behavior follows the same patterns discussed under *PDP BATTERY* and, thus, will not be evaluated in detail.

Findings

First, it can be stated that in total PC-I, i.e. the softer approach to PC with a lower energy penalty, is chosen more often.[630] Some months are PC-II only and others are PC-I only. It can also be observed that PC was always scheduled for the demand-setting day of each month. A more detailed analysis showed that if PC-II and PC-I occur in one month, on the demand-setting day PC-II will be used. Apart from this, no further pattern can be determined, which leads to the conclusion that the scheduling of PC is influenced by the specific load profile of the month.

In addition, it is interesting to observe that in the month of August the limit for days of PC was not relevant and only one day of PC was scheduled by DR-DER-CAM. This shows the achieved peak reduction by PC does not always compensate for the energy penalty.[631]

Cost Analysis

In total, the application of PC with the discussed PC profiles drives a decrease of total annual electricity costs of $ 3,076 under the given load profiles in comparison to TOU BATTERY. These savings are exclusively driven by savings on demand charges, while electricity costs remain unchanged.[632] The savings are almost equally distributed over the summer months with savings of about $ 500 each month.[633] This is particularly interesting as in August only one day of PC was enough to drive these savings and more PC would have actually increased costs.

Another remarkable finding was made during the comparison of the savings between *TOU BATTERY* and *TOU PC* to the savings between *TOU FIXED DEMAND* and *TOU PC WITHOUT BATTERY*[634]. It was observed that in the scenarios without battery application, PC would

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[627] For the energy balance i.e. the amount of energy provided by the grid, PV, and battery, the turquoise line is of relevance in this scenario. The black line is only shown to visualize the changed load.

[628] All months are set to 30 days.

[629] See chapter 5.4.2. for a definition of PC profiles.

[630] See Appendix F for detailed list.

[631] For the profiles assumed in this project.

[632] Increase of $ 8 considered neglectable in comparison to the total electricity costs.

[633] Actually, September shows slightly higher savings and June and July slightly below average savings.

[634] This scenario is not presented in detail as it has no practical relevance for SRJ but was evaluated to drive deeper insights.

generate higher savings. This can be explained by the fact that the battery controls the *on-peak* demand levels and if PC is applied it must be applied in such way that the already flat *on-peak* demand level can be lowered for the whole month.[635] Without the parallel application of electric storage the peak demand levels are higher and more rugged and lowering the demand in one peak day through PC might already drive more substantial savings.

Conclusion

Summarizing, under the TOU PC scenario some savings can be driven compared to *TOU BATTERY*. Depending on the specific load profile, different PC load profiles are chosen by the optimization. In addition, PC in this scenario is only used to lower demand charges and does not lower energy costs at all. This could be due to the assumed PC load profiles but it must be said that an energy penalty of only 4 % under PC-I is already at the lower end of energy penalty values derived from academic literature. Therefore, it is likely that the conclusion drawn for these theoretical PC profiles will last once PC is evaluated more thoroughly with SRJ specific PC profiles. The clear focus on demand charges also means that the scheduling of PC can only be conducted properly if the load profile for the full month is somewhat certain in advance and optimal demand levels are determined by an optimization tool such as DR-DER-CAM.[636]

Finally, it was determined that the simultaneous application of battery and PC lowers the savings potential of PC compared to scenarios with no battery application. This means that the evaluation of PC must be conducted even more thoroughly in microgrid environments and savings might be lower than in comparable buildings with no microgrid integration.

7.2. Peak Day Pricing

In the second chapter of the analysis section the PDP tariff structure will be researched in detail. Looking into PDP is the given next step as PDP can be considered the new standard tariff for customers such as SRJ. If customers do not actively opt out of the program, they are automatically enrolled. In addition, PDP as a price-responsive program can be considered the first step towards DR involvement of a customer, as outlined above.[637] Especially the structure of PDP as a full on tariff that defines rates for all periods of the year, allows customers that want to get involved in DR an easy entry point as actual DR programs more complex in their evaluation due to their incentive structures.[638]

So far, SRJ has always been opting out of changing to PDP rates, as no detailed analysis was available on the effects of such a change.[639] The following analyses will provide a detailed evaluation to answer the question whether SRJ would be better off under PDP. The analyses

[635] See discussion under *TOU BATTERY*.

[636] The assumption of perfect knowledge for the power requirement is true for all the analyses conducted in this report. However, in this scenario it is especially relevant as a slight off-set in forecasting could eliminate all savings and actually increase costs. In comparison, if lighting shed would be scheduled on a non-optimal day, the savings would not be as high as possible i.e. the solution would not be cost minimal, but the costs would still be lower than if no lighting shed would be used. Poorly scheduled PC can increase costs.

[637] See sub-chapter 3.2.2.

[638] See chapter 3.2.

[639] As stated by Alameda County Energy Program Manager Matthew Muniz in a meeting with LBNL representatives on 4/24/2012.

will give an overview on the costs under PDP compared to E-20 costs for the different scenarios evaluated before. In parallel to the comparison to E-20 case, the analyses will also identify the potential cost savings that can be generated from using the electric storage, load shedding and shifting capabilities as well as the combination of all these measures under PDP. Before diving deep into the analysis, it is of outmost importance for the reader's understanding to recall the structure and rates of the PDP tariff, especially in comparison to the previously discussed TOU tariff. For doing so, please refer to the PDP tariff presentation above.[640]

7.2.1. Fixed Demand

In this first scenario of the second set of analyses, the jail load is – once again – considered totally fixed. In this scenario the jail has to supply all its demand from the PG&E grid at the times it occurs. As under TOU DR-DER-CAM is only used to calculate total costs as no variables are available for optimization. This analysis is, nevertheless, very relevant as it will provide the foundation to be able to evaluate the saving potentials that the installed electric storage can generate under PDP.

Energy Balance for PDP Event Day

As no optimization actually occurs, the energy balance is exactly identical to the fixed demand scenario under TOU for every single time step and day. This means that for a non-event day the energy balance presented above[641] is still valid for this analysis and will, therefore, not be presented again. However, what is new to PDP is that peak days are called by PG&E depending on a variety of influencers.[642] During peak days, the energy balance itself still remains unchanged but the time periods that are integrated in the depiction change slightly during an event day. To familiarize the reader with this change in depiction, below one event day is shown.

[640] See sub-chapter 3.2.2.

[641] See energy balance under TOU FIXED DEMAND.

[642] See sub-chapter 3.2.2.

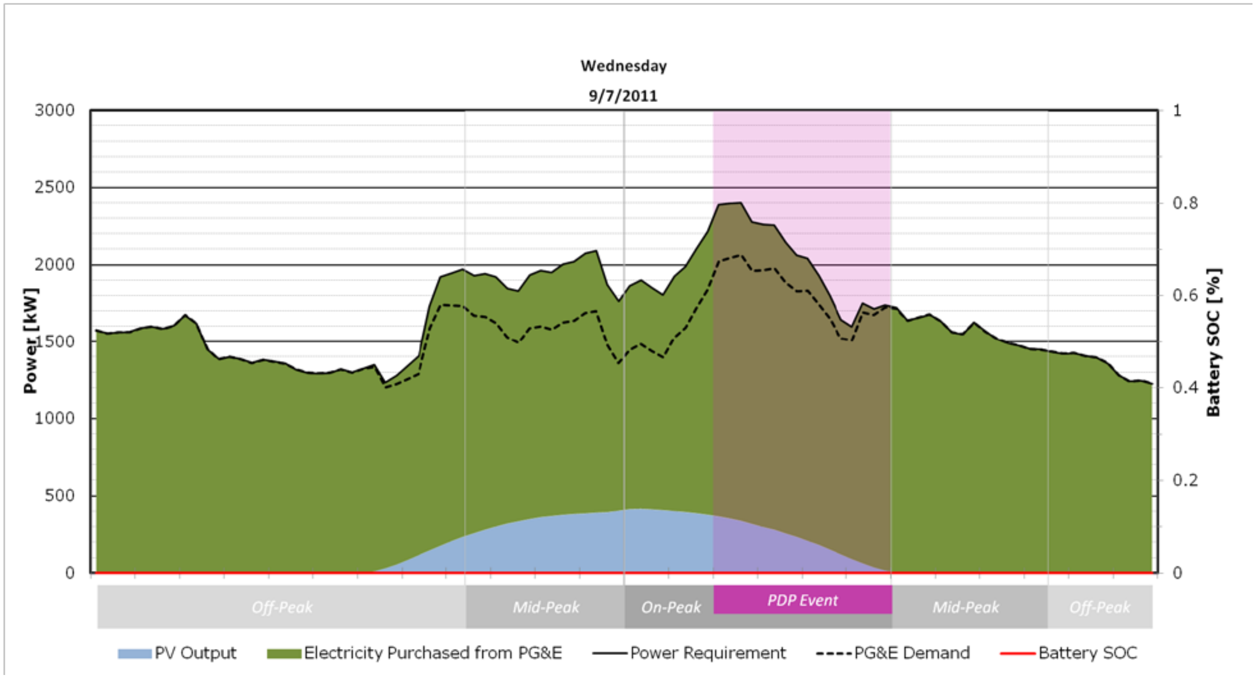

Figure 34: Energy Balance SRJ - PDP FIXED DEMAND

The relevant change in depiction is the addition of the PDP event indicator in purple amongst the grey TOU periods. The PDP event is marked by a smaller box than the other TOU periods and sits on top of the on-peak period. This representation is to emphasize that during PDP Event time the energy charge is different but the demand charge is not influenced by the event. Even during a PDP event the demand charge is evaluated for the whole *on-peak* period and multiplied with the standard weekday on-peak charge as defined in the PDP tariff.

Cost Analysis

Although the load shapes remain unchanged, as visible in the exemplary energy balances above, the total costs of electricity change under PDP due to the changed rates[643] compared to TOU.[644] The total costs of electricity for 2011 under PDP are $ 1,428,923, with $ 354,935 demand charges and $ 1,073,988 energy charges. Within the energy charges $ 83,371 are contributed by energy consumed during PDP events. Although only nine PDP events lasting for four hours each have been called in 2011, the associated energy costs are that high due to the significant price per kWh. The summer on-peak energy charges add up to $ 132,299, which is not that much higher than the PDP event charges considering the difference in times of application.[645] Amongst the energy charges[646] the major share is contributed by the off-peak charges over the full year's span. For the power charge over two thirds are contributed by the monthly max demand charge.

[643] See sub-chapter 3.2.2.

[644] See sub-chapter 3.2.2.

[645] Event energy only during 4 hours on 9 days, normal on-peak for six hours every weekday in summer.

[646] Excluding PDP event charges.

Compared to the TOU FIXED DEMAND[647] the total electricity costs are $ 18,446 or 1.3 % lower under PDP. The demand charges are $ 90,727 lower than under TOU due to the decreased rates. The charges for on-, mid- and off-peak are $ 11,090 lower than under TOU, due to the lower rates for on- and mid-peak energy. These two effects caused by the lower non-event PDP rates compensate for the PDP event energy costs of $ 83,371 that did not occur under TOU. The ratios of the different time periods[648] remain basically unchanged under PDP compared to TOU. For the demand charges, the fee for the monthly maximum demand takes up a significantly bigger portion than under PDP[649]. This is due to the change in demand charge structure. While the monthly maximum demand charge remains unchanged, on- and mid-peak charges were lowered significantly. The total energy costs[650] make up 69 % under both tariffs in the fixed demand scenario; the total demand charges are six percentage points lower under PDP. To give an overview of the development of the distinct cost drivers, the monthly costs are shown in the appendix.[651]

Peak Demand Analysis

No detailed peak demand analysis will be conducted for this scenario as the demand levels and peaks remain unchanged compared to *TOU FIXED DEMAND* as they are both based of the 2011 load data and no load influencers are enabled.[652] Differences in total costs compared to the *TOU FIXED DEMAND* scenario are solely due to changes in tariff structure, while consumption behavior remains untouched in this first scenario.

Conclusion

Even without any reaction to the called PDP events SRJ would have saved $ 18,446 by being enrolled in PDP rather than the E-20 TOU tariff in 2011. PG&E designed the PDP tariff in such way that customers who switched from TOU to PDP would be off equally with some minor reactions to the called events. By making their load even more responsive to event calls, customers should be able to drive savings compared to TOU. However, PG&E stated that customers with no reaction to the called events would look at slightly increased electricity costs[653]. Obviously, PG&E could only make this calculation for average load profiles. Thus, it seems that the load profile of SRJ was beneficial for a change to PDP in 2011 and, consequently, could have generated savings over TOU without reacting to the called events. In more detail, it can be derived that SRJ has less load during the PDP events compared to all other TOU periods with reduced rates[654] than the average customer PG&E considered when designing PDP rates. This conclusion goes along with the previously made observation that the daily SRJ load profile is relatively flat and only shows little increase of demand during the day. Apart from the already relatively flat total consumption behavior this is also caused by the provision of

[647] See chapter 7.1.1.

[648] Except PDP events.

[649] TOU: 53 % - PDP: 67 %.

[650] Except PDP events.

[651] See Appendix F.

[652] Refer to chapter 7.1.

[653] See sub-chapter 3.2.2.

[654] Mid- and on-peak in summer.

electricity from the PV arrays that lower grid consumption during the day-time and flatten out the PG&E demand even more.[655]

Nevertheless, when switching to PDP, the PDP event energy, although only a minor cost factor over the whole year, can have a significant impact on the monthly bills and is worth close observation and consideration.

7.2.2. Battery

In the second PDP scenario the battery is enabled to optimize the PG&E consumption. All other parameters remain unchanged compared to the fixed demand PDP scenario. DER-CAM will perform an optimization considering the technical restrictions of the battery[656], the load requirement and PV output as well as the PDP tariff charges. When performing the optimization, the actual 2011 PDP event days are used to obtain the actual costs that SRJ would have had in 2011. Equal to the TOU battery-only scenario, DER-CAM will be used to determine the optimal i.e. cost minimal operation schedule for the battery in the given setting. In the following, the operating schedule will be discussed based on select exemplary daily energy balances as well as costs and peak demand levels. In general, the analysis will focus on highlighting differences in comparison to the TOU battery scenario and only touch upon the comparison of fixed demand and battery under PDP briefly.[657] It will also be at the core of the analysis to understand how the changed ratios of rates between TOU and PDP[658] will influence the battery operation. In the analysis of this scenario, the demand-setting day for September will be presented. A non-demand-setting day is discussed in the appendix.[659]

Energy balance for Demand Setting Day

First, the relevant demand-setting day for the month of September will be presented. As the demand-setting day did not change compared to TOU BATTERY, the energy balance for the 20th of September is presented below.[660]

[655] See chapter 5.1.

[656] See chapter 4.2.4.

[657] The step from fixed demand to battery was already discussed in much detail for the TOU tariff and will therefore not be presented in that much detail for PDP. Lessons learned previously apply accordingly.

[658] The changed rates already resulted in a changed distribution of costs between TOU and PDP Fixed Demand.

[659] See Appendix F.

[660] It is not given that the demand-setting days have to be identical for the two different scenarios. As explained, the determination of the demand-setting days depends on numerous inputs of the optimization.

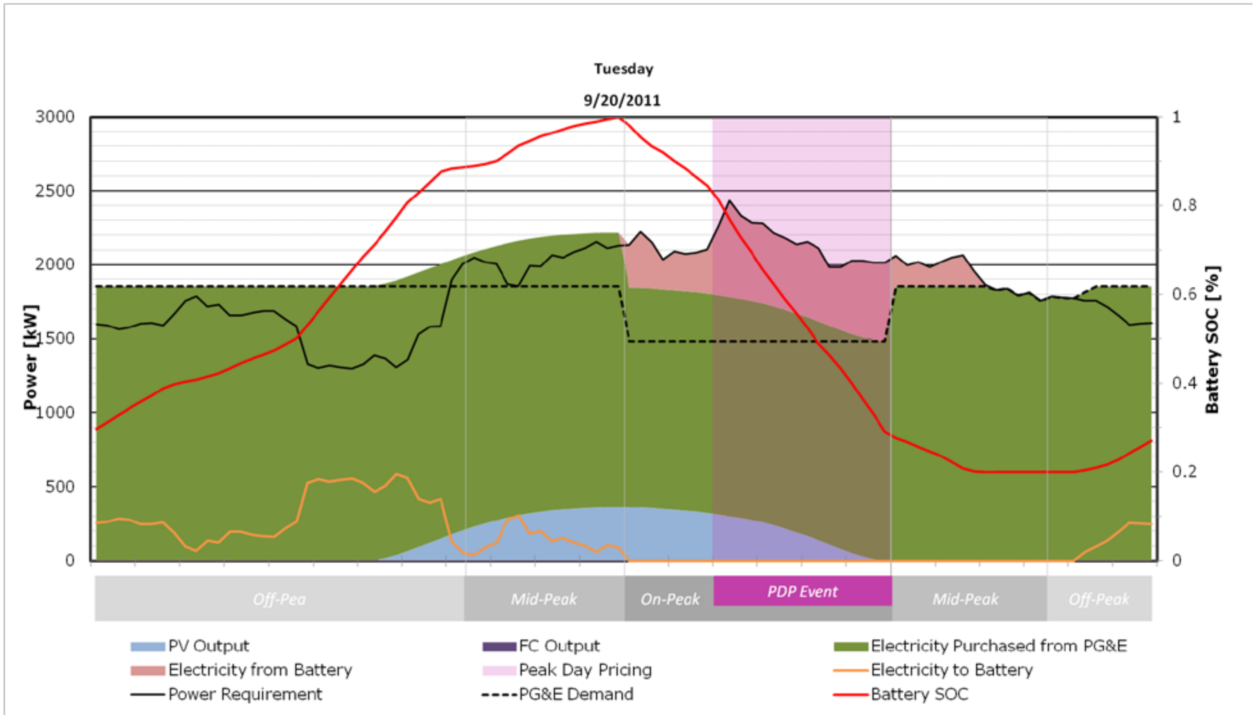

Figure 35: Energy Balance SRJ - PDP BATTERY

As indicated by the pink marker, the demand-setting day is also a PDP event day. The simultaneity of these two characteristics is not essentially given, but occurs in three out of the four months that have PDP event days in 2011. Therefore, it is reasonable to review the 20th of September, which shows this overlay. The connection can also be argued easily if one bears in mind that PDP event days can be triggered by especially hot days or when the total load is expected to be very high.[661] On a hot day the jail is also expected to have a higher load as a major share of its load is caused by HVAC related equipment. Also, if the total load on the PG&E grid is expected to be very high, the likelihood that a single customer has an above average load that day is increased.[662]

Even though the 20th of September is a PDP event day, the behavior of the battery and the general layout of the energy balance are not significantly different from the behavior under TOU.[663] Only the demand levels changed slightly, which will be discussed in more detail in the Peak Demand Analysis.

From the battery behavior DER-CAM determined to be optimal on the demand-setting day it can be concluded that even with the steep increase on energy charges during the PDP event the demand charges are still the key driver for the battery utilization. If the PDP event charge were more relevant than the demand charges, the battery would be scheduled to reduce the load during the event hours and all available energy[664] would be discharged during the event.

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661 See sub-chapter 3.2.2.

662 This only means that a demand-setting day is likely to be a PDP event day.

663 See Figure 28.

664 3.6 MWh.

However, this is not the case as the graph above shows; the battery is still used, as under TOU, to set a flat *on-peak* demand level and even to ensure a lowered *mid-peak* demand level during the second *mid-peak* period of the day. A discussion of a non-demand setting PDP event day, showing that the energy discharge of the battery is postponed from the beginning of the *on-peak* period to the beginning of the PDP event period, is given in the appendix.[665]

Cost Analysis

Under PDP the total costs of electricity for SRJ add up to $ 1,304,252. This is composed from power charges of $ 266,863 and energy charges of $ 1,037,389. Within the energy charges $ 982,104 are charged for consumption during the "standard" TOU periods and $ 55,863 are due to energy consumed during the nine PDP events in 2011.[666] This differentiation is relevant as it allows to better understand the PDP event energy costs. For the power charges, the biggest contributor is the maximum monthly demand fee and for the TOU energy charges the key driver is the consumption during off-peak. The monthly split of demand charges, TOU period energy charges and PDP event energy charges is included in the appendix.[667]

Compared to the previously presented fixed demand scenario under PDP, the battery utilized under the optimal DER-CAM operation schedule generates savings of 9 % of the total electricity costs, which is $ 124,671. The savings are mainly generated from savings on demand charge, which are lowered by 25 %. Between *TOU FIXED DEMAND* and *TOU BATTERY* the battery utilization was able to deliver a very close 26 % lowered demand charges. However, under *PDP BATTERY* the battery also helps to reduce the PDP event energy charges by 34 % compared to *PDP FIXED DEMAND*.[668] As a result, in the electricity cost split[669] the ratio of demand charges compared to the *FIXED DEMAND* scenario goes down to 20 %.[670] PDP event energy costs are lowered to 4 % of total electricity costs.[671] Of all these savings, 75 % are generated in summer. As PDP events are only called during summer in 2011 the battery generated its entire savings on PDP event energy in summer. Due to the significantly higher rates, 64 % of the power charge savings occur during summer months. These two findings could have been expected, what is interesting, however, is the fact, that during summer the savings on TOU energy charges are higher than the total annual savings.[672] This means, that during winter months the utilization of the battery actually increases the costs of energy usage.[673]

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[665] See Appendix F.

[666] Also under PDP, the TOU time periods still apply and are referred to as TOU periods or standard TOU periods.

[667] See Appendix F.

[668] By ensuring that available battery capacity (that is not needed to maintain optimal demand levels) is discharged in the beginning of PDP event.

[669] TOU energy, demand, PDP energy.

[670] From 25 %.

[671] From 6 % before.

[672] 111 %.

[673] This is due to the fact that during winter months the battery is exclusively used to level the demand and not run on a daily cycle. Thus the battery decay is more relevant and due to the smaller difference in energy charges the battery might shift load from off-peak to mid-peak, which is optimal in total but causes higher energy costs.

Compared to *TOU BATTERY* the total costs of electricity supply under *PDP BATTERY* are $ 14,994 lower. While the costs for TOU energy are slightly lower due to lowered rates and the fact that the event energy is counted separately, looking at total energy costs[674] shows that the costs under PDP are $ 47,917 higher than under TOU. These higher costs are counterbalanced by demand charge savings of $ 62,911. While the ratio of energy to demand charges was 75 % to 25 % under TOU, it is now 80 % to 20 % due to the relatively high energy costs during event times. Within the TOU energy costs[675] the shares remain almost unchanged between *TOU* and *PDP BATTERY* scenario. This is due to the fact, as discussed before, that the overall battery operation strategy is still closely related and that the reduction in energy rates from TOU to PDP was only minor. However, for the power charges the ratios changed more noticeable. While under TOU the monthly max demand charge represented 41 % of the power charges, under PDP this went up to 69 %. This significant change is mainly due to the fact that the *on*- and *mid-peak* demand charges have been substantially lowered while the total maximum demand charge remained unchanged under PDP. To be able to evaluate if this change in demand costs is mainly driven by the changed cost structure or if the underlying scheduling was altered[676] as well, the peak demands will be discussed in more detail below.

Peak Demand Analysis

Peak demand analysis of the *PDP BATTERY* scenario will solely focus on the comparison to the *TOU BATTERY* scenario and explain the deviations. The change of the peak demand levels when going from *PDP FIXED DEMAND* to *PDP BATTERY* is very similar to the changes that were presented and explained for that very step under TOU and will not be repeated for this scenario.[677] The peak demand levels for this scenario are given in the graph below.

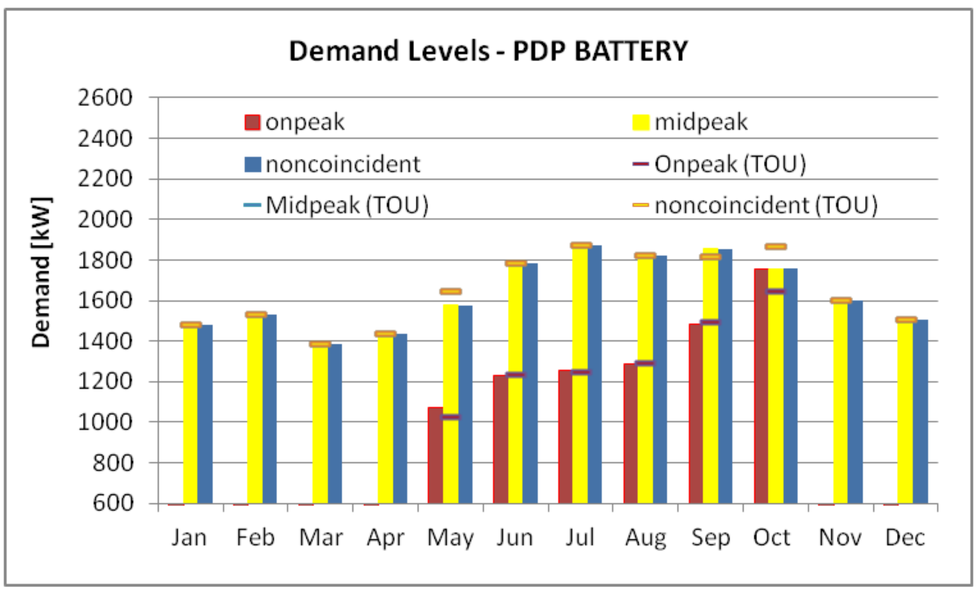


Figure 36: Demand Levels - PDP BATTERY

674 TOU period energy and PDP event energy.

675 Not including PDP event energy.

676 Which would have also been induced by the cost structure.

677 Refer to sub-chapter 7.1.2.

Enhancing the previously used representations of the demand levels, the graph also shows in small bars in the respective colors the equivalent demand levels under *TOU BATTERY* to visualize the differences. First, it must be stated that the big picture of peak demand levels did not change compared to TOU. Still, mid-peak demand and total maximum demand are leveled for each month and the on-peak demand level is below that.[678] On annual average, the on-peak demand level did increase by 25 kW while the mid-peak demand and the monthly maximum demand levels were both lowered by 12 kW compared to *TOU BATTERY*. This tendency of higher on-peak levels and simultaneously lowered mid-peak and total max demand peaks is caused by the changed rates under PDP. While under TOU the on-peak charge was about 4.7 times higher than the mid-peak charge, it is only about factor 4 under PDP. Even more drastically, the ration between on-peak charge and maximum demand charge is 1.5 under TOU and only 0.8 under PDP. This change in rate structure means that the optimization will give relatively more importance to controlling the monthly total maximum demand and the mid-peak level than under TOU. The result of the changed summer rates can be most clearly seen for the month of October, where no PDP event interferes. In October the mid-peak and maximum demand level were lowered by 112 kW and the on-peak was increased by 110 kW leading to an equal match of all three levels.[679] For the month of September the overall tendency of increased on-peak and lowered monthly maximum does not hold true. In September, the on-peak level was actually lowered by 15 kW and the mid-peak and total max demand level increased by 37 kW. Although this counteracts the average behavior this outlier can be explained by the high number of PDP events in September. PDP event time coincides with the on-peak time and the steep PDP event charges gives more relevance to a lower total consumption during this time. And when giving high relevance to keep the consumption low during the event time it can be understood that a lowered on-peak level is optimal.[680] The remaining summer months however remain unchanged in comparison to TOU or support the average tendency outlined above.[681]

Conclusion

Compared to the previous *PDP FIXED DEMAND* scenario the battery is able to generate electricity cost savings of $ 124,671 for the SRJ load of 2011. As under TOU these annual electricity cost savings are compared to the initial battery investment and the resulting NPV of the battery is with
§ -1,7014,414 even lower than under TOU.[682]

Comparing the *TOU BATTERY* case with this *PDP BATTERY* case, it was determined that the resulting battery schedule is still identical. The main difference is that on non-demand-setting days with PDP event, the discharge of available[683] battery capacity is postponed by two hours

[678] Or equal in October.

[679] The fully flat demand only occurs in October as it is also influenced by the total load and its shape that differs month by month.

[680] Also on no-PDP-event days.

[681] As PDP and TOU rate structure are equal in winter months and no PDP events occur, the demand levels in winter remain unchanged.

[682] Risk free interest rate of 3 % and 25 years life time of battery.

[683] Meaning not used to maintain optimal demand levels.

from the beginning of the on-peak period to the beginning of the PDP event period. This offsets the additional battery decay and generates higher savings as during the PDP event the energy charge is significantly higher than during normal on-peak. In addition, it was described that due to the changed rates for energy and even more important for power, the optimal demand levels were slightly changed compared to the *TOU BATTERY* scenario. The *on-peak* demand level is set slightly higher[684], as the *on-peak* power charge is lower under PDP and therefore it has less weight in the optimization compared to other charges. Concluding the comparison of *PDP BATTERY* and *TOU BATTERY*, it can be stated that the costs of electricity supply for SRJ in 2011 would have been $ 14,944 lower under TOU. This means that being enrolled in PDP is still preferable under the battery scenario compared being billed under the current E-20 TOU tariff.

7.2.3. Lighting Shed

In this third scenario lighting shed opportunities are introduced to the optimization under PDP. This scenario is – apart from the tariff – equivalent to the *TOU LIGHTING SHED* scenario.[685]

The idea of introducing load shedding to the optimization of the SRJ electricity consumption was developed in combination with the planned involvement of SRJ in DR. The concept of load shedding basically was to introduce load shedding in such way that it could be used to reduce electricity consumption[686] on PDP event days. To allow for a better comparability of different scenarios[687], tariffs,[688] and also different months within a year, the load shedding was implemented with a total maximum amount of hours that can be shed per day and per month. These limits do not depend on the PDP events called in a specific month. The way these limits are set up in the optimization allows the tool to find the optimal operation schedule for the battery and load shed. It will be analyzed, how the lighting shed is optimally used by DER-CAM, especially during the summer months, and if there is any correlation with the occurrence of PDP event days.

Load shedding in this case study for SRJ is realized by lighting shed. The amount of lighting that can be shed is 341 kW in the beginning and the end of the day and 419 kW in between. In this scenario, as under TOU, the shed of lighting is limited to a maximum of two hours a day and a total of eight hours per month.[689, 690]

Energy Balance for PDP Event Day

To go into detail on the changed behavior of consumption an energy balance of an exemplary day is chosen and discussed in the following. As under *TOU LIGHTING SHED* and under *PDP BATTERY*[691] the energy balance for the 20th of September is presented below.

