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Evaluation of Representative Smart Grid Investment Grant Project Technologies: Thermal Energy Storage

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Pacific Northwest
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Summary

This document is one of a series of five reports commissioned by the United States Department of Energy, Office of Electricity Delivery and Energy Reliability. The purpose of these reports is to estimate some of the benefits of deploying technologies similar to those implemented on the Smart Grid Investment Grant (SGIG) projects. Four technical reports cover the various types of technologies deployed in the SGIG projects: distribution automation, demand response, energy storage, and distributed generation. While the results of these reports provide insight into the variation of impacts by technology, feeder composition and region, it should be noted that the actual impacts and benefits of employing specific technologies in individual SGIG projects may vary from these projections. A fifth report in the series examines the benefits of deploying these technologies on a national level. This technical report examines the impacts of distribution automation technologies deployed in the SGIG projects.

1 Introduction

As part of the American Recovery and Reinvestment Act of 2009, the U.S. Department of Energy (DOE) Office of Electricity Delivery and Energy Reliability (OE) provided Smart Grid Investment Grant (SGIG) funding to 99 award recipients totaling $3.4 Billion [1]. Coupled with matching funds of $4.6 Billion from industry, the SGIG projects are intended to accelerate the modernization of the nation's electricity infrastructure. To help evaluate the effect of these projects, a set of impact metrics has been developed by the DOE [2]. Once the SGIG projects are complete, it will be possible to analyze collected field measurements and determine the exact benefit from each of the various technologies within each of the projects. OE has several initiatives operating in current and near-term time frames to assess impacts and disseminate information as data becomes available. These initiatives include analysis partnerships with individual SGIG recipients, specific technology assessments, stakeholder briefings, and improvements to existing algorithms and tools.

In order to examine the SGIG project benefits, the Pacific Northwest National Laboratory (PNNL) utilized the GridLAB-D simulation environment to conduct extensive simulations on representative technologies. GridLAB-D was originally developed at PNNL, via DOE OE funding, to provide an open source simulation environment to evaluate the impacts of emerging technologies on the nation's electricity infrastructure. The unique multi-disciplinary agent based structure of GridLAB-D allows for the effective evaluation of complex emerging technologies such as voltage optimization and demand response. These are the same technologies that being deployed as part of the SGIG projects.

The impact of these technologies, at the distribution feeder level across various climate regions of the United States [3], is presented in a series of 4 technical reports, of which this report is the first. Each of the 4 technical reports examines a class of technologies deployed in the SGIG projects. The 4 technical reports examine distribution automation, demand response, energy storage, and renewable integration. A 5th report uses the results of the four technical reports to generate a policy level examination of the various technologies. The final report includes extrapolation to a national level deployment at various penetration levels.

To ensure that the results of this report can be reproduced by other researchers, all of the tools, models, and materials used are openly available at [8]. Through detailed time-series simulations conducted in GridLAB-D, the impact of adding thermal energy storage to the grid can be examined on the relevant prototypical feeders. Utilities, regulators, vendors and other stakeholders interested in analyses more specific to their systems, goals, and conditions may make use of these open tools for their own purposes.

1.1 Report Scope

Due to the large number of SGIG projects and the wide range of specific implementations, it is not feasible to simulate each of the specific SGIG projects. In addition to the numerous implementations, it would be necessary to model the electrical infrastructure of each of the projects. To address these issues, the technical reports will model a selection of technologies that are representative of those seen in the SGIG projects, and it will examine their impact on a set of prototypical distribution feeders that are representative of those seen in the various climate regions of North America [3]. By utilizing representative technologies and prototypical distribution feeders, it will be possible for this report to estimate the feeder level impact of each technology. Once the impact of the technologies has been evaluated on the prototypical feeders, the results will be extrapolated to explore the impacts and considerations associated with deploying the technology on a national level.

The technologies deployed as part of the SGIG projects can be placed in one of two categories: direct and enabling. Direct technologies are those that provide direct benefit to the system. Enabling technologies are those that may not provide a direct benefit to the system, but they enable other beneficial technologies. As an example, a communications network does not provide any reduction in energy consumption, but it does enable demand response systems that create reductions in energy consumption.

The technical reports focus on the benefits obtained from the deployment of direct technologies when supported with the necessary enabling technologies.

1.1.1 Direct Representative Technologies

These are the 15 technologies that will be specifically analyzed using GridLAB-D simulations. Within each of the four technical reports there are one or more specific direct technologies that are examined.

Distribution Automation (DA)

- t1: Volt-VAR Optimization (VVO)
- t2: Capacitor Automation (CA)
- t3: Reclosers and Sectionalizers (R&S)
- t4: Distribution Management and Outage Management Systems (DMS&OMS)
- t5: Fault Detection Identification and Reconfiguration (FDIR)

Demand Response (DR)

- t6: TOU/CPP with enabling technologies
- t7: TOU/CPP without enabling technologies
- t8: TOU with enabling technologies
- t9: TOU without enabling technologies
- t10: Direct Load Control (DLC)

Energy Storage (ES)

- t11: Thermal Energy Storage (TES)

Distributed Generation (DG)

- t12: Solar residential
- t13: Solar commercial
- t14: Solar combined
- t15: Wind commercial

1.1.2 Enabling Technologies

In addition to technologies that provide direct benefits to the system, there are those that enable other technologies to benefit the system, but themselves may not provide a direct benefit. The majority of the projects in the SGIG program have committed to deploying a large number of enabling technologies that do not provide any direct measurable benefit. Despite the lack of a direct benefit, these technologies form the foundation needed for the technologies that do provide direct benefits to the system.

1.1.2.1 Smart Meters

Traditional electromechanical metering devices have proven to be accurate and reliable over multiple decades, but have the significant disadvantage of requiring manual data collection; there is no network connectivity. The deployment of new "smart meters" is the largest common element to the SGIG projects, ranging from projects with a few thousand, to projects with multiple millions. These new meters are able to bi-directionally communicate information via a wired or wireless communications network. Communications to the customer can now include time-based electricity rates or event-triggered signals. Communications from the customer allow remote meter reading, as well as usage patterns.

1.1.2.2 Communications Infrastructure

Communications infrastructure, both wireless and wired, is an excellent example of an enabling technology. A communications infrastructure in an isolated environment does not provide any direct benefit to the system. However, direct technologies and capabilities, such as demand response, would not be possible without a supporting communications infrastructure. For the purposes of the conducted analysis, it is assumed that the required communications infrastructure is available, but it will not be simulated. Zero latency and infinite bandwidth is assumed. While an explicit communications system model is not used in this analysis, there are issues outside the scope of this work where a communications system model would be essential.

1.1.2.3 Human Machine Interface

Human Machine Interfaces (HMI) can exist in many forms. In a single family residence the HMI can range from a simple thermostat to a fully functional Home Energy Management System (HEMS). An HMI can allow a residential user to see the current price of electricity, interact with their heating and cooling system or with an energy storage system. By providing an end user with more information about the current price of electricity and the state of their consumption, the effectiveness of demand response opportunities can be increased.

1.2 Report Structure

The structures of the four technical reports follow a similar design. The four reports share a common introduction in Section 1 with Section 2, discussing the representative technologies to be examined in each report. Section 3 contains the detailed feeder level examination of the impact of each technology, while Section 4 examines the change in the impact metrics between the base case and the case with various technologies. It should be noted that the base case is a representative simulation without new technologies; it is not representative of the operation of any actual SGIG project. Section 5 contains the concluding comments. Additionally, there are multiple appendices. Appendices A, B, and C are common to all 4 reports with Appendix A giving a detailed description of the SGIG impact metrics, Appendix B detailing the taxonomy of prototypical distribution feeders, and Appendix C discussing GridLAB-D and the simulation methodology. Appendix D is specific to each report and contains the plots produced for individual feeders from the simulations. Appendix E contains the impact metric values for each technology and is the basis for the differential impact metrics in Section 4.

The fifth report has a structure independent of the four technical reports.

2 Energy Storage Technology Areas

Energy Storage represents technologies that take energy from the power system and store it for later use. The storage can be accomplished using electrochemical processes (such as a battery), physical processes (such as pumped hydro), or thermal processes (such as ice energy storage). A review of the SGIG proposals showed that the benefits of energy storage and preparing the underlying infrastructure for future storage integration were often mentioned. However, the storage actually deployed as part of the SGIG proposals was predominately thermal energy storage (TES). This section will examine this particular type of energy storage, as well as its specific implementation.

2.1 Thermal Energy Storage

For this study, thermal energy storage is based on the Ice Bear® technology produced by Ice Energy® [4]. The Ice Bear® unit is a 5-ton cooling unit that is used in conjunction with the normal heating, ventilation and air conditioning (HVAC) unit to cool a building in place of the normal air conditioning unit. The unit stores energy in the form of ice during off peak hours and then uses the ice to cool the building during peak hours. This allows the most substantial portion of the cooling system load, the compressor, to occur during off-peak hours.

To ensure that the results of this report can be reproduced by other researchers, all of the tools, models, and materials used are openly available at [8]. Thermal energy storage is loosely based on the Ice Bear® unit, but uses the basic principles of thermal dynamics and does not have the size restrictions of the Ice Bear® unit. However, for this study, thermal energy storage was restricted to commercial buildings. The SGIG projects referencing energy storage were using an ice energy storage unit on one or two commercial buildings. Furthermore, the Ice Bear® itself is marketed as a commercial system. Residential deployment is possible, but does not appear commercially feasible at this time.

2.1.1 SGIG Impact Metrics Affected by Thermal Energy Storage

A detailed list of the SGIG impact metrics can be found in Appendix A. These metrics are for all of the SGIG projects. The SGIG metrics shown in Table 2.1 are affected by thermal energy storage and will be tracked in this analysis:

Table 2.1: Impact metrics affected by thermal energy storage

Index	Metric	Units
1	Hourly Customer Electricity Usage	kWh
2	Monthly Customer Electricity Usage	MWh
3	Peak Generation	kW
	Nuclear	%
	Solar	%
	Bio	%
	Wind	%
	Coal	%
	Hydroelectric	%
	Natural Gas	%
	Geothermal	%
	Petroleum	%
4	Peak Load	MW
7	Annual Electricity Production	MWh
12	CO2 Emissions	Tons
13	SOx Emissions	Tons
	NOx Emissions	Tons
	PM-10 Emissions	Tons
17	Annual Storage Dispatch	MWh
18	Average Energy Storage Efficiency	%
21	Feeder Real Load	MW
	Feeder Reactive Load	MVAR
29	Distribution Losses	%
39	CO2 Emissions	Tons
40	SOx	Tons
	NOx	Tons
	PM-10	Tons

2.1.2 Specific Implementation of Thermal Energy Storage

There are currently only a limited number of commercially available thermal energy storage devices on the market. The concept is relatively simple, but is only economically viable for commercial applications at this time [5]. These units are typically purchased and controlled by utilities and installed on the commercial buildings, contributing to a significant reduction in the peak load via cooling. In this study, thermal energy storage is randomly applied to 10% to 20% of the commercial buildings. Therefore, the selected buildings may not represent the optimal locations for distribution feeder peak reduction or other applications. This mirrors the real world situation where a utility is not always able to obtain the participation of the commercial customers they would prefer. This lack of participation could be due to lack of customer interest or limitations with the existing infrastructure.

The implemented method of thermal energy storage is based on the Ice Bear® unit manufactured by Ice Energy®. The Ice Bear® unit consists of a compressor, pump, refrigerant, heat exchanger, a reservoir for water/ice, and electronics for control and communication. The energy consumption for each portion of the Ice Bear® unit is used for the model of the thermal energy storage technology and is scaled appropriately for the size of the commercial building. Thermal energy storage in GridLAB-D does not currently support the communication and control by the utility, but does interface with the normally installed HVAC unit. Therefore, demand on the energy storage unit is dictated by building demand and a simple time-of-use scheduling, not a dynamic utility control signal.

2.1.2.1 Thermal Energy Storage Charging and Storage

The means by which the thermal energy storage unit stores energy is to freezing water during off peak hours and to use the ice to condense the refrigerant during peak hours, in lieu of a normal condenser. The Ice Bear® is rated as a 5-ton unit, but uses a 4.3-ton compressor to make the ice, which uses 3,360 kW at 75°F. For the purposes of this report, the thermal energy storage unit is not limited to 5 tons and is scaled to match the cooling needs of the commercial building. All of the energy consumption, volume of ice, cooling capacity, and thermal losses (as a function of surface area based on ice/water volume) is scaled linearly. This is not ideal, but serves as a rough approximation of the thermal energy storage unit characteristics for different deployment sizes. Like the Ice Bear®, thermal energy storage is limited in total storage of 30 ton-hours (360,000 Btu) for a 5-ton unit, which equates to six hours of run time at 100% duty cycle.

Starting with the standard Ice Bear® specifications and assuming a linear correlation between charge times and outdoor temperature, the time to charge can be calculated as shown in equation 2.1, where t is time in hours and T is the outdoor air temperature in degrees Fahrenheit.

$$t = 0.075T + 5.875 \tag{2.1}$$

Using equation 2.1, the ton-hours of storage can be calculated by dividing the total storage by the time to charge and summing the results over each hour of charge. This can be shown in equation 2.2 for time summed in seconds, where Z_{hr} is the ton-hrs of storage and T_n is the temperature at second n. This can also be represented as equation 2.3 for a constant temperature (T) over time (Δt) in seconds.

$$Z_{hr} = \sum_{1}^{n} \frac{1}{9T_n + 705} \tag{2.2}$$

$$Z_{hr} = \frac{\Delta t}{9T + 705} \tag{2.3}$$

The power consumption of thermal energy storage during the recharge or ice making portion is dependent on the outside temperature as a compressor is used to condense the R-410a refrigerant. A 5-ton unit will consume 3,360 Watts at 75°F. The power consumption is scaled linearly such that a 10-ton unit will consume 6,720 Watts at 75°F. The power consumption can be calculated as a linear function based on the temperature and the power consumption at 75°F [6]. Equation 2.4 shows the compensation for power consumption based on outside temperature, where P_{act} is the actual power consumption in Watts, P_{norm} is the rated power in Watts at 75°F, and T is the outside temperature in degrees Fahrenheit.

$$P_{act} = P_{norm}\left(1 + \left(75 - T\right) * 0.0106\right) \tag{2.4}$$

The thermal energy storage model has the ability to customize the losses by having a definable coefficient of thermal conductivity for the insulation surrounding the ice block. Equation 2.5 shows the rate of thermal conductivity, where R is the rate in Joules per second (Watts), k is the coefficient of thermal conductivity in Watts per meter per degrees Centigrade, ΔT is the difference between the outside temperature and the temperature of ice (0°C), A is the surface area of the block of ice in square meters (assumed to be a cube and calculated from the volume of water), and d is the thickness of the insulation in meters (set to 0.05m).

$$R = \frac{kA\Delta T}{d} \tag{2.5}$$

As with the Ice Bear® unit, thermal energy storage has limitations on the operational range. It can only recharge or make ice when the outside temperature is between 15 and 115°F.