684 On annual average.

685 See introduction of sub-chapter 7.1.3.

686 And perhaps demand levels.

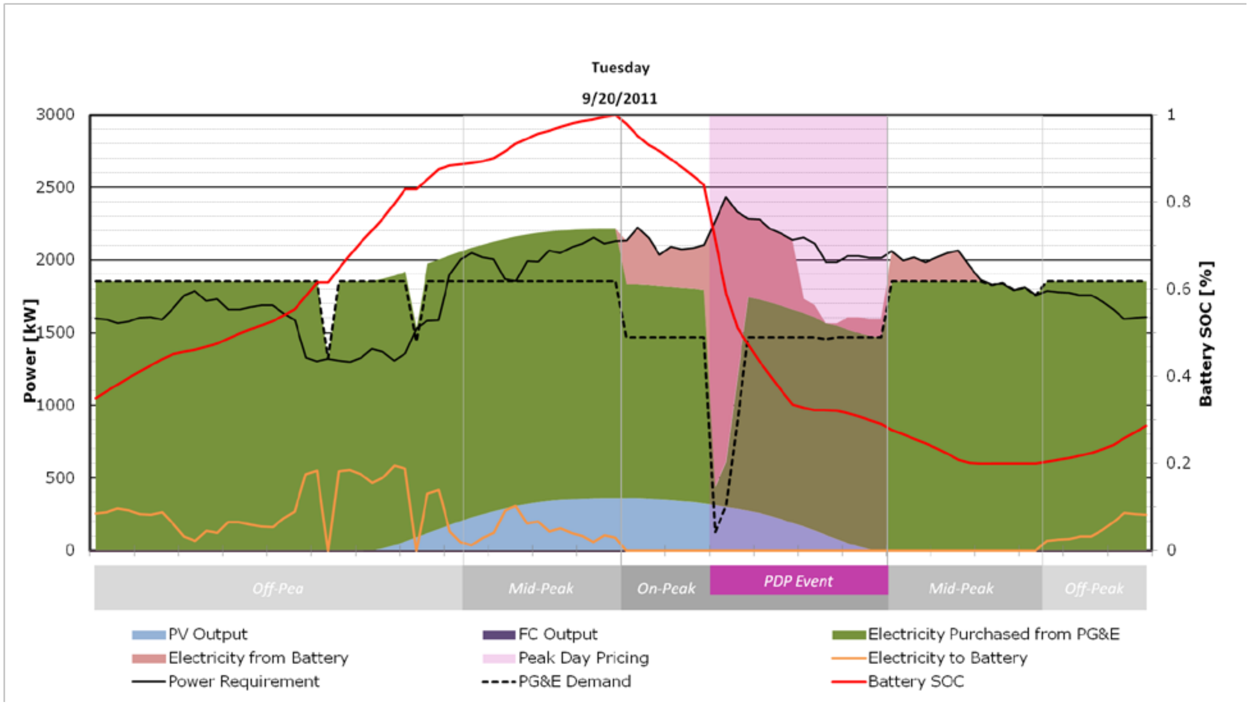
687 Especially TOU tariff, that has no event days, to PDP with event days.

688 Only allowing load shedding on PDP event days would distort the comparison to TOU, where no event days occur.

689 Equal to the *TOU LIGHTING SHED*.

690 See sub-chapter 5.4.1.

691 The two scenarios most relevant for comparison to this scenario.



Under *TOU LIGHTING SHED* as well as under the *PDP BATTERY* the 20th of September was a demand-setting day for the month.[692] Choosing the same day as an exemplary day for *PDP LIGHTING SHED* proves the point that was already mentioned above: Under a different scenario the identical power requirement[693] might result in a different optimization with different demand levels and eventually different demand-setting days. For the 20th of September it can be seen that the lighting shed is still used at the end of the on-peak and PDP event period as under *TOU LIGHTING SHED*.[694] With demand levels about identical to *PDP BATTERY*,[695] the lighting shed frees battery capacity that can then be discharged in the beginning of the PDP event period to save as much electricity charge as possible.[696] Due to this freed capacity the 20th of September is no longer the demand-setting day for the month of September 2011.[697] When analyzing the other summer months in this scenario in more detail they show the same behavior as presented in the exemplary day. Whenever a PDP event day occurs, lighting shed is used at the end of the event period to lower electricity costs.[698] Driven by the high energy charges during the event time it can be observed that the maximum available time per day of eight time steps is scheduled to be shed at the end of the event time.[699] In addition, it can be seen

692 Refer to 7.1.3 and 7.2.2.

693 Before the application of electric storage.

694 Reasoning for this timing under 7.1.3.

695 See chapter 7.2.2 for details in peak demand analysis.

696 See discussion of this effect 7.2.2.

697 Now it is the 23rd of September.

698 And the demand level respectively.

699 This holds true for all nine PDP event days.

that apart from the PDP event days almost all summer demand-setting days show at least some occurrence of lighting shed.[700]

For the sake of a focused analysis the depiction of a demand-setting day is skipped in this paragraph as no new insights would be generated from the discussion.

Cost Analysis

For *PDP LIGHTING SHED*, the total costs add up to $ 1,285,942 composed from $ 979,243 normal energy charges, $ 47,175 PDP event energy charges, and $ 259,524 demand charges.

Compared to *PDP BATTERY* the shares of the different TOU periods within the normal energy charges and the demand charges remain almost unchanged.[701] However, compared to *PDP BATTERY* lighting shed generates annual savings of $ 18,310. Of these savings 44 % are achieved from reductions in PDP event energy and 40 % from reduction in demand charges. Analyzing the savings by season, it can be observed that 75 % of the savings from reduced demand charges due to lighting shed are achieved in summer. This is due to the fact that in summer demand charges are significantly higher and therefore the same amount of lighting shed can be leveraged more effectively in summer. Also, all savings in PDP event energy are obviously in summer as only in summer PDP events occurred in 2011. In total, 82 % of savings from lighting shed under PDP are achieved in summer.

Compared to *TOU LIGHTING SHED*, the total costs of electricity supply in this scenario are $ 16,129 lower. As for the comparison of the *TOU BATTERY* and *PDP BATTERY*, the energy charge is increased under PDP due to the expensive event energy, while demand charges are lowered significantly due to the decreased rates. The detailed discussion of how cost ratios changed between *TOU* and *PDP LIGHTING SHED* is not presented for this analysis as observations and findings are very closely aligned with the previous comparison of cost ratios between *TOU* and *PDP BATTERY*.[702]

Peak Demand Analysis

For the peak demand analysis in this scenario basically only the resulting changes in comparison to *PDP BATTERY* and *TOU LIGHTING SHED* scenario are given as the underlying principles have already been explained previously.

Compared to *PDP BATTERY*, the usage of load shedding lowered the average mid-peak and total monthly maximum demand by 21 kW and the average on-peak demand by 106 kW.[703] Compared to *TOU LIGHTING SHED,* under *PDP LIGHTING SHED* the mid-peak and monthly

[700] In this scenario, for most summer months the demand-setting days are PDP event days anyway, as outlined under 7.2.2.

[701] See sub-chapter 7.2.2.

[702] For detailed insights see sub-chapter 7.2.2.

[703] For a detailed discussion of the underlying principles that change peak demand behavior from a battery-only scenario to a battery and load shedding scenario, please refer to the respective discussion under TOU (See sub-chapter 7.1.3.). As the overall tariff structures between TOU and PDP are still comparable the conclusions drawn for TOU do apply for PDP

maximum demand levels have been lowered by 22 kW and the on-peak demand level increased by 61 kW. These changes are mainly driven by changes in rates between TOU and PDP.[704]

Lighting Shed Distribution Analysis

As under *TOU LIGHTING SHED*, a lighting shed specific analysis is conducted to understand how the DER-CAM optimization schedules the lighting shed opportunities under PDP and how the behavior differs from what was discussed under TOU.

The previous discussion showed that lighting shed is, as under TOU, mainly used at the very end of the on-peak and PDP event period. The following graph gives an overview regarding the question in which time steps light was shed how often in the summer of 2011.

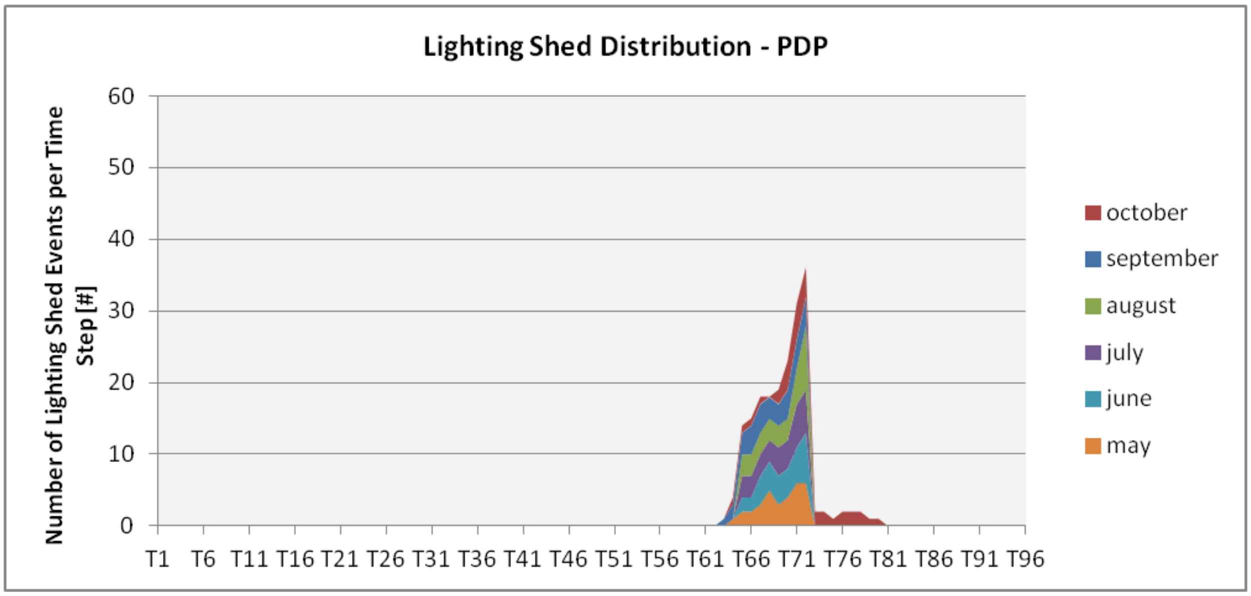


Figure 37: Lighting Shed Distribution - PDP

First, the general structure is very similar to the lighting shed distribution under TOU, meaning that the light is also shed during the last two to three hours of the on-peak period. However, minor differences occur that will be discussed in the following. The graph for the lighting distribution under PDP is not as pointy as under TOU and with a maximum lighting shed of 36 time steps at the 6 p.m. time step it is less high. As the same amount of lighting shed was available under TOU and PDP it can be concluded that the orientation towards the very end of the on-peak period is less immanent under PDP. In addition, there are no outliers in the beginning of the graph, as there were under TOU.[705] The earliest lighting shed ever occurring under PDP is at 4:15 p.m. As under TOU, there are still some outliers in the second mid-peak period of the day that cannot be explained intuitively. Under PDP these outliers only occur in October though. Remembering the discussion of the peak demand behavior under *PDP*

[704] A detailed discussion, that also applies to this scenario, was conducted under the PDP BATTERY Peak Demand Analysis already (See sub-chapter 7.2.2.).

[705] Compare Figure 31.

BATTERY,[706] one knows that in October all demand levels were set almost equal. While lighting shed slightly lowered the on-peak demand in October, the demand levels for mid-, on- and total peak are still closer aligned in October than in any other summer month by far. Knowing, in addition, that there was no PDP event called in October, it is concluded that in October the energy saving during event time is not relevant and in addition maintaining a flat maximum demand has a high priority.[707] Therefore, lighting shed is also leveraged in the second mid-peak period to be able to maintain the optimal mid-peak and total maximum demand levels.

As under TOU, in a second step the lighting shed analysis will analyze what lighting shed event durations have to be used to maintain to lowest cost of electricity. To support this analysis the two graphs are shown below. On the left-hand side the number of lighting shed events for the different durations[708] are shown. The graph on the right hand side shows the total time of lighting shed for each duration.[709]

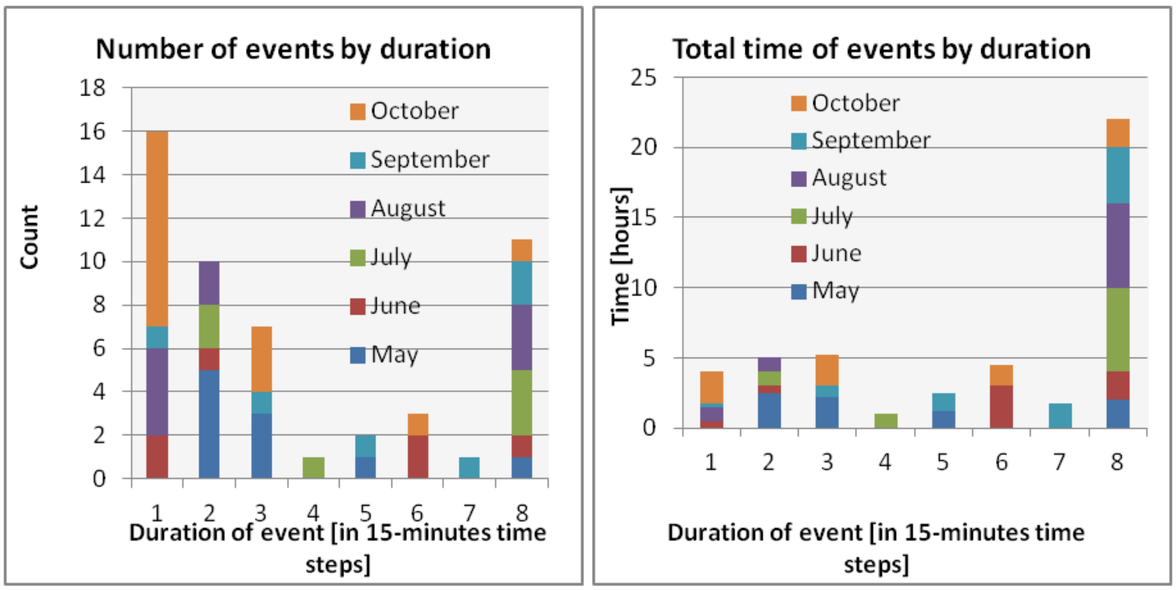


Figure 38: Lighting Shed by Duration of Event - PDP

In comparison to *TOU LIGHTING SHED*[710] it must be stated that the overall impression is almost identical. However, for the number of events by duration[711] it can be seen that the amount of one-time-step events was significantly lowered. With an identical number of eight-time-step events, this shows that lighting shed under PDP is used more often in longer events. It can also be seen[712] that the one-time-step events are mainly contributed by the month of October, which has some specific characteristics to it, as discussed above. Nevertheless, as discussed under

[706] See sub-chapter 7.1.2.

[707] On-peak is only slightly lower than total monthly max (1668 / 1709).

[708] From 0 hours to two hours, in 15 minute time steps.

[709] From 0 hours to two hours, in 15 minute time steps.

[710] Compare to Figure 32.

[711] Left graph.

[712] From both graphs.

TOU, the biggest total time of lighting shed clearly occurs in eight-time-step events. Looking at either one of the graphs above it is interesting to analyze the number of eight-time-step events per month. It has been said before that during demand-setting days as well as PDP event days, the optimization schedules the most lighting shed possible. Looking at the graphs above it can be stated that in May one, in June two, in July three, in August three, in September two, and in October one eight-time-step lighting sheds occurred. May and October do not have any PDP events and detailed analysis of the months' energy balances showed that the eight-time-step events were scheduled on the demand-setting days. June does have one PDP event day and one demand-setting day.[713] Detailed load analysis showed that in June the demand-setting day is not on the PDP event day and therefore two eight-time-step lighting sheds were scheduled. With two PDP event days per month and separate demand-setting days in July and August the optimization scheduled three eight-time-step events. September has four PDP events and a separate demand-setting day. Following the previous argumentation one would expect that all lighting shed occurs in five eight-time-step shedding events. However, not more than four eight-time-step events can occur due to the lighting shed limitations.[714, 715] Looking at the graphs above one can identify two eight time steps events and one event for one, three, five, and seven time steps in September. This does not match the outlined theory at first sight, but looking into more detail it was discovered that the one and seven time step events occurred on the same day and were only separated by one time step without lighting shed. Same holds true for the three and five time step events. Therefore these events can be considered eight-time-steps events as well and it can be concluded that at PDP event days[716] as well as on demand-setting days[717] the optimization schedules the maximum of lighting shed available[718] towards the very end of the on-peak period.

Finally, the underlying data of both graphs proves that in every summer month the total available lighting shed per month of eight hours was used.

Conclusion

Summarizing, the scheduling of lighting shed and battery under PDP are closely related to the scenario under TOU. When lighting shed is used, it occurs almost exclusively in the end of the on-peak period. Under PDP, the lighting is predominantly scheduled on PDP event days as during the PDP event the highest energy charges apply. In this period, lighting shed can offset the most costs. Second to PDP days, the optimization focuses lighting shed on the demand-setting days.[719] This order of priorities shows that the PDP event energy charges seem to have a higher influence on the optimization – at least for the scheduling of the lighting shed – than the

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[713] Not identical days in this case.

[714] See sub-chapter 5.4.1.

[715] The finding that the demand-setting day is more often than not separate from the peak day is different from an earlier observation made for the PDP battery only scenario. This, however is not a flaw of the analysis but shows how the addition of other scheduable loads (lighting shed) can change the optimal scheduling result.

[716] Primary priority.

[717] Secondary priority.

[718] Eight time steps.

[719] As previously discussed under TOU lighting shed.

demand charges. On PDP event and demand-setting days typically the total available potential for lighting shed, i.e. two hours, is used in a block[720] at the end of the PDP event/ off-peak period.

Compared to *PDP BATTERY*, the added lighting shed is able to deliver savings of $ 18,310 per year.[721] These savings are generated – at almost equal shares – from reductions of energy consumption during PDP events and from lowered demand levels. In total, 82 % of savings from lighting shed are achieved during the summer months. Compared to *TOU LIGHTING SHED*, the total annual costs of electricity supply under this scenario are $ 16,129 lower.

7.2.4. Precooling Load Shift

In this sub-chapter the potential for PC under PDP will be evaluated. After previously evaluating the PC under TOU as the base case, *PDP PC* now is the intended use case application of PC with DR.

In this scenario the usage of the battery will be enabled for reasons similar to the previous PC and lighting shed cases[722]. Otherwise, apart from the change in tariff from TOU to PDP, all settings are identical to *TOU PC*[723]. Also, a similar structure will be applied to the presentation of the analysis that was already argued and used under *TOU PC*. For the sake of a focused analysis, observations made and conclusions drawn under *TOU PC* will not be discussed again and this analysis of *PDP PC* will focus mainly on differences caused by the changed tariff structure.

In the following, key findings that differ from findings under TOU PC will be presented, afterwards the costs and savings will be discussed and ultimately a scenario-specific conclusion will be drawn.

Findings

First, it can be stated that under *PDP PC*, PC-II is used more often over the whole summer than PC-I.[724, 725] Also, while the only recognizable pattern for PC under TOU previously was that it would occur on every month's demand-setting day, under PDP the PC is driven more by the occurrence of PDP event days. Having identified this change in driver it can be explained why the majority of PC events now uses PC-II profile. PC-II has a higher energy penalty but also allows for a higher load reduction during *on-peak*. With the significant increase in pricing during a PDP event, the reduction of PDP event energy consumption by using PC-II seems to offset the higher consumption during *off-peak* more often than under the TOU rate structure. In line with these findings is also the fact that the amount of scheduled PC usages in August goes up from one day to two days.[726] Detailed analysis showed that PC with the PC-II load profile is

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720 With two negligible 15-minute breaks in September.

721 Under 2011 load shapes.

722 *TOU LIGHTING SHED*, *TOU PC*, *PDP LIGHTING SHED*.

723 Refer to sub-chapter 7.1.4.

724 Which was the other way around under TOU.

725 An overview on how often which PC profile was leveraged in which month is given in the appendix.

726 Which is equal to the number of events in August.

actually scheduled on the two PDP event days in August[727]. This observation holds true for 89 % of all PDP events in 2011. Apart from this, observations made under *TOU PC* apply.

Cost Analysis

In total, the application of PC with the discussed PC profiles drives a decrease of total annual electricity costs of $ 4,560 in comparison to *PDP BATTERY*. These savings are mainly contributed by savings in PDP event energy. Actually, the savings in PDP event energy are almost $ 5,000 while the costs of standard TOU period energy rose by almost $ 700. Demand charges were lowered by $ 259. Looking into detail into the savings in the different months it can be observed that September[728] sees the highest savings with over $ 2,000, basically only contributed by savings in PDP event energy[729]. On the other end, the smallest savings are achieved in May and October[730] with only about $ 300 and $ 100 respectively. In these months the savings are mainly contributed by savings in demand charges.

Conclusion

It can be concluded that savings can be generated through PC compared to *PDP BATTERY*. It can also be stated that the cost reduction potential of PC is higher under PDP than under TOU. The majority of cost savings between PDP BATTERY and PDP PC is contributed by savings in PDP event energy costs. Also, it was determined that during events mostly PC-II is chosen by the optimization. This was explained by the fact that the steep PDP event energy charges compensate for the higher energy penalty of PC-II.[731]

It was discussed before that the scheduling of PC under TOU would require an accurate load forecast to be able to achieve meaningful reductions in demand charges.[732] This still holds true under *PDP PC* for the share of reductions contributed by demand charges. However, under *PDP PC* almost two thirds of the savings are derived from reducing PDP event energy costs. To achieve these savings accurate load forecasts are not needed[733] as PC could be implemented once the PDP event is called for the next day.[734]

7.3. Demand Bidding Program

In this third chapter of the analysis section the first non-tariff DR program is being evaluated.[735] DBP is a program that does not define rates for all time periods, as PDP does, but only defines a

[727] 23rd and 29th.

[728] Four PDP event days.

[729] They are actually slightly decreased by higher TOU period energy costs.

[730] With no PDP events.

[731] Compared to PC-I.

[732] See chapter 5.4.2.

[733] However, they are still needed to determine optimal demand levels for the battery scheduling.

[734] The assumption of perfect knowledge for the power requirement is true for all the analyses conducted in this project. However, in this scenario it is especially relevant as a slight off-set in forecasting could eliminate all savings and actually increase costs. In comparison, if lighting shed would be scheduled on a non-optimal day, the savings would not be as high as possible i.e. the solution would not be cost minimal, but the costs would still be lower than if no lighting shed would be used. Poorly scheduled PC can increase costs.

[735] For differentiation between tariff and DR program refer to chapter 3.2.

rate for lowered consumption during an event and a mechanism to determine the lowered consumption during a called event. Therefore, this program has to be evaluated in combination with an underlying tariff that forms the basis for the billing of the actual electricity consumption. In this evaluation the underlying tariff is going to be the PDP tariff rather than the E-20 TOU base case due to fact that PDP generates cost savings compared to TOU under every scenario observed.[736] Hence, as outlined above,[737] it is reasonable to consider PDP the new base case. Changes in demand structure and costs will be determined and analyzed in comparison to the previously presented results of the PDP analysis.[738] Also, as DBP is not a tariff but a DR program, savings are only generated, if the load is able to react to called events to some extent. Thus, the *FIXED DEMAND* analysis is not performed in this chapter as there would be no relevant changes to the previous PDP scenario.[739] The analysis of DBP will be looking into a battery-only scenario, a battery and lighting shed scenario, and a battery and pre-cooling scenario.

Before kicking of the analysis, the key points of DBP shall be recalled briefly. In this analysis the Day-Ahead version of DBP is evaluated. Under this version of DBP an event is called on the day prior to the event. During the event customers decrease their consumption and afterwards the consumption during the event is evaluated against the average of the consumption on the ten prior similar weekdays. The evaluation is done on an hourly basis. If the consumption was lower than the ten-day-average, the customer is incentivized with $ 0.5 per kWh of reduction. The bidding and bid acceptance process is not integrated in this optimization as it can be assumed that under perfect knowledge of its consumption and DER generation[740] SRJ can forecast how much shedding can be achieved the next day.[741] As DBP events are called Day-Ahead, the assumption of full knowledge of the future consumption and generation does not cause a problem with regards to the advance notice for the event, which is not included in the assumption of perfect knowledge of the future. The battery is reset every day[742] and therefore the scheduling for the event day, only begins at the end of the day prior to the event. At this point, the information of the event that is – in the simulation - already given at the start of the optimization, i.e. the beginning of the month, is already known to the customer – in reality – and can therefore be considered in the scheduling.

7.3.1. Battery

In this first scenario of the DBP evaluation, the operation of the battery will be optimized under PDP in combination with DBP to determine the cost-minimal operation behavior. All parameters remain unchanged compared to the previously presented *PDP BATTERY* scenario

[736] *FIXED DEMAND, BATTERY, LIGHTING SHED, PRECOOLING.*

[737] See conclusions of sub-chapters 7.2.1, 7.2.2, 7.2.3, and 7.2.4.

[738] As outlined in chapter 7.2.

[739] Actually, even under fixed demand some savings from DBP could be generated if the load on the event day is, by chance, lower than the load on the days that form the average for comparison. However, such arbitrary effects are not at the core of this evaluation. Refer to chapter on DBP description.

[740] This assumption is underlying to all evaluations under DR-DER-CAM and was discussed in the beginning of section 7.

[741] Also, the actual shed only has to be in a range of 50 % to 200 % of the bid.

[742] Going through a full charging and discharging cycle every summer weekday.

and only the incentive structure of DBP is added to the algorithm. The analysis will focus on outlining changes in behavior of the battery charging and discharging schedule that are implied – or not – by the DBP incentive.[743]

In the following, the operating schedule of the battery will be discussed based on one select daily energy balance. Costs and changes in peak demand levels – if any - will be discussed afterwards.

Energy Balance for DBP Event Day

In this scenario the energy balance is presented for one of the two DBP event days in 2011 in the graph below.

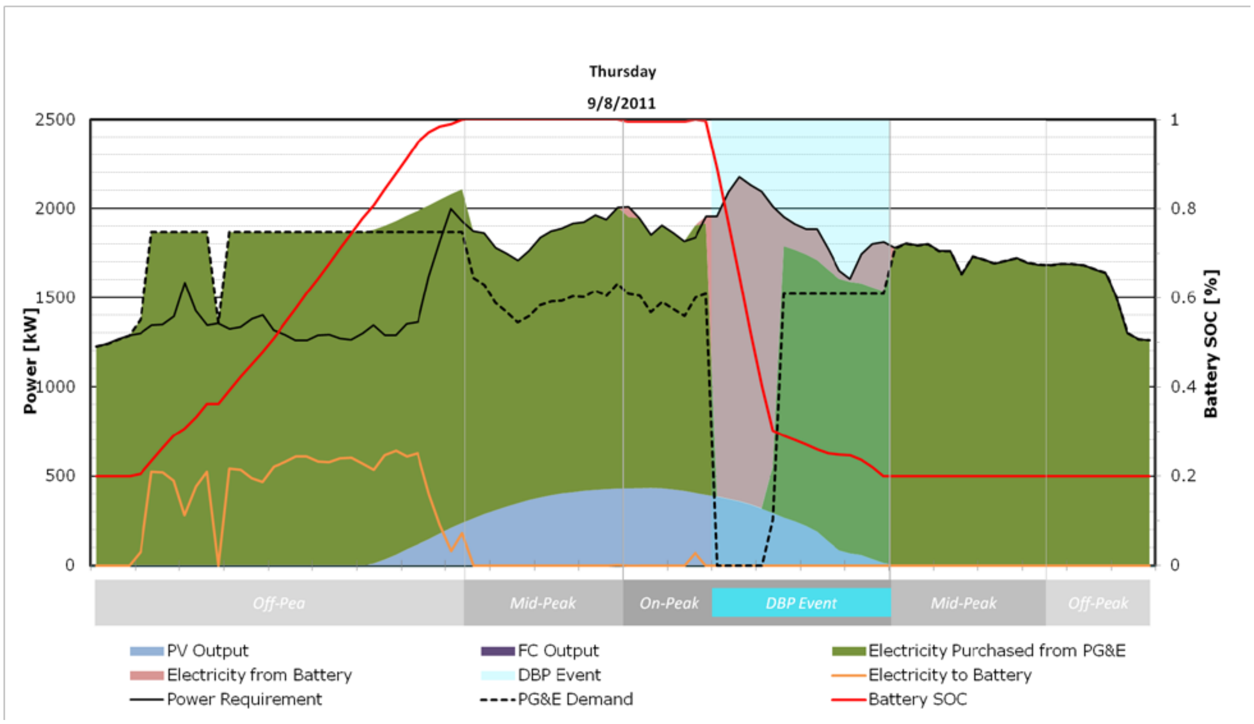

Figure 39: Energy Balance SRJ - DBP BATTERY

The depiction is closely related to the depiction of PDP event days except for one key difference: From 2 p.m. to 6 p.m. a DBP instead of a PDP event occurs.[744] The marker for the DBP event is not as high as the normal TOU on-peak period markers and not aligned to the top or bottom to visualize that during these times the normal on-peak charges for energy and demand still apply. The DBP event only adds the potential for reduction incentives to the known PDP tariff structure.[745] The chosen exemplary day is – by standards of PDP – categorized as a non-demand setting, no-PDP event day.[746] During such a day the discharge of the battery would usually

[743] PDP event days apply as discussed above. See sub-chapter 3.2.2.

[744] This is marked in turquoise.

[745] The fact that the DBP events also last from 2 p.m. to 6 p.m. (as the PDP events do) is coincidental. DBP events can occur for different time periods. Refer to DBP description.

[746] See 7.2.2.

begin at the very beginning of the on-peak period to minimize battery decay. In this example though, it can be seen that on a DBP event day the discharging of the battery is postponed to 2 p.m. This allows generating savings from DBP. These savings are higher than the additional decay caused by shifting the energy cost offsetting battery discharge. What looks intriguing at first sight is the fact that there is no continuous battery discharging from noon to 2 p.m. This, however, is due to the demand levels in September 2011 and the specific day's load profile that does not require the discharge of battery in the beginning of the *on-peak* period to maintain the optimal on-peak demand levels. This behavior is specific to the load shape and the determined optimal load levels and is not caused by DBP.[747] Actually, the power requirement during *on-peak* is so low that the battery can even be re-charged slightly before 2 p.m. to compensate the decay of the past hours. Load levels under PDP with DBP and without DBP are basically identical and the influence of DBP on demand levels can be neglected for now.[748] The other elements of the energy balance remain unchanged compared to the operation under PDP battery scenario.