2.1.2.2 Thermal Energy Storage Cooling

Thermal energy storage uses its stored ice to condense the R-410a refrigerant instead of a compressor, thereby reducing the energy consumption during peak hours. The refrigerant runs through a heat exchanger that is either incorporated into the standard HVAC unit or placed into the duct work of the building to provide cooling. When the thermostat sends the need for cooling, thermal energy storage interfaces with the normal HVAC system to not engage the compressor, but to simply run the fan while thermal energy storage supplies the cooling.

Thermal energy storage only uses a pump to circulate the refrigerant when cooling, excluding the fan motor running in the normal HVAC unit. On a 5-ton unit, this pump will only consume 300 Watts, which is less than 10% of the compressor rated consumption. The power consumption is scaled linearly by taking the ratio of the known values of the 5-ton unit, as well as the associated power consumption and the desired cooling capacity defined by the building in GridLAB-D. For instance, if the building requires a 10-ton cooling unit, it will have a pump that consumes 600 Watts.

Determining the reduction in ice energy storage from cooling is determined by multiplying the run time by the cooling capacity of the thermal energy storage unit and subtracting that from the total thermal energy storage capability. For instance, a 5-ton unit holds 30 ton-hrs (360,000 Btu) of ice energy and running the unit for 2 hours will use up 10 ton-hrs of storage, leaving 20 ton-hrs.

2.1.3 High Level Thermal Energy Storage Simulation Results

This section will examine high-level results for the thermal energy storage deployment. High level results are examined on an annual basis in this section, with monthly analysis values included later in Chapter 3, as well as in Appendix D. Simulation results from 28 feeders, which include a commercial-only feeder simulated in each of the 5 weather regions (see Appendix B for details on the taxonomy of feeders utilized). Annual results examined in this section will include primary benefits of thermal energy storage, such as peak power changes and changes in annual energy consumption [2]. Also examined are annual results for changes in losses on the system, carbon dioxide emission changes, and the total storage energy dispatched.

2.1.3.1 Annual Peak Load

The primary application of the implemented thermal energy storage system is to reduce peak load at the distribution feeder level. By creating the ice in the thermal energy storage during off-peak hours, and using the ice to cool (discharging the storage) during peak hours, the cooling load is shifted to off-peak hours.

Figure 2.1 shows the peak power values for each of the feeders simulated. As Figure 2.1 indicates, the introduction of thermal energy storage does appear to reduce the peak load on the system. Obviously, certain feeders and deployment scenarios have larger impacts than others, partially due to the fact that some feeders have a larger percentage of commercial loads. Furthermore, many of the differences are not easily discernible from a figure such as Figure 2.1.

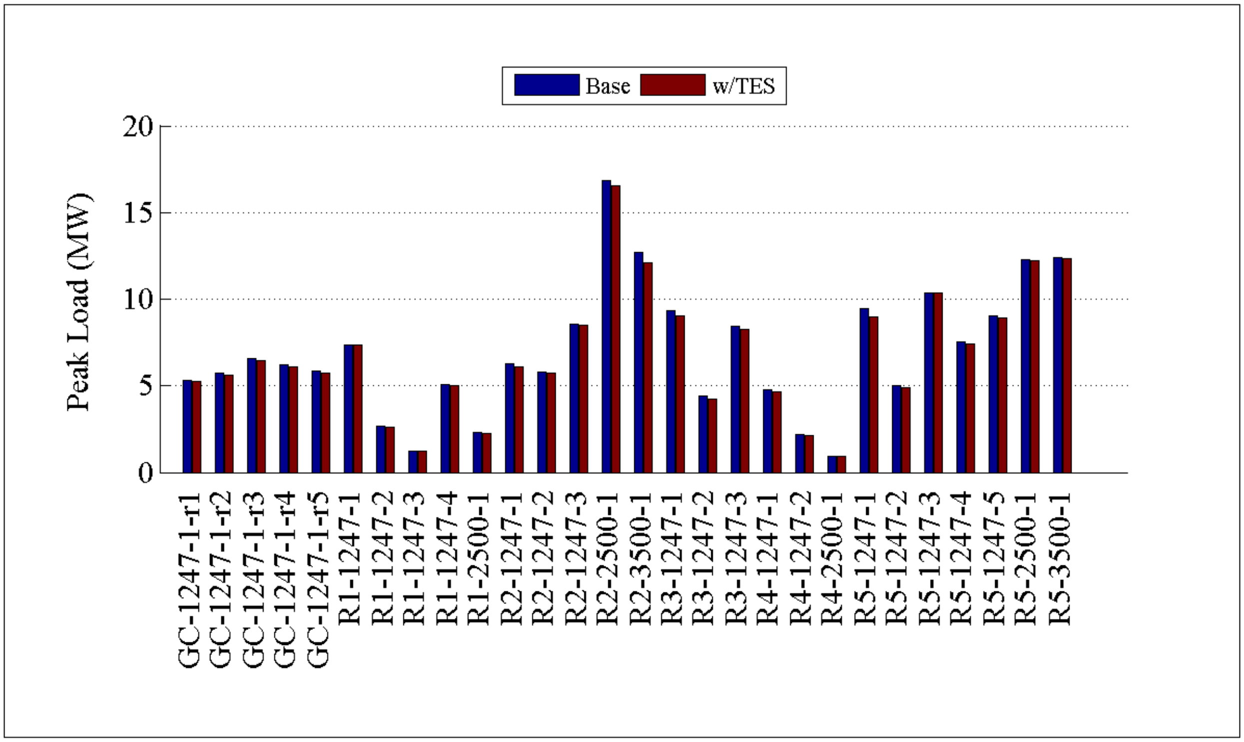

Figure 2.1: Peak power load by feeder

To examine the effects of thermal energy storage on the different feeders in a direct manner, the changes in power values were plotted. Figure 2.2 represents the difference in kW and Figure 2.3 represents the change as a percentage of the base load value.

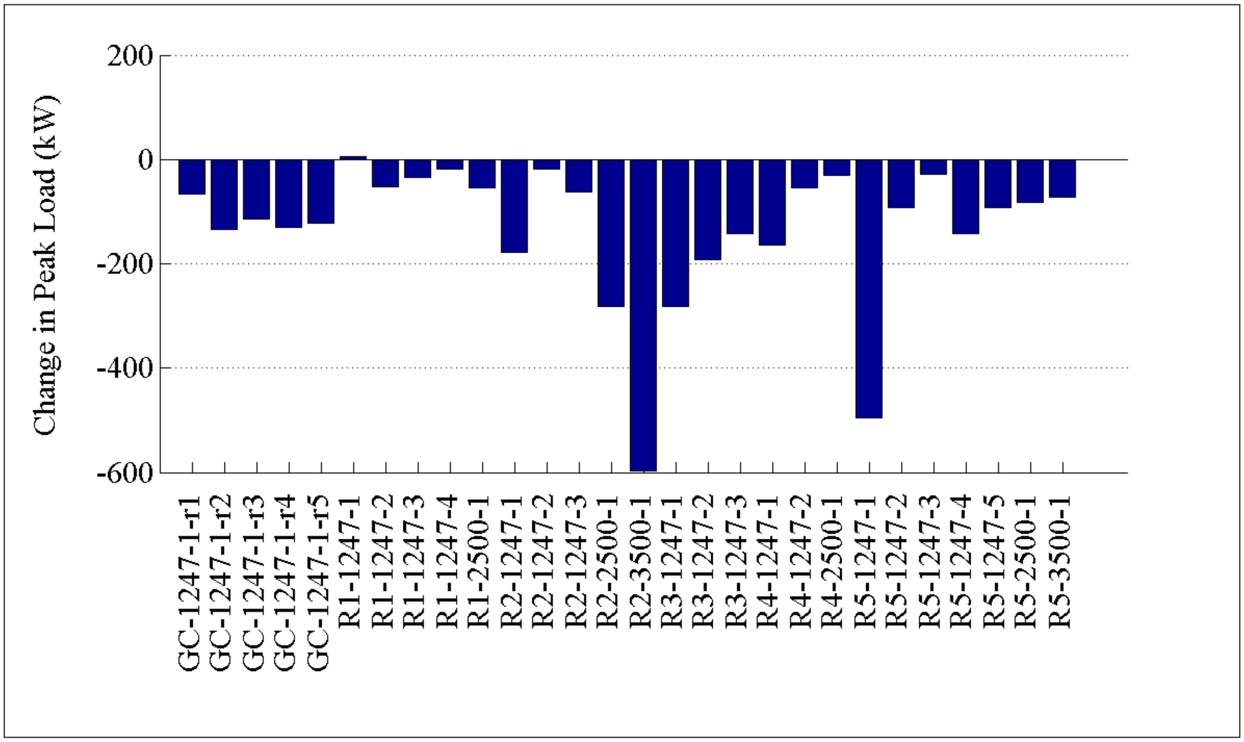

Figure 2.2: Peak load power differences by feeder

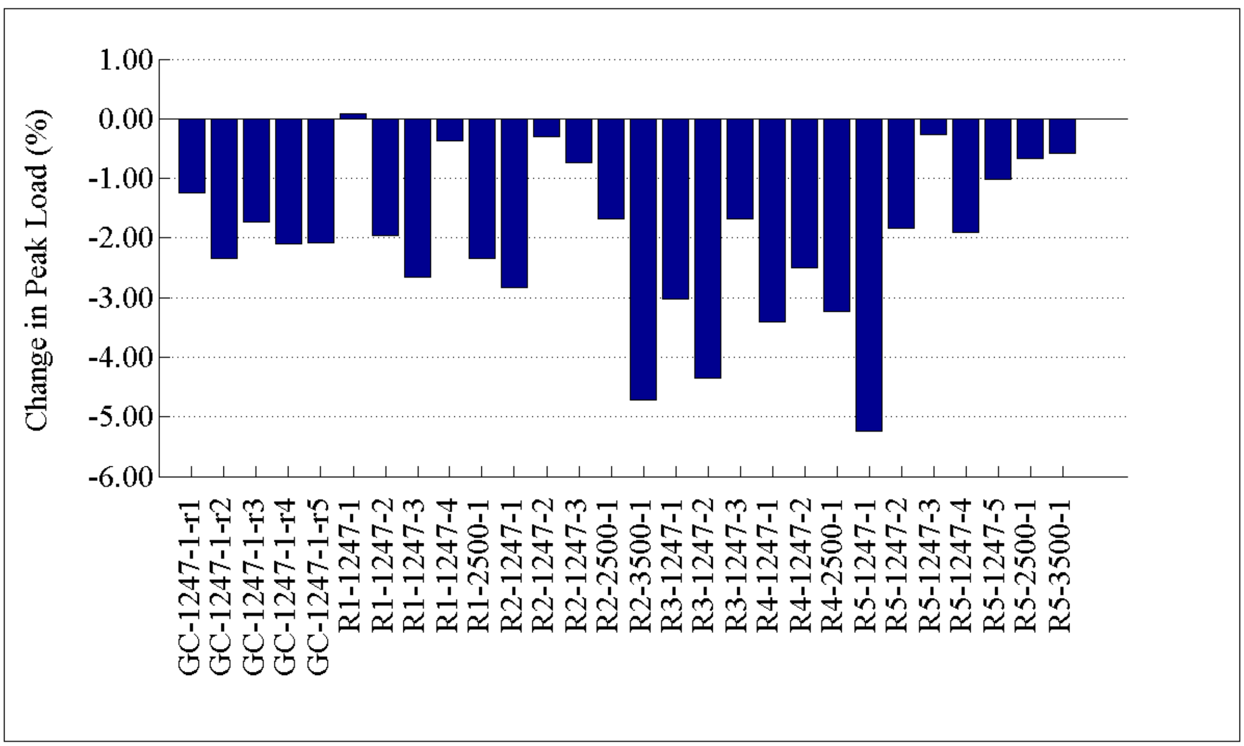

Figure 2.3: Peak load percent differences by feeder

As Figure 2.2 and Figure 2.3 demonstrate, the actual peak power reduction varies significantly for each of the simulated feeders. Most of the feeders demonstrated a peak reduction of 1.5% – 2.0%. The feeders of Regions 3 and 4 appear to gain the largest peak reduction for the different climate regions.

Contrary to the other results, feeder R1-12.47-1 appears to actually increase peak load slightly. However, the measured increase is only a 6 kW increase on the system, which represents 0.08% of the total load on the system. Furthermore, R1-12.47-1 only has two energy storage units deployed on a smaller strip mall. This level of impact on the system is quite small, representing a deployment to only 5% of the commercial buildings and only 0.12% of the total building population (residential and commercial). With such a small footprint on the system, the thermal energy storage is reducing load, but is also changing the voltage slightly. This very slight increase in voltage is causing the overall system load to be slightly higher. Although a minor increase, it serves to highlight the interdependence of different aspects of the power system and how even a minor change can affect the overall load of the system.

2.1.3.2 Annual Energy Consumption

A side effect of shifting load to off-peak periods is a change in the annual energy consumption for each feeder. With a peak reduction occurring on nearly all of the feeders, some change in the energy consumption is expected. However, characteristics of the load and underlying feeder behavior may cause an energy increase, despite the peak reduction. Furthermore, under certain weather conditions, the production of the ice used in the storage may require more energy than directly running an HVAC system.

Figure 2.4 shows the annual energy comparison for the prototypical feeders. As the figure indicates, most of the feeders show very little energy consumption changes.