The change in the energy balance for the 8th of September between *PDP BATTERY* and *DBP BATTERY*[749] is directly compared in the graph below:

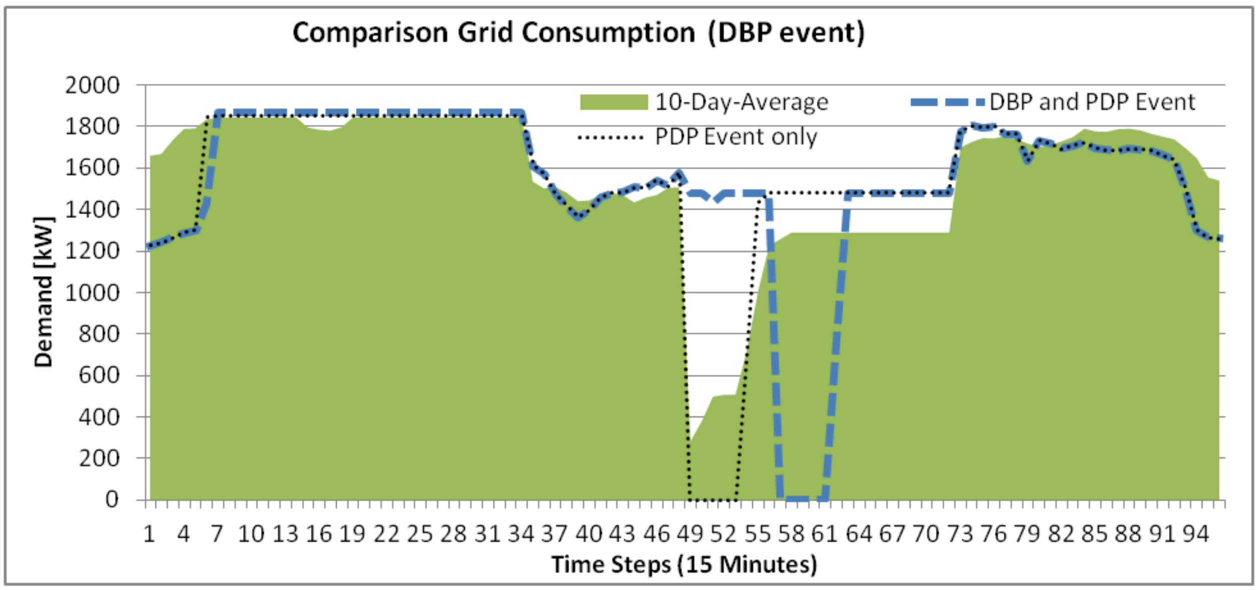

Figure 40: Comparison Grid Consumption (DBP event)

The dashed lines show the total electricity purchased from PG&E that can be interpreted as the result of the battery scheduling optimization. The black dashed line represents a no-PDP-event day without DBP enrollment and the blue dashed line represents the same no-PDP-event day with DBP enrollment and DBP event occurrence.[750] Now it can be very clearly seen that during morning and night the PG&E demand with DBP event and without is closely aligned, meaning

[747] However, without DBP the battery would be discharged directly after noon and it would not be that obvious that this discharge is a pure reduction of energy charges and not - or at least partially - a control of demand levels.

[748] Difference of 15 kW for total max demand and 6 kW for on-peak period.

[749] DBP is, as mentioned, based on PDP. Therefore, the only difference is the addition of the DBP incentive structure.

[750] Same day as shown in the energy balance above.

that the DBP event does not have any significant influence on the scheduling in these periods. However, during on-peak the discharging is postponed to the beginning of the DBP event resulting in a significant decline of PG&E grid purchases for that time. The graph shows that basically the same discharge happens two hours later due to the DBP event. The DBP event has no to very little influence on the rest of the electricity balance and especially the consumption from the grid.[751]

The green area in the background of the figure represents the average of the grid consumption from PG&E for the ten prior identical weekdays, Thursdays in this case, under *DBP BATTERY*.[752] It can be seen that usually some discharging happened in the beginning of the on-peak period and therefore the average consumption shows a decline in this time. For the time from 2 p.m. on, the average consumption is 186 kW below the level of the day without DBP. In the beginning of the event time the average consumption is significantly higher than on the day with DBP. For about the second half of the event the actual consumption on the day with DBP is higher than the average. This shows that the optimal operation schedule means to discharge as much energy in the beginning of the DBP event, even if it means that later in the event the actual consumption exceeds the average. This behavior is due to the battery characteristics and the underlying structure of DBP. An early discharge is favorable to avoid battery decay and the incentive is paid per kWh, meaning that the optimization can choose if it wants to lower demand for a short time very significantly or lower demand less drastically for a longer time period without any difference in earned incentives as long as the total amount of reduced energy consumption is identical. No penalties apply for consumption above the ten-day-average and the incentive is calculated hourly and then added up for the whole event period. Thus, from a DBP incentive standpoint it does not matter when the available energy is discharged. Therefore, to avoid battery decay the early and quick discharge is the optimal behavior although the above average consumption in the second half of the event is counter-intuitive at first sight.

The behavior on the second DBP event day[753] is similar. DBP does not imply any relevant changes to the energy balances and associated costs of the non-DBP event days.[754, 755]

Cost Analysis

Partaking in DBP does not change the load shape on non-DBP-event days.[756] Thus, the costs in all months except September remain unchanged, as DBP only pays an incentive if an event was actually called. In September, however, during the two called events SRJ is able to achieve load reductions worth of $ 732 in DBP incentive. Of this total incentive, the major share of $ 633 is

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751 As already explained at length in the beginning, the consumption from the grid is the only cost driver, as charges only apply to consumption from the grid.

752 No DBP events occur in this period, therefore the average is almost identical to what would be calculated for the ten-day-average under *PDP BATTERY*. If events would occur, they would be excluded from the calculation of the average as outlined above. See sub-chapter 3.2.3.

753 22nd of September.

754 Refer to PDP battery scenario for more detailed information on this behavior.

755 Minor change in peak demand levels will be discussed very briefly in Peak Demand analysis.

756 Minor exception in load levels for the month of September is discussed in Peak Demand analysis below.

achieved in the first event that was presented in detail above. The annual electricity costs for *DBP BATTERY* are $ 1,303,527.[757]

The detailed analysis of the cost structure is not conducted in this scenario, as apart from the subtraction of the incentive in September, the cost structure remains unchanged compared to *PDP BATTERY*.[758]

Peak Demand Analysis

In this scenario a detailed peak demand analysis is not conducted as for all months except September no changes in peak demand levels occurred and therefore the discussion under *PDP BATTERY* can be applied.[759]

Nevertheless one point shall be discussed briefly. In September, the peak demand levels changed slightly as touched upon several times in the previous discussion. Total max demand and mid-peak demand level increased by 15 kW and on-peak demand level decreased by 6 kW compared to *PDP BATTERY*. These changes only result in a change in costs of less than $ 10 and could therefore be neglected without endangering the validity of the results. The occurrence of DBP events in the month of September during the on-peak period places additional weight to lower consumption during this time in the total optimization. As the ten-day-average of similar weekdays takes days into account that are in months previous to September a reduced on-peak demand level in September[760] allows the optimization to drive higher incentives from DBP. As the demand levels are connected to the total capacity of the battery a lowered on-peak demand has to be counter-balanced by an increase in mid-peak and total maximum demand levels. However, this change in demand levels is caused by the knowledge of the event occurrence at the beginning of the month which is not a perfect representation of the real world conditions. Under real operating conditions the demand levels in the month of September under *PDP BATTERY* and *DBP BATTERY* would be set identical. Nevertheless, the results can still be considered valid as the change in demand levels only causes a change in costs of less than 0.07 % of the total monthly costs and 0.0008 % of the total annual electricity costs.

Conclusion

Compared to *PDP BATTERY* the general algorithm of battery scheduling is exactly identical for all no-DBP event days. On DBP event days the discharge of the battery is shifted to the beginning of the DBP event period. The demand levels basically remain unchanged. (With the minor exception for September discussed above which is caused by the limitation of the model). Compared to PDP BATTERY under *DBP BATTERY* the total electricity costs are reduced by $ 725 and add up to $ 1,303,527.

Although the savings from partaking in DBP are minimal it should be kept in mind that the incentive payments for load reduction could increase if more DBP events were called. Also, it

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757 This is actually only $ 725 less than without DBP. The difference of $ 7 between savings and DBP incentive is caused by additional decay on the battery (accurate) and a minor change in the demand levels that can be neglected at this level of analysis.

758 See sub-chapter 7.2.2.

759 See sub-chapter 7.2.2.

760 Compared to the average composed of days in and before September.

must be considered that the savings are achieved without any risk of increased costs by participation in DBP.

7.3.2. Lighting Shed

In this second analysis of DBP lighting shed is introduced equivalent to *TOU LIGHTING SHED* and *PDP LIGHTING SHED*. The lighting shed capability is – again – only evaluated in combination with an active electric storage for reasons given above.[761]

This sub-chapter will determine, if the battery is scheduled in a different way compared to *DBP BATTERY*. Another focus is put on outlining differences in scheduling of the lighting shed opportunities compared to *PDP LIGHTING SHED*. In an effort to streamline the analysis and present a comprehensive results, this chapter will only present relevant differences as they are caused by the enrollment in DBP and not re-discuss the general effects of DBP enrollment[762] or the discussed general effects of lighting shed introduction.[763]

As under *DBP BATTERY* the whole evaluation is conducted for a DBP enrollment in combination with the PDP tariff.[764]

To ensure comparability to the previous lighting shed scenarios the amount of lighting shed is limited to a maximum of two hours a day and eight hours a month.[765]

Energy Balance for Event Day

For the presentation of the energy balance it would be interesting to observe if the DBP event changes the scheduling of the battery or lighting shed. However, detailed analysis showed that the addition of lighting shed capabilities does not change the behavior on the DBP event days. Therefore the depiction is skipped of the energy balance is skipped in this paragraph. For the 20th of September it can be referred to the energy balance provided for *DBP BATTERY*.[766] Basically under *DBP LIGHTING SHED* the energy balance is identical to what was presented and discussed in detail above.[767]

It can be stated that on none of the two DBP event days any lighting shed was scheduled in the optimal operation schedule determined by DR-DER-CAM and the energy balance for the DBP event days is very similar to what was presented under *DBP BATTERY*. From this finding it can be concluded that the DBP incentive structure is not high enough to influence the lighting shed scheduling and the other influencing factors such as reduction of PDP event energy and reduction of demand levels outweigh the effects of DBP participation. The behavior of lighting shed on non-DBP-event days will be evaluated in the Lighting Shed Distribution analysis later on.

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[761] See reasons for this under sub-chapter 7.1.3.

[762] For general effects see sub-chapter 7.3.1.

[763] Refer to sub-chapter 7.1.3 and 7.2.3.

[764] See introduction of chapter 7.3.

[765] kW limits apply as outlined above. Refer to sub-chapter 5.4.1.

[766] See Figure 39.

[767] See sub-chapter 7.3.1 for reference. The only minor exception are the changed peak levels that will be discussed in the Peak Demand Analysis.

However, compared to *PDP LIGHTING SHED* the participation in DBP imposes a change to the energy balance on the DBP event days. For the DBP event days the energy cost reducing discharge of the battery is postponed from the beginning of the *on-peak* period[768] to the beginning of the DBP event period. This change of the battery behavior was already discussed before under *DBP BATTERY*.[769]

Cost Analysis

For *DBP LIGHTING SHED*, the total costs add up to $ 1,285,503 composed from $ 979,268 normal energy charges, $ 46,732 PDP event energy charges, and $ 259,853 demand charges. In total $ 350 of DBP incentives can be achieved that are subtracted from the energy and demand charges.

Compared to DBP BATTERY savings of $ 18,024 can be achieved by leveraging lighting shed in an optimal way. As mentioned before and discussed in more detail in the lighting shed distribution analysis the participation in DBP does not influence the scheduling of lighting shed and therefore the discussion of cost reductions and changed cost ratios. Therefore the discussion for the change from BATTERY to *LIGHTING SHED* presented under PDP can be considered applicable accordingly. As the DBP incentive is very minor compared to the total costs it does not influence the discussed ratios worth mentioning.

Compared to *PDP LIGHTING SHED* the total electricity costs are reduced by $ 439, which is mainly contributed by the savings from DBP incentives that were achieved during the two event days in 2011.[770]

Peak Demand Analysis

For the peak demand analysis in this scenario basically only the resulting changes in comparison to *DBP BATTERY* and *PDP LIGHTING SHED* scenario are given as the underlying principles have already been explained previously.

Compared to *DBP BATTERY*, the usage of load shedding lowered the average mid-peak and total monthly maximum demand by 23 kW and the average on-peak demand by 96 kW.[771] The similarity in demand level reductions from BATTERY to LIGHTING SHED scenario under DBP and PDP confirm the previously made point that the enrollment in DBP has little influence on the overall optimal operation behavior[772]

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[768] Where it occurs under *PDP BATTERY* and *PDP LIGHTING SHED.*

[769] Refer to 7.3.1.

[770] The difference of $ 89 of additional cost reductions is due to a lowered accuracy in the optimization under *DBP LIGHTING SHED* and should be neglected at this initial level of analysis. Unfortunately the accuracy of the optimization had to be reduced slightly under *DBP LIGHTING SHED* as with the additional optimization criteria run times exceeded several hours of calculation time per month at the standard accuracy level that is applied throughout all other scenarios. Due to the insignificant amount of deviation it was decided to accept this reduced accuracy for the sake of a working optimization.

[771] For a detailed discussion of the underlying principles that change peak demand behavior from a battery-only scenario to a battery and load shedding scenario, please refer to the respective discussion under TOU (See sub-chapter 7.1.3). As the overall tariff structures between TOU and PDP are still comparable the conclusions drawn for TOU do apply for PDP.

[772] Under PDP the reductions from battery to lighting shed were 21 kW for the mid-peak and total monthly maximum demand and 106 kW for the on-peak demand level.

Compared to *PDP LIGHTING SHED*, under *DBP LIGHTING SHED* the *mid-peak* and *monthly maximum* demand levels have been lowered by 1 kW and the *on-peak* demand level increased by 9 kW. This shows the same directional behavior that was determined under *PDP LIGHTING SHED*.[773] However, under *PDP LIGHTING SHED* the changes were more significant, which can be easily understood when considering that changing from PDP to DBP only the demand levels for September are influenced. Apart from this the previous discussions and conclusions apply accordingly.[774]

The Lighting Shed Distribution Analysis is not presented for this scenario as no relevant changes in comparison to *PDP LIGHTING SHED* could be observed.

Conclusion

Summarizing, being enrolled in DBP and taking part in the two events of 2011 does not change the lighting shed algorithm in any relevant form and lighting shed is not scheduled for any of the DBP event days. Due to not leveraging lighting shed to obtain DBP incentives in combination with lowered demand levels caused by lighting shed capability the obtained DBP incentive is actually lowered significantly compared to *DBP BATTERY*.[775]

Compared to *DBP BATTERY* the addition of lighting shed lowers the total electricity costs by $ 18,024. Compared to *PDP LIGHTING SHED* the enrollment in DBP lowered the total electricity costs by $ 439.

7.4. Base Interruptible Program

In this fourth chapter of the analysis section BIP will be reviewed in detail for its applicability at SRJ based on 2011 load data. As the previously presented DBP, BIP is a real DR program that needs to be evaluated in combination with an underlying tariff. Consumption at any point of the year – even during events – is billed in accordance with the chosen underlying tariff, because BIP only delivers an incentive framework that tries to motivate customers to lower their demand during certain event times. The base interruptible DR program and the underlying tariff are therefore two separate parts of a customer's electricity bill. They must be evaluated jointly as choices made under consideration of the DR program influence costs under the tariff and the other way round.[776] The underlying tariff for the analysis of BIP will be – as under DBP – the PDP tariff for the same reasons that were presented above.[777] Also in line with the previous analysis, the evaluation of the *BIP FIXED DEMAND* scenario will be dropped as a fixed demand does not allow for participation in DR programs and no changes to *PDP FIXED DEMAND* would occur.[778] For BIP the battery-only scenario and the battery and lighting shed scenario will

[773] In comparison to *TOU LIGHTING SHED*

[774] A detailed discussion that also applies to this scenario, was conducted under PDP BATTERY peak demand analysis already (respective comparison to *TOU BATTERY*). See sub-chapter 7.2.2.

[775] No major influence on overall costs though as incentive is small compared to total costs.

[776] For more detailed argumentation turn to introduction of chapter 7.3.

[777] See chapter 7.3.

[778] While under DBP still some arbitrary savings could be realized depending on the load shape, under BIP literally no savings would be generated as with no reserved battery capacity the PLR would always be zero and therefore *BIP FIXED DEMAND* is exactly identical to *PDP FIXED DEMAND*.

be evaluated and discussed in detail. Pre-cooling will not be evaluated at all under BIP as BIP events are called with a 30 minutes advance notice only and therefore pre-cooling cannot be used to generate savings from BIP.[779]

Before starting off the detailed analysis of the optimal operating schedule under BIP in combination with PDP, the most relevant key characteristics of BIP shall be recalled briefly.[780] BIP is an emergency program which means that customers are not paid for actual achieved load reduction but for the promise of a potential load reduction in case of an event.[781] When enrolling in BIP the customer has to determine a FSL that he is willing and able to reduce its load to or below when a BIP event is called by PG&E. To calculate the incentive the customer's PLR is determined, which is the difference of his average monthly on-peak demand[782] and the chosen FSL. The PLR[783] is then multiplied by the appropriate incentive level.[784, 785] It shall be also recalled that a BIP event can occur at any time of the day and year-round.

As a last remark before starting of the detailed analysis it must be mentioned that in the following analyses the base cases for comparison will be *PDP BATTERY* and *PDP LIGHTING SHED* and not the according scenarios under DBP.[786]

7.4.1. Battery

In this first scenario of the BIP evaluation the operation of the battery will be optimized under PDP in combination with BIP to determine the cost-minimal operation behavior.

While most parameters remain unchanged when analyzing BIP[787] one significant change to the usage of the battery has to be made and was also implemented in the optimization. As outlined in the description of the optimization,[788] when partaking in BIP SRJ needs to set aside some capacity of its battery to be able to always meet its designated FSL. Under BIP an event can occur any time of the day and therefore the state of the battery cannot be known in advance. The assumption of perfect knowledge of the future is only limited to the SRJ consumption and

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[779] See sub-chapter 3.2.4.

[780] For a more detailed presentation refer to sub-chapter 3.2.4.

[781] If customers break this promise they are charged with steep penalties that diminish any previous savings achieved under BIP. In the analysis it is ensured that the promised load reduction can be kept at any time and, thus, the penalties are not implemented in the optimization.

[782] In summer.

[783] In kW.

[784] In $ per kW, which depends on the amount of PLR.

[785] In actuality this multiplication is carried out every month and the incentive level can change based on changing PLRs in different months. For the sake of simplification of the analysis however, the incentive level is determined based on the average PLR over the whole year.

[786] This is to clarify because in all other analyses the comparison was always made to the previous chapters. This is not possible in this case due to the fact that BIP is added to the PDP case and not evaluated on-top of the DBP scenarios. Program Schedules and Dual Participation Information state diverting information with regards to the question if a customer can partake in PDP, DBP and BIP simultaneously. For this analysis it is assumed that PDP can be combined with DBP and BIP separately but participation in both DR programs with PDP as an underlying tariff is not possible.

[787] Compared to *PDP BATTERY.*

[788] Refer to section 6.

DER generation[789] but does not include the occurrence of events. If one would know about the event in advance, the DER-CAM optimization would prepare for it in a way that could not be resembled in reality and therefore the results would not be meaningful.[790] Therefore, to simulate the 30-minutes advance notice in this optimization a certain level of battery capacity is designated to be used only if a BIP event occurs. To be totally certain that the FSL can always be reached, the FSL is calculated by taking the highest consumption at any time step of the year and subtracting the BIP battery reserve.[791] By doing so it is ensured that even if the event is to be called during a period of high consumption and a low SOC for the battery[792], the BIP battery reserve is still high enough to ensure that the FSL is not exceeded during the BIP event.[793]

To account for the more complex structure of BIP and the numerous sub-scenarios that are evaluated under *BIP BATTERY*, the structure of this sub-chapter will slightly deviate from the previous BATTERY scenarios. First, the different BIP Battery Reserve Levels (BRL) will be introduced. Afterwards, different sub-scenarios dealing with the BIP event duration are introduced. Then, before going into detail on the resulting costs for the numerous sub-scenarios, two exemplary energy balances will be discussed and presented.[794]

BIP Battery Reserve Level Scenarios

As touched upon before the result of *BIP BATTERY* directly depend on the battery capacity that is set aside to ensure that the FSL is not exceeded during a BIP event,[795] independent of the current consumption and DER output or the battery SOC. As the choice of the BIP BRL has multiple non-linear effects on the total resulting costs that depend on different parameters as well as on the specific load shape under evaluation, the optimal BIP BRL cannot be determined intuitively or through DER-CAM optimization. Therefore, in the following, different potential BIP BRLs will be evaluated to find a good approximation of the optimal BIP BRL.

First, it must be stated that 20 % of the battery capacity are always reserved for technical and emergency reasons.[796] This standard BRL was mentioned before and kept in all previous scenarios and is also kept under BIP. The BIP BRL is a reserve of battery capacity beyond the standard BRL that is hold for almost all the year and only allowed to be used during a BIP event.

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[789] As for these cases it could theoretically be achieved to a good standard by using detailed load and generation forecasts.

[790] This has not been an issue with events under DBP and PDP as these events are called on the previous day and the battery goes through a full charging cycle every summer weekday and therefore the optimization does not start to prepare the battery for the event before the event was actually called.

[791] Divided by the event duration.

[792] In its normal PDP arbitrage cycle.

[793] To determine the point of highest consumption for each level of BIP battery reserve – as presented below – correctly, each scenario and BIP BRL was simulated once without any BIP-event occurrence before simulating the actual year with the correct BIP events.

[794] A detailed Peak Demand Analysis will not be presented in this chapter to streamline the analysis. This is acceptable as the total peaks are considered in the evaluation of the BIP battery reserve levels and a more detailed analysis did not reveal any changing insights.

[795] This can be called at any time of the day.

[796] DER-CAM standard assumption/ setting during all previous analyses on SRJ.

To be able to get a good approximation of the best BIP BRL all potential BRLs from 0 % to 80 %[797] are evaluated in steps of 10 % or 400 kWh.[798]

When limiting additional battery capacity for most of the year, obviously the potential for daily energy cost arbitrage and demand level reduction is influenced. The increased costs due to lowered arbitrage will be discussed later on in the detailed cost analysis. The influence on demand levels and especially the annual maximum demand is crucial for the analysis of the different sub-scenarios as the annual maximum demand is the starting point for the determination of the FSL and the PLR that drives the BIP incentive. The graph below shows how the annual maximum demand develops for increasing BIP BLR levels:

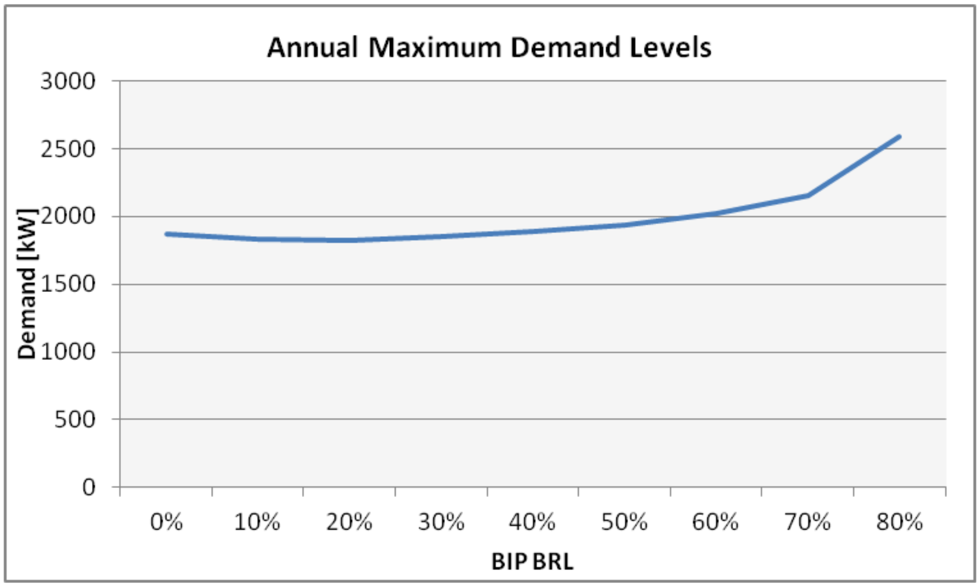

Figure 41: Annual Maximum Demand Levels by BIP BRL

The starting point for 0 % shows the same annual maximum demand that also occurred under *PDP BATTERY.*[799] This shows that *BIP BATTERY* with a BIP BRL of 0 % is basically identical to *PDP BATTERY*. For the BIP BRLs up to 40 % the graph shows a development that was not expected and is counter-intuitive at first sight. With a decrease of available battery capacity for daily arbitrage and demand level reduction the annual maximum demand is lowered slightly. More detailed analysis showed that this development is not true for the *on-peak* demand levels but only for the total maximum demand, which is relevant for this evaluation and mainly occurs during *mid-* or *off-peak* periods. From this finding it can be concluded that with higher levels of on-peak demand and less battery capacity available for arbitrage the charging during mid- and off-peak periods is reduced and therefore the total maximum demand levels decrease slightly. For BIP BRLs beyond 40 % this effect is not relevant anymore and the expected development of an increase in demand levels occurs as the available battery capacity for daily arbitrage and

[797] Of the total battery capacity – including the 20 % standard BRL.

[798] Smaller iterations would allow for a better approximation but increase calculation and simulation time extensively, therefore 10 % are chosen as compromise for this initial analysis.

[799] In July; see sub-chapter 7.2.2.

demand level control goes down. Especially for 70 % and 80 % BIP BLR[800] the total maximum demand level goes up significantly as peaks in the power requirement cannot be shaved off anymore due to the very limited[801] or non-existing[802] battery capacity available. For 80 % BIP BLR the annual maximum demand is equal to the level that was already presented under *TOU FIXED DEMAND* and *PDP FIXED DEMAND* because the battery is only used during the BIP events and apart from that the power requirement of SRJ is fixed and cannot be optimized through the application of the electric storage.

BIP Event Duration Scenarios

After having discussed the BIP BRLs that are set aside to be able to reduce consumption to or below the FSL during BIP events the BIP event duration needs to be considered. To calculate the FSL based of the highest consumption within the year[803] under consideration of the reserved battery capacity[804] the BIP event duration[805] is the denominator that distributes the BIP battery reserve over the event time.

$$FSL = Annual\ Maximum\ Demand - \frac{Reserved\ BIP\ Battery\ Capacity}{Event\ Duration} \qquad (Eq.\ 7.1)$$

Obviously, the shorter the BIP event time is assumed to be, the lower the FSL can be set and the higher the incentives received will be. The BIP event duration is not known until the event is called and can actually be changed by PG&E during the course of the event. Therefore, a universal BIP event time must be chosen for the full year.

The first sub-scenario and most obvious choice for the maximum BIP event duration is four hours, which is the given regulatory maximum defined in the BIP regulatory sheets.[806] This can be considered the most conservative case which ensures a full compliance with the FSL at all times. However, looking at the past years since the start of BIP it can be observed that no BIP event ever lasted longer than two hours. Therefore, a second sub-scenario will be analyzed in which the maximum event duration is set to two hours. Assuming that the BIP events only last two hours obviously bears the inherent risk that the event could be longer by the regulatory standards. However, in the two hour scenario a lower FSL can be set as the same BIP reserve battery capacity allows for double the reduction. Another argument for evaluating this more risky scenario is the fact that by taking the highest annual consumption and by reserving battery capacity especially for BIP usage the whole optimization is set up for the worst case. This means, that even if the FSL is set up assuming a maximum of two hours per event and an event with a longer duration would occur, chances are that still enough battery capacity would be available to not exceed the FSL as the consumption might be at the annual maximum demand level and the SOC of the battery might not be at its respective minimum. However, choosing this the scenario for real-life implementation would require some additional research and

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800 Only 10 % and 0 % of the battery capacity are available for daily arbitrage and demand level control.

801 70 % BIP BRL leaves 10 % battery capacity for daily arbitrage and demand level control.

802 80 % BIP BRL leaves 0 % battery capacity for daily arbitrage and demand level control.

803 Both values in kW.

804 In kWh.

805 In hours.

806 See sub-chapter 3.2.2.

evaluation. In this context the two-hour sub-scenario is presented to get a good initial estimate of the additional savings that can be achieved by accepting the described risk.

Charging Scenarios

For the above presented two- and four-hour maximum BIP event duration scenarios it was assumed that during the 30-minutes between event notice and the beginning of the event no further actions are taken. However, the time between the event notice and the beginning of the event could actually be used to charge the battery. If the battery SOC allows for additional charging, i.e. the battery is not at full charge due to a high BIP BRL anyway, the battery could be charged at maximum rate of 2,000 kW for 30 minutes resulting in additional capacity of 1,000 kWh.

$$FSL = Annual\ Maximum\ Demand - \frac{Reserved\ BIP\ Battery\ Capacity + Additional\ Charging}{Event\ Duration} \qquad (Eq.\ 7.2)$$

This additional battery capacity allows setting a lower FSL and increase BIP incentives.[807] For the charging scenarios it must be recalled that the BIP BRL only comes into play if the battery is in a low SOC in the daily arbitrage cycle. If the battery is at full charge due to the normal cycle enough energy is stored to reduce consumption to the FSL anyway and the additional charging is not possible but also not needed because the battery is already topped up.

However, the option of charging the battery in the last 30-minutes prior to the event and including this additional capacity in the calculation of the FSL drives the risk that the charging in the period prior to the event might cause higher demand charges that exceed the optimal demand levels that have been determined by the optimization and would therefore cause increased power charges. These additional power charges might exceed the savings from the lowered FSL. However, the occurrence of this effect can only be evaluated for every single BIP event in combination with the specific load shape prior to the event[808] and under consideration of the full month's load shape[809] Nevertheless, chances are that the additionally charged capacity can be taken to reduce the FSL without causing any adverse effects as the battery is either at full charge already or the specific load shape in the 30 minutes prior to the event allows for increased demand without increasing the respective load levels. For now, the risk shall be kept in mind and a more detailed discussion will be performed when looking at the load shape of the actual BIP event day in 2011.

Scenario Overview

Summarizing, four scenarios will be evaluated for each BIP BRL:

- Maximum BIP event duration of two hours, no additional charging
- Maximum BIP event duration of two hours, additional charging after event notice
- Maximum BIP event duration of four hours, no additional charging
- Maximum BIP event duration of four hours, additional charging after event notice

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[807] For a BIP BRL of 60 % only 800 kWh can be added before the battery is at maximum capacity. For a BIP BRL of 70 % only 400 kWh can be added before the battery is at maximum capacity. At 80 % BIP BRL no charging is possible.

[808] To see if additional charging would be possible without increasing demand levels.

[809] For the determination of the optimal load levels.

Concluding, it is important to bear in mind that the BIP BRL and the additional charging are only needed during the low SOC in the daily arbitrage cycle. During high SOC in the normal arbitrage cycle the BIP BRL and the charging are still effective but simply already fulfilled as the battery has high SOC anyway. However, the BIP BRL and the charging must be considered, obeyed and evaluated in detail as the BIP event can occur at any point of time during any day.

In the following two energy balances will be presented to visualize the effects of taking part in BIP.

Energy Balance for Non-BIP Event Day

The first energy balance presented for *BIP BATTERY* is for the 20th of September.[810]

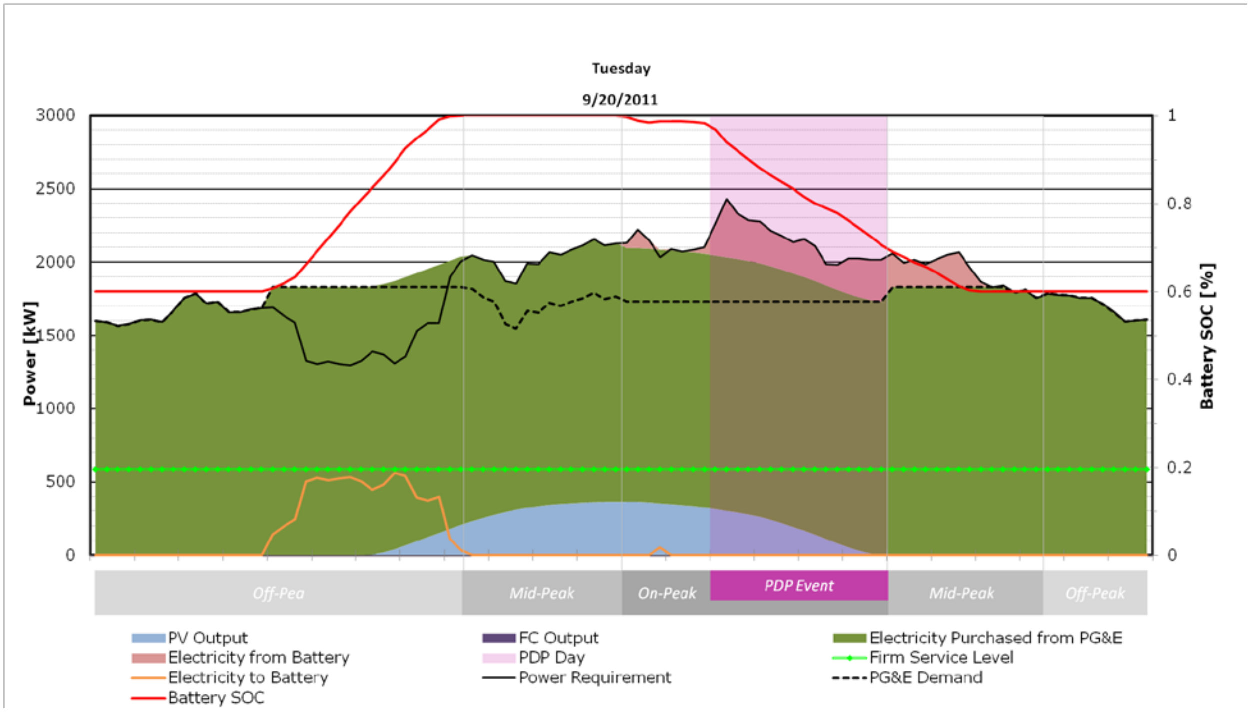

Figure 42: Energy Balance SRJ - BIP BATTERY (no BIP event)

The graph above shows the energy balance for *BIP BATTERY* with a BIP BRL of 40 %. The chosen scenario is limited to two-hour maximum event duration and additional charging of the battery after the event notice.[811] The BIP BRL level can be clearly derived from the picture above by analyzing the battery SOC. The SOC never goes below 60 % of the full battery capacity.[812] Within these 60 %, 20 % are the standard BRL and 40 % are reserved to ensure full compliance with the FSL in case of an event. In comparison to the energy balance of the same day under *PDP BATTERY* it can be clearly seen that the *on-peak* demand level is significantly higher as less battery capacity is available to control the consumption during on-peak. All battery capacity is

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[810] Same day as presented under 7.2.2.

[811] The maximum event duration and the choice on additional charging do not influence the depiction for the exemplary day as the 20th of September apart from the FSL level.

[812] Plotted to the secondary axis.

used to control demand levels during *on-peak* and the second *mid-peak* period, which makes this day the demand-setting day of the month.[813]

The depiction of the energy balance was enhanced by one additional graph that represents the FSL. The FSL is shown by a bright green line with square markers. The FSL is plotted to the primary axis and is 589 kW for this scenario. In this graph the FSL is only shown for informational reasons and does not have any effect as the 20th of September did not have a BIP event.[814]

Energy Balance for BIP Event Day

The second energy balance presented for the *BIP BATTERY* scenario is for the 7th of September, the only summer BIP event day in 2011.

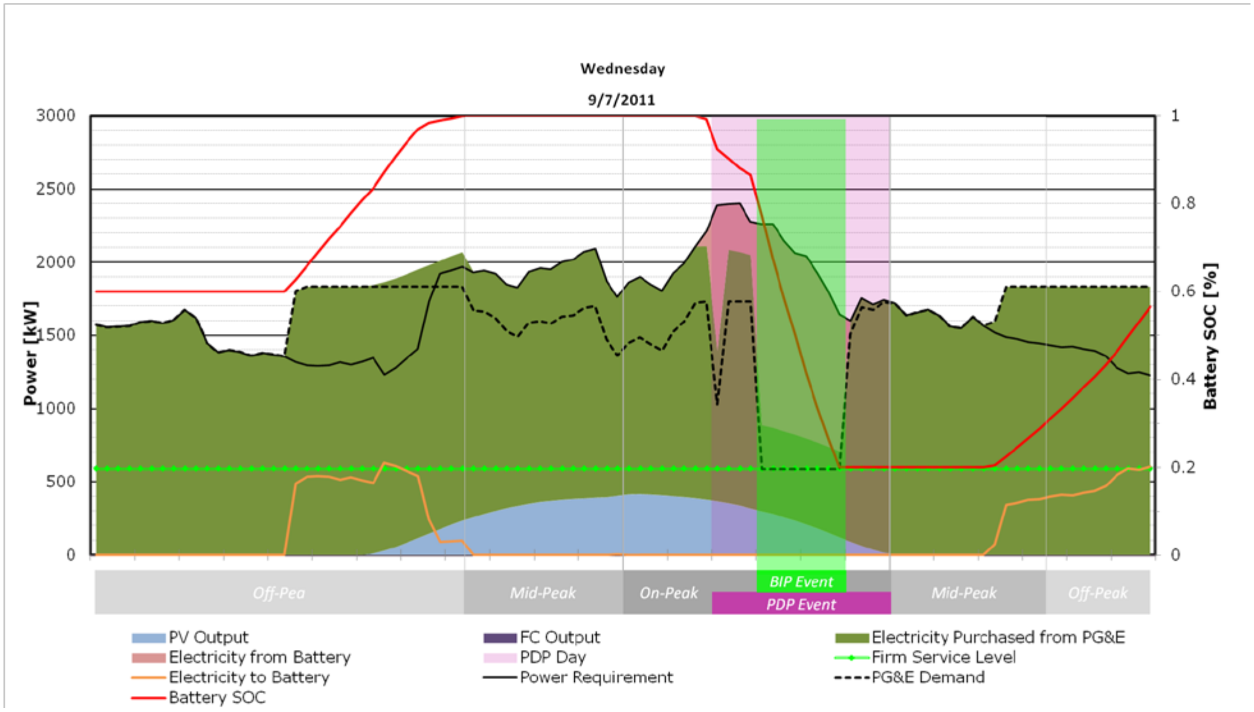

Figure 43: Energy Balance SRJ - BIP BATTERY (BIP event)

The sub-scenario settings in this depiction are identical to what was described for previous energy balance.[815] The BIP event on this day is from 3 p.m. to 5 p.m. which is indicated by the transparent bright green box and the event marker at the bottom. It can be seen very clearly that during the BIP event time the power requirement is lowered to exactly fulfill the FSL while being significantly higher prior and post the BIP event time.

Looking at the SOC of the battery, it can be seen that during the morning the SOC does not go below 60 % which is due to the fact that the standard BRL and the BIP BRL are activated.

[813] Demand-setting day characteristics discussed under sub-chapter 7.1.2.

[814] For a more detailed description of the energy balance with a detailed discussion of the battery behavior, please refer to sub-chapter 7.2.2.

[815] 40 % BIP BRL, two-hour maximum event duration, additional charging activated.

During mid-day, the battery is at high SOC due to its normal arbitrage and demand level control cycle. However, during the end of the *on-peak* period the SOC goes down to 20 %[816] before going towards 60 % again at the end of the day. This behavior is explained by the fact that up to the beginning of the BIP event the BIP BRL is activate and then released with the beginning of the event. By realizing the BIP BRL at the beginning of the BIP event, the battery capacity can be used to ensure a compliance with the FSL during event time. After the BIP event the BIP BRL is not directly reactivated, because this would mean that the battery could not actually be leveraged during the event time. The BIP BRL is only activated again at the beginning of the next day. This is why the battery is charged again up to 60 % before midnight.

Looking at the discharging behavior of the battery, additional energy that was not used to maintain the demand levels was discharged in the beginning of the on-peak under TOU and at the beginning of the PDP event under PDP. Under BIP however, major discharge of the battery happens during the BIP event to ensure that the power requirement does not exceed the FSL.

It can also be very nicely seen from the graph that the behavior is only influence by the BIP after the event notice[817] because at the beginning of the PDP event[818] DR-DER-CAM scheduled the expected discharge of additional energy to reduce PDP event energy charges. However, upon receiving the notification 30-minutes prior to the event the discharging is discontinued to ensure that enough battery capacity is available for the FSL.[819]

As mentioned above the chosen sub-scenario allows for an additional charging of the battery prior to the event. Nevertheless in the energy balance of the 7th of September no charging occurs prior to the event. This is due to the fact that under the specific load shape analyzed the battery SOC at the point of event notification is already slightly above the level that is needed to maintain the FSL during the event time. This very nicely illustrates the fact mentioned before that the BIP BRL and the additional charging only come into play if the SOC is relatively low at the point of the event notice. In the sub-scenario of 40 % BIP BRL with additional charging the battery is ensured to be at 85 % capacity at the beginning of the BIP event.[820] At the point of the event notice the battery capacity is due to the normal arbitrage cycle[821] at a SOC higher than 85 %. Therefore no additional charging is needed and instead even a small amount of additional battery capacity can be used to flatten the power requirement prior to the event. At the beginning of the BIP event then, the SOC is exactly at 85 %[822] and therefore the amount of energy stored in the battery is exactly timed to ensure compliance with the FSL for a two-hour event.

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[816] Standard BRL.

[817] 30 minutes prior to the event.

[818] 1 hour prior to the event.

[819] Due to the 15-minute resolution the charging and discharging lines are not totally vertical as they are supposed to be but detailed analysis of the underlying data showed that no changes to the behavior occurred prior to the event notice although the shown graph might suggest a slightly early change in behavior. Again, this is due to the finite, 15-minute resolution of the data.

[820] 20 % standard BRL, 40 % BIP BRL, added 1000 kWh at maximum charging rate in 30 minutes.

[821] Basically arbitrarily in connection to BIP.

[822] Exactly meeting this point is controlled by the amount of discharge between the event notice and the beginning of the event.

As a final remark for the discussion of the BIP-event day energy balance it shall be noted that the chosen sub-scenario was the two-hour maximum event duration. This does not cause any issues in this case because the event actually only lasts two hours but it is also very easy to understand from the depiction. If at 2:30 p.m. PG&E called a BIP event lasting four hours, the battery capacity available would not have been enough to keep consumption below the FSL for the full event duration and therefore steep penalties would have been faced.[823]

Cost Analysis

In the graph below the total costs of electricity supply for SRJ are shown for the different BIP BRLs. The lines represent the different maximum event durations and additional charging scenarios and all possible combinations thereof.

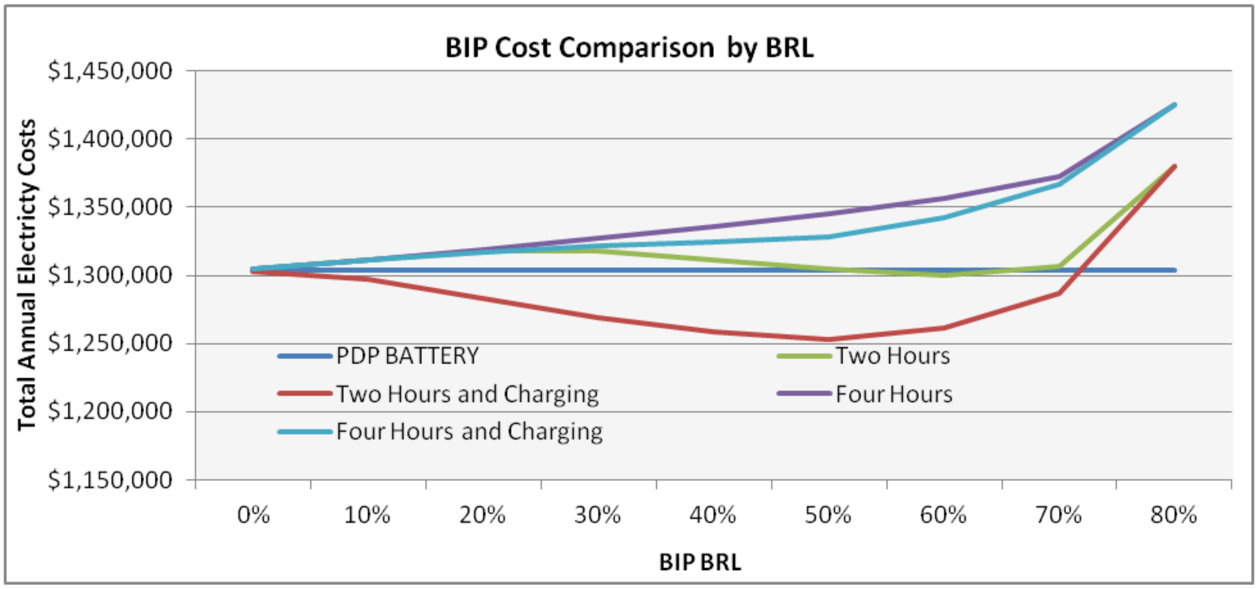

Figure 44: BIP Costs Comparison by BRL

To set the results of the different scenarios into perspective, the horizontal line shows the total costs of electricity for *PDP BATTERY*. This line is horizontal over all BIP BRLs as there is no BIP BRL under the PDP only scenario. This line simply serves as a reference scenario. Costs below this line mean, that the involvement in BIP under the specific scenario would drive savings and should be considered in more detail.

Discussing the position of the different scenarios towards each other it can be seen that costs are higher for all scenarios with four-hour event durations[824] than for the scenarios assuming two-hour event duration.[825] This is due to the fact that with four-hours assumed event duration the battery capacity that is reserved for BIP must be able to keep the FSL for twice the amount of time compared to assuming an event duration of two hours. Therefore the FSL is significantly

[823] Actually, upon notice of the four hour event the battery could have still been charged to full capacity (instead of a slow discharge that occurred now) prior to the event but nevertheless the designated FSL, which was calculated assuming a maximum event duration of two hours, could not have been met for full four hours.

[824] Turquoise and purple line.

[825] Green and red line.

higher in the four-hour scenarios and less BIP incentives can be achieved, resulting in higher total annual costs. A similar observation can be made when comparing the scenarios with additional charging after the event notice[826] to the scenarios that have no additional charging implemented.[827] It can be stated that for the same maximum event duration, the scenario with additional charging implemented shows lower total costs. This is due to the fact that the additional charging allows to set a lower FSL as more battery capacity is available during a BIP event at no additional costs.[828] In this context it is worth mentioning that the charging and non-charging scenarios have equal costs for 80 % BIP BRL as in these scenarios the battery is always fully charged[829] and additional charging cannot be conducted. For 70 % BIP BRL it can be seen that the charging and non-charging scenarios for the respective event durations already start to narrow in on each other[830] as under 70 % BIP BRL only 400 kWh can be charged after the event notice before full capacity is reached – instead of the usual 1000 kWh. Under 60 % BIP BRL the effect is still relevant but hardly shows in the depiction above.[831]

Before going into detail on the description of the different line graphs in the diagram it shall be stated that the costs for TOU energy charges[832], demand charges and PDP event energy charges are almost equal[833] for each BIP BRL scenario, because the battery behavior is identical for all days of the year except the two BIP event days. Therefore the differences in costs are mainly explained by differences in BIP incentive.

For the **four-hours-maximum-BIP-event-time-and-no-additional-charging scenario**[834] the course of the line graph is most easily explained. The line graph only starts at 30 % BIP BRL because below this level the available battery capacity is not enough to reach an FSL that fulfills the regulatory requirements.[835] From 30 % to 70 % the costs increase almost linear because the increase in BIP BRL leaves less battery capacity available for every-day arbitrage and therefore the total electricity costs increase.[836] Due to the long maximum BIP event duration the FSL is relatively high and the resulting BIP incentives cannot compensate the increase in electricity costs due to the limited availability of the battery for every-day arbitrage. Actually only for the scenarios between 50 % and 70 % BIP BRL any BIP incentive is achieved and even in the best case it never exceeds $ 3,000, which is about 0.2 % of the total costs of electricity.[837] The additional uptick in costs for the 80 % BIP BRL case is explained by the over proportional

[826] Red and turquoise line.

[827] Green and purple line.

[828] Adverse effects on demand levels are not implemented in this optimization but have been mentioned as a potential risk above.

[829] Except during and after BIP events. 80 % BIP BRL plus 20 % standard BRL.

[830] Precisely, the charging scenario gets closer to the non-charging scenario

[831] 800 kWh can be charged before the full capacity is reached.

[832] In TOU periods.

[833] Only differ by a maximum of a few hundred dollars in over the full year.

[834] Purple line.

[835] BIP regulations require the FSL to be below 85 % of the maximum summer on-peak and winter mid-peak demand.

[836] See difference in costs between *PDP FIXED DEMAND* and *PDP BATTERY*

[837] No BIP incentive is achieved if for all months the FSL is higher than the monthly on-peak average and therefore the PLR is negative.

increase of the annual maximum demand in this scenario, that was already shown and discussed before (link to graph for annual maximum demand levels), which leads to a significantly higher FSL (and therefore lower PLR) and in addition causes significantly higher demand charges. (as short peaks in the load profile cannot be shaved off and trigger high demand charges that could have been avoided with a very small amount of available battery capacity already)

For the **four-hours-maximum-BIP-event-time-with-additional–charging scenario** (turquoise line) the line graph begins already at the 10 % BIP BRL because the additional charging of the battery prior to the event allows setting the FSL lower and therefore the regulatory threshold can be reached earlier. Up to 60 % BIP BRL the costs develop almost linear for the same reasons that have already been described in the four-hours-maximum-BIP-event-time-and-no-additional-charging scenario. From 60 % to 80 % the costs start to narrow in on the costs of the scenario without charging because the effect of the additional charging starts to be limited by the maximum battery capacity. This effect has been described before when comparing the additional-charging to the no-additional-charging scenarios and causes a gradual incline of the line graph from 60 % BIP BRL on, up to the point where – at 80 % BIP BRL – the scenario with and without additional charging are identical.[838]

For the **two-hours-maximum-BIP-event-time-and-no-additional-charging scenario**[839] the line graph starts at 20 % as before the achievable FSL is not within the regulatory framework of BIP. From the start up to 60 % BIP BRL the costs decrease in a somewhat linear fashion. While costs increased with increase of the BIP BRL for the four-hour scenarios, for the two hour scenarios the total costs decrease with an increase in BIP BRL. This is due to the fact that the available battery capacity only needs to be distributed over half the time and therefore the reduction of the FSL and the resulting increase in BIP incentive is higher than the increase in energy and demand charges caused by the decrease of battery capacity available for daily arbitrage. The linear behavior of the graph within these boundaries is due to the fact that energy[840] are also increasing in a linear fashion over all BIP BRL. Power charges and BIP savings[841] are also linear up to about 60 % BIP BRL. At 60 % the graph starts to go up again representing increased costs as annual maximum demand level[842] and the related power charges increase more than between the previous BRL BIP levels.[843] This effect starts at 70 % BIP BRL in a very slight fashion and it can be said that between the 50 % and 70 % BIP BRL the change in BIP BRL hardly causes any to the resulting costs as the increase in BIP savings is almost exactly counter-balanced by the increase in energy and demand charges.[844] For 80 % the significant increase in maximum peak level[845] causes an increase in the resulting FSL and the BIP savings actually go down compared

[838] See description three paragraphs above.

[839] Green line.

[840] PDP event and normal TOU charges.

[841] Counted negatively.

[842] See Figure 41.

[843] Disproportionate.

[844] The difference in total costs between these scenarios is only about $ 6,000, which is less than 0.5 % of the total electricity costs.

[845] See Figure 41.

to the 70 % BIP BRL scenario. Combined with increased costs for energy charges[846] and higher demand charges[847] this causes a steep incline in total costs for the 80 % BIP BRL scenario, which results in the significant uptick of the green line towards the last scenario. For 60 % BIP BRL in this sub-scenario the costs under BIP are slightly lower than under PDP.[848]

For the **two-hours-maximum-BIP-event-time-with-additional-charging scenario**[849] the graph starts at 0 % BIP BRL and the costs go down in a somewhat linear fashion up to 50 % BIP BRL. This decrease in costs is due to the same characteristics as under the two-hours-maximum-BIP-event-time-and-no-additional-charging scenario. The uptick of the line graph thereafter is basically also caused by the same effects that were discussed in the previous scenario. The fact that the uptick already begins at 60 % BIP BRL[850] is due to the fact that at 60 % BIP BRL the additional charging and therefore the related reduction of the FSL already begins to be constraint by the total battery capacity. Finally, all scenarios between 10 % and 70 % BIP BRL generate cost savings by being enrolled in BIP compared to PDP with the lowest costs at 50 % BIP BRL. At 50 % BIP BRL the potential cost savings are $ 50,946.

In this most profitable scenario the energy costs for normal TOU periods make up 78% and the PDP energy costs 5 % of the total electricity costs. Demand charges account for about 23 %, while BIP incentives are 7 % compared to the total costs. It is interesting to consider that the BIP savings in the two-hours-maximum-BIP-event-time-with-additional-charging scenario are actually higher for 60 % BIP BRL but these additional savings of about $ 5,000 are eliminated by demand charges being over $ 8,000 higher than at 50 % BIP BRL.

Conclusion

Concluding, it can be stated that only if a maximum event duration of two hours is assumed the participation in BIP can drive savings. Assuming this scenario obviously bears the risk that PG&E, at some point, might call an event that exceeds two hours as the electric schedule for BIP allows for events up to four hours. Without assuming additional charging prior to the event, the savings would be rather low and might not justify taking this risk.

However, if additional charging after the event notice is implemented almost all BIP BRLs would drive savings compared to the PDP benchmark at an assumed maximum event duration of two hours. The highest savings would be achieved, if at 50 % BIP BRL. Considering additional charging for the termination of the FSL bears the risk that the charging might drive increased demand charges, which was not the case for the events in 2011 and was therefore not evaluated in more detail in this analysis.

A brief summary of the risks associated with the different scenarios is given in the appendix.[851]

[846] Due to non-existing daily arbitrage.

[847] As no demand-level control is possible.

[848] $ 3,802.

[849] Red line.

[850] And not at 70 % BIP BRL as under the previous scenario.

[851] See Appendix F.

7.4.2. Lighting Shed

In the second analysis section under BIP the potential of adding the functionality of lighting shed to the battery scheduling in researched in detail.

As before, the parameters of the battery scheduling remain unchanged compared to *BIP BATTERY*. However, under *BIP LIGHTING SHED* the structure of the analysis will vary from the previous lighting shed scenarios to conform to the special characteristics of BIP. The scheduling of the lighting shed is basically identical to the scheduling under *PDP LIGHTING SHED*. This means the discussion of an energy balance, the peak demand levels, and the lighting shed distribution analysis are skipped in this sub-chapter as no relevant new insights would be derived. Instead, the lighting shed will be analyzed under two sub-scenarios. First, the lighting shed is going to be scheduled by the optimization in such way that energy costs are minimal without taking the special characteristics of BIP into account.[852] Second, the lighting shed is going to be implemented in the optimization in such way that it can be used to lower the FSL and thereby drive increased incentives from BIP.

In this part only the most profitable BIP BRL for each of the sub-scenarios will be considered as there is no reason to go with BIP BRL that would cause higher costs.[853] As before, a limitation of two hours of lighting shed per day and a total amount of eight hours of lighting shed applies.

Standard Lighting Shed Scenario

As the BIP events are only called 30 minutes in advance, the optimization does not consider the event occurrence, however, it might still be optimal to use some lighting shed during the event time. In this scenario the usage of lighting shed during the event time is never needed to ensure FSL compliance during the event. Using the lighting shed under this scenario could also help to mitigate the risk of increased demand charges for the scenarios that involve an additional charging between the event notice and the beginning of the event. However, it should be considered that the events are not known to the facility at the beginning of the month, when the scheduling for the full month is done, and therefore it could happen that all lighting shed is already used before an event is called and occurs.[854] However, related increases in cost due to a non-optimal scheduling of lighting shed caused by an unforeseen event occurrence are very unlikely to be significant as demand levels are only influenced very slightly by lighting shed.[855] Concluding, it is important to bear in mind that in this scenario maintaining the FSL can always be achieved without being dependent on the availability of lighting shed and therefore the

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852 Comparable to previous lighting shed scenarios

853 Four-hours-maximum-BIP-event-time-and-no-additional-charging scenario: 30 % BIP BRL

Four-hours-maximum-BIP-event-time -with-additional-charging scenario: 20 % BIP BRL

Two-hours-maximum-BIP-event-time-and-no-additional-charging scenario: 60 % BIP BRL

Two-hours-maximum-BIP-event-time-with-additional-charging scenario: 50 % BIP BRL

854 In the DER-CAM implementation of this scenario, the events are known and therefore will be considered in the optimization. This must be stated as a minor risk associated to the usage of lighting shed in this scenario but is considered acceptable due to the small number of occurring events.

855 See *PDP LIGHTIGN SHED.*

addition of lighting shed does not increase the risks associated with the participation in BIP the risks that were discussed before[856] and could actually help to lower some of the discussed risks.

Although a detailed analysis of the lighting shed distribution is not presented for *BIP LIGHTING SHED* a detailed analysis showed that the findings from the previous chapters apply.[857]

BIP specific lighting shed scenario

In a second step the lighting shed scheduling algorithm was specifically tailored to the characteristics of BIP to see if this would drive additional savings over the standard lighting shed algorithm.

The concept behind this altered lighting shed algorithm is to designate the available lighting shed specifically to the BIP event times. By doing so the lighting shed could be considered in the calculation of the FSL and thereby increase the savings from BIP incentives due to a lowered FSL. In this scenario the evaluation is only conducted for the two-hour-maximum-BIP-event-time scenario as lighting shed is also limited to a maximum of two hours per day.[858]

To be able to guarantee that the reduced FSL can be reached the usage of lighting shed in this scenario has been limited to the occurrence of BIP events, which is also very easily implementable in reality. However, due to the low number of BIP events over the year this would mean to forgo significant savings potential from lighting shed. This is accounted for as lighting shed will be used in the last days of the month, when it is certain that it will not be used for FSL compliance any more.[859] By doing so, the lighting shed is not optimally scheduled to lower demand levels and also by using it during the off-peak period of the day, the avoided energy charges are rather low. However, using the lighting shed here is still beneficial to not using the lighting shed available in the month. The evaluation of the resulting costs in the following will show if the reduction in FSL justifies this "non-optimal" scheduling of the lighting shed at the end of the month or not.

However, also applying this scheduling algorithm to lighting shed is associated with an inherent risk. Under the lighting shed limitations in this scenario only a maximum of four times two hours of lighting shed are available in each month, but BIP allows for up to ten events per month and in the most extreme case each event could last four hours.[860] If PG&E would decide to call the maximum amount of BIP allowed under the program, the limited amount of lighting shed would not be enough to ensure full compliance with the FSL at all times. However, as in

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[856] Under *BIP BATTERY*.

[857] See sub-chapter 7.2.3. for details.

[858] Even with two hours of lighting shed the FSL could also be lowered in the four-hour-maximum-BIP-event-duration scenarios. By applying the lighting shed potential the available battery capacity could be spread over a longer time period and allow for a lowered FSL compared to no lighting shed. However, the additional complexity would distract from the key characteristic of this analysis and is not essential at this initial state of analysis.

[859] For example if one BIP event is called in the middle of August three times two hours of lighting shed will still be available three days before the end of the months. As, with the end of the 28th of August it is certain that not more than two BIP events can be called in August one two-hour block of lighting shed will be used from 10 p.m. to midnight on the 28th. The same procedure will be applied – if no events occur – to the following two days in August.