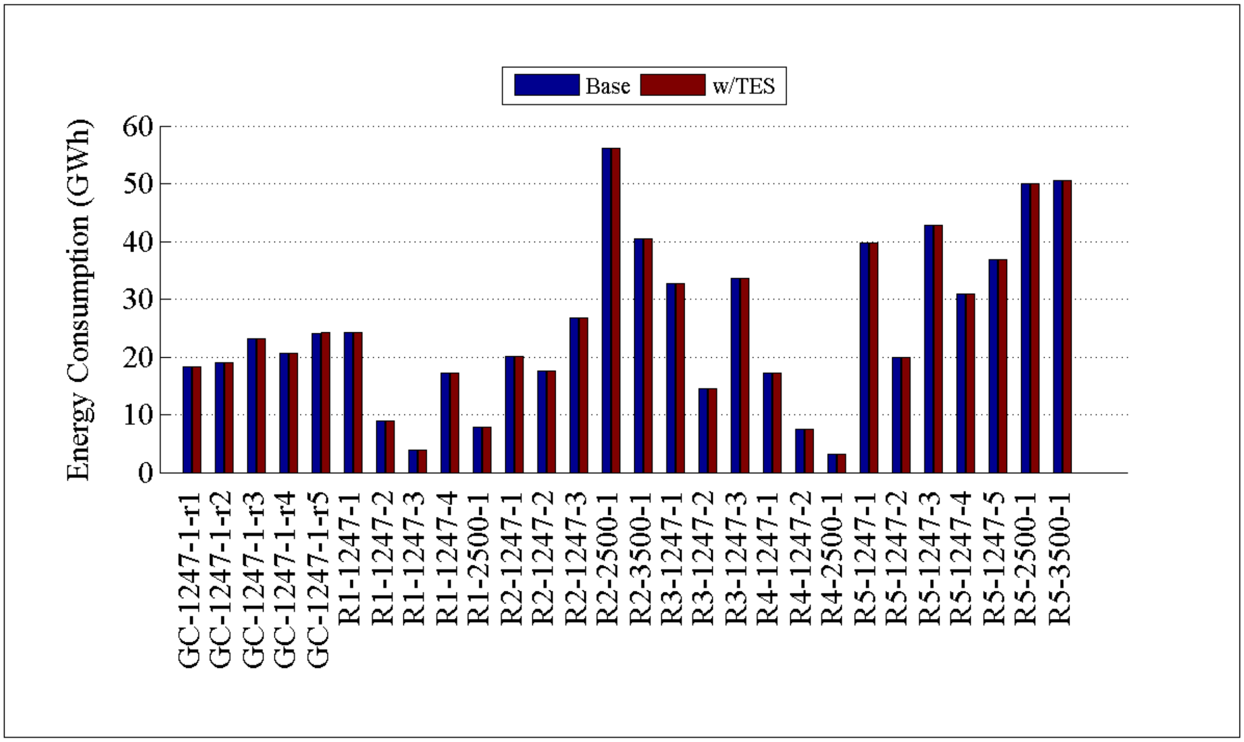

Figure 2.4: Energy consumed by feeder

To clearly show the energy consumption difference, the difference in MWh and percentage of the base feeder energy consumption are plotted. Figure 2.5 and Figure 2.6 show the energy difference and percent difference, respectively. As both of the difference figures indicate, the change in energy consumption is minor for most feeders. Many of the feeders actually show a slight increase in annual energy consumption when thermal energy storage is deployed. This is a reasonable result given that the production of ice for the thermal energy storage (which is later used to cool the air) will require slightly more energy than just cooling the air directly [7].

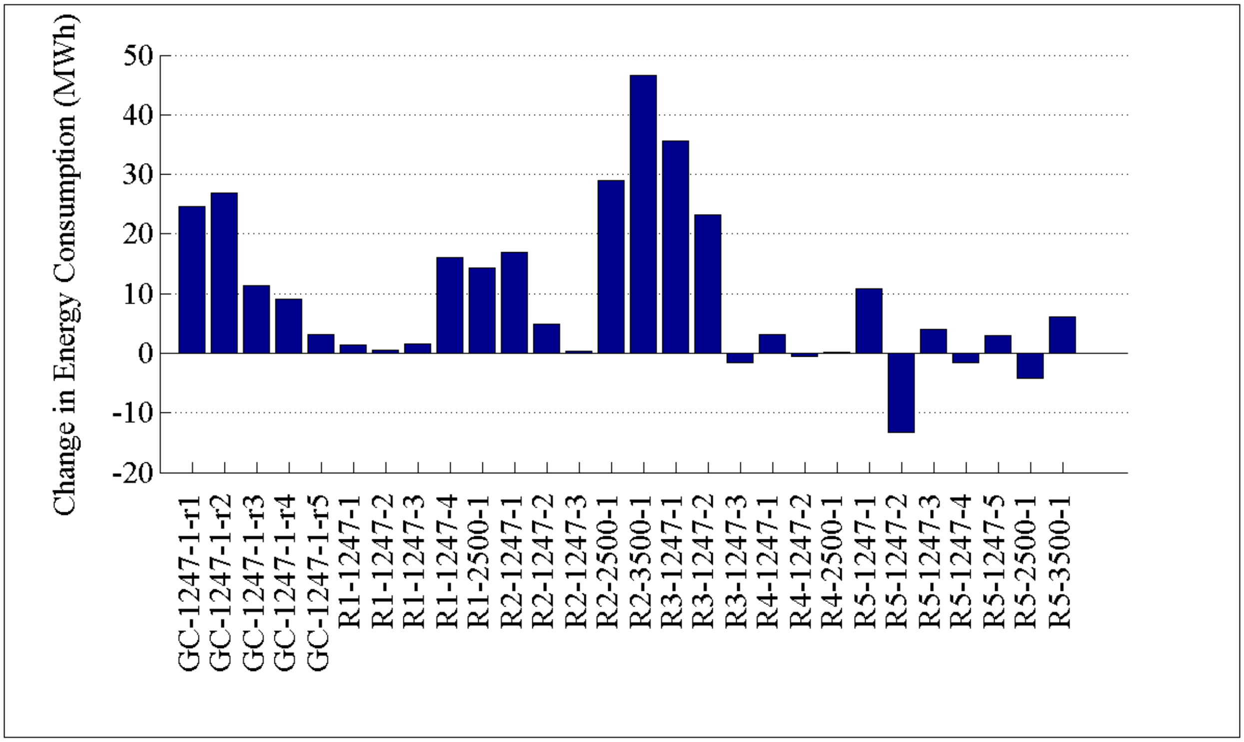

Figure 2.5: Energy differences from deployment of thermal energy storage by feeder

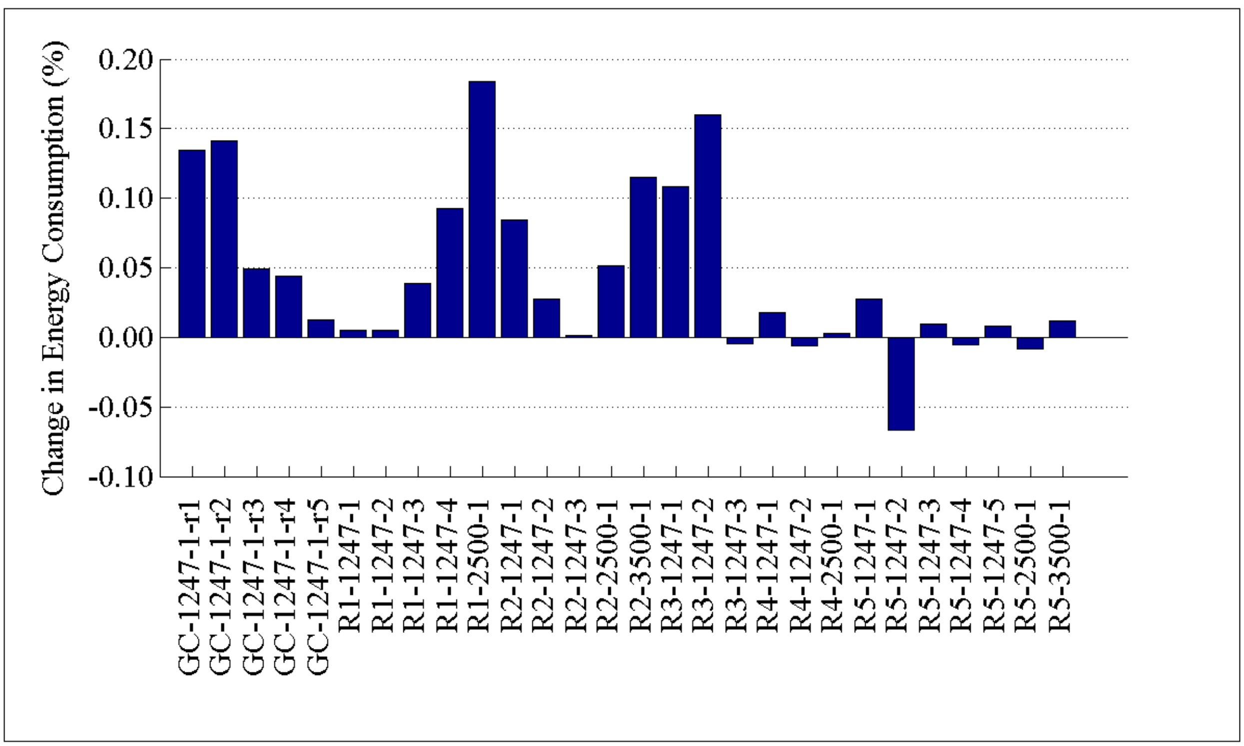

Figure 2.6: Energy percent differences by feeder

The energy consumption savings on R5-12.47-2 are quite surprising. However, as Figure 2.6 indicates, this reduction is less than one tenth of one percent of the feeder's annual energy consumption. Daily analysis of the plots reveals that the deployment of thermal energy storage on R5-12.47-2 lowered the overall load on the feeder very slightly. The next section will show most of this reduction was in reduced system losses, but most of the savings are smaller, incremental savings in power consumption. However, when this slight decrease is aggregated over an entire year, the savings easily accumulate.

2.1.3.3 Annual System Losses

Another result of deploying thermal energy storage is changes in the losses of the system. These losses are typically associated with resistive and inductive losses on distribution lines, cables, and transformers. If overall power consumption is reduced, often times the decrease in power load results in lower losses. Figure 2.7 shows the losses for the various feeder studies for the base and thermal energy storage cases. Similar to the previous energy consumption section, no significant differences appear in the energy losses between the base case and the thermal energy storage deployment.

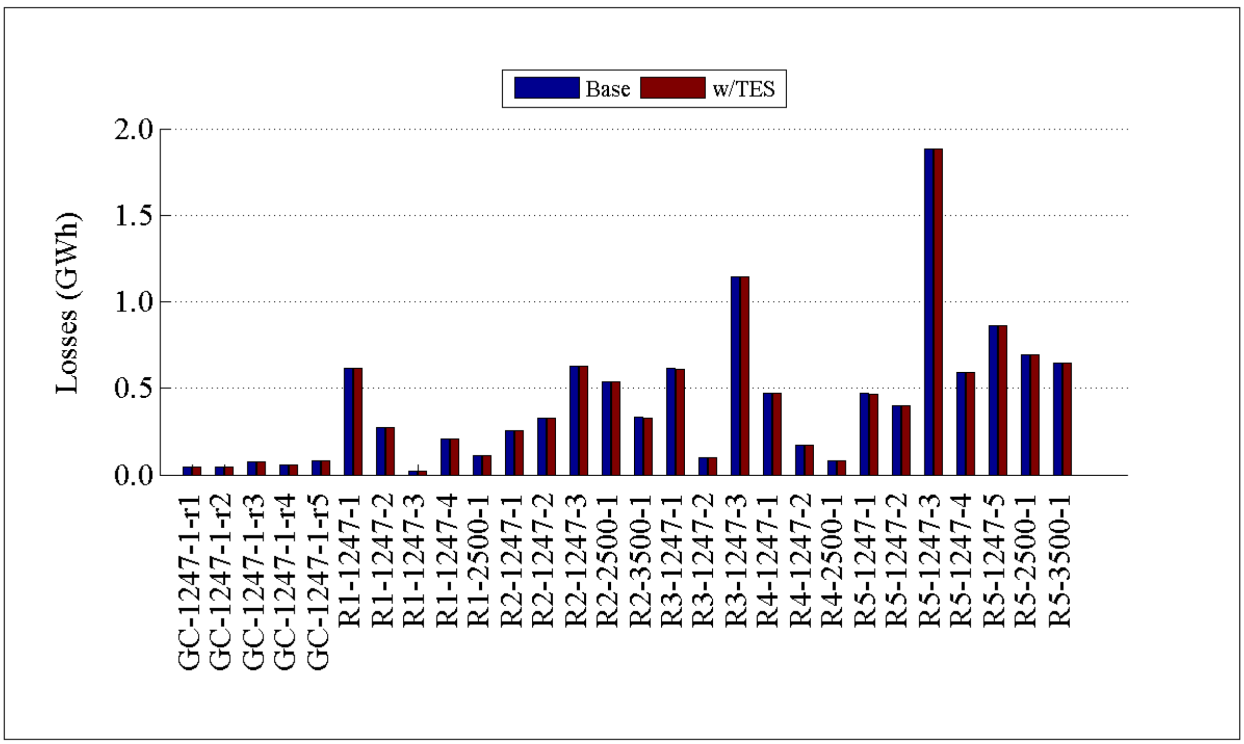

Figure 2.7: Distribution losses by feeder

To further examine the change in losses with thermal energy storage deployed, the difference plots are also useful. Figure 2.8 and Figure 2.9 show the MWh difference and percent difference plots for the change in energy losses. As with the overall energy change, R5-12.47-1 shows the largest energy change. Unlike the overall energy plot, Figure 2.8 shows that all of the feeders had either a net decrease or no effective change in the energy attributed to losses. R1-12.47-1 still shows a very marginal increase, but it represents only a 0.01% change in the energy associated with losses.

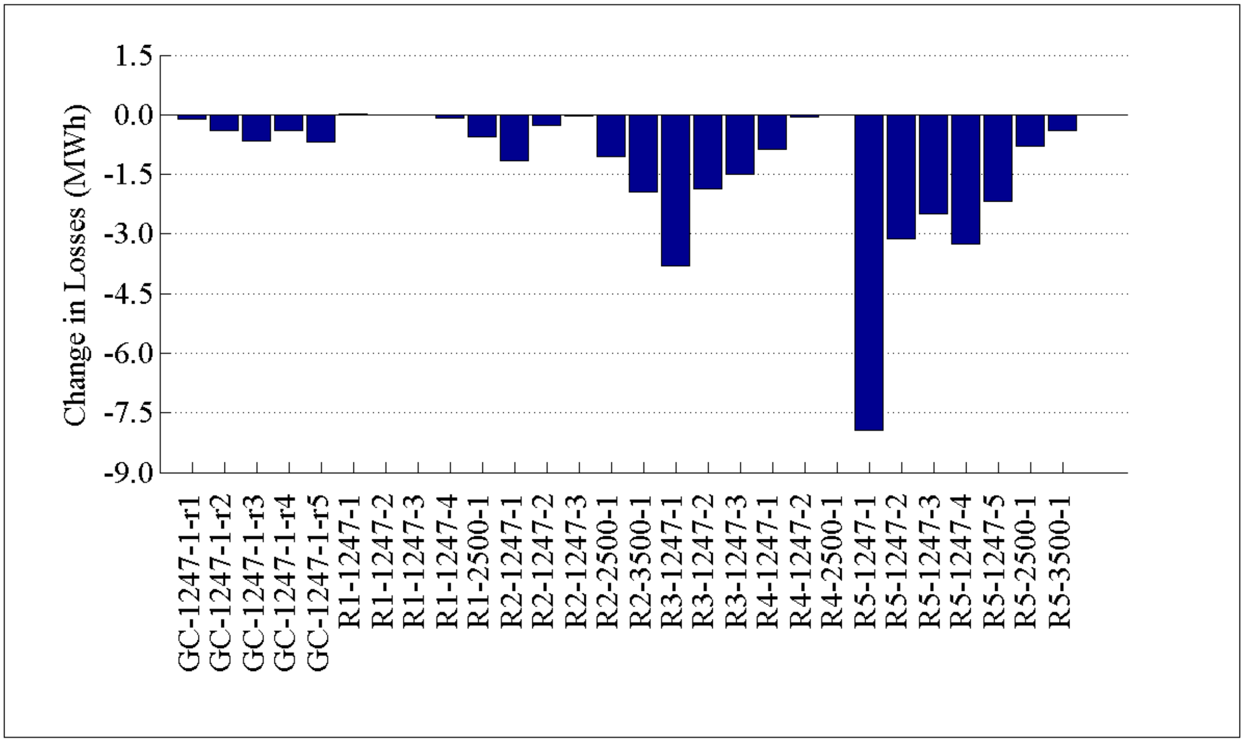

Figure 2.8: Distribution losses energy by feeder

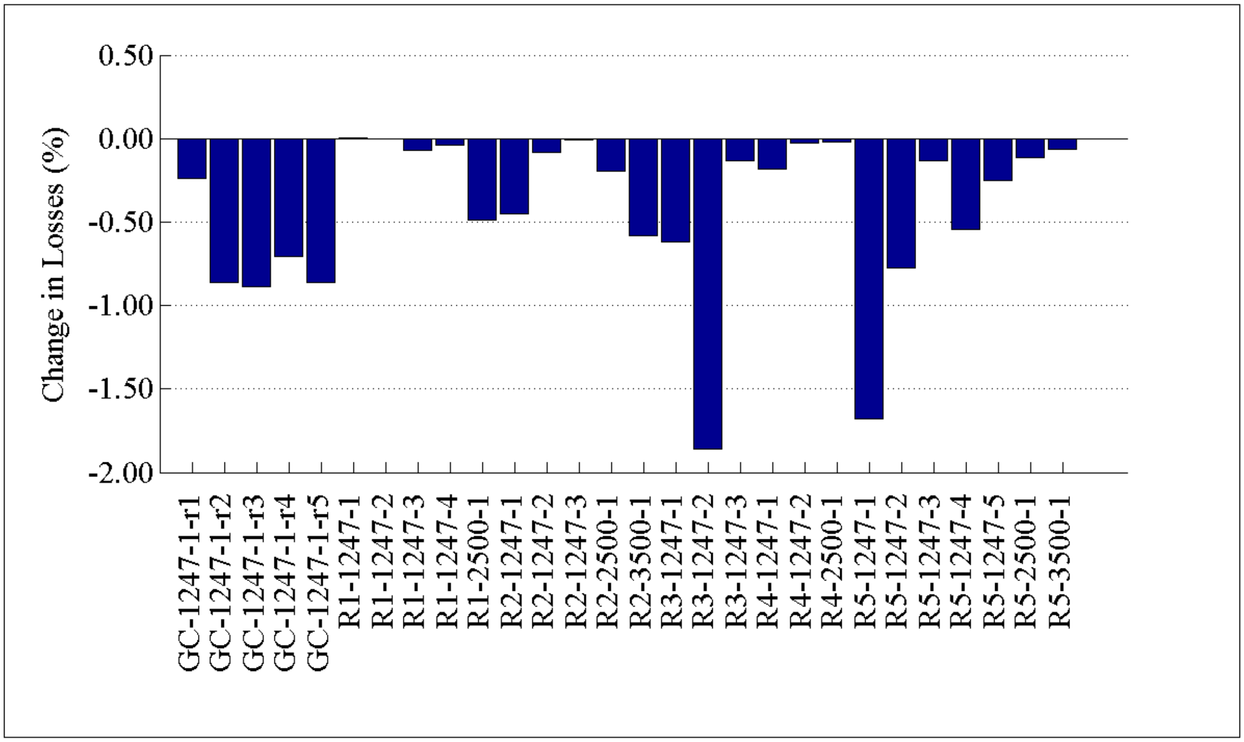

Figure 2.9: Distribution energy losses percent differences by feeder

Another interesting difference in the losses is apparent in Figure 2.9. While the overall loss values in Figure 2.8 follow trends similar to the energy consumption value, Figure 2.9 shows that the change in losses is more significant. Whereas most of the overall energy changes were small, the change in losses after deploying thermal energy storage is noticeably higher across all feeders. Given the peak reduction nature of thermal energy storage, this is not a surprising observation. High losses can often be attributed to heavier loaded systems (more current flowing through the overhead and underground lines), so a reduction in the peak load can have a direct impact on reducing the losses of the system.

2.1.3.4 Annual CO_2 Emissions

With the changes in energy consumption associated with the deployment of thermal energy storage, the influence on the environmental impacts is another secondary consideration. In particular, carbon dioxide emissions will change with the energy consumption. Decreasing the energy will affect carbon dioxide emissions associated with a particular feeder.

Environmental emissions for each feeder were estimated using a simple dispatch algorithm. Generation sources were sized by the regional generator types, and ranked to dispatch in an appropriate order. Full commitments were achieved before proceeding to the next generator. For example, consider a region where natural gas turbines dispatch first and support 250 MW of load, followed by 400 MW of petroleum-fired generation. To support 300 MW of load, the natural gas is fully dispatched, then the remaining 50 MW is attributed to petroleum-fired generation. Representative heat rates and emission rates are then applied to these power outputs to determine the overall environmental impacts. The details of these rates, along with the dispatch orders and amounts for each region, are explained in Appendix B.3. Figure 2.10 shows the annual carbon dioxide outputs associated with the output for each feeder.

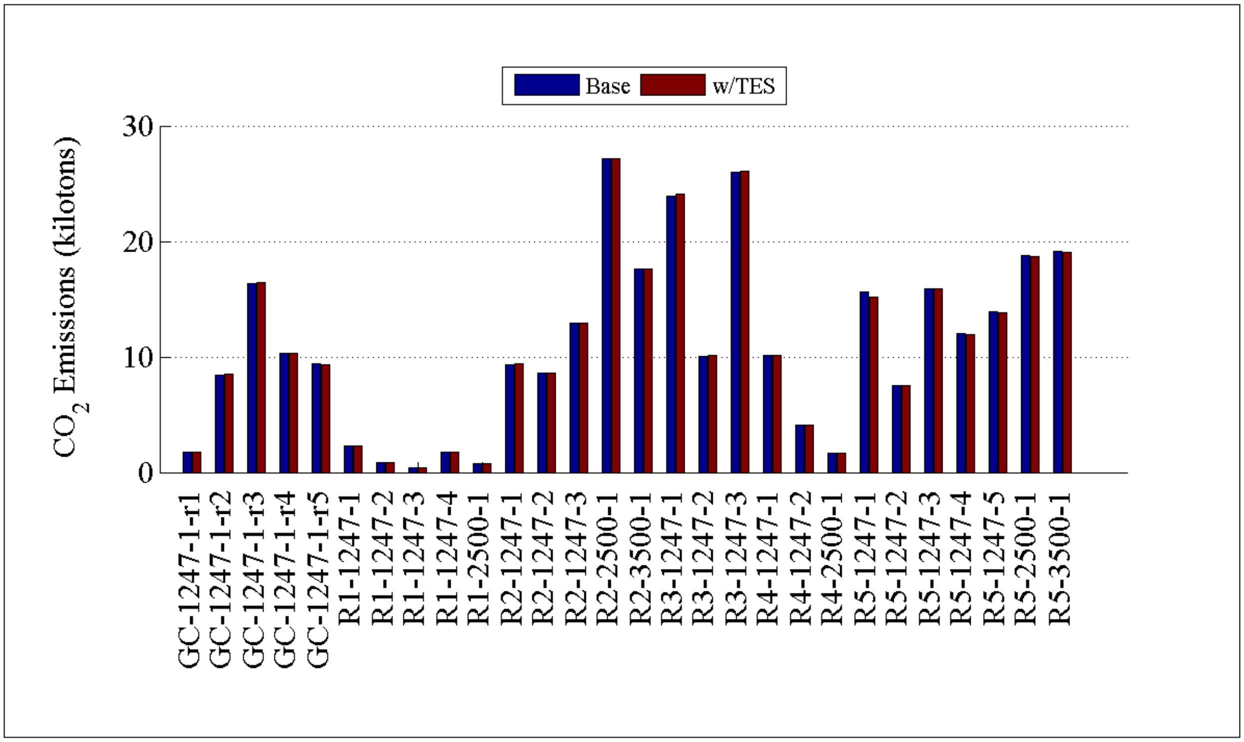

Figure 2.10: CO_2 emissions by feeder

As Figure 2.10 demonstrates, many of the carbon dioxide emissions levels did not change significantly. Some feeders, such as R5-12.47-1 and R5-12.47-5, show a decrease in CO_2 emissions when thermal energy storage is utilized. However, feeders such as R3-12.47-1 and R3-12.47-3 show a slight increase in carbon dioxide emissions with thermal energy storage. Figure 2.11 and Figure 2.12 allow an easier observation of the changes by plotting the emissions differences and percent differences, respectively.