[860] The limit of 120 hours of BIP event time per year limits this risk to three months in this most extreme setup.

the past only a very limited number of BIP events were called, this risk can be considered acceptable.

Cost Analysis

In the cost analysis the standard lighting shed scenario was evaluated for all four sub-scenarios under the most profitable BIP BRL determined in *BIP BATTERY*. The BIP specific lighting shed scenario was evaluated for the two hour scenarios.[861] The results of the cost analysis are shown in the graph below.

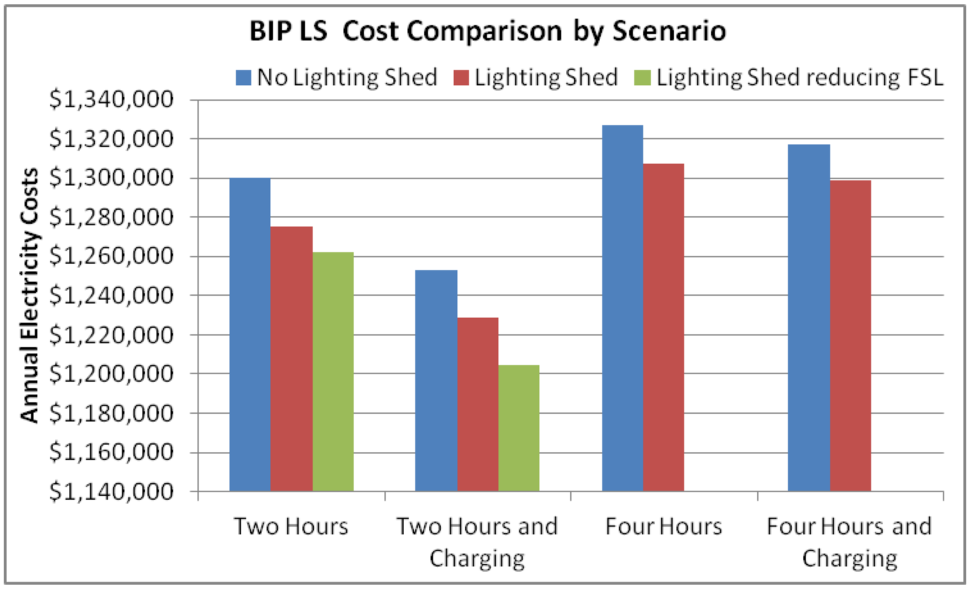


Figure 45: BIP LS Cost Comparison by Scenario

The blue bars indicate the costs with no lighting shed for the most profitable BIP BRL results from *BIP BATTERY* for each scenario. They can be considered the benchmark for the evaluation of the *BIP LIGHTING SHED* sub-scenarios.

The red bars indicate the costs under the four different scenarios for the standard lighting shed algorithm. Under the four-hour scenarios the lighting shed generates around $ 19,000[862] and under the two-hour scenarios about $ 25,000[863]. The higher savings from lighting shed in the two-hour scenarios[864] are mainly driven by higher savings in demand charges. This is due to the fact that the most profitable two-hour scenarios under *BIP BATTERY* have higher BIP BRLs than the four-hour scenarios. Due to the limited available battery capacity in the two-hour scenarios higher demand peaks occur and thus the lighting shed can help to reduce these peaks and drive higher demand charge savings.

[861] It is assumed that lighting shed lowers the costs in a somewhat linear fashion and therefore the above shown curves (link to graph) will still have their minimums at the same BIP BRLs.

[862] No charging: $ 19,845; Charging: $ 18,677.

[863] No charging: $ 24,922, Charging: $ 24,584.

[864] Compared to the four hour scenarios.

The green bars indicate the costs under the BIP specific lighting shed scenario. It can be seen that the tailored application of lighting shed drives higher savings than the standard lighting shed scheduling algorithm. Without charging this scenario drives $ 13,362 in additional savings compared to the standard application of lighting shed. For the additional charging scenario the savings are even higher with $ 23,957 compared to the standard lighting shed scheduling.

Conclusion

For *BIP LIGHTING SHED* it can be concluded that the standard application of lighting shed is able to deliver around $ 20,000 in savings over the comparable *BIP BATTERY* scenario. When looking at these savings some additional risk have to be considered that are mainly associated with the assumption of perfect knowledge in the DER-CAM optimization that is challenged by the unforeseeable occurrence of BIP events on short notice. This might influence the total height of additional savings but cannot trigger any penalties or additional costs above the *BIP BATTERY* level.

For the BIP specific lighting shed algorithm the savings are even higher and are about $ 40,000[865] and about $ 50,000[866] compared to the respective *BIP BATTERY* scenarios. The only considerable risk associated specifically with this lighting shed algorithm is that the total number of events per months could exceed the available lighting shed potential.

7.5. Summary of Results

The total annual electricity costs for all scenarios are presented in the table below:

[$]	Fixed Demand	Battery	Load Shed	Load Shift
TOU	1,447,368	1,319,246	1,302,071	1,316,170
PDP	1,428,923	1,304,252	1,285,942	1,299,692
DBP		1,303,527	1,285,503	
BIP		1,253,306	1,228,723	

Figure 46: Overview of Annual Electricity Costs by Scenario

In the following, the key results will be summarized briefly in two dimensions. First, the different tariffs and DR programs will be compared[867] and afterwards the different load influencers will be discussed.[868]

7.5.1. Tariffs and DR Programs

Time of Use

The E-20 tariff is the tariff that SRJ is currently served under and basically formed the base case throughout the evaluation above. The costs under *TOU FIXED DEMAND* can be considered the actual costs of electricity for SRJ in 2011. By applying the electric storage, annual savings of

[865] No additional charging.

[866] With additional charging.

[867] See sub-chapter 7.5.1.

[868] See sub-chapter 7.5.2.

almost $ 130,000 could be achieved. Load shedding generated another $ 17,000 in addition, while PC was only able to drive savings of $ 3,000 in addition to the battery savings.

As TOU has no dynamic pricing and no events occur under this tariff, the three load influencers could only be used to lower cost under the Time-of-Use structure of the tariff. It was determined that the battery is mainly focused on reducing demand charges during *on-peak* in summer and lowers the total electricity costs by flattening those. Lighting shed under TOU is used mostly during *on-peak* and – in combination with the battery – is scheduled to reduce demand charges. 80 % of savings from lighting shed were generated during the summer months. Finally, PC was only able to drive minor savings under TOU. However, these savings were also achieved by focusing on lower demand charges during *on-peak.*

Peak Day Pricing

PDP was the second major case that was evaluated for all four load scenarios. It can be seen that by using the battery under PDP, savings of almost $ 125,000 were generated. Load shedding generated additional $ 18,000 and PC almost $ 5,000.

It is interesting to observe, that even under the FIXED DEMAND scenario, PDP results in lower costs than TOU. As PDP was laid out to motivate demand response it is interesting to see that even without any reaction to called events, SRJ is better off under PDP. This results from the relatively flat grid consumption due to the on-site PV arrays. For the application of the battery, the behavior compared to TOU did not change significantly. The only major change observed is the fact that on non-demand-setting days with a PDP event, the energy discharge of the electric storage aiming at reducing energy charges is postponed from the beginning of *on-peak* to the beginning of the event period. This is explained by the significantly higher costs during the PDP event period. Lighting shed is predominantly scheduled on event days under PDP and would, therefore, be easier to apply in reality. Lighting shed still aims at reducing demand charges to some extent but the high event energy charges also help to generate savings on the energy side. Finally, PC still only generates minor savings but – as for lighting shed – it can be observed that an increased share of these savings results from reductions in energy charges. PC is also scheduled predominantly on PDP event days.

Concluding the results on PDP, it must be stated that under all four load scenarios, the total electricity costs for 2011 are lower under PDP than under TOU. This means that SRJ would - under all scenarios evaluated - have been better off in 2011 if they had not opted out of PDP.

Demand Bidding Program

Compared to *PDP BATTERY*, the additional enrollment in DBP allows driving savings of $ 725. *DBP LIGHTING SHED* generates savings of $ 425 compared to *PDP LIGHTING SHED*.

Being enrolled in DBP in combination with an underlying PDP tariff hardly changes the behavior of battery charging and discharging or lighting shedding in comparison to being served under PDP without DBP participation. The minor savings under DBP occurred due to the fact that incentives under DBP are only earned if actual events are called. Unfortunately, in 2011 only two events were called and, therefore, the savings potential was limited. However, DBP should not be directly excluded from further analysis, as an increase in the number of called events could raise the savings potential of this program. This is especially interesting as there is no upper boundary for the number of events called under DBP.

Finally, it should be kept in mind that the savings under DBP are achieved at no risk because the participation in the events is voluntary. This means that being enrolled in DBP cannot cause any costs above the PDP level and savings could be tapped as SRJ sees fit.

Base Interruptible Program

Exactly as DBP, BIP is evaluated with PDP being the underlying tariff and evaluated against the cost of being served under PDP without BIP enrollment.

The costs stated in the overview table above are the best case scenarios bearing some of the inherent risks that have been discussed above. However, in the best evaluated case BIP is able to drive almost $ 51,000 savings compared to *PDP BATTERY*. Compared to *PDP LIGHTING SHED*, BIP could even drive savings of over $ 57,000. If enrolled in BIP, the addition of lighting shed to the standard battery usage drives savings of about $ 20,000 if the lighting shed scheduling algorithm is not changed. If tailoring the lighting shed scheduling algorithm to the BIP program structure, this figure can increase up to $ 50,000.

Although these figures are promising, it must be clearly mentioned that they can only be generated if SRJ is willing to take certain risks. Most important is the fact that the savings were calculated assuming that a BIP event would never exceed a duration of two hours. This limit was never exceeded in the past, but the regulations allow for up to four hours for BIP. When simulating BIP with four hour events, it was shown that absolutely no savings can be generated compared to PDP and costs can – depending on the scenario – actually be higher than under PDP.

Apart from the associated risk, BIP is more complex to implement as the customer has to determine its FSL in advance for a full year. The results for BIP clearly indicate savings potential. Though, to be able to tap these savings, additional research must be conducted and the extent of risk that SRJ is willing to take in relation to its electricity costs must be clarified.

7.5.2. Load Influencers

The term load influencers refer to the electric storage, lighting shed and precooling as these installations or measures allow influencing in order to minimize the total electricity costs.

Battery

The cost reduction potential of the battery is only evaluated for TOU and PDP as only under these scenarios the evaluation of fixed demand was considered reasonable.

The battery can generate annual savings of over $ 128,000 under TOU and almost $ 125,000 under PDP. As promising as these savings are, it must be stated that the NPV of the electric storage is negative and under current market conditions the installation of a battery at SRJ would not have been viable. Even for the best – and most risky – scenario under BIP, if all additional savings generated from the BIP program are attributed to the battery, the NPV of the battery would still be negative.

However, at SRJ the electric storage is already installed and operational and as this document is a case study for SRJ, it was included in all analyses. Under all tariffs and programs, the battery is basically used to flatten the demand levels and set them to an optimal level. As demand charges during *on-peak* are highest, the battery always tries to reduce the demand the most in this period. In addition, the battery is used to shift energy consumption from the more expensive *on-peak* to *off-peak*. It is also remarkable that during winter, as price variation between periods is lower, the battery is basically only used to shave off some extreme peaks but not cycled every day as in summer.

It must be stated that the highest savings under BIP can be achieved if about half of the battery is set aside for almost the whole year and only used during the two called events. If such operational pattern is technically feasible, it should be evaluated in more detailed research.

Finally, the battery reduces the savings potential from lighting shed as well as precooling. Without the battery, load shed and shifting could be used to shave off extreme loads spikes and thereby drive significant savings on demand charges. However, in combination with the battery, load shed and shifting are confronted with flattened demand levels already and to achieve the identical demand reduction more electricity consumption must be shed or shifted. This finding means that within microgrids the common estimates on load shed and shift savings potential derived in non-microgrid settings may not apply.

Lighting Shed

In the presented scenarios, lighting shed is always evaluated in conjunction with the usage of the electric storage. In this setting, the lighting shed is able to drive savings of slightly below $ 20,000 under every tariff.[869]

In all scenarios, lighting shed is always used towards the end of the *on-peak* period. This allows the battery to be discharged as early as possible during *on-peak* and thereby avoid decay. Occurrence during *on-peak* is driven by the high demand and energy charges in this period. Under TOU, lighting shed is mainly used on demand-setting days to lower the demand levels. In reality, this can cause an issue as very precise load forecasts need to be made to determine the relevant demand-setting day in each month. However, under PDP, the lighting shed is used during PDP events, and this can be easily implemented in reality. Due to the high PDP event energy charges, lighting shed under PDP is not only focused on the reduction of demand charges but also generates savings from reductions in PDP event energy charges. Under BIP, the adaption of the lighting shed algorithm to the specific program structure helped to increase savings significantly. Using lighting shed to be able to set a lower FSL and use the remaining lighting shed at the end of the day is not only the most viable application of lighting shed under BIP but also most reasonable for practical implementation. Upon event notice, the lighting can be shed easily and the shed of the remaining light at the end of the month is also very easily implementable without having the need for any type of load forecast.

Finally, it must be stated that lighting shed can only be implemented if occupant comfort is considered and controlled.

[869] Slightly more under the most profitable and most risky BIP scenario.

Precooling

PC was evaluated under TOU and PDP. Under TOU PC could drive $ 3,000 in savings compared to the battery scenario; under PDP over $ 4,000.

Under TOU, the savings are mainly contributed by reductions in demand charge. This means that PC is predominantly allocated to the demand-setting days of the months. Savings in energy charges were not realized under TOU as the energy penalty inherent to PC eliminates all energy cost savings generated during *on-peak*. Under PDP, the situation changed slightly. The majority of savings under PDP is due to reductions in PDP event energy consumption, which means that PC must be scheduled on PDP event days. As the price difference between PDP event period and *off-peak* is high, the energy penalty does not eliminate all savings. Having determined that PC is scheduled on PDP event days predominantly also eases the practical implementation of PC as perfect load forecasts are not needed and PC can be activated a few hours after the event notice was received.

Under PC, two different PC profiles were available for the optimization to choose from. With regard to this, it can be stated that both profiles have been used, even though the energy penalty of PC-II is three times as high as the energy penalty of PC-I.

Finally, it should be stated, that due to the lack of a PC-capable BES model or detailed measured load and temperature data, the PC profiles for this evaluation are based on a literature review. While the general findings with regards to the scheduling behavior will not change under different PC profiles, a more detailed PC analysis should be conducted once a new BES of SRJ becomes available to see if savings increase when using a more SRJ-specific PC profile.

CHAPTER 8: Conclusion and Next Steps

8.1. Conclusion

With the increasing penetration of renewable and distributed energy resources and the correlated change in the electricity infrastructure, two concepts are emerging in the electricity sector that are expected to ease the change in the electricity supply paradigm while ensuring reliability of supply. The first emerging concept, microgrids, entails the grouping of different DER and loads at a local level. Microgrids assist in the grid integration of intermittent resources and can help to ensure reliability of supply even further. First, on a local level, all loads connected to the microgrid benefit from the microgrids ability to island in case of a macrogrid disturbance or fault. Second, on a more regional level, microgrids could use their controllable resources to provide additional services to the grid. One of these services is demand response. Demand response is the second emerging concept. It evolves around the idea that, as energy production becomes more volatile and less controllable due to renewable resources such as PV or wind, the demand needs to be more flexible to ensure constant alignment of load and supply.

It was evaluated in this report, if under current market conditions in California, the participation in demand response would be financially viable for one of the world's most modern microgrids. Although being clearly focused on the facility under research, the study can serve as an entry point to this topic of involving microgrid in demand response markets.

The report focused on the evaluation of the applicability of different tariffs and DR programs to Santa Rita Jail. Apart from the standard time of use tariff, Peak Day Pricing, the Demand Bidding Program and the Base Interruptible Program have been evaluated in detail and selected for inclusion in the analysis.

As the analysis of the DR potential was specifically conducted for SRJ, it was necessary to understand the detailed load and generation behavior as well as the key load drivers. For this purpose a detailed load and generation analysis has been conducted that showed that the Fuel Cell cannot be considered a reliable source of supply. Apart from this it was determined that SRJ has a rather flat daily load profile as the mid-day peak is almost perfectly compensated for by PV output. As detailed load break-downs were not available, an existing building energy simulation model was leveraged and adapted to serve as a good approximation of the actual loads. It showed that lighting is a significant and very constant load share, while the next big load driver, cooling load, fluctuates more on a day-to-day basis. Based on these detailed load splits and additional wiring information provided by SRJ load shed potential by lighting shed and load shift potential by precooling was identified and quantified.

Based on these findings the optimization model DER-CAM has been extended by demand response, lighting shed and precooling capabilities. So called DR-DER-CAM minimizes the total electricity costs under each of the given tariffs and programs by optimally scheduling the usage of electric storage, lighting shed, and precooling.

Using DR-DER-CAM, the different tariffs were evaluated under four different load scenarios. These scenarios are: fixed demand, the usage of the battery by itself, the usage of the battery and lighting shed, and the usage of the battery and precooling. Several interesting insights have been derived in these analyses.

First, Peak Day Pricing shows a significant savings potential across all different scenarios analyzed in comparison to the current TOU tariff SRJ is served under. Most remarkably, costs under PDP would even be lower if absolutely no reaction to the called events is implemented due to the PV-driven, relatively flat specific load shape of SRJ. Second, DBP, a price responsive DR program, was evaluated and it was determined that the savings potential in 2011 would have been relatively low under this program. On the upside, however, it must also be stated that these minor savings could be realized at absolutely no risk as the participation in the called events is voluntary and no penalties for non-compliance apply. Third, BIP, an emergency DR program, was analyzed. BIP was evaluated for numerous sub-scenarios. The sub-scenarios are differentiated by the battery capacity that is set aside to fulfill the demand reduction promise, by the expected maximum event duration, and by the capability of charging the electric storage between event notice and the beginning of the event. It was shown, that only if accepting some risk, savings can be generated by partaking in this program. Under a risk-averse approach the participation in this program is not viable.

The results also generated findings with regard to the different opportunities to influence the load and their viability. The electric storage at SRJ is able to drive savings from flattening the demand levels and conducting energy charge arbitrage on a daily level. The electric storage is able to generate significant savings at SRJ, but when taking the investment costs into consideration it is not financially viable under current market conditions. For Lighting shed, it was shown that small amounts of lighting shed can generate savings. Lighting shed is optimally used on demand-setting days under TOU or event days under PDP. The vast majority of savings from lighting shed are generated during summer. For precooling the generated savings were relatively small under all tariffs and programs researched and were mainly resulting from reductions in demand charges while energy costs actually increased.

Concluding this analysis, it can be stated that the microgrid at SRJ with its installed electric storage, on-site PV arrays and load management capabilities shows potential for the participation in DR under tariffs and programs offered by the local utility.

8.2. Next Steps

For the future it should be considered to broaden the data base of the analysis by including previous and future years in the evaluation to determine if the findings change under different load conditions.

Based on the results of this report the further pursuit of lighting shed should be discussed and perhaps a small scale practical study of the effects of lighting shed could be conducted at the facility under research. The results of this study could then be easily entered in DR-DER-CAM to fine-tune the actual savings potential.

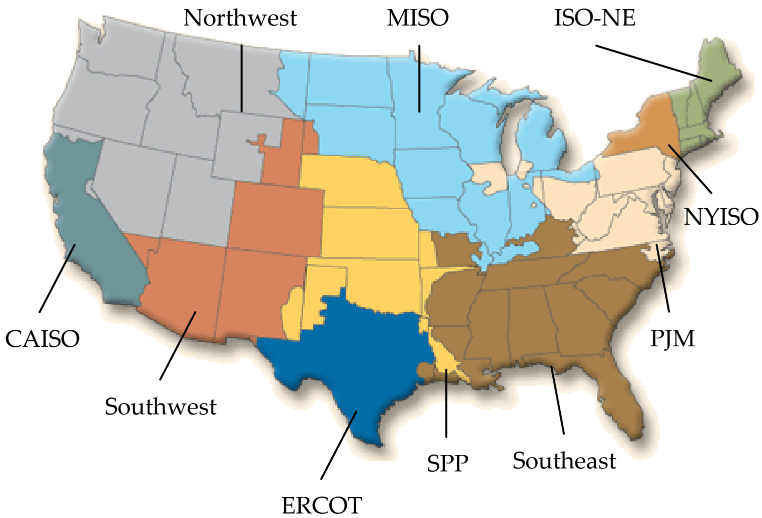
For precooling, a more detailed evaluation of precooling load profiles is needed to ensure that all building specifics are mirrored correctly. This could either be done by actually changing the HVAC system set points under close observation of resulting temperature. If this is not possible, a new building energy simulation, which is currently being developed at LBNL, could be used to generate more SRJ-specific precooling profiles.

Finally to broaden the scope of this research beyond the specifics of SRJ and to validate the findings an analysis of different microgrid settings with regards to their potential for participation in demand response should be continued in the future.

APPENDIX A
Section 2

ISOs and RTOs in the United States

Apart from trading the pure demand satisfying electricity on the spot markets also ancillary services that are needed to stabilize grid operation are traded and thus open for non-discriminating access. Leveraging this market, the stable operation of the grid is under the responsibility of the ISO/RTO. In addition, ISO/RTO try to minimize overall system costs, to plan infrastructure extensions and to initiate and coordinate measures for peak reduction and demand response as well as an integration of renewable energy resources.[870] The figure below gives an overview of the existing ISOs and RTOs in the U.S.[871]



ISOs and RTOs in the U.S.

List of ISOs:

- CAISO - California ISO
- NYISO - New York ISO
- Electric Reliability Council of Texas (ERCOT)

List of RTOs:

- PJM Interconnection (PJM)

[870] (ISO/RTO Council, 2009)

[871] Not all states are deregulated yet and, therefore, do not have an ISO or RTO at the moment.

- Midwest Independent Transmission System Operator (MISO); an RTO despite the ISO in its name
- Southwest Power Pool (SPP); also a Regional Reliability Council
- ISO New England (ISONE); an RTO despite the ISO in its name

PG&E Service Territory

PG&E Service Territory[872]

[872] http://www.research-alliance.org/images/rebates/pge/pge_map.jpg

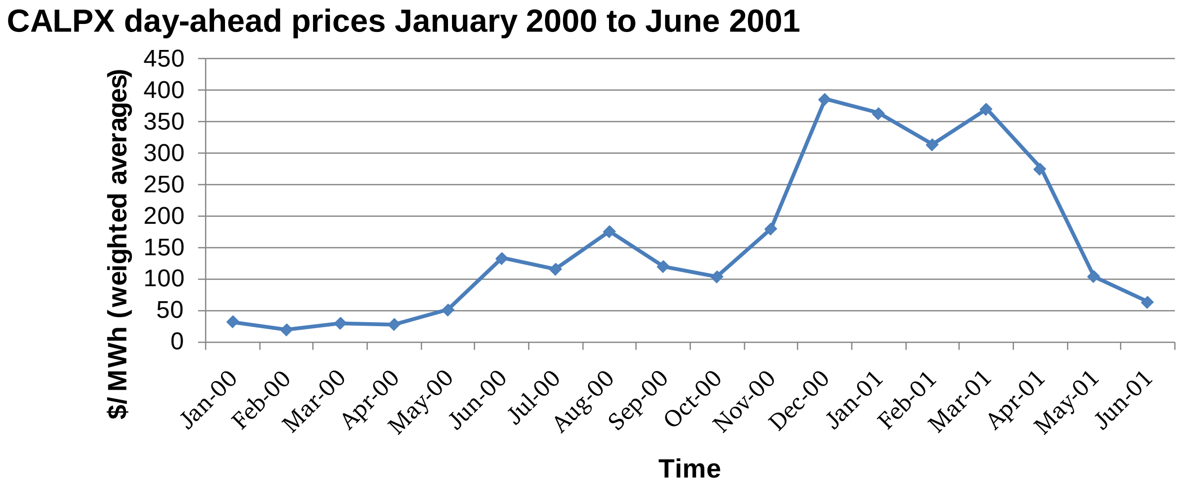


Figure 0-1: CALPX Day-ahead prices[873]

[873] (Joskow P. L., 2001)

APPENDIX B
Section 3

California DR assessment tools for customers

Two tools worth mentioning[874]are the InterAct tool, offered by PG&E, and the Demand Response Quick Assessment Tool (DRQAT), developed by LBNL. InterAct is available to any larger customer with interval data for free and allows the customer to evaluate his theoretical electricity costs under a different tariff. The tool mainly tries to help customers to determine how much load they need to shed or shift during an event to benefit from enrolling[875] in a dynamic pricing scheme. Once enrolled in a dynamic pricing tariff the customer can use the tool to track and improve its usage especially during DR events.[876] DRQAT gives customers the opportunity to theoretically evaluate their energy savings by simulating different load shed and shifting measures depending on numerous variables such as building type and location. Through DRQAT, customers have to option to get a first idea of their savings potential as well as fine-tuning their DR measures and participation.[877]

Other PG&E Demand Response Programs - excluded from detailed analysis

In this part of the appendix the remaining PG&E DR programs will be described. For the sake of a more focused analysis only the two most relevant DR programs for the case study facility offered by PG&E are analyzed in the core part of the report. In the following part of the appendix, the other DR programs will be described briefly. Along with each program also the reasons why this program was not chosen for a more detailed analysis in this report will be given.

Optional Binding Mandatory Curtailment Plan

Optional Binding Mandatory Curtailment (OBMC) is available to most of PG&E's industrial customers[878] who filed a detailed OBMC Plan[879] that was accepted by PG&E.

Customers enrolled in the OBMC Plan will receive notice for a load reduction of 5 % to 15 %. The load reduction is calculated based on a baseline derived from the previous ten business days.[880] An OBMC event is triggered by PG&E if CAISO initiates a firm load curtailment or if PG&E decides to – on its own – run a firm load curtailment in parts of its service territory.[881] Once customers have received a notice regarding such event they must immediately commence the load reduction and reach the demanded level of load reduction within 15 minutes after the

[874] This is also highlighted by the National Plan (Federal Energy Regulatory Commission, 2010x)

[875] Or more precisely: not opting-out.

[876] (Pacific Gas and Electric Company, 2013b)

[877] (Demand Response Research Center, 2011)

[878] Bundled service, community choice aggregation service and direct access customers.

[879] Specified under (Pacific Gas and Electric Company, 2010c, p. 5).

[880] (Pacific Gas and Electric Company, 2010c, p. 2)

[881] (Ibid, p.1)

notification. If the load reduction cannot be achieved by the customer within time, financial penalties apply.[882, 883]

The customers' benefit from participating in OBMC is, however, not a financial benefit. Confirming participants under OBMC are – as the sole advantage from this program – excluded from rolling outages that might occur under a stage 3 emergency.[884] As the last stage 3 emergency occurred in 2001[885], this is a rather vague benefit but might still be worth more detailed research. The ultimate reason why this program is not analyzed in more detail is that the facility under research has significant back-up generation on-site and is able to seamlessly switch into islanding mode and also maintain islanded operation for an extended period of time due to two diesel back-up generators that can cover the most relevant loads easily and – under normal conditions – even supply the full demand of the facility.

Scheduled Load Reduction Program

The Scheduled Load Reduction Program (SLRP) is available to customers under A-10, E-19 and E-20 with a minimum average demand of 100 kW and, therefore, the facility under research would be eligible in general.[886]

SLRP provides customers enrolled in the program with the option to provide load reductions to PG&E at prescheduled times. During these prescheduled times the customer must reduce its load by at least 15 % versus its baseline.[887] The baseline is determined by the past ten similar days excluding SLRP days and other DR event days.[888] Under SLRP a customer has to pick one to three from 15 possible SLRP options. The options correspond with the business days of the week[889] and during each day three four-hour time steps are selectable.[890, 891] When the selected time steps occur, the customer must reduce its load every time during the summer season; PG&E does not give any additional notification for the reduction. Participants are incentivized to take part in this program with a $ 0.1 per kWh payment for the energy reduction during their preselected SLRP option.[892, 893] It must be noted that customers are not allowed to shift their lowered loads to *peak* periods[894] of the same[895] or another day.[896]

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[882] To specify penalties: $ 6 per kWh for all energy usage above the designated level during the time of the event.

[883] (Pacific Gas and Electric Company, 2010c, p. 3)

[884] The customer is only excluded from planned rotating outages. In case of network problems OBMC customers might still face rotating outages (Pacific Gas and Electric Company, 2010c, p. 3)

[885] (California ISO, 2012)

[886] (Pacific Gas and Electric Company, 2010d, p. 1)

[887] (Ibid.)

[888] For details see (Pacific Gas and Electric Company, 2010d, p. 3).

[889] Monday through Friday.

[890] From 8 a.m. to 12 Noon, Noon to 4 p.m., and. 4.p.m. to 8 p.m.

[891] (Pacific Gas and Electric Company, 2010d, p. 2)

[892] Compared to their baseline.

[893] (Pacific Gas and Electric Company, 2010d, p. 3)

[894] From 12 Noon to 6 p.m.

[895] If operating morning SLRP option.

The layout of this program might be interesting to be evaluated for the facility under research and the facility would also be eligible for participation in the program. However, since 2009 CPUC capped the DR load under this schedule at 0 MW, which basically means that the program is closed.[897] This is also in accordance with information provided by PG&E on DR program participation stating that during 2011 no service accounts have been enrolled in SLRP.[898] Although customers can sign up for a waiting list for the program in case the cap might go up or erased altogether, the practical non-availability made it irrelevant for detailed analysis within this report.[899, 900]

Permanent Load Shift

Permanent Load Shift (PLS) is eligible for industrial, agricultural and large residential customers within the service territory of PG&E.

The core of the program is basically the support of the installation of thermal energy storage at the customer's facility by one of two predetermined contractors that will help to shift cooling load from mid-day *peak* hours to the earlier *partial-peak* or even *off-peak* hours.[901]

This program will not be analyzed in more detail in the report at hand for three reasons. First, the incentive is based on the amount of installed equipment primarily,[902] which basically makes the evaluation a financial investment decision. Second, the load is shifted permanently and thereby is not in accordance with the above definition of DR used in this report. Third, during the final stage of the production of this report, PLS was totally closed for new enrollments, awaiting the start of a new, statewide PLS program.[903]

Smart AC

Smart AC is a program rolled out by PG&E for residential and industrial customers that focuses on the distribution and utilization of Smart AC controls. PG&E offers its customers the installation of a Smart AC device at the customer's facility allowing PG&E to remotely control the thermostat set points. Once a customer is enrolled in the program PG&E can use the Smart AC device to increase thermostat set points during select peak hours by a maximum of 4° F. By doing so, PG&E tries to mitigate peak demands and thereby ultimately increase security of supply for its customers.[904] The program does not affect the electrical load of the customer directly but the affects of the change of set points on electricity consumption could be measured exemplary or obtained from a detailed building energy model.