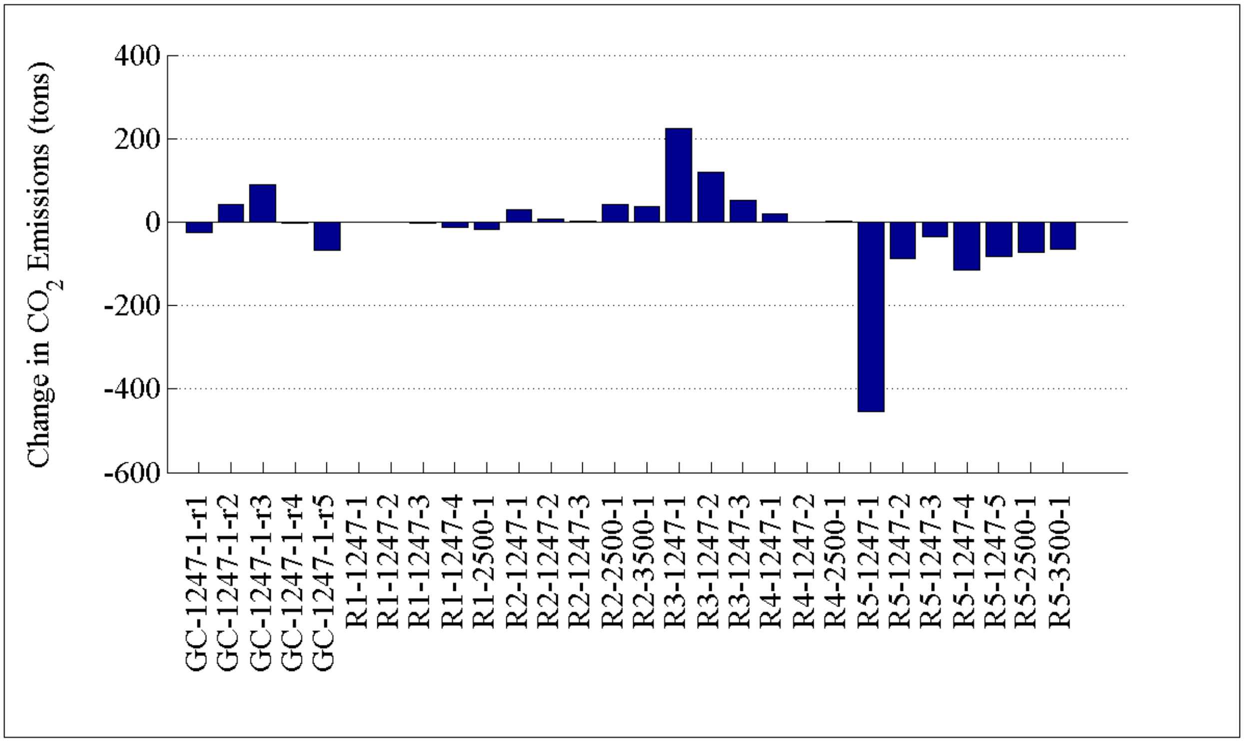

Figure 2.11: Carbon dioxide emissions differences by feeder

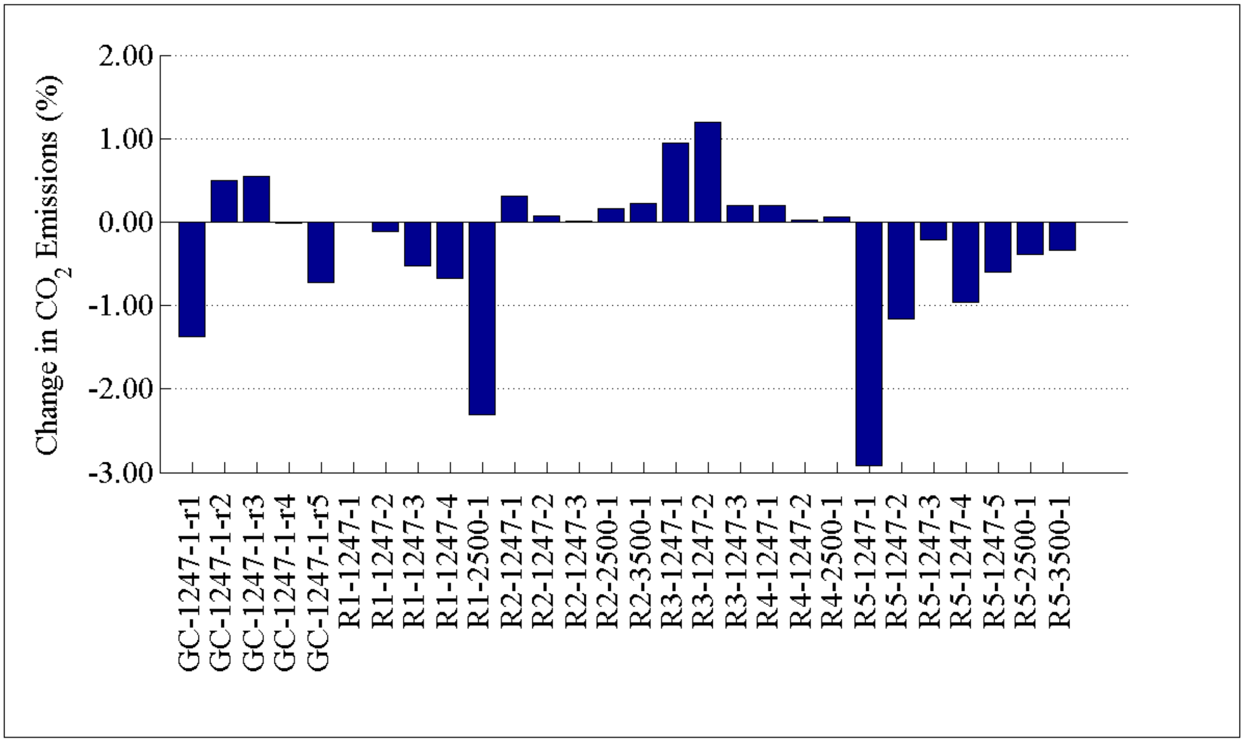

Figure 2.12: Carbon dioxide percent differences by feeder

Figure 2.11 and Figure 2.12 highlight the variable nature of the carbon dioxide emissions results associated with thermal energy storage. Many of the feeders show a decrease in carbon dioxide emissions, while others show an increase. The inconsistent nature of the emissions across the different feeders is a relationship between the actual energy consumption and the marginal power sources.

Consider the plot of Figure 2.13, which shows the carbon dioxide emissions for given times of the day for the feeder R3-12.47-1. As the figure shows, the carbon dioxide emissions are slightly less using thermal energy storage during the peak hours. However, thermal energy storage results in a larger carbon dioxide emissions footprint during the early morning hours (midnight to 5 AM). Energy consumption for the day is 1.04 MWh less for thermal energy storage, but 0.26 tons more carbon dioxide was produced.

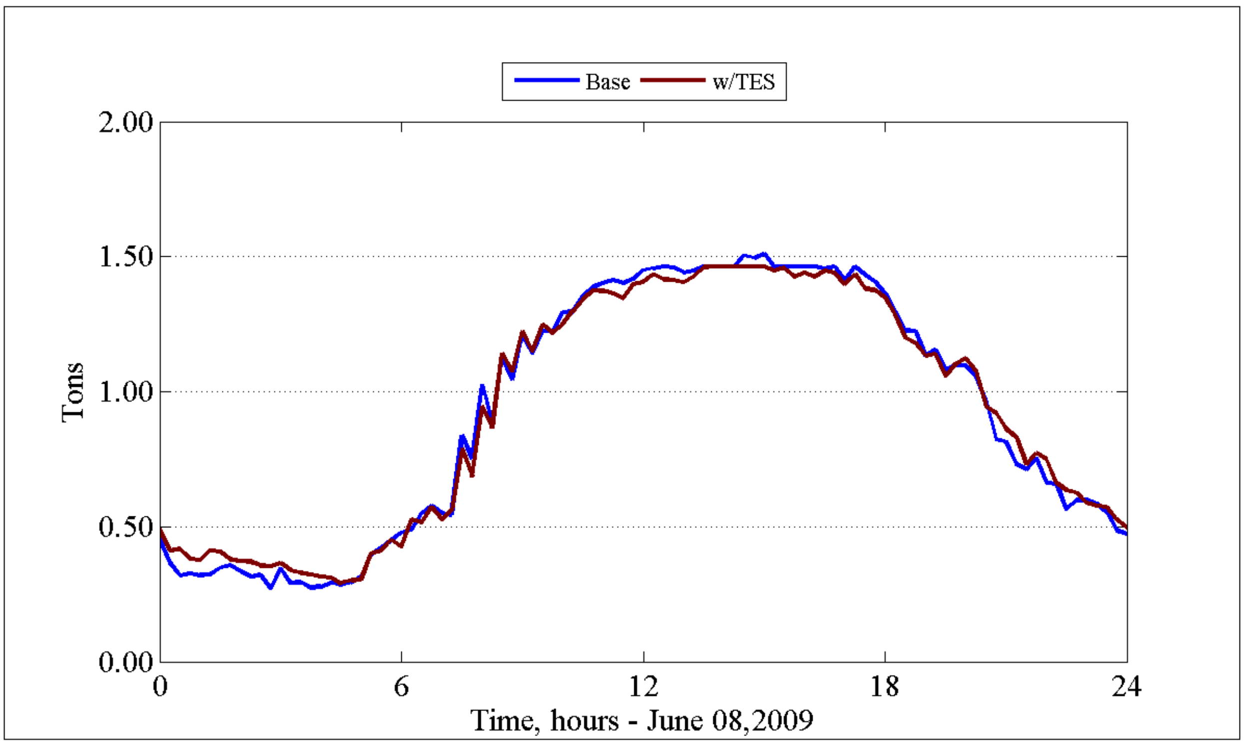

Figure 2.13: CO_2 emissions for June 8, 2009 on the R3-12.47-1 feeder

This disparity is directly related to the marginal generation at each time period. During the peak hours, the cooling load is mostly served by natural gas units in this climate region. This is why the thermal energy storage results show only a slight reduction in the CO_2 emissions. However, at 3 AM, coal generating plants are the marginal unit. While the thermal energy storage is recharging, its predominant energy source is the more CO_2 intense coal generation. The result is more carbon dioxide per “cooling unit” than the normal HVAC utilized in the base case.

Figure 2.14 shows the marginal generator for different instances during the day shown in Figure 2.13. As the figure shows, the marginal generator only changes for a few intervals during the peak portion of the day. While thermal energy storage is deferring the usage of more carbon intensive petroleum generation sources, this deferment is only for a short period. Much of the peak is still spent with natural gas turbines as the marginal generation. However, during the recharging time of the thermal energy storage, coal is the marginal generation source. Comparing the duration and pollution emissions of a coal plant to a natural gas plant, the shifting of thermal energy storage is actually producing more carbon dioxide than a unit running on the margin during peak load. As indicated earlier, this result is heavily dependent on the region and generation mix of this particular feeder.

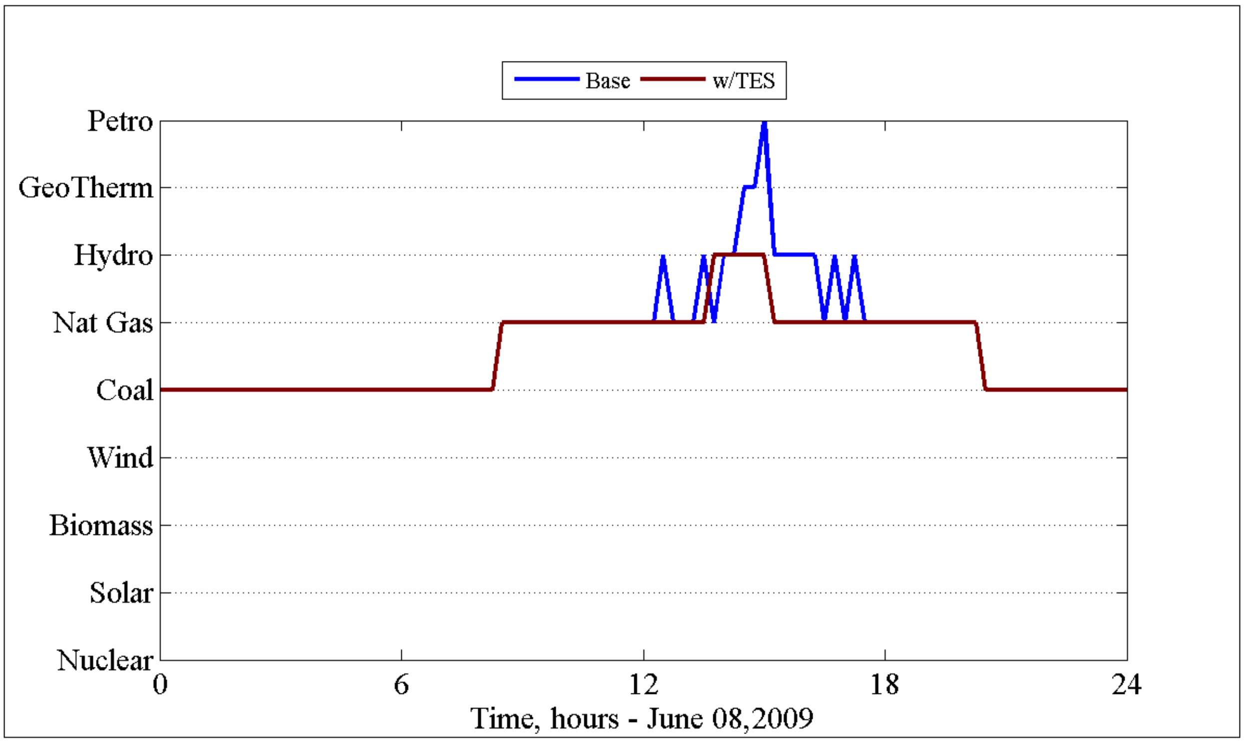

Figure 2.14. Marginal generators for June 8, 2009 on the R3-12.47-1 feeder

2.1.3.5 Annual Storage Dispatched

The final consideration of deploying thermal energy storage is examining how much storage energy is actually deployed on the feeder. Unlike the peak reduction and energy reduction, the amount of storage dispatched indicates how much load was shifted to another period of the day. Figure 2.15 shows the amount of storage dispatched for each feeder.

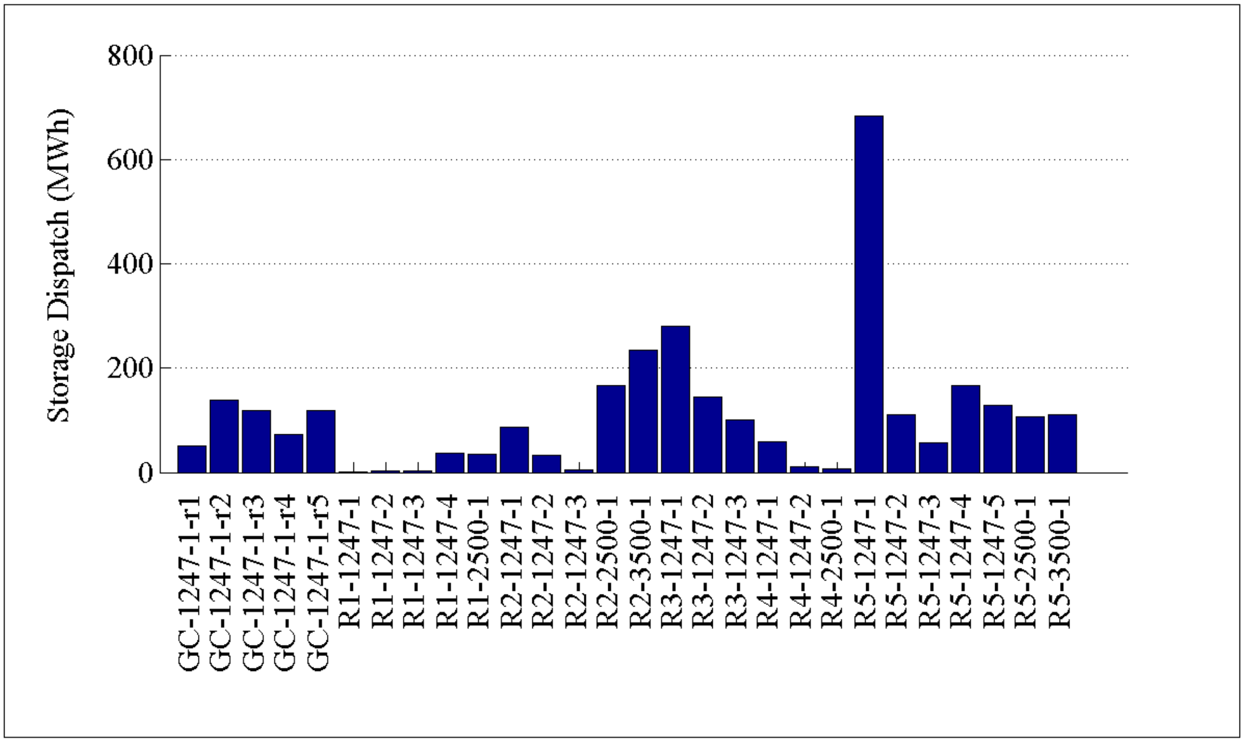

Figure 2.15: Storage dispatched by feeder

Figure 2.15 indicates that most of the feeders dispatched less than 200 MWh of storage over the year-long simulation. Despite this lower dispatch amount, the values of Figure 2.15 are not really referenced to their particular feeder's conditions. For example, R5-12.47-1's 700 MWh of storage could be equivalent to R1-2500-1's 50 MWh in terms of overall energy content. To help provide this frame of reference, the energy dispatched was normalized against the total energy consumption of the feeder. The results are shown in Figure 2.16.