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[896] (Pacific Gas and Electric Company, 2010d, p. 4)

[897] (Ibid., p. 1)

[898] (Pacific Gas and Electric Company, 2012a)

[899] In addition, the prescheduled character of the load reduction is not exactly within in the definition of DR provided above.

[900] The program was briefly characterized as PG&E lists the program under DR.

[901] (Pacific Gas and Electric Company, 2013e)

[902] Not the load shift.

[903] (Pacific Gas and Electric Company, 2013e)

[904] (Pacific Gas and Electric Company, 2013f)

Once a customer has installed the Smart AC device and participates in the program PG&E will provide free of charge service for the Smart AC device and the customer's HVAC system. However, if the service personnel detects that failure is related the customers HVAC system PG&E does not provide further service free of charge. Apart from this error-detection service, PG&E does not offer direct financial benefits to the customers partaking in the program. Instead, PG&E indirectly tries to give an incentive to the customers by the promise of an increased security of supply through increased participation in the Smart AC program.[905]

This program will not be analyzed in detail in this report for two particular reasons. First, a single-customer evaluation of the benefits of this program is hard to conduct as no direct monetary incentives are offered.[906] Second, the program is currently[907] not open for enrollment of industrial customers.[908]

Aggregator Programs

All programs aforementioned are listed by PG&E under *DR Business programs* and are at the core of this evaluation. For the sake of completeness it should be mentioned that a facility as the one under research could also operate DR under *Aggregator Programs*. Aggregator Programs are DR programs that customers cannot directly enroll in but must go through a designated aggregator appointed by PG&E for the specific aggregator program.

PG&E lists two programs under its Aggregator Programs:

First, the **Aggregator Managed Portfolio** (AMP) sets a framework for the implementation of bilateral contracts between aggregators and PG&E. Aggregators can contract price-sensitive customer loads and can then negotiate a payment for this service with PG&E. The customers will be incentivized for their participation based on the contract they signed with the respective aggregator. The AMP basically only defines when and how often events can be called. The event notification is not centrally defined and may vary from one aggregator to another.

Second, the **Capacity Bidding Program** (CBP) is structured more similar to the business programs listed above. Customers sign up for this program through PG&E certified aggregators.[909] CBP is more defined than AMP and clearly defines the incentives for load reduction. Incentives are paid on a capacity and energy level and penalties occur for non-compliance. The program can be called by PG&E, if the dispatch of power plants with heat rates of 15,000 BTU/kWh or greater is expected based on the day-ahead and hour-ahead market situation.[910]

[905] (Pacific Gas and Electric Company, 2013f)

[906] This argument is even more relevant as the facility under research in this project has seamless islanding and extensive back-up capabilities and is, thus, more independent from the macrogrid than the average customer.

[907] Fall 2012.

[908] (Pacific Gas and Electric Company, 2013f)

[909] Although the short program description on the PG&E website (Pacific Gas and Electric Company, 2013g) the detailed tariff description (Pacific Gas and Electric Company, 2012c) clearly states that customers can only enroll through certified aggregators.

[910] (Pacific Gas and Electric Company, 2013f)

However, the two Aggregator Programs will not be considered in the analysis as essential contract details (AMP) or secondary participation details such as fees (CBP) could only be reliably determined by a detailed research of the aggregator market. This is beyond the scope of this project, which focuses on direct PG&E DR programs.

PDP Event Days in 2011

1. 6/21/2012
2. 7/5/2011
3. 7/29/2011
4. 8/23/2011
5. 8/29/2011
6. 9/2/2011
7. 9/6/2011
8. 9/7/2011
9. 9/20/2011

DBP Event Days in 2011

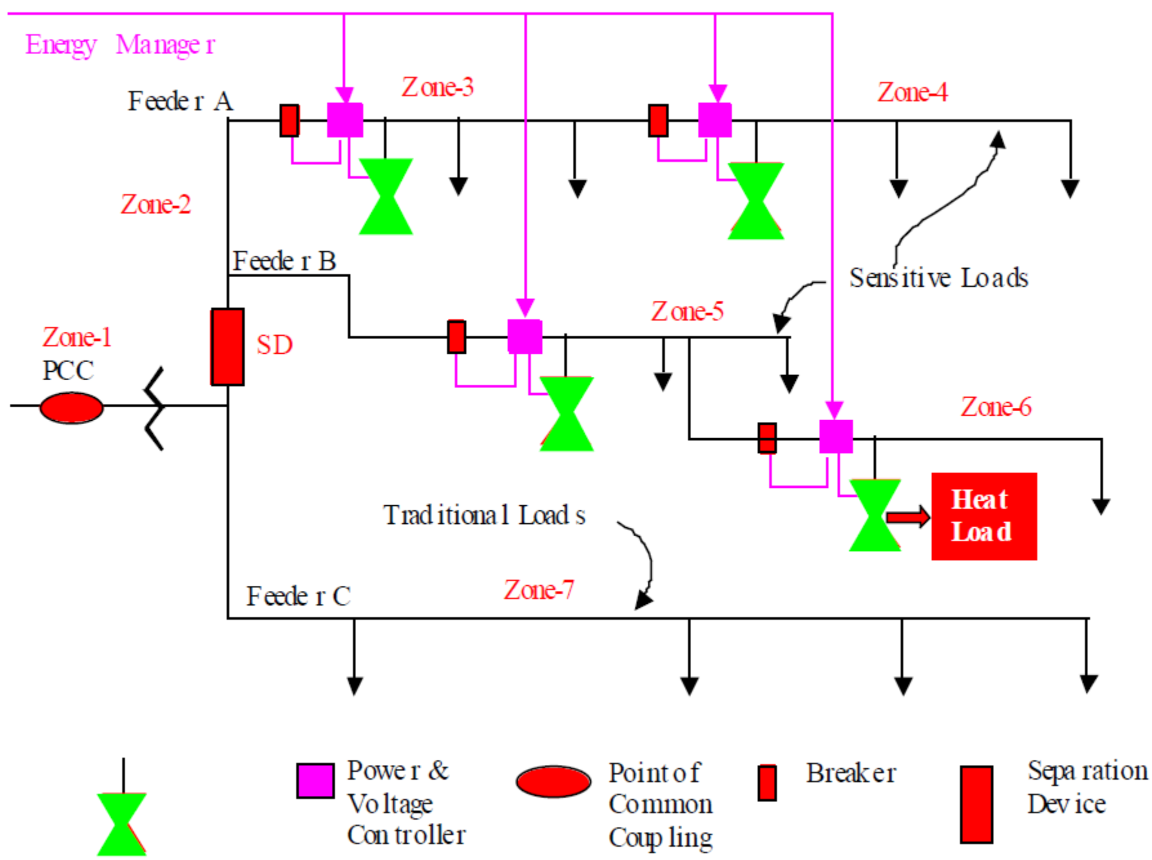
1. 9/8/2011 2:00 pm to 6:00 pm
2. 9/22/2011 2:00 pm to 6:00 pm

BIP Event Days in 2011

1. 3/11/2011 7:35 am to 8:00 pm
2. 9/7/2011 3:oo pm to 5:00 pm

CERTS Microgrid Architecture

To better visualize the presented concept, the CERTS microgrid architecture is shown in the graphic below and briefly described afterwards.



CERTS Microgrid Architecture[911]

The PCC on the very left hand side is the separation between the bulk power system[912] and the microgrid. At this interface[913] the microgrid needs to fulfill the relevant interconnection standards that apply to every electricity customer. Behind this point, the microgrid is structured into three feeders A, B, and C with different loads connected. Feeder A and B are where the different DER are connected. The DER[914] are connected to the circuits through power electronics and are voltage and power controlled. Each DER also has a breaker to ensure fast disconnection in case of fault. The power electronics of each DER operate the source in accordance to the set points that are provided by the Energy Manager, shown in magenta. This layout allows for easy plug-and-play installation of new DER on the feeder circuits. In this exemplary layout, Feeder A and B can be disconnected from the bulk energy system to protect sensitive loads in case of a disturbance on the macrogrid. In this case, the separation device would open and the power electronics of the DER would ensure voltage and power control within the islanded system.

[911] (Lasseter et al., 2002, p. 6)

[912] Also referred to in this report as „macrogrid“.

[913] More precisely at the transformer next to the PCC.

[914] Green double-triangular shape.

Non-critical loads on feeder C would still be connected to the bulk power system and ride through the disturbance.[915]

CERTS Power Electronics

The key element of the CERTS microgrid layout are the power electronics, control and communications capabilities that permit the system to work semiautonomous.[916] The power electronics at each DER need to ensure that islanding and reconnection to the macrogrid is possible, that reactive and active power can be controlled, that voltage sag and system imbalances can be managed, that the grid's load dynamics are met, and that existing DER can be modified and new DER installed without a change of the overall system. The key to the implementation of these goals under CERTS microgrid architecture is that each DER controller can react to changing states of the system without communication with other controls. The set points and desired characteristics are provided by the energy manager so that no further communication between the different microsources is needed.[917] To be able to fulfill these demands, the power electronics at each DER need to be upgraded beyond common inverter standards used with today's non-microgrid DER. The upgraded power electronics are then able to:[918]

- Control real and reactive power output
- Regulate voltage through droop
- Track changing load requirements very fast
- Manage frequency droop through power sharing

CERTS Microgrid Laboratory Test Bed

Until 2012 the only means of testing and ultimately proving the CERTS microgrid concept was a full-scale test facility near Columbus, Ohio. The test facility is shown in the picture below.

[915] This is only one exemplary representation of a layout. If the DER can supply the full demand of all loads, Feeder C could also be included in the islanding.

[916] (Lasseter et al., 2002, p. 2)

[917] (Ibidem, p. 11)

[918] This is just a summarized overview of the control functions provided and not meant to go into detail on the control strategies themselves, as that is not within the focus of this report. For details regarding the implementation of these control strategies please refer to (Lasseter et al., 2002, p. 11 ff.).

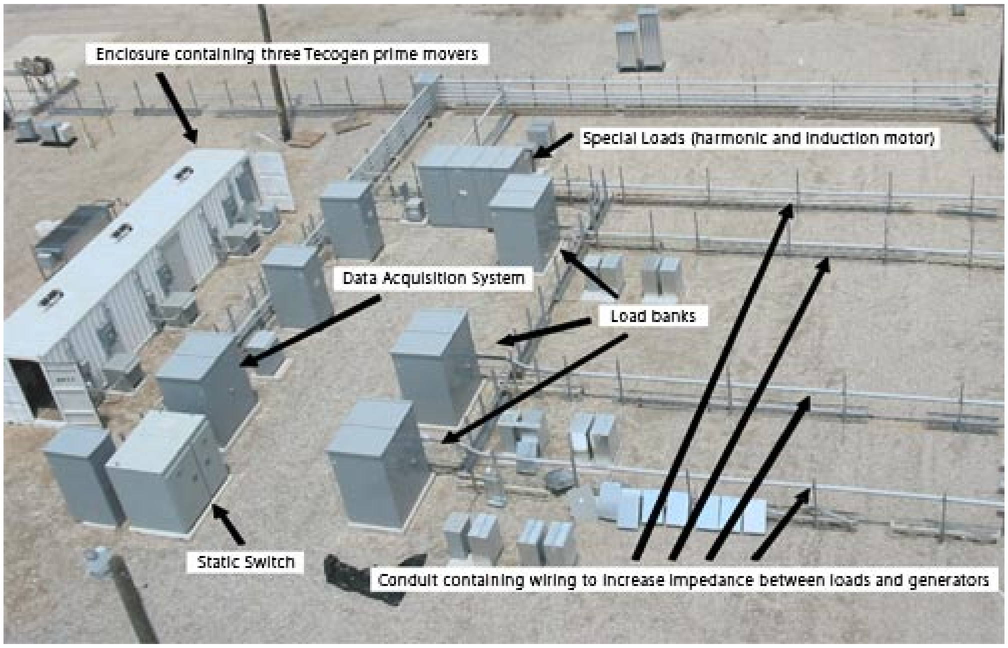


Figure 2: CERTS Test Bed Facility[919]

This facility was put into place to test the above-outlined concept of intelligent interaction of autonomous units and consists of three key features: the separation device[920], different DER and loads. Like the typical CERTS architecture[921] the test bed has three feeders. Each feeder has four load banks and three microsources connected to it. The load banks reach up to 90 kW and 45 kVAr and the biggest microsource is a natural gas prime mover with heat recovery. The DER are able to balance power using power-frequency controllers and can achieve local stability through local voltage control. In accordance with the CERTS concept the main distinction of this microgrid compared to other existing facilities is the lack of a master controller. Each DER sets its operating points based on locally measured voltage and current, depending on active local control scheme.[922]

Based on the findings from this test bed the first large-scale real-life application of the CERTS concept had its grand opening at Santa Rita Jail in California in March 2012[923] and, therefore, replaces the Columbus test bed as the most modern CERTS microgrid application. Santa Rita Jail and its microgrid will be described in detail in the next chapter.

919 http://certs.lbl.gov/images/certs-mgtb.jpg

920 This is in form of a static switch.

921 As presented above in CERTS Microgrid Architecture.

922 (Lasseter et al., 2011) quoted from (von Appen, J., 2011)

923 (U.S. Department of Energy, 2010, p. 12)

APPENDIX C
Section 4

Air condition chiller replacement

In a joint project with the installation of the PV rooftop arrays the old AC chiller was replaced with a new 850-ton high efficiency chiller. The key improvement of the new chiller was that due to more modern technologies it could respond to the cooling load in real-time while the old chiller had to be operated at constant full speed. In addition, the new chiller does not use chlorofluorocarbon (CFC) and therefore is less harmful to the ozone layer.[924, 925]

Lighting retrofits

The lighting retrofit was conducted in 2009 and 2010 and entailed the replacement of over 600 traditional high-pressure light fixtures outdoors and 822 indoor lights with induction lighting that is expected to consume 60 % less energy. Savings are estimated to be over 1 GWh per year resulting in almost $ 300,000 annual energy cost savings at current tariff rates. The retrofit was supported by a $ 300,000 fund from the U.S. DOE Energy Efficiency Conservation Block Program (EECBG)[926] as well as $ 200,000 county funds.[927]

Flat-mounted PV panels

Figure 3: Flat mounted PV at SRJ[928]

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[924] (County of Alameda, 2002)

[925] A separate view of costs and expected savings for chiller replacement is not available as the upgrade was seen as part of the PV array installation project.

[926] (California Energy Commission, 2012)

[927] (General Services Agency, 2012, p. 2)

[928] http://blogs.scientificamerican.com/plugged-in/files/2012/06/SRJ-on-site-generation_rooftopPV_small.jpg.

This horizontal flat mount is due to the roof construction of the jail that is not sturdy enough to hold tilted panels that need a proper fixing to be able to withstand wind pressure. Therefore, the panels have been mounted horizontally and fixed to ballast below.[929] The biggest disadvantage of a flat mount is the lower overall annual output. Though, the flat mount of the panels also delivers three distinct advantages compared to a tilted mounting system. First, the flat mount delivers the highest peak production during noon in summer in correlation with the highest cooling load that is a key load driver in California in general and at the jail in particular. The lower production in winter can be accepted due to the local climate requiring no cooling and little heating in winter.[930] In addition, the flat mount increases the expected life time of the roofs to 25 years and finally the panels, as well as their specific mounting system[931], increase the thermal insulation of the roof and thereby reduce the demand for air conditioning.[932] To enhance the insulation effect even further, roof areas not covered with panels were treated with special reflective painting that lowers the roof temperature by 50° Fahrenheit.[933]

Fuel cell operation principle

Without going into too much detail the basic operation principle of FC will be presented briefly. Even though there are many different types of FC, they can all be summarized under the definition that *"a fuel cell is an electrochemical 'device' that continuously converts chemical energy into electric energy (and some heat) for as long as fuel and oxidant are supplied."*[934] As most FC, the SRJ FC uses hydrogen as the basic fuel. The SRJ FC is a direct FC, meaning that it is supplied with natural gas from the gas grid and internally converts the natural gas into processable hydrogen. This part is called the fuel processor. After the fuel processing starts the core of a FC, the fuel cell stack, which produces direct current electricity. In the last process step the power conditioner converts the direct current into high quality alternating current.

The 1 MW DFC1500 FC consists of four separate stacks each containing many single cells, where the actual electrochemical reaction takes place. A cell consists of three components, the anode[935], the cathode[936] and the electrolyte in between. For power production, hydrogen is fed to the anode while oxygen[937] is delivered to the cathode. Depending on the type of FC the chemical process differs but the overall chemical reaction is always identical:

$$2H_2 + O_2 \rightarrow 2H_2O \text{ (steam) + electrons (electricity)}$$

[929] (Dierckxsens, C., 2009, p 9)

[930] (Dierckxsens, C., 2009, p 8)

[931] Powerlight's PowerGuard

[932] This is especially relevant in California with very high summer temperatures and a generally lower standard of building insulation compared to e.g. Germany.

[933] (County of Alameda, 2002, p. 7)

[934] (Hoogers, G., 2003) quoted from (de Celis Gutiérrez, A et al., 2012)

[935] Positive charge.

[936] Negative charge.

[937] The oxygen is extracted from the outside air in case of the SRJ fuel cell.

The free electrons from the process are being extracted by the direct current circuit applied to the cell and ultimately create the electricity output of the FC.[938] The steam is used in the heat recovery unit to preheat the domestic hot water.

[938] (de Celis Gutiérrez, A et al., 2012)

SRJ Grid Layout

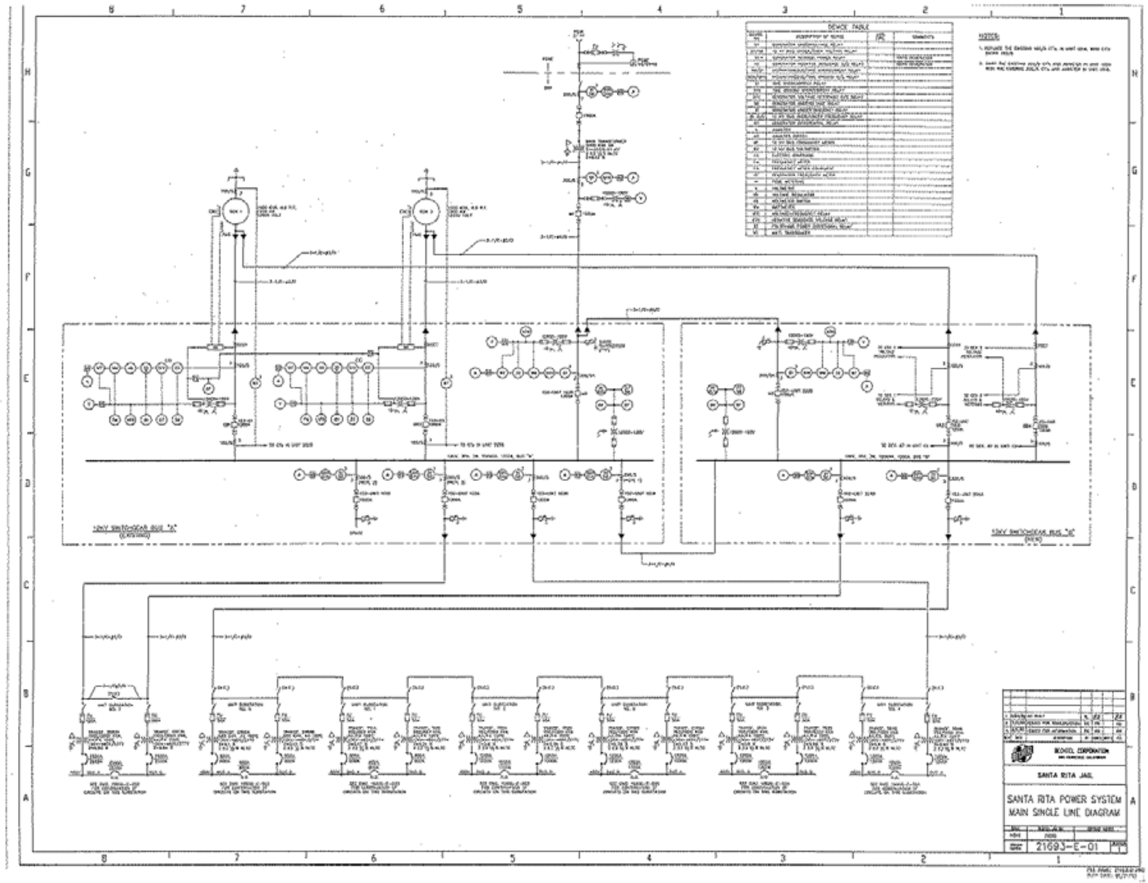

Figure 4: SRJ Main Single Line Diagram[939]

[939] Wiring Information provided by Alameda County

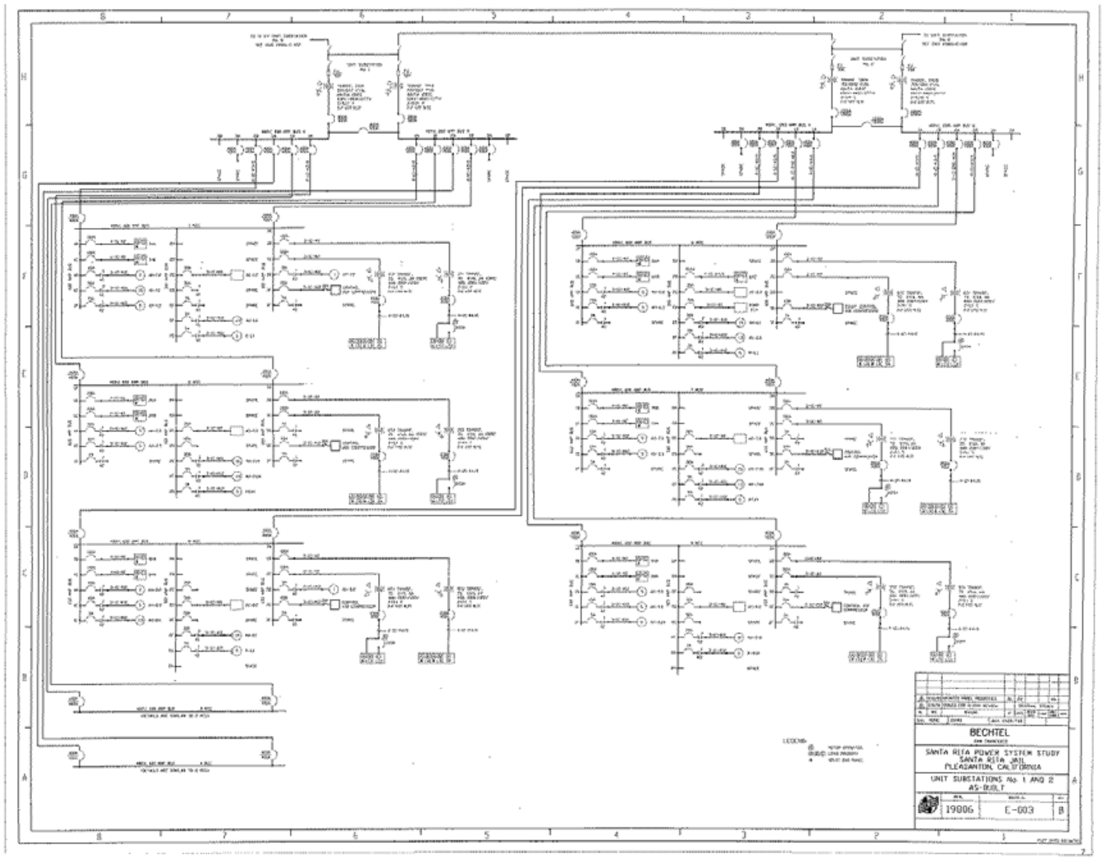

Figure 5: Single Line Diagram Substation 1 and 2[940]

Substation Details

Substation	Location	Feeding	Details	Back Feed
1	between HU1 and HU2	Main breaker 1mcc	HU1	
		main breaker 2mcc	HU2	
		main breaker 3mcc	HU3	
		main breaker 4mcc	HU4	
2	between HU1 and HU2	main breaker 9mcc	HU9	
		main breaker 6mcc	HU6	6kva wind turbines back feed
		main breaker 7mcc	HU7	
		main breaker 8mcc	HU8	
3		main breaker 25mcc	HU25	
		main breaker 23mcc	HU23	
		main breaker 24mcc	HU24	225kva solar array back feed
	between HU21 and HU22	main breaker 21mcc	HU21	
		main breaker 22mcc	HU22	

940 Wiring Information provided by Alameda County

4	between HU32 and HU33	main breaker 35mcc	HU35	225kva solar array back feed
		main breaker 33mcc	HU33	
		main breaker 34 mcc	HU34	
		main breaker 32mcc	HU32	225kva solar array back feed
		main breaker 31mcc	HU31	
6	facility core	main breaker CMCC6A	core	
		main breaker CMCC6B	core (outside , chapel)	
		Main Breaker CMCC6C	core	
		main breaker CPLC	core (infirmary)	
		Main breaker CPHB	core (records, x-ray)	
		Main Breaker CPLB	core (security, infirmary, dining)	
		Main breaker CPLA	core (visitor, records	
		Main breaker CPHA	core, mail tube, clothing conveyor	
		Main Breaker CPHC	core	
7	service building	SPH7C	exhaust fans, Air conditioning	
		SMCC7B	miscellaneous service	
		SPH7A	Kitchen	
		SMCC7A	exhaust fans, Air conditioning	
		SPH7B	compressors	
		SPL7B	kitchen, AGV platform	
		SPL7A	food carts	
8	service building	SPH8B	Guard house, laundry, electric shop	
		SPL8B	Print, carpenter, paint shop, metal, combined, electrical , laundry shop	
		SPH8A	Fans	
		SPL8A	Firehouse, Warehouse	

Table 9: Details on substations[941]

[941] Own analysis based on panel schedule and wiring information provided by Alameda County

Microgrid Costs and Funding

The information on the total costs of the microgrid implementation vary slightly by source[942], but all sources consistently state total costs of about $ 12,000,000. As the microgrid is a demonstration project at the forefront of the better integration of renewable energy sources, significant funding could be obtained by Alameda County to support the project:[943]

- DOE Grant:	$ 6,900,000
- CEC Grant:	$ 2,000,000
- PG&E Incentives:	$ 2,500,000
- Chevron Energy Share:	$ 200,000
- Alameda County Share:	$ 100,000

Due to the demonstration and research character of the project, no estimates on saving potentials or break-even estimates are communicated to the public. Most of the goals of the project do not have a direct monetary benefit for the operator of the jail. The demonstration of the CERTS protocol is the best example for this type of goal. Other goals outlined above, such as the reliable 24/7 power supply to the jails operations, can theoretically be monetarized but in reality this evaluation is very difficult as the costs of an outage in the jail are not as precisely determinable as in a production facility.

Nevertheless, the goal of electricity price arbitrage as well as the participation in DR programs will drive some savings. Although these savings will not pay off the project costs in a reasonable time span, it is the purpose of this report to determine these savings and to establish which DR programs are best suited for microgrid participation. Based on the analysis of these savings, future projects can be calculated more accurately and utilities might get some helpful insights on what incentive structures might foster the installation of microgrids in general and electric storage on the demand side specifically.

[942] Compare (General Services Agency, 2012) and (Alegria, E., 2012, p. 12).

[943] All figures based on (General Services Agency, 2012) and (Alegria, E., 2012, p. 12).

APPENDIX D

Section 5

History of BES and current applications

BES has been a topic in the research community since the 1960s and became even more relevant during the energy crisis of the 1970s. However, due to the limitations in computation power, the programs available have not been very user friendly and modeling a single building took some significant time and expert knowledge to be conducted properly. However, the increase in computational power and the rise in environmental awareness since the late 1990s have given the topic of BES a new push. BES more and more leaves the research-only area and is – in all sorts and forms – adopted by practitioners.[944] Architects as well as building engineers can use BES at all stages of the life cycle of a building. During the early planning phase, BES can be used to evaluate general layout decisions as basic as the building orientation. Moving on in the planning process, different building materials and HVAC systems can be simulated to evaluate their effect on the total building energy consumption. Even after the construction of the building BES can be leveraged to allow for the evaluation of energy efficiency measures.[945] If no detailed measurement of internal loads of a building is available, BES can also help to get a better understanding of the different load drivers of a building without installing expensive measurement equipment and conducting expensive and time-consuming, perhaps even year-round, measurements.[946] Hong et al. group the application of BES into seven categories[947]:

1. Building heating/ cooling load calculations
2. Energy performance analysis for design and retrofitting
3. Building energy management and control system design
4. Compliance with building regulations, codes and standards
5. Cost analysis
6. Passive energy saving options study
7. Computations fluid dynamics analysis

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[944] (Tiazhen Hong, S.K., Chou, T.Y. and Bong, 2000, (p. 3)

[945] (Tiazhen Hong, S.K., Chou, T.Y. and Bong, 2000, (p. 1)

[946] This is what the BES is used for in this project.

[947] (Tiazhen Hong, S.K., Chou, T.Y. and Bong, 2000, (p. 3)

The vast amount of programs available to perform different BES-related task can be grouped into two general categories. First, design tools operate on a more general level and support the early stages of the building life cycle while less detailed information is available. These programs are mostly easy to use and provide rough estimates based on limited input data. For a more thorough analysis, the second category of design tools is used, namely detailed simulation programs. These detailed simulation programs require a significant amount of detailed input and use computational methodologies such as finite difference, finite element, state space and transfer functions to calculate building load and energy.[948]

Overview of Data Manipulations to create consistent data base for SRJ load and generation data

2003_15min	**Data from all billing cycles involving 2003**			
	dates	2002-12-20	-	2004-01-20
	bills	2003 - 1	-	2004 - 1
	timestep		15 minutes	
	content	PG&E		PV
	rows	35040 data sets in 2003		
	Watch out	No real billing information. Created artificial billing cycles from segmentation of raw input data		
		4 time-stamps not consecutive --> corrected and marked in light blue		
		Average Power Generated missing in 5760 data sets --> corrected with PV Power Generated and marked in blue		
		Average PV power was calculated as non-rolling 30-min-average **PV Power Generated** in 15094 sets --> corrected and marked in purple		
		Data missing for PG&E Energy for 1 dataset --> corrected with average of prior and next set and marked in dark blue		
		Average PG&E Demand was calculated as non-rolling 30-min-average **PG&E Energy** in all datasets --> corrected with Demand=4*Energy and marked in purple		

2004_15min	**Data from all billing cycles involving 2004**			
	dates	2003-12-19	-	2005-01-18
	bills	2004 - 1	-	2005 - 1
	timestep		15 minutes	
	content	PG&E		PV
	rows	35135 data sets in 2004 (leap year)		
	Watch out	No real billing information. Created artificial billing cycles from segmentation of raw input data		
		Average PV power was calculated as non-rolling 30-min-average **PV Power Generated** in 16344 sets --> corrected and marked in purple		
		Data missing for PG&E Energy from 5/20-6/22 (3167 data sets) --> marked in blue		
		Average PG&E Demand was calculated as non-rolling 30-min-average **PG&E Energy** in all datasets --> corrected with Demand=4*Energy and marked in purple		
		Total demand <=100 in 1754 data sets (missing PG&E data and some values in 1-6) --> marked in dark blue		
		Daylight saving time considered incorrectly. Change dates 04-04(not considered) and 10-31(not considered)		

[948] (Tiazhen Hong, S.K., Chou, T.Y. and Bong, 2000, p. 4)

2005_15min	Data from all billing cycles involving 2005			
	dates	2004-12-21	-	2006-01-19
	bills	2005 - 1	-	2006 - 1
	timestep		15 minutes	
	content	PG&E		PV
	rows	34168 data sets in 2005		
	Watch out	No real billing information. Created artificial billing cycles from segmentation of raw input data		
		Average PV power was calculated as non-rolling 30-min-average **PV Power Generated** in 16456 sets --> corrected and marked in purple		
		Average PG&E Demand was calculated as non-rolling 30-min-average **PG&E Energy** in all datasets --> corrected with Demand=4*Energy and marked in purple		
		PV 288 data sets in January with wrong data (2004 instead of 2005)--> corrected		
		FC 384 data sets with wrong/ doubled dates for 5-17, 10-6, 10-7, 10-8, 10-30, 11-21, 12-13, 12-16 --> corrected		

2006_15min	Data from all billing cycles involving 2006			
	dates	2005-12-20	-	2007-01-19
	bills	2006 - 1	-	2007 - 1
	timestep		15 minutes	
	content	PG&E	FC	PV
	rows	33788 data sets in 2006		
	Watch out	No real billing information. Created artificial billing cycles from segmentation of raw input data		
		Average Power Generated missing in 5760 data sets --> corrected with PV Power Generated and marked in blue		
		Average PV power was calculated as non-rolling 30-min-average **PV Power Generated** in 16269 sets --> corrected and marked in purple		
		Average PG&E Demand was calculated as non-rolling 30-min-average **PG&E Energy** in all datasets --> corrected with Demand=4*Energy and marked in purple		
		Daylight saving time considered incorrectly. Change dates 04-02 (considered) and 10-29 (not considered).		

2007_15min	Data from all billing cycles involving 2007			
	dates	2006-12-19	-	2008-01-16
	bills	188	-	200
	timestep		15 minutes	
	content	PG&E		PV
	rows	35040 data sets in 2003		
	Watch out	**Average PV power** was calculated as non-rolling 30-min-average **PV Power Generated** in 112 sets --> corrected and marked in purple		
		PV power and **Average PV power** off by factor 4 (kWh vs kW in 15 min steps) in 3112 sets --> marked in light blue		
		Average FC Power Generated was calculated as non-rolling 30-min-average **FC Power Generated** in 176 datasets --> corrected and marked in purple		
		PG&E energy and **PG&E average** demand off by factor 4 (kWh vs kW in 15 min steps) in 8832 data sets --> marked in blue		
		FC data for 02-07 16:15 to 02-08 20:00 is missing (was filled in by using 02-08 20:15 to 02-09 23:30 twice) --> Wrong data set to 0 for 02-07 16:15 to 02-08 20:00		
		Daylight saving time not considered correctly. All data in standard time. Corrected for non-aligned FC data in spring time change! --> marked in dark blue		
		Total demand is negative in 11 data sets --> marked in dark blue		

2008_15min	Data from all billing cycles involving 2008			
	dates	2007-12-18	-	2009-01-14
	bills	200	-	212
	timestep		15 minutes	
	content	PG&E	FC	PV
	rows	35136 data sets in 2008 (leap year)		
	Watch out	**PG&E energy** and **PG&E average** 0 in 617 data sets (39 data sets coincide with 0 **Total demand**) --> marked in light blue		
		Total demand is zero or negative in 194 data sets --> marked in dark blue		
		No switch to daylight saving time. Measurement all year long in standard time?! (Switching dates 2008 03-09 and 11-02)		
		Timestamp on FC and PG&E missing for 06-16 --> corrected		

2009_15min	Data from all billing cycles involving 2009			
	dates	2008-12-16	-	2010-01-14
	bills	212	-	224
	timestep		15 minutes	
	content	PG&E	FC	PV
	rows	35040 data sets in 2009		
	Watch out	No switch to daylight saving time, therefore missing data for one hour in spring switch (03-08) and no "double hour" in autumn (11-01) --> missing datamarked light blue		
		Total demand is zero or negative in 14 data sets --> marked in dark blue		

2010_15min	Data from all billing cycles involving 2010			
	dates	2009-12-16	-	2010-12-31
	bills	224	-	235
	timestep		15 minutes	
	content	PG&E	FC	PV
	rows	35040 data sets in 2010		
	Watch out	December data not complete. Missing first 2011 bill --> corrected		
		FC power and **Average FC power** off for two separate data sets --> marked in blue		
		Average FC power and FC power negative in 8462 data sets --> Migth be correct data for FC outages!		
		Average FC power zero in 11 data sets. 4 of those sets have values for **FC power** (03-07) --> filled in and marked in dark blue		
		PG&E energy and **PG&E average** slightly off in 1 data set --> marked in light blue		
		PG&E average zero in 8 data sets. 4 of those sets have values for **PG&E energy** (03-07) --> filled in and marked in dark blue		
		No switch to daylight saving time. Measurement all year long in standard time?! (Switching dates 2010 03-14 and 11-07)		
		Time stamp corrupted in 14499 data sets --> corrected		
		Time stamps corrupted in second half of december for PV and PG&E datasets (2880 data sets) --> corrected		
		Total demand is zero or negative in 16 data sets --> marked in dark blue		

2011_15min	**Data from all billing cycles involving 2011**			
	dates	2011-01-01	-	2011-01-31
	bills	no billing data available		
	timestep		15 minutes	
	content	PG&E	FC	PV
	rows	35040 data sets in 2011		
	Watch out	All timesteps corrupted --> corrected with 2009 data		
		No switch to daylight saving time. Measurement all year long in standard time?! (Switching dates 2010 03-11 and 11-04)		
		PV power and **Average PV power** off by factor 4 (kWh vs kW in 15 min steps) in 16536 sets --> marked in light blue		
		No information on **FC power**		
		No information on **PG&E energy**		
		PG&E average 0 in 274 data sets (246 data sets coincide with 0 **Total demand**) --> marked in light blue		
		Total demand is zero in 251 data sets --> marked in dark blue		
		No billing cycle information available!		

Discussion of PV underperformance based on daily power output

The graph below shows the day with the highest power value[949], the day with the highest energy output[950] and the day with the lowest energy output[951] in 2011. It can be seen that the highest power production in 2011 is 607 kWp, which is only about half of the 1.2 MWp rating of the PV installation.

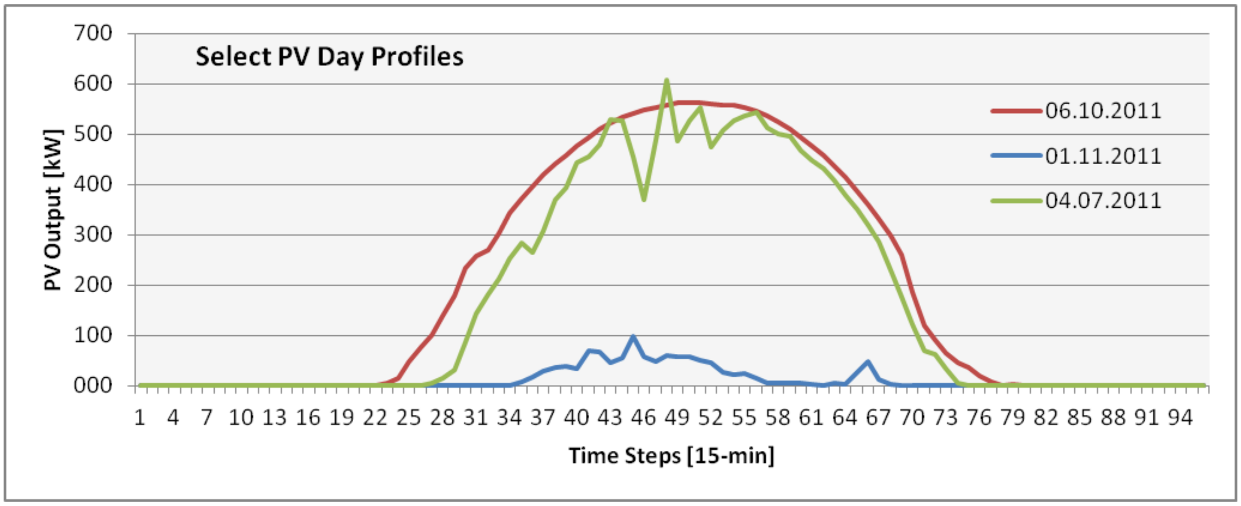

Figure 6: Select PV Day Profiles

Apart from the maximum value, the graph above shows important characteristics of PV that need to be considered and will also be relevant for the following analysis. The day with the highest total energy output in 2011, 10th of June, shows an almost perfect inverted parable indicating a full day blue-bird sky with no technical issues. However, this is not the standard scenario to be expected – even in California. The day with the highest power output peak, 7th of April, shows a more jagged profile.[952] This profile shows that the sun was covered by clouds before noon, resulting in a decreased output. When the sun comes out from behind the clouds, the load peaks and generates higher electricity than during an all sunny day. This is due to two effects that are detailed below.[953]

The third line in the graph represents the power output during 11th of January, the day with the lowest daily energy output in 2011.[954] On this day the output only reached 100 kW during mid day and showed another small peak in the afternoon. The shape of this exemplary load curve is not to be considered a typical daily load shape but it shows that, during winter, the generation curve is significantly flatter and more effected by the specific day's weather i.e. cloud coverage. In addition, it is to be considered that the peak of the PV output varies by the factor six between maximum and minimum output days.

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949 Represented by green line graph.

950 Represented by red line graph.

951 Represented by blue line graph.

952 This would also be more typical for a middle European PV profile.

953 See below.

954 Three days have actually zero output but that is due to inconsistencies in the data set that could not be corrected.

Effects of Cloud Coverage on PV output

Increased PV output after cloud coverage is due to two effects. First, during the cloud coverage the temperature of the PV elements decreases and, thus, the output is higher shortly after the sun comes out again. The increase in output when the cloud coverage ends is due to the fact that PV arrays have a negative temperature coefficient and cooled down during the covered period. The second effect is related to the breaking of the sun light at the edge of the clouds. This may cause the direct sunlight, as well as some diffused, redirected sunlight from the edges of the cloud, to hit the arrays and therefore results in a higher total output.[955]

Monthly FC Net Benefits

The analysis of the net benefit by month is shown below.[956]

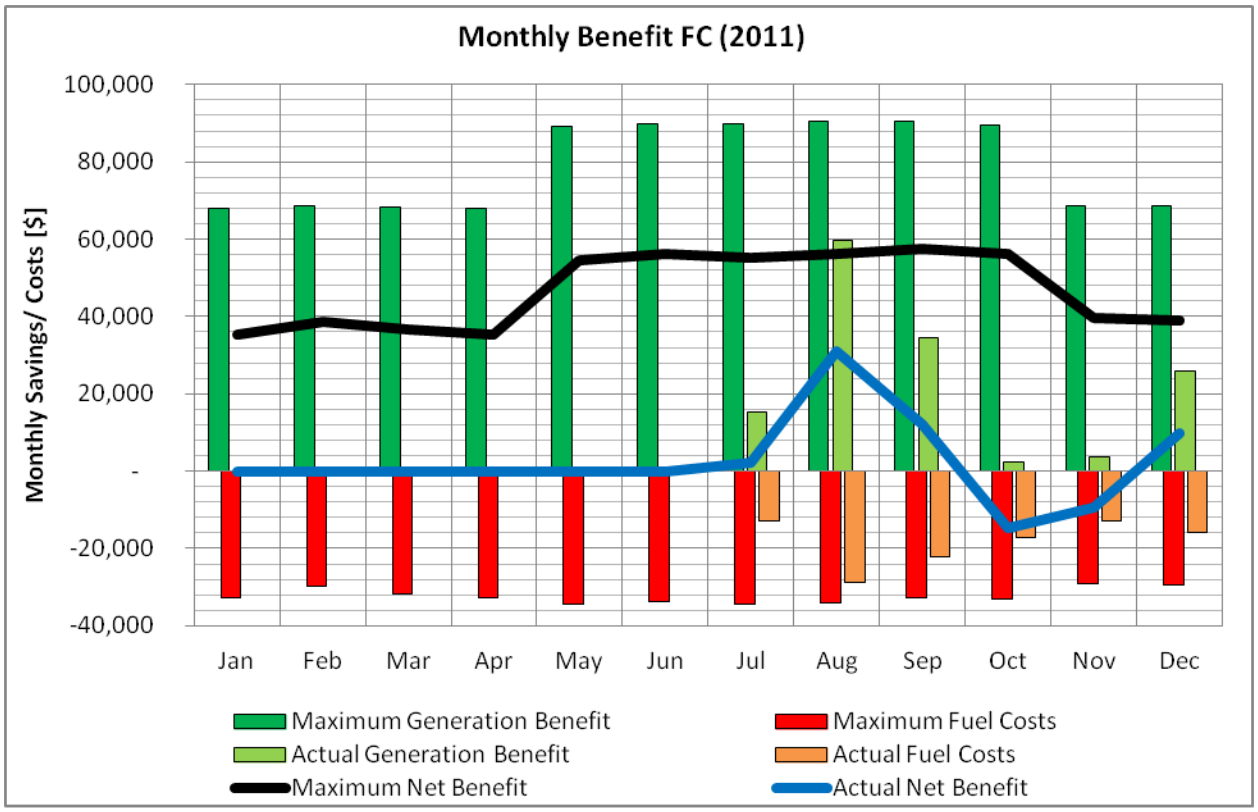

Figure 7: Monthly Benefit FC (2011)[957]

The dark green bars indicate the maximum generation benefit the FC could deliver, if functioning as expected. The red bars show the costs of natural gas that would be caused in that case, while the black line is the differential of those two and shows the potential net benefit of the FC for each month. In winter months, this would be almost $ 40,000 and during summer months just shy of $ 60,000. These kinds of savings, however, were never realized at SRJ. The

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[955] (Wirth, G., 2012)

[956] The analysis was conducted using the O_DER-CAM optimization tool which will be introduced in section 6.

[957] Own analysis using O-DER-CAM (See section 6) based on billing and load data provided by Alameda County. The underlying data is provided in the included data CD.

light green bars indicate the actual electricity output of the FC and the orange bars the natural gas that was consumed to do so. The blue line is the differential between those two and shows the net benefit. Obviously, during the first months no net benefit was generated while July, August, September and December show some savings, still far from the maximum savings potential. During October and November the performance of the FC was so bad that it actually caused operating costs due to its gas consumption with almost no electricity output.[958]

DOE-2 Program Description

DOE-2 is a dynamic simulation tool and uses the transfer function method to calculate heat gains and cooling loads under the assumption of a constant indoor air temperature. In a second step the program calculates heat extraction rates of the equipment. By doing so, DOE-2 is able to determine the plant and system energy requirements for every hour of a simulated year.[959] DOE-2 does so by predicting the hourly energy use and cost, based on weather information, building geometry and the HVAC system specifications as well as the utility rate structure. Internally, DOE-2 makes use of one subprogram that translates the input in the Building Description Language (BDL) into computer-readable code and four following subprograms that deal with loads, systems, plants and the economics. These later four subprograms are executed sequentially while report outs are created at each stage.[960] The overall program structure is shown below:

[958] This analysis was conducted with the DER-CAM tool simulating a perfectly working FC and the actual FC performance. The benefits given are based on 2011 tariffs for electricity and gas. The generation benefits include demand as well as energy charges. Actual fuel costs are based on natural gas billing information and the maximum fuel costs have been extrapolated based on the natural gas prices of the respective month and the maximum potential electricity production.

[959] (Drury, B et al., 2008, p. 7)

[960] (Tiazhen Hong, S.K., Chou, T.Y. and Bong, 2000, p. 3)

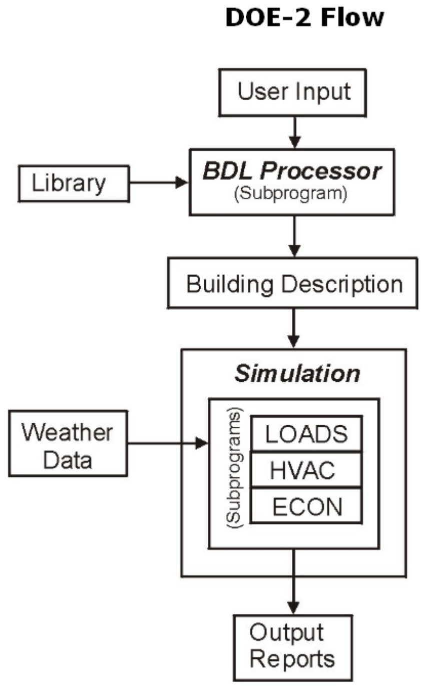


Figure 8: DOE-2 Program Flow[961]

DOE-2 is developed in Fortran programming language and the input needs to be specified in ASCII text files. However, the input subprogram is supported by libraries. These libraries contain descriptions and specifications for all sorts of building materials for walls and windows as well as specifications of HVAC equipment. Once the detailed description is translated into machine-readable code by the BDL processor, the response factors for the transient heat flow in walls are calculated. Furthermore, the processor calculates weighting factors for the thermal response of building spaces before the four afore-mentioned subprograms *Loads*, *Systems*, *Plants*, and *Econ* are executed. In this graphical representation, the subprograms *Systems* and *Plants* are summarized under the *HVAC* label. In the following, a short description of each subprogram is given:[962]

Loads

This subprogram calculates the hourly heating and cooling loads for each space in the building, assuming a constant temperature. To be able to do so, the load program leverages detailed weather information, including solar irradiance information, occupancy as well as operating schedules of heat generating equipment such as machinery and lighting. Also, the heat transfers through interior and exterior walls and the roof are considered in this subprogram.

HVAC

Under *HVAC* the two subprograms S*ystems* and *Pl*ants are grouped together. While *Systems* handles secondary systems such as fans and coils, *Plants* handles primary systems such as

[961] (DOE Energy Storage Database, 2005, p. 2)

[962] (DOE Energy Storage Database, 2005, p. 3)

boilers, chillers and storage tanks. First, the subprogram *Systems* is run to determine, which air flow and coil loads are necessary to maintain the previously determined temperature set points. Second, the *Plants* subprogram bases on this information and calculates how boilers and chillers need to be operated to supply the previously determined coil loads. The output of the *Plants* subprogram is the information on fuel and electricity consumption of the primary equipment installed in the building.

ECON

Finally, the fuel and electricity demand is run through the *Econ* subprogram to determine the related costs. *Econ* also provides information on potential cost savings that can be tapped by conducting energy efficiency measures.

Apart from these subprograms and the building description, the weather data has been mentioned and it must be stressed how important this input is and what level of detail is required. The weather information goes far beyond basic hourly temperatures observed and includes humidity information, cloud coverage, solar radiation, wind speeds etc.[963]

eQuest Wizards

In this part of the appendix a short description of the eQuest Schematic Design Wizard, the Design Development Wizard, and the Energy-Efficiency Measures Wizard is given.

Schematic Design Wizard:

This wizard is used to support the start of a new building project and takes the user through the steps of describing the general building layout and the relevant equipment. This information is requested from the user, starting off with very general information and drilling deeper and deeper into detail. One of the first input screens, helping determine the building footprint from a list of example footprints that can then be scaled and adapted, is presented below.

[963] (DOE Energy Storage Database, 2005 p. (4))

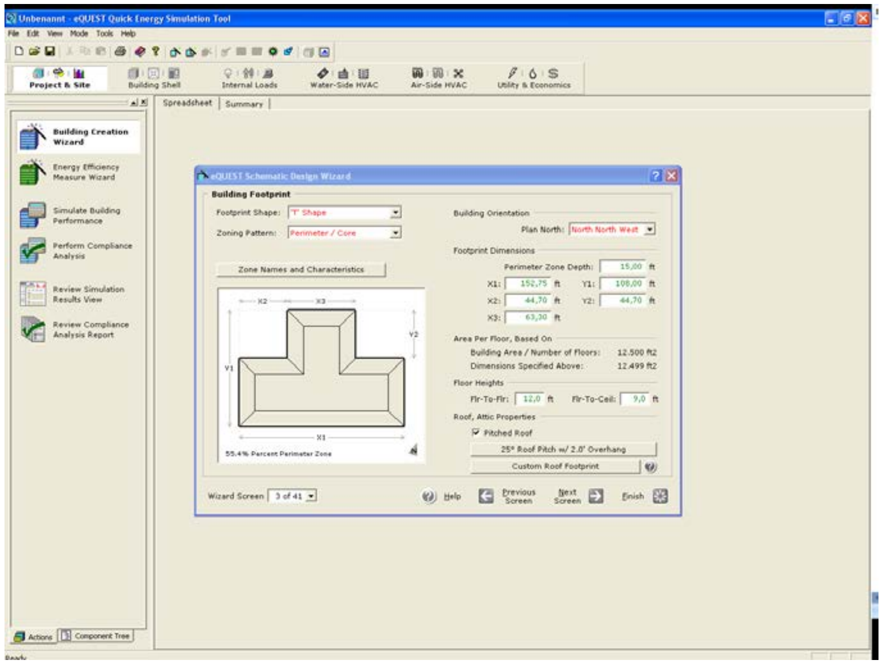


Figure 9: Sample Input Screen from Schematic Design Wizard

From one input screen to the next, "intelligent defaults" offer advice and help. Based on previous, more general input, eQuest adapts the defaults of all following input parameters. The user can then decide whether he wants to adapt these given defaults or go with the suggested industry standard. With adapting dynamic defaults, the user also has the option to finish the modeling process once he feels he has reached the level of detail needed to answer his specific questions.

Design Development Wizard

Usually, after completion of the Schematic Design Wizard, the Design Development Wizard can be used for an even more specific design definition. More detailed information can be entered and the available drop-downs are more specific. For very large or multi building facilities with complex loads and sophisticated HVAC systems, the Design Development Wizard can also be used to start the development of the model right away. This approach requires more detailed user knowledge and experience in the BES field as well as more specific information on the building itself and its systems. Once the Design Development Wizard was used, the user cannot go back to the simpler Schematic Design Wizard without losing information. The Design Development Wizard is also supported by the previously mentioned "intelligent defaults" for all its inputs.

Energy-Efficiency Measures Wizard

Once a building description is complete at the level of detail needed for the specific purpose, the Energy-Efficiency Measures Wizard can be used to determine options for energy-efficiency improvements. eQuest allows the user to select from a predefined list or to self-determine nine design alternatives with regards to energy efficiency and simulate these alternatives in parametric runs. Results can be displayed in an integrated way to ease comparison.

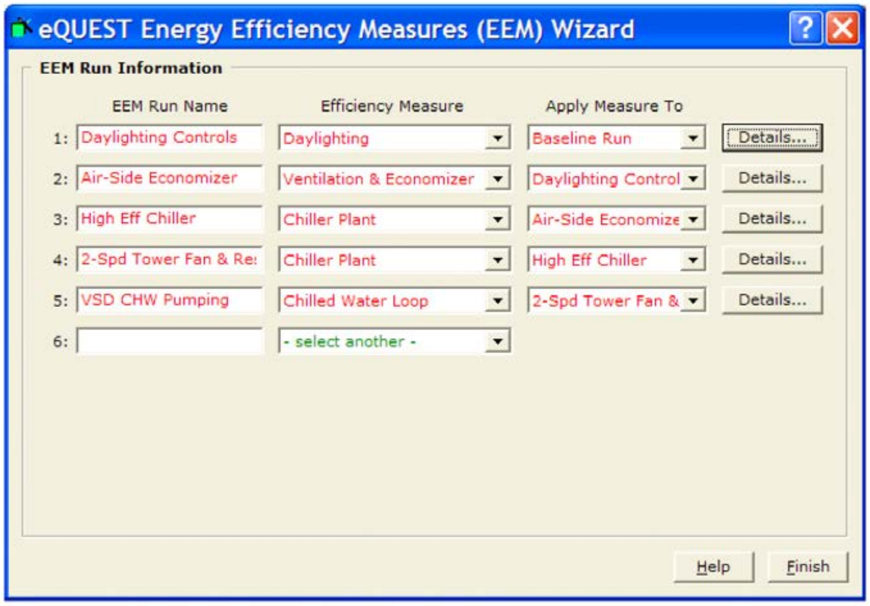


Figure 10: Energy Efficiency Measures Wizard Input Screen[964]

The energy efficiency measures that can be evaluated are extensive and the screenshot above only shows some examples of what could be evaluated using this wizard.

Apart from these wizards, the usability of eQuest and, thereby, of DOE-2 is enhanced by a 2-D and 3-D graphical representation of the building, a graphical representation of the installed HVAC systems and its interconnections and graphical representation of the simulation results.

Replacing TMY2 weather data with 2011 specific weather data in eQuest

A TMY is a detailed set of weather information on an hourly basis that includes temperatures, solar radiation, cloud coverage as well as much more detailed information for a period of one year. Instead of providing information for one specific year, a TMY is composed from months selected from different years, which then form a typical year. If a TMY is generated for a 20-year period, the 20 Januaries in this period are compared for the five elements of global horizontal radiation, direct normal radiation, dry bulb temperature, dew point temperature and wind speed. The most typical January is picked to represent the month of January in the TMY. This process is then conducted for each month and each station that TMY is provided for. TMY weather information is intended to be used for comparison of energy building performance on average and cannot be used to design buildings as it does not cover extreme weather conditions.[965] This characteristic of the TMY is what might cause the changing alignment of the eQuest model to actual 2011 consumption.

The SRJ eQuest model uses TMY2. TMY2 is the second set of TMY information that was composed and provided by the National Solar Radiation Data Base. It is composed of weather information for the years 1961 to 1990.[966] A small improvement could now be achieved by using

[964] (Department of Energy (2009, p.5)

[965] (Renewable Resource Data Center, 2010)

[966] (National Renewable Energy Laboratory, 2009a)

the most current TMY3 data set that covers the years 1991 to 2005 and also includes 800 more locations and, therefore, can - geographically - be more accurate. While TMY2 data is only available for San Francisco, TMY3 information is available for the Livermore Municipal Airport that is basically adjacent to the jail facility.[967]

Using TMY3 weather information, a slight improvement of model alignment could be achieved but the significant difference in model fit between summer and winter season was still evident. Therefore, in a next step to achieve a better alignment of the load shapes of model and actual 2011 consumption, actual 2011 weather information will be used.

Due to budget restrictions, only free-of-charge available weather information could be used in this effort. The most detailed, free weather information for 2011 for the Livermore Municipal Airport is provided by the Weather Underground.[968] While the download of a full data set for 2011 had to be paid for, the download of daily data sets was available for free. After completing the needed 365 downloads and cleaning the obtained data[969], a good set of weather information was obtained, including hourly information on temperature, dew point, humidity, pressure, visibility, wind direction, wind speed, gust speed, precipitation and relevant weather events.

However, this weather information cannot be directly entered in eQuest or its input file, as eQuest is designed to work with TMY information mostly and the weather input file for eQuest is binary. It is possible, though, to edit a TMY-like formatted weather file with the 2011 data, then convert it to an Energy Plus Weather file using the Energy Plus Unit and Weather Conversion Tool and finally convert it to eQuest input format using the eQuest EPW Conversion Manager.[970] This process caused the problem that the available information only specifies ten weather characteristics for every hour while the TMY3 dataset covers 68 columns for each hour. It was therefore decided to use the TMY3 dataset for Livermore Municipal Airport and enhance the data with the actual information from 2011, where available, in order to get as close to the actual weather behavior in 2011 as potentially possible. Replacing the existing 2011 information in the TMY3 data set initially caused an issue in the first conversion to Energy Plus format as the Energy Plus Unit and Weather Conversion conducts causality cross-checks for the weather information. The only stand-alone information that could be used without hindering the conversion was the temperature information. Luckily, this information was also considered the most relevant driver for the cooling load of the jail.[971] Therefore, the 2011 temperature information from Weather Underground was pasted into the TMY3 dataset for Livermore Airport, then converted to Energy Plus weather file format and subsequently translated to binary eQuest weather input format.[972]

[967] (National Renewable Energy Laboratory, 2009b)

[968] www.wunderground.com. A private company that offers free of charge as well as paid weather service. It was founded in 1991 and is part of the Weather Channel Corporation since 2012.