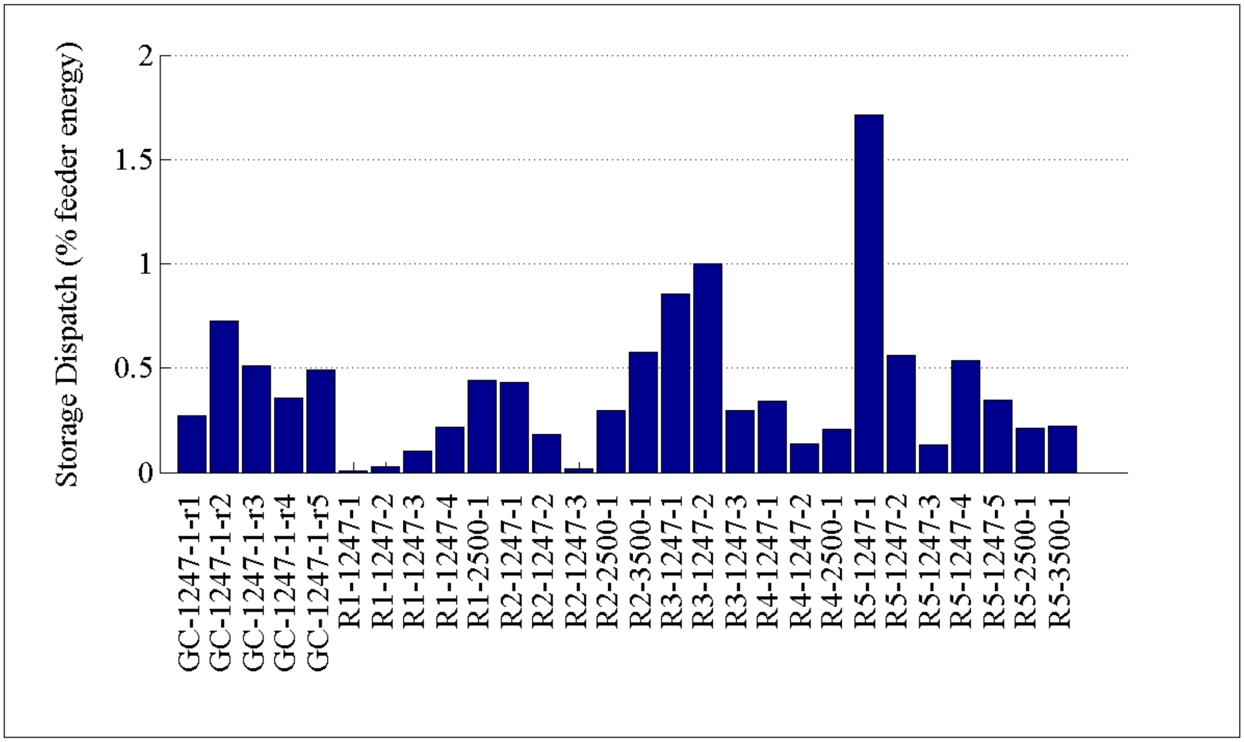

Figure 2.16: Percent of overall energy dispatch storage by feeder

The results of Figure 2.16 show that most of the feeders dispatch less than one percent of the total annual energy output as storage. The low energy penetration shown in Figure 2.16 is primarily a result of the small deployment of thermal energy storage on the test feeders. The low energy percentage is also a result of the peak deployment of thermal energy storage. If the thermal energy storage were allowed multiple charge and discharge periods during the day, the energy content may increase to a larger portion of the overall feeder energy consumption.

3 Detailed Individual Prototypical Feeder Results

Due to the large number of plots generated for each feeder, compounded by the total number of feeders, it is not practical to discuss all of the results in great depth. This section will examine the output results of a single feeder. The plots associated with the other feeders will be available in Appendix D. Analysis presented in this section can easily be extended to any of the feeder results presented in Appendix D.

3.1 Example Feeder R3-12.47-2

The data presented in this section represents the results from the simulation of feeder R3-12.47-2. This particular feeder is located in climate region associated with non-coastal south western United States cities. As such, it is characterized by a hot and arid climate condition shown in Figure B.1. This particular feeder also represents one of the smaller feeders in the taxonomy of prototypical feeders [3]. Thermal energy storage was deployed to a level of roughly 7.6% of the commercial building space, which represents approximately 7.6% of the total feeder buildings. These numbers indicate the deployment of thermal energy storage was a little lower than the 10% penetration criterion, but still represents a reasonable level of implementation. This feeder also only contains commercial buildings, with no residential homes present on the feeder. The lack of residential load means thermal energy storage has a greater feeder-level-building penetration than a mixed load feeder. That is, thermal energy storage is deployed on 7.6% of both commercial and total buildings on the feeder, where a mixed-load feeder may have it on 7.6% of commercial load, but only 1% of the total buildings in the feeder circuit.

With the focus narrowed to a particular feeder, monthly results for the various quantities of Section 2 can also be examined. Figure 3.1 shows the difference in peak load values for each month of the simulation. The figure demonstrates that the thermal energy storage is accomplishing its fundamental goal in R3-12.47-2: the thermal energy storage is reducing the peak load. Furthermore, the reduction appears to be consistent for all months of the year.

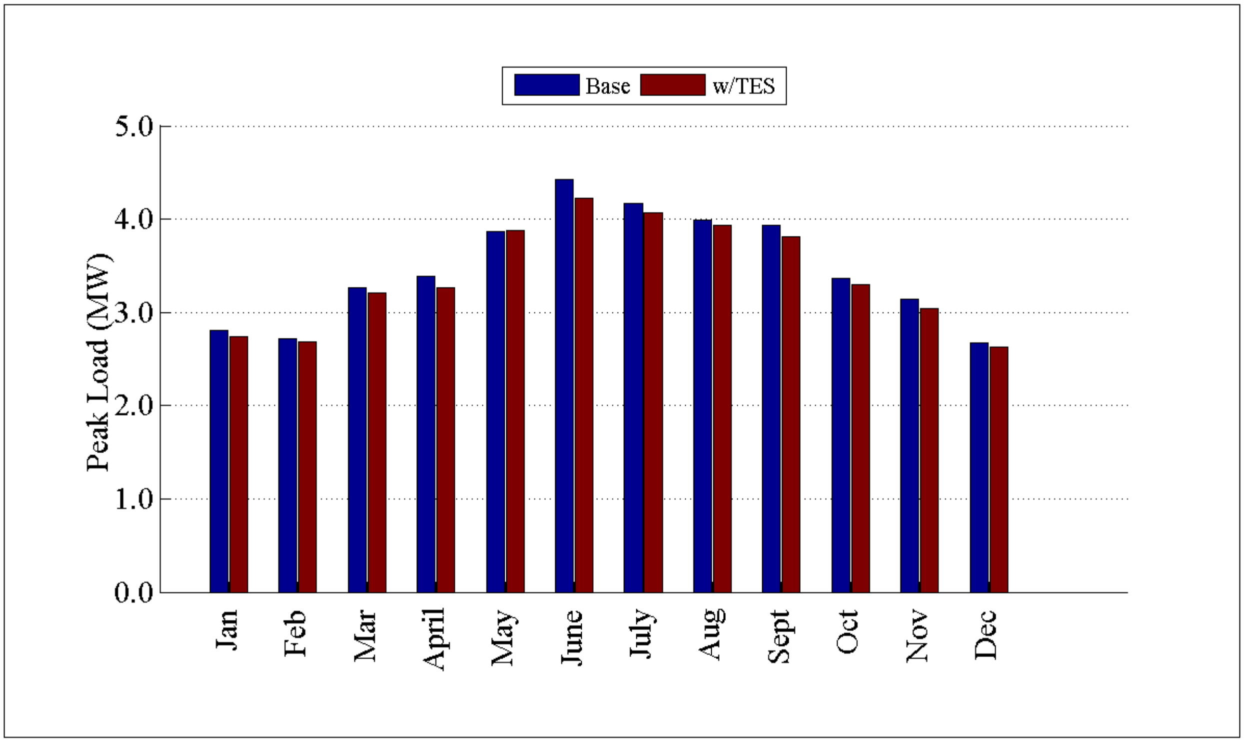

Figure 3.1: Peak load by month of R3-12.47-2 feeder

Given the hot and arid conditions the climate region of this feeder represents, it is not surprising that the thermal energy storage is providing a peak reduction for all months of the simulation. Even during cooler months of the year, this particular region may still use HVAC systems to cool buildings (especially the commercial buildings composing this feeder) during peak load hours. As such, thermal energy storage units will still be utilizing the ice-energy storage to shift load to a lower peak period.

The next quantity of interest for the R3-12.47-2 feeder was the change in monthly energy consumption when thermal energy storage was deployed. As with the peak power figures, by examining the feeders individually it is possible to show the monthly values. The monthly changes in energy consumption are shown in Figure 3.2.

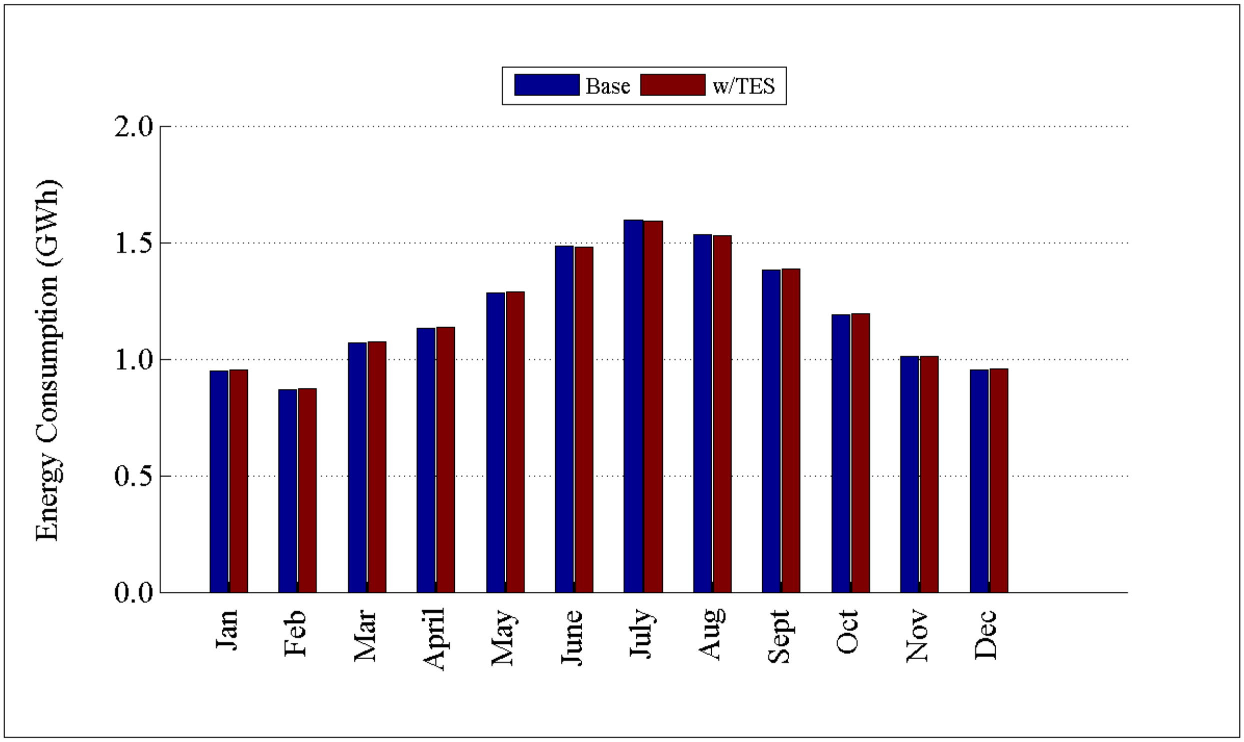

Figure 3.2: Monthly energy consumption for R3-12.47-2 feeder

The monthly values for the energy consumption, shown in Figure 3.2, show the energy consumed by the feeder increases and decreases when thermal energy storage is present. Energy reduction primarily comes as a result of the thermal energy storage recharging in the early morning hours. The amount of energy needed to "charge" the thermal energy storage (create ice) is lower when the temperature is lower during the early morning. This is related to how efficiently the compressors operate in the lower temperatures, as well as the amount of cooling needed to reach a freezing point. The same thermal cooling during the peak hours requires a noticeably larger amount of energy to accomplish. As such, the thermal energy storage is effectively providing a more efficient cooling mechanism.

While the decrease in energy consumption can largely be attributed to the thermal energy storage cooling efficiency, some of the savings come from other sources. Another potential source of the energy savings is in the energy attributed to losses on the distribution system. With the reduced peak load on the system, the loads on the distribution lines and transformers are reduced. This translates into lower current flows, which is directly related to the losses in these devices. With lower values of current, the amount of losses on the devices is reduced and contributes toward the energy savings. Figure 3.3 shows the change in loss energy for the R3-12.47-2 feeder with thermal energy storage present. In Figure 3.3, OHL represents overhead lines, UGL represents underground lines, TFR represents losses in secondary transformers, and TPL represents losses associated with triplex (secondary) lines.

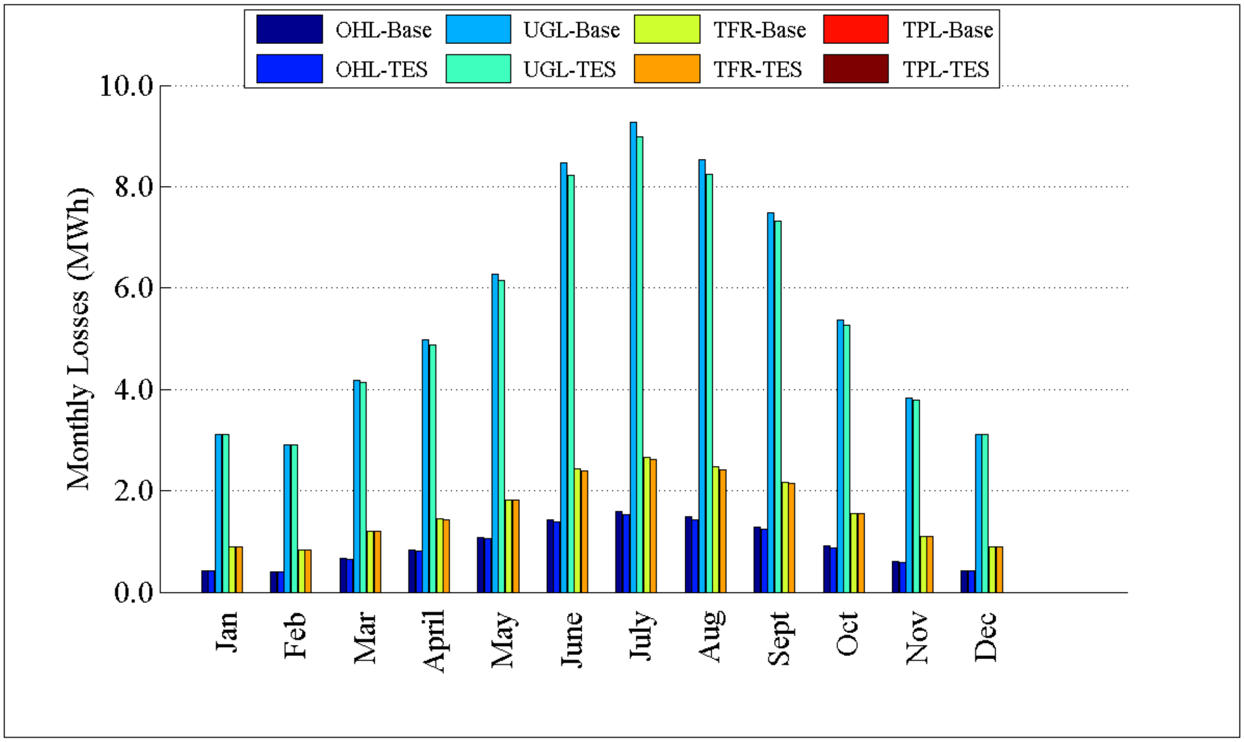

Figure 3.3: Distribution system losses by month for R3-12.47-2

As Figure 3.3 indicates, there was not a significant change in the energy associated with losses on the system. The largest change is attributed to the underground lines on the system, but only resulted in a 0.1 MWh energy reduction per month. Changes in the overall energy consumption will also influence the environmental emissions of the feeder. Carbon dioxide emissions, in particular, may change significantly for certain generation mixes. Figure 3.4 shows the overall changes to CO_2 emissions when thermal energy storage is deployed.

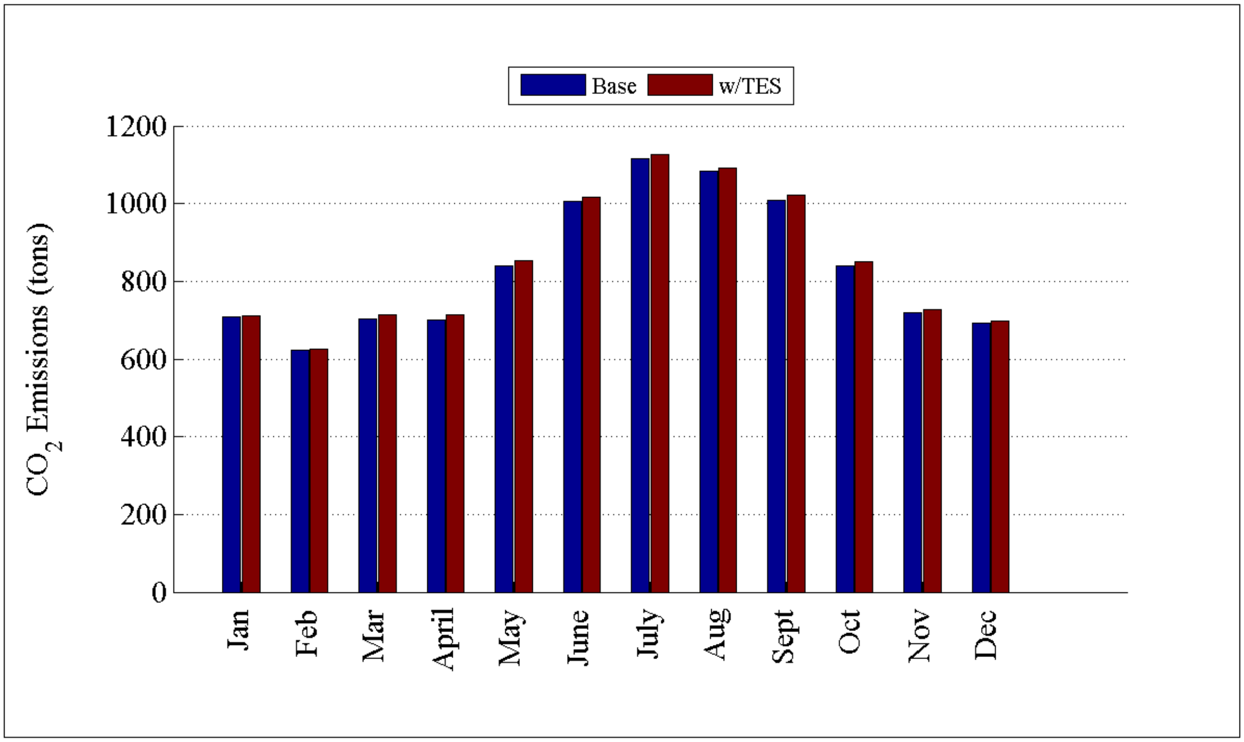

Figure 3.4: CO_2 emissions by month for R3-12.47-2

Figure 3.4 does show an overall increase in carbon dioxide emissions with the deployment of thermal energy storage. The slight increase in energy consumption of the feeder is the major driver of this result, but the generation mix also plays a key role. If the early morning generation produced significantly higher carbon dioxide emissions, the thermal energy storage could result in higher CO_2 emissions. Figure 3.5 shows the peak consumption day for the year with the CO_2 emissions overlaid. As the figure demonstrates, despite shifting the cooling demand to the early morning hours, CO_2 emissions were not significantly increased. However, they were not noticeably decreased during the mid-day hours, resulting in a slight increase in the overall carbon dioxide emissions.

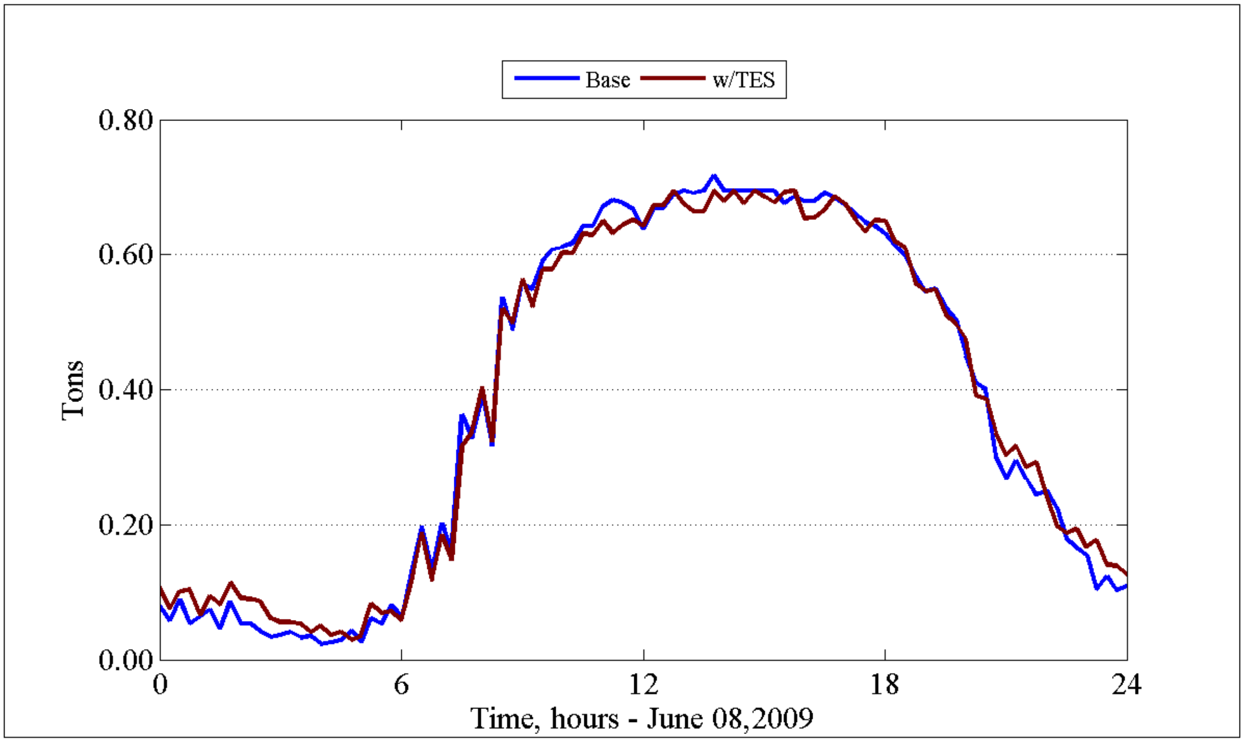

Figure 3.5: Carbon dioxide emissions for peak day of R3-12.47-2

With all of the system impacts of the thermal energy storage, it is also useful to examine how the storage was dispatched across the different months. Figure 3.6 shows the amount of energy the thermal energy storage dispatched for each month of the year. Similar to the overall studies shown in previous sections, it is useful to examine this result of a percentage of total feeder consumption. This information is shown in Figure 3.7.

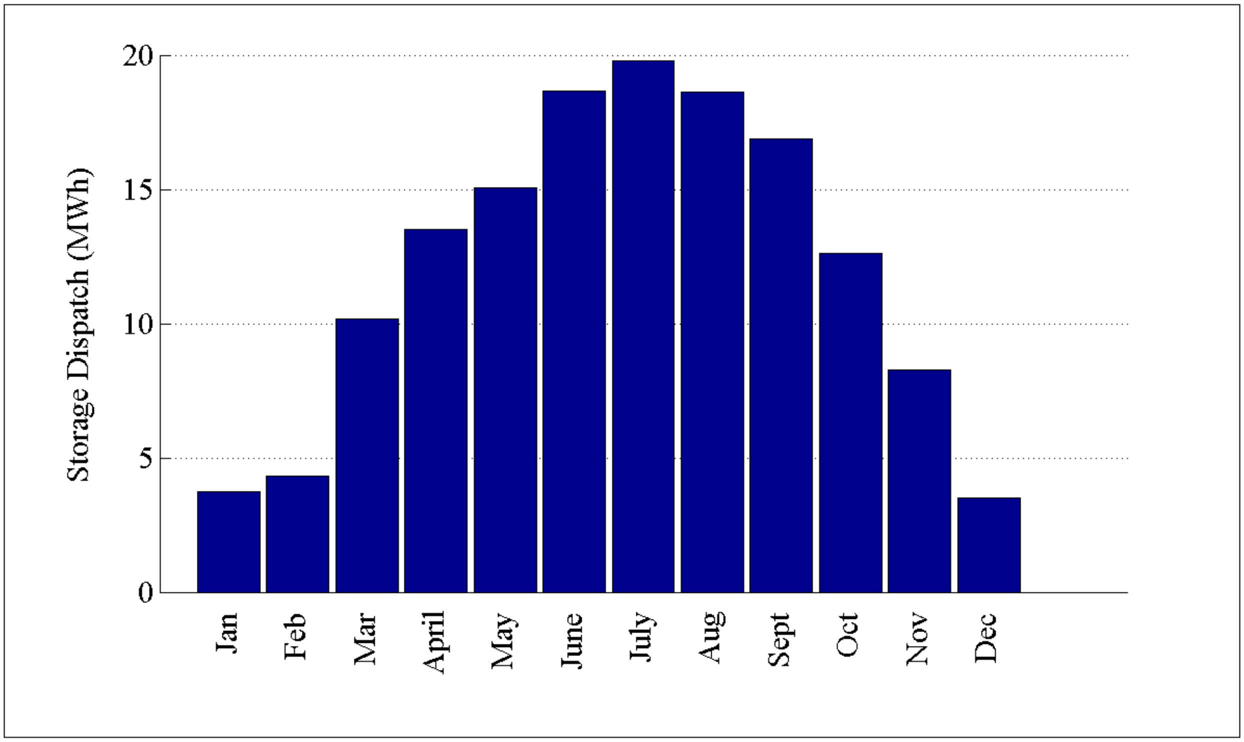

Figure 3.6: Monthly storage dispatch energy for R3-12.47-2

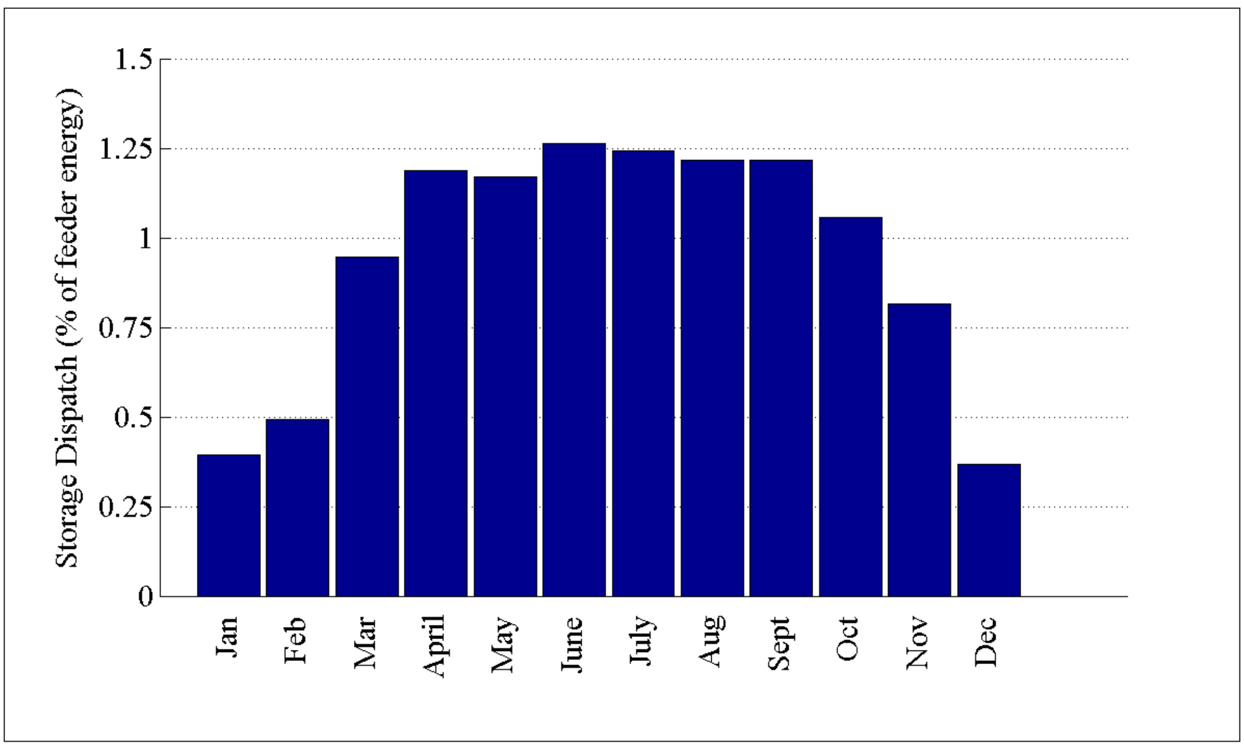

Figure 3.7: Monthly storage dispatch energy percentage for R3-12.47-2

Figure 3.6 indicates that thermal energy storage dispatched the most energy during the month of July. However, Figure 3.7 shows that, proportionally, this amount of energy was similar to that of the April to September months. This is an indication that as temperatures rose and consumption increased (due to HVAC loads being used longer), the thermal energy storage still had sufficient capacity to meet the increased demand of its building.