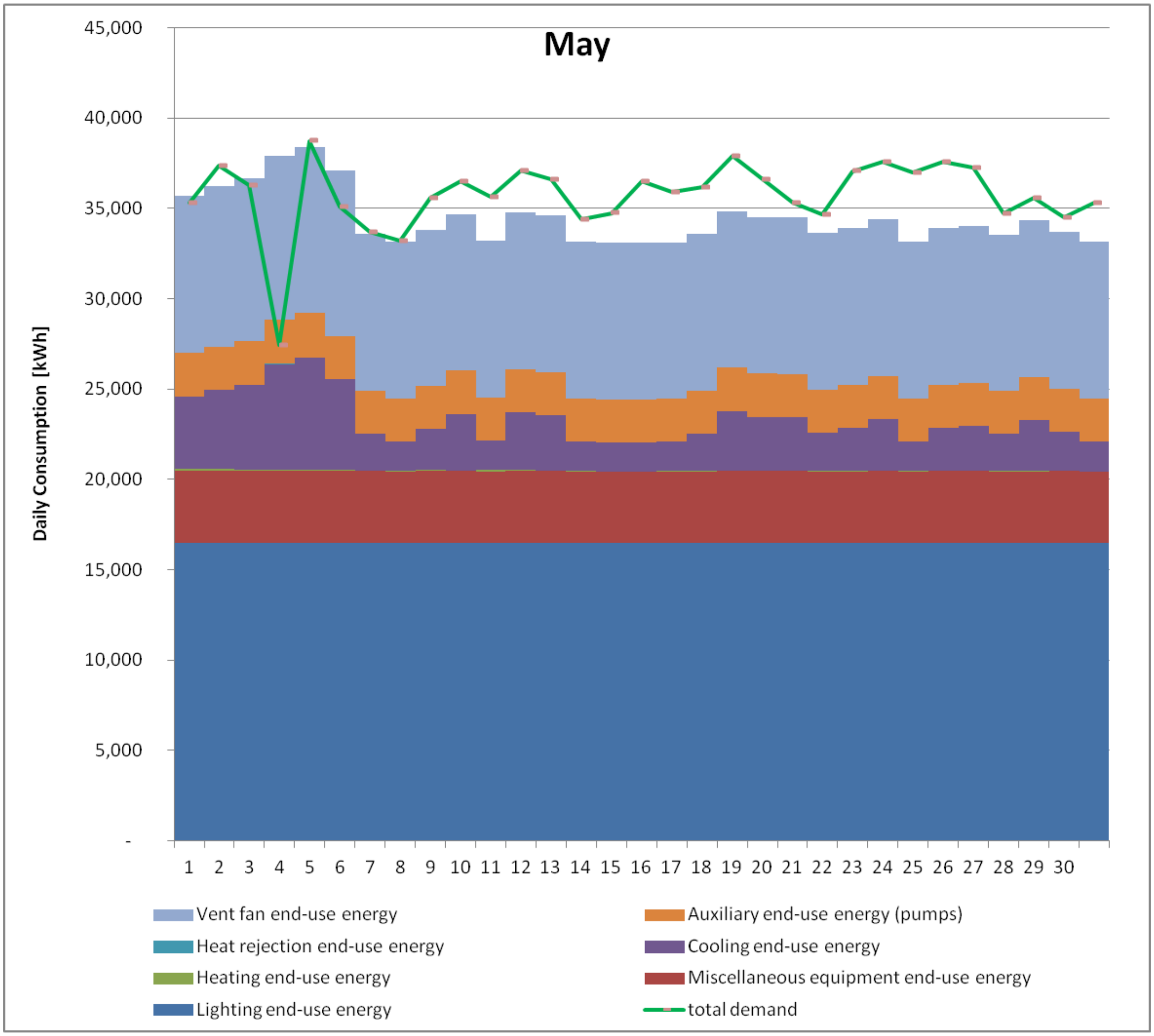
[969] Weather Underground did not provide information at consistent hourly timestamps but at changing time stamps and sometimes had multiple measurements for a single hour etc. and therefore significant data cleaning was conducted.

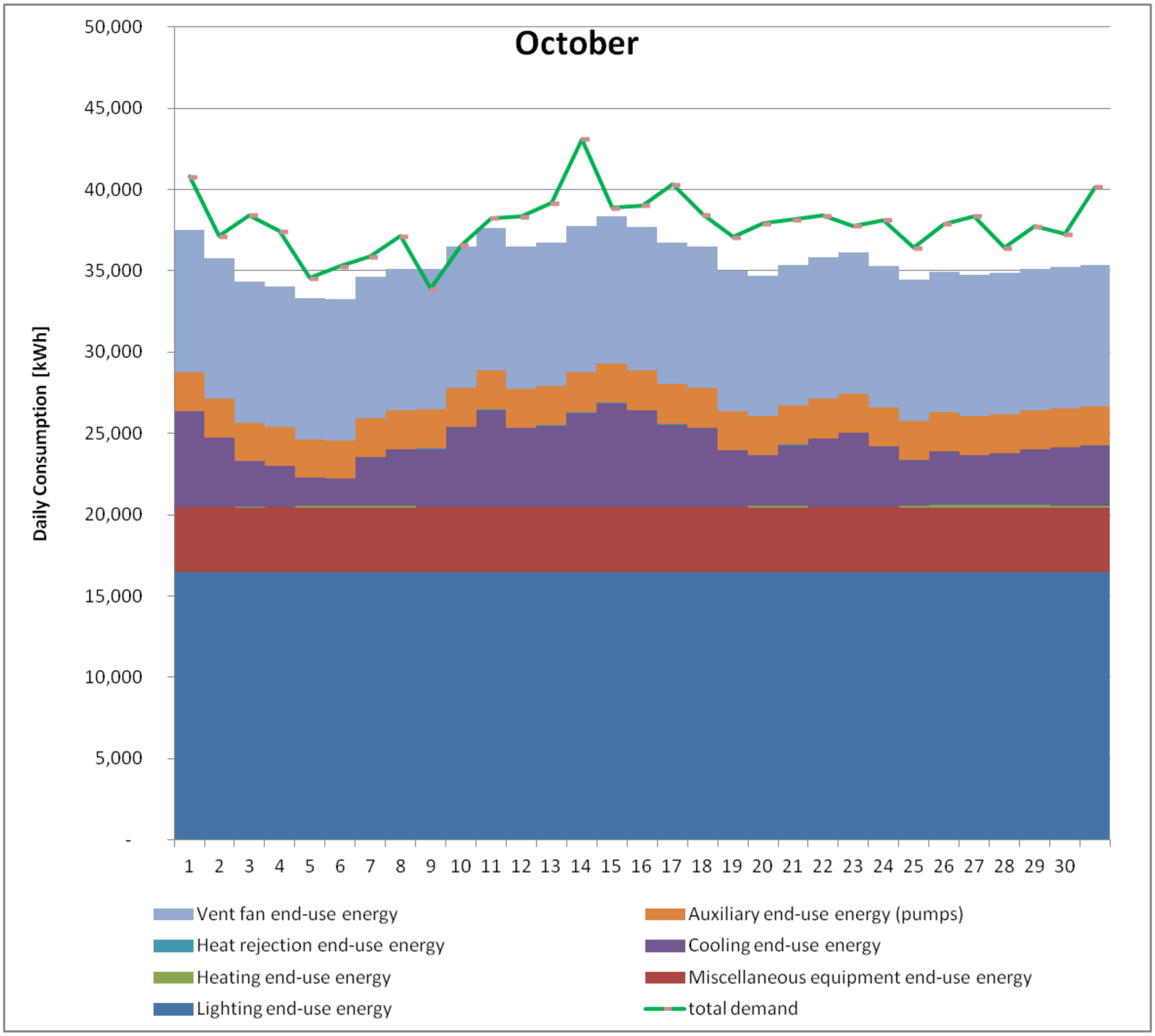
[970] The converters are part of the Energy Plus and eQuest Program Suites respectively.

[971] Solar radiation was not available in the free data-set anyway and would also have less-than-normal influence at the jail due to the roof construction and the limited window area as well as the thicker walls.

[972] The complicated conversion problem solution was strongly supported by Wei Feng, building energy simulation expert at LBNL.

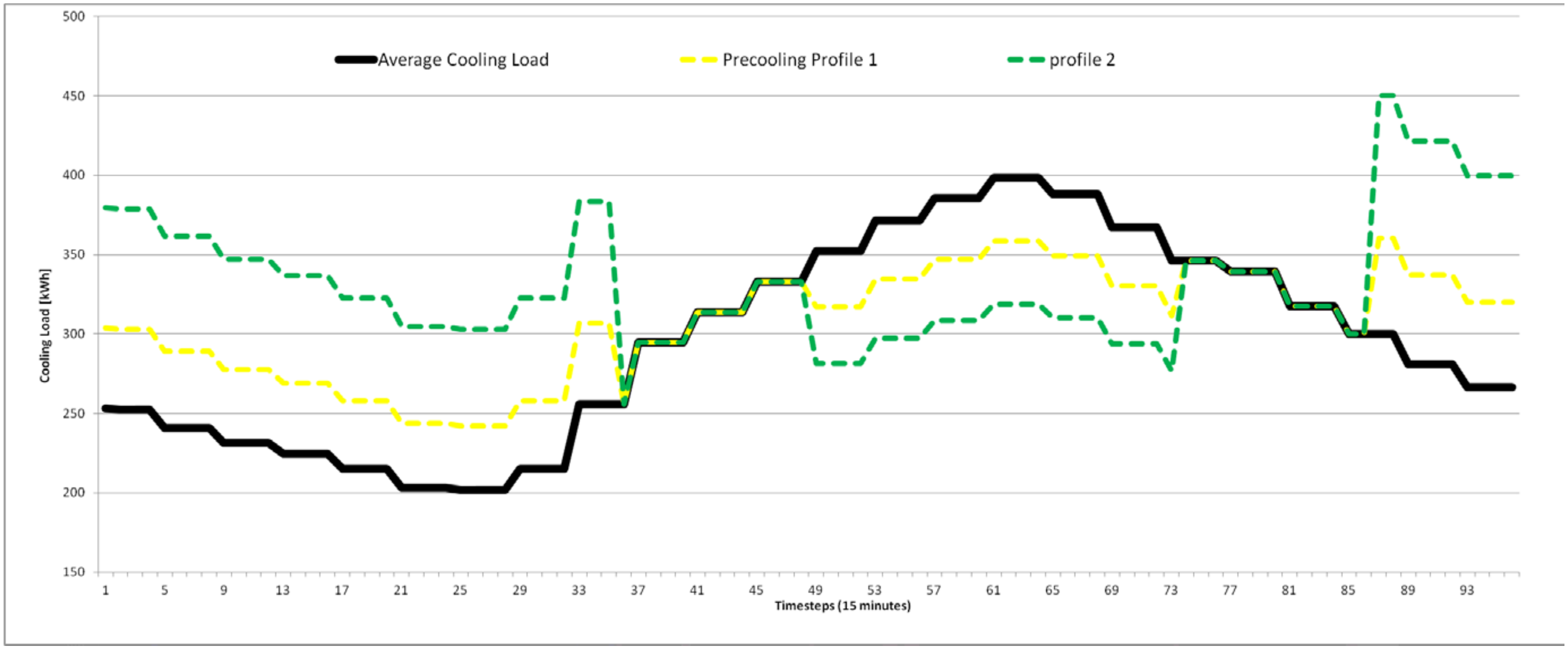
Measured load versus eQuest model comparison on daily time steps for May and October





October
Daily Consumption [kWh]
50,000
45,000
40,000
35,000
30,000
25,000
20,000
15,000
10,000
5,000
-
1 2 3 4 5 6 7 8 9 10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 25 26 27 28 29 30
Vent fan end-use energy
Auxiliary end-use energy (pumps)
Heat rejection end-use energy
Cooling end-use energy
Heating end-use energy
Miscellaneous equipment end-use energy
Lighting end-use energy
total demand

Daily and average cooling load profile for September. Resulting PC-I and PC-II cooling profiles based of the average September cooling profile.



APPENDIX E
Section 6

DBP GAMS Code

Not included in this version due to DER-CAM confidentiality. In case of interest, details can be requested from LBNL Microgrids Group directly.

BIP GAMS Code

Not included in this version due to DER-CAM confidentiality. In case of interest, details can be requested from LBNL Microgrids Group directly.

Lighting Shed GAMS Code

Not included in this version due to DER-CAM confidentiality. In case of interest, details can be requested from LBNL Microgrids Group directly.

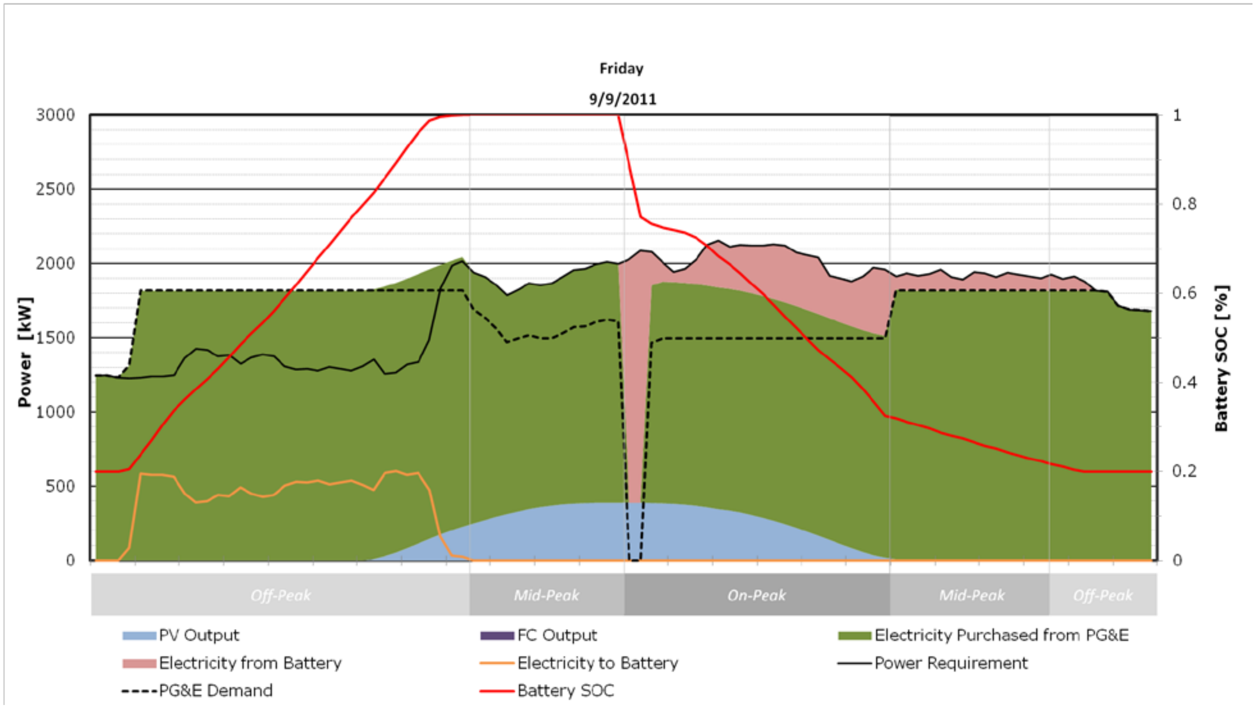
Precooling GAMS Code

Not included in this version due to DER-CAM confidentiality. In case of interest, details can be requested from LBNL Microgrids Group directly.

APPENDIX F
Section 7

TOU BATTERY - Discussion of energy balance of Non-Demand Setting Day

To give an idea of the energy balance on every weekday except the demand-setting day, the energy balance of the 9th of September is shown as an example in the graph below.



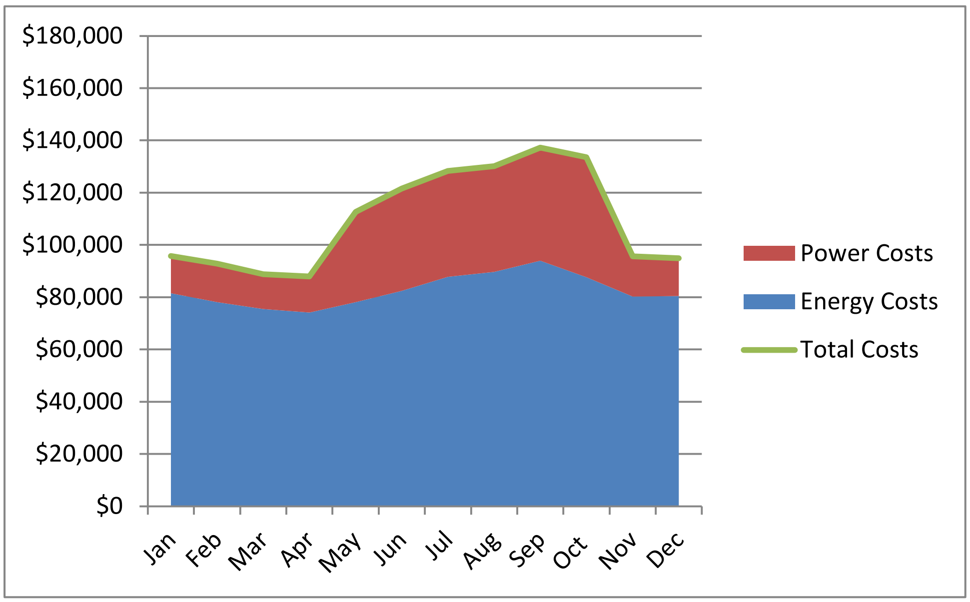
The graph shows in overall a comparable behavior of the battery charge and discharge with a charging period in the morning hours and a discharge during on-peak mainly and a small discharge during the off-peak hours. As the load is at a lower level during the first off-peak period, the charging of the battery can begin later on the 9th than on the previously discussed demand-setting day. Also, due to the lower level during the first off-peak period, the battery can be fully charged before the mid-peak period begins and no charging needs to occur during the first mid-peak period. It appears that the decay of the battery over the mid-peak period is lower than the cost of charging it again to full capacity before the highest charges apply during the on-peak period. Then, during the on-peak period and the following mid-peak period the major share of the battery capacity is needed to keep the determined on-peak and mid-peak demand levels. Theoretically, there would be enough available battery capacity to achieve a lower on-peak and/or mid-peak demand level. Though, as during the demand-setting day, the demand levels cannot be lowered beyond what is shown in the graph, this would have no effect on the costs.[973] Therefore, the optimal behavior on the 9th and every other weekday except for the demand-setting day includes a discharge of the additional battery capacity, which is not

[973] As the highest consumption during the different TOU periods is relevant for determining the demand charges.

needed to maintain the optimal demand levels, at the beginning of the on-peak period. This discharge aims at reducing energy costs during the period of high energy charges. The discharge happens at the beginning of the peak period in order to consequently minimize the decay of the stored electricity over time.

The optimal behavior of the battery deviates from the intuitive and non-optimized approach that would just charge and discharge the battery at a constant rate. It has been shown by LBNL previously that the optimal battery schedule drives – under the assumption of perfect knowledge of load and DER generation – higher savings than the simply constant charge and discharge that does not take demand levels into detailed consideration.

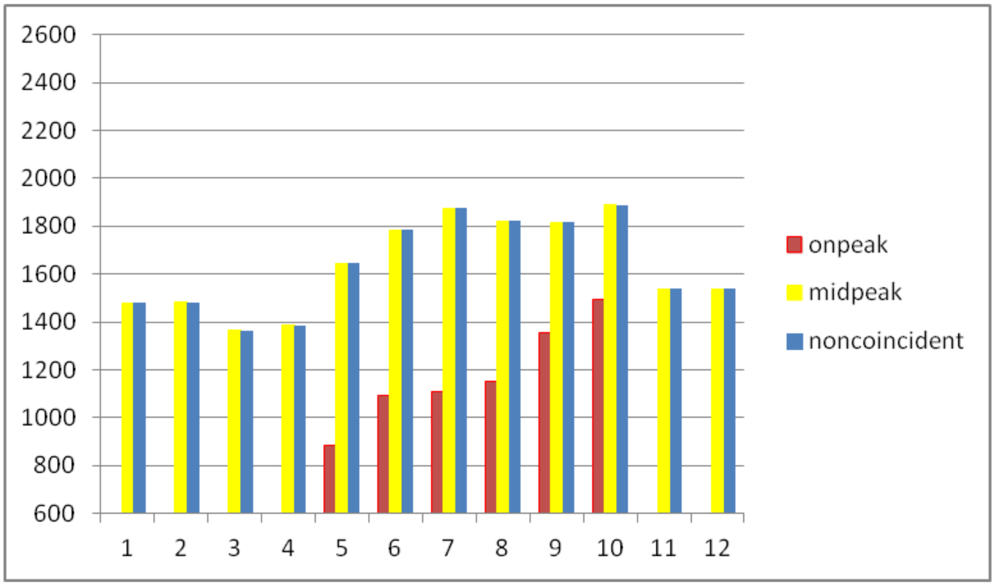
TOU BATTERY - Monthly Cost Split



While the graph still shows the same basic structure as under the previous scenario, a detailed comparison shows that the blue area remains almost unchanged, while the red area indicating power costs, is noticeably lower,[974] compared to the fixed demand scenario. As discussed, most savings are achieved from the power charges that are higher during summer. Thus, it is no surprise that almost 60 % of the savings, the usage of the battery can generate, are achieved in summer months.

[974] Especially in summer

TOU LIGHTING SHED - Demand Levels

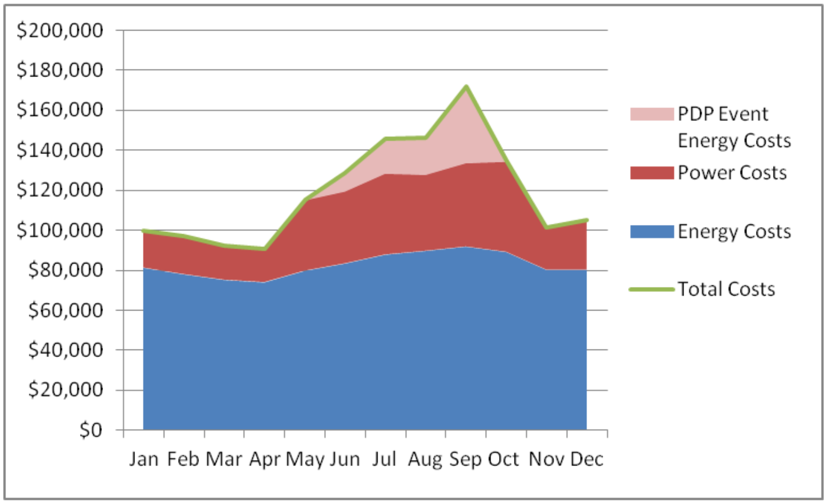


TOU PRECOOLING - Chosen Profiles

The table below displays – for each month – how often which of the two PC profiles was chosen by the optimization to be optimal:

	PC-I	PC-II
May	2	2
June	4	0
July	4	0
August	0	1
September	3	1
October	0	4

PDP FIXED DEMAND - Monthly Cost Split



In addition to the known depiction of the monthly electricity costs, the light red area on top is added representing the PDP event energy charges. As loads are fixed the costs of PDP event energy are dependent on the number of event days called per month.[975] PDP event energy represents 6 % of the total electricity costs over the whole year. Nevertheless, in a month with several PDP events[976], the charges for PDP event energy can go up to about 22 % of the total electricity costs of the month.

PDP BATTERY - Discussion of energy balance for Non-Demand Setting Day

As before, apart from the demand-setting day also a non-demand setting day's energy balance shall be presented to give an idea of the battery utilization on all other weekdays. However, under PDP a differentiation between non-demand-setting day without PDP event and with PDP event has to be made.

Under the TOU battery scenario the 9th of September was chosen as an exemplary day to discuss the energy balance of a non-demand-setting day. Since under PDP there is no PDP event on this day, it is chosen again to represent a non-demand setting, no-PDP-event day. The detailed analysis of this day showed that as for the demand-setting day the battery energy balance hardly changed. Except for the minor changes in demand levels, which were mentioned in relation to the demand-setting day already[977] the balance is identical to the TOU battery scenario.

For the non-demand-setting, PDP-event day the energy balance changed and thus the exemplary energy balance for the 2nd of September is presented in the figure below.

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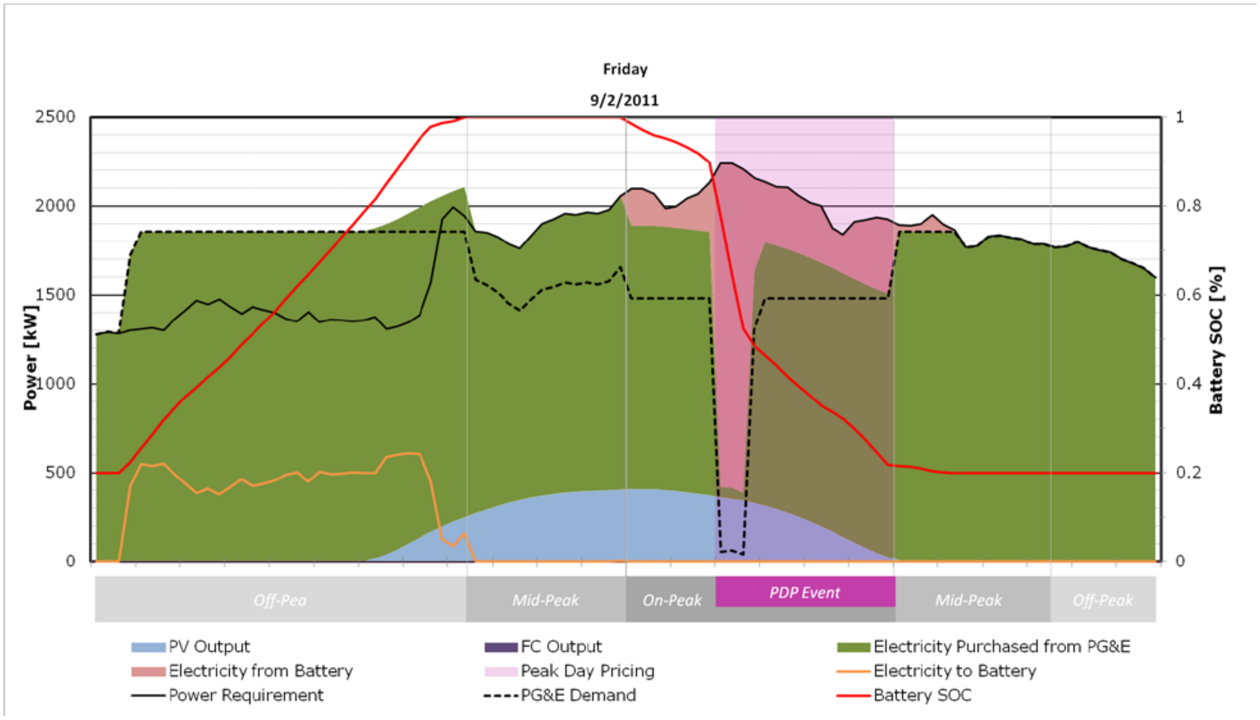
975 One in June, two in July and August, four in September.

976 Such as September with four events.

977 The demand levels are equal throughout the month for each TOU period and, therefore, the levels on the 9th are equivalent to the once showed for the 20th.



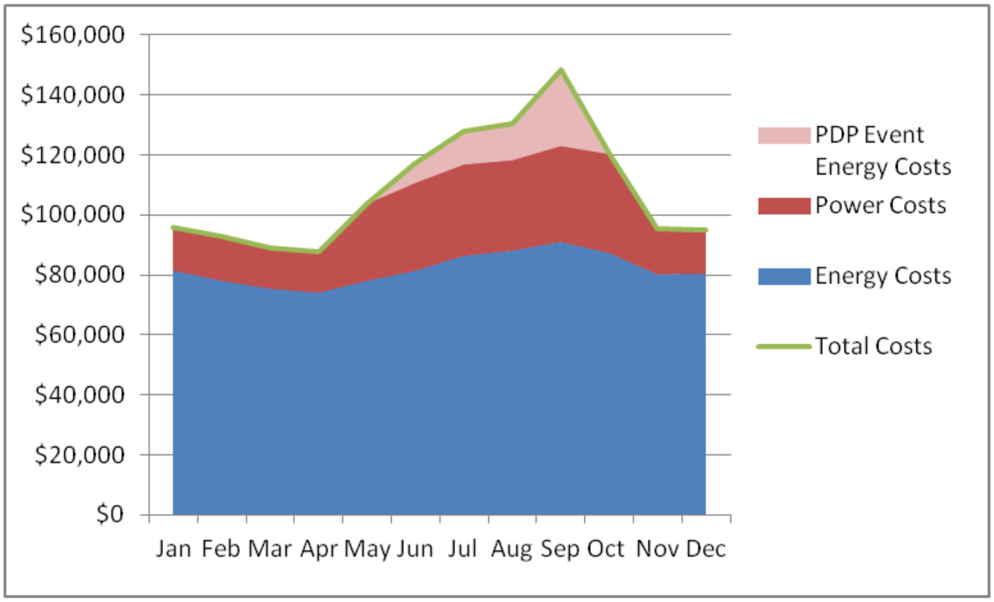
For a non-demand-setting PDP event day both start[978] and end[979] of the battery discharge are equal to the non-demand-setting day under TOU battery scenario. What changed is the point of time of the discharge of battery energy that is not needed to maintain the optimal demand levels.[980] Under TOU the discharge aiming to offset on-peak energy charges was conducted in the very beginning of the on-peak period to avoid as much battery decay as possible. Under PDP, on contrast, this energy costs offsetting discharge of available storage capacity is scheduled two hours later, at the beginning of the PDP event. As energy charges are significantly higher during the event hours, compared to the normal on-peak period, it is very intuitive that energy cost reduction would occur in this period. Going into detail on the underlying mechanism of the optimization, this result means that the difference in energy charges is higher than the decay of the battery for the two hours late start. This finding of the postponed energy reducing discharge holds true for all non-demand-setting, PDP event days in 2011.

[978] At the beginning of the on-peak period.

[979] In the second mid-peak period of the day.

[980] Obviously, on this day, the demand levels are also slightly changed compared to TOU battery, as described before for the demand-setting day and the demand-setting, no PDP event day.

PDP BATTERY - Monthly Cost Split



BIP - Risks

However, in the following a quick estimate for this risk caused by increased demand levels through additional charging shall be given: The risk is limited if the events are called, as in summer 2011 during the middle of the on-peak period – or even better of the PDP event period – as in these cases the battery SOC is high anyway and the additional charging potential does not need to be used. In addition, if the event would occur in the off-peak period and additional charging would have to happen the disadvantage would also be relatively small as only the total maximum demand charge would be increased. If the total maximum demand level would be increased by 2,000 kW this would drive costs of about $ 18,000, which would still leaving enough savings that would justify the participation in BIP. However, if the additional charging with a significant increase in the demand level happens during mid-peak or on-peak or more than once the viability threshold of partaking in BIP could be broke.)

APPENDIX G:
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