The secondary implication of Figure 3.7 is that the thermal energy storage may be oversized for the load. If the load increases and the thermal energy storage units are able to meet the same proportion of the load, this indicates the thermal storage is not being completely depleted. Figure 3.8 shows the minimum "state of charge" for each month for the thermal energy storage devices on R3-12.47-2.

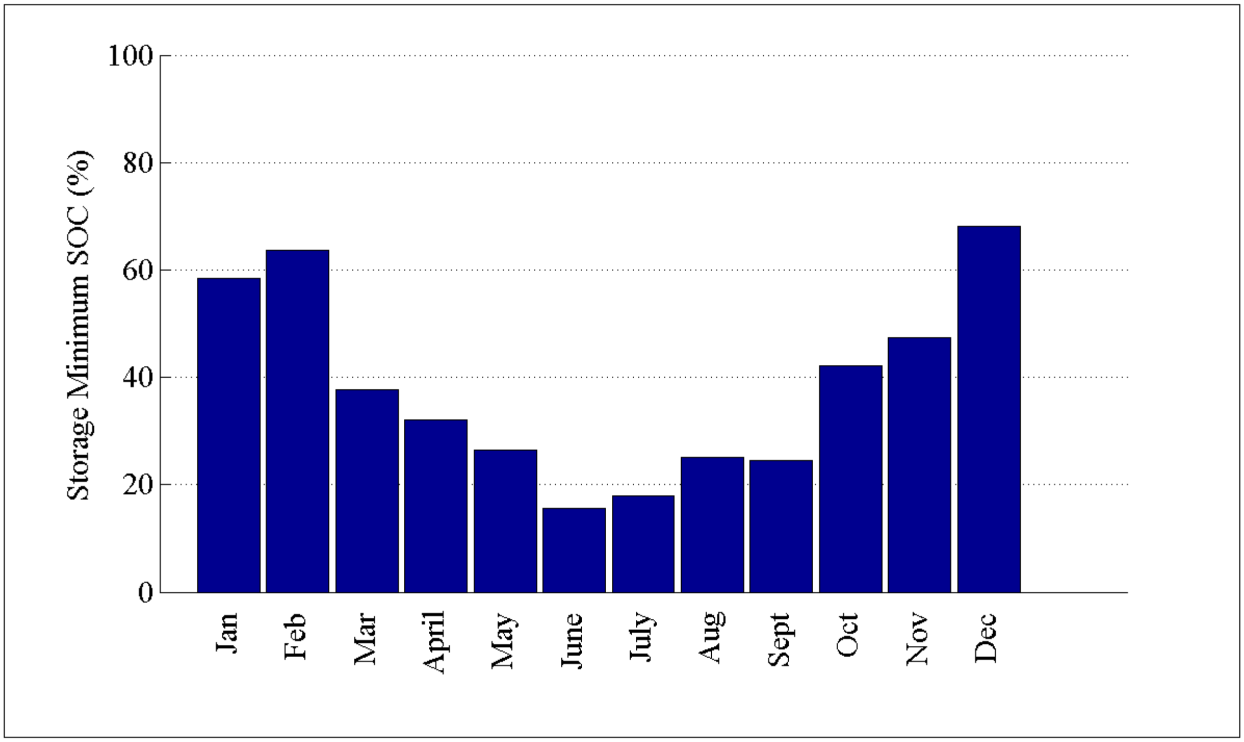

Figure 3.8: Minimum state of charge for thermal energy storage on R3-12.47-2

It is important to note that this is the state of charge for all thermal energy storage on the feeder. A non-zero minimum state of charge indicates that there may be excessive TES capacity and that the optimal level is lower than what is deployed. Unlike chemical storage, thermal energy storage can be discharged to 0% SOC without adverse impact on the units capacity. Some of the units may be fully depleting, but others may be oversized for their particular building, and therefore never completely discharge. Furthermore, the excess state of charge provides margins for temperature variations in other years. The implications of any excess thermal energy storage capacity would need to be decided for each individual situation.

4 SGIG Impact Metric Values

The specific impact metrics examined were determined in Section 0. The raw metric values are available for each feeder in Appendix E.

4.1 Thermal Energy Storage Impact Metrics

The impact metrics of interest for thermal storage were outlined in Table 2.1. Tables 4.1 to Table 4.5 show the impacts for each feeder, grouped by climate region. The impact values are determined as the difference between the base information contained in Table E.1 to Table E.5 and the thermal energy storage information contained in Table E.6 to Table E.10. Note that the values in the impact tables may be rounded appropriately, so very small differences may be rounded to 0 (e.g., emissions tonnage).

Table 4.1: Impact metrics for climate region 1

Index	Δ Metric	Units	GC-12.47-1 R1	R1-12.47-1	R1-12.47-2	R1-12.47-3	R1-12.47-4	R1-25.00-1
1	Hourly Customer Electricity Usage	kWh	2.81	0.15	0.06	0.17	1.84	1.70
2	Monthly Customer Electricity Usage	MWh	2.05	0.11	0.04	0.13	1.34	1.24
3	Peak Generation	kW	-66.16	5.67	-52.27	-33.50	-18.38	-54.16
	Nuclear	%	0.00	0.00	0.00	0.00	0.00	0.00
	Solar	%	0.00	0.00	0.00	0.00	0.00	0.00
	Bio	%	0.00	0.00	0.00	0.00	0.00	0.00
	Wind	%	0.00	0.00	0.00	0.00	0.00	0.00
	Coal	%	0.00	0.00	0.00	0.00	0.00	0.00
	Hydroelectric	%	0.00	0.00	0.00	0.00	0.00	0.00
	Natural Gas	%	0.00	0.00	0.00	0.00	0.00	0.00
	Geothermal	%	-0.90	0.00	-1.60	-2.31	0.00	-1.99
	Petroleum	%	-0.35	0.08	-0.35	-0.35	-0.36	-0.35
4	Peak Load	MW	-66.16	5.67	-52.27	-33.50	-18.38	-54.16
7	Annual Electricity Production	MWh	24.55	1.32	0.49	1.49	16.03	14.30
12	CO2 Emissions	Tons	-24.47	0.11	-0.89	-2.07	-11.91	-17.30
13	SOx Emissions	Tons	0.00	0.00	0.00	0.00	0.00	0.00
	NOx Emissions	Tons	0.00	0.00	0.00	0.00	0.00	0.00
	PM-10 Emissions	Tons	0.00	0.00	0.00	0.00	0.00	0.00
17	Annual Storage Dispatch	MWh	50.15	1.22	2.28	3.83	37.78	34.31
18	Average Energy Storage Efficiency	%	102.91	103.65	103.76	103.55	103.04	102.79
21	Feeder Real Load	MW	2.80	0.15	0.06	0.17	1.83	1.63
	Feeder Reactive Load	MVAR	-1.58	-0.03	-0.08	-0.14	-1.28	-1.22
29	Distribution Losses	%	0.00	0.00	0.00	0.00	0.00	0.01
39	CO2 Emissions	Tons	-24.54	0.11	-0.92	-2.09	-12.09	-17.63
40	SOx	Tons	0.00	0.00	0.00	0.00	0.00	0.00
	NOx	Tons	0.00	0.00	0.00	0.00	0.00	0.00
	PM-10	Tons	0.00	0.00	0.00	0.00	0.00	0.00

Table 4.2: Impact metrics for climate region 2

Index	Δ Metric	Units	GC-12.47-1 R2	R2-12.47-1	R2-12.47-2	R2-12.47-3	R2-25.00-1	R2-35.00-1
1	Hourly Customer Electricity Usage	kWh	3.12	2.06	0.59	0.04	3.42	5.53
2	Monthly Customer Electricity Usage	MWh	2.28	1.51	0.43	0.03	2.50	4.04
3	Peak Generation	kW	-134.59	-178.34	-17.48	-62.86	-281.70	-596.80
	Nuclear	%	0.00	0.00	0.00	-1.62	0.00	0.00
	Solar	%	0.00	0.00	0.00	0.00	0.00	0.00
	Bio	%	0.00	0.00	0.00	-0.02	0.00	0.00
	Wind	%	0.00	0.00	0.00	-0.29	0.00	0.00
	Coal	%	0.00	0.00	0.00	1.64	0.00	0.00
	Hydroelectric	%	-1.84	-2.34	0.00	-1.63	-1.17	-4.21
	Natural Gas	%	0.00	0.00	0.00	1.86	0.00	0.00
	Geothermal	%	-0.07	-0.07	0.00	-0.05	-0.07	-0.07
	Petroleum	%	-0.43	-0.43	-0.30	-0.37	-0.43	-0.43
4	Peak Load	MW	-134.59	-178.34	-17.48	-62.86	-281.70	-596.80
7	Annual Electricity Production	MWh	26.93	16.92	4.88	0.36	28.91	46.51
12	CO2 Emissions	Tons	42.56	28.79	6.21	1.17	43.42	39.02
13	SOx Emissions	Tons	0.04	0.02	0.00	0.00	0.04	0.04
	NOx Emissions	Tons	0.02	0.01	0.00	0.00	0.02	0.03
	PM-10 Emissions	Tons	0.01	0.00	0.00	0.00	0.01	0.01
17	Annual Storage Dispatch	MWh	138.11	86.72	32.24	4.57	166.77	233.80
18	Average Energy Storage Efficiency	%	102.84	102.40	102.98	102.83	102.74	102.71
21	Feeder Real Load	MW	3.07	1.93	0.56	0.04	3.30	5.31
	Feeder Reactive Load	MVAR	-5.74	-3.74	-1.47	-0.18	-7.36	-10.26
29	Distribution Losses	%	0.00	0.01	0.00	0.00	0.00	0.00
39	CO2 Emissions	Tons	42.45	28.52	6.15	1.18	43.19	38.32
40	SOx	Tons	0.04	0.02	0.00	0.00	0.04	0.04
	NOx	Tons	0.02	0.01	0.00	0.00	0.02	0.03
	PM-10	Tons	0.01	0.00	0.00	0.00	0.01	0.01

Table 4.3: Impact metrics for climate region 3

Index	Δ Metric	Units	GC-12.47-1 R3	R3-12.47-1	R3-12.47-2	R3-12.47-3
1	Hourly Customer Electricity Usage	kWh	1.37	4.49	2.86	-0.02
2	Monthly Customer Electricity Usage	MWh	1.00	3.28	2.09	-0.01
3	Peak Generation	kW	-113.97	-282.36	-192.35	-141.46
	Nuclear	%	0.00	0.00	0.00	-1.22
	Solar	%	0.00	0.00	0.00	0.01
	Bio	%	0.00	0.00	0.00	-0.04
	Wind	%	0.00	0.00	0.00	-0.25
	Coal	%	0.00	0.00	0.00	-0.10
	Hydroelectric	%	-0.28	-1.38	-2.70	-1.81
	Natural Gas	%	0.00	0.00	0.00	3.60
	Geothermal	%	-1.25	-1.40	-1.40	-0.14
	Petroleum	%	-0.20	-0.25	-0.25	0.44
4	Peak Load	MW	-113.97	-282.36	-192.35	-141.46
7	Annual Electricity Production	MWh	11.37	35.52	23.20	-1.64
12	CO2 Emissions	Tons	90.22	224.13	120.44	51.96
13	SOx Emissions	Tons	0.07	0.17	0.09	0.04
	NOx Emissions	Tons	0.04	0.10	0.05	0.02
	PM-10 Emissions	Tons	0.01	0.03	0.02	0.01
17	Annual Storage Dispatch	MWh	118.86	279.76	145.18	100.11
18	Average Energy Storage Efficiency	%	103.42	103.12	103.42	103.64
21	Feeder Real Load	MW	1.30	4.05	2.65	-0.19
	Feeder Reactive Load	MVAR	-5.08	-12.16	-6.24	-4.81
29	Distribution Losses	%	0.00	0.01	0.01	0.00
39	CO2 Emissions	Tons	90.01	225.06	119.85	52.63
40	SOx	Tons	0.07	0.17	0.09	0.04
	NOx	Tons	0.04	0.10	0.05	0.02
	PM-10	Tons	0.01	0.03	0.02	0.01

Table 4.4: Impact metrics for climate region 4

Index	Δ Metric	Units	GC-12.47-1 R4	R4-12.47-1	R4-12.47-2	R4-25.00-1
1	Hourly Customer Electricity Usage	kWh	1.08	0.45	-0.05	0.01
2	Monthly Customer Electricity Usage	MWh	0.78	0.33	-0.04	0.01
3	Peak Generation	kW	-131.05	-163.14	-55.08	-30.54
	Nuclear	%	0.00	0.00	0.00	0.00
	Solar	%	0.00	0.00	0.00	0.00
	Bio	%	0.00	0.00	0.00	0.00
	Wind	%	0.00	0.00	0.00	0.00
	Coal	%	0.00	0.00	0.00	0.00
	Hydroelectric	%	-1.63	-2.20	-2.17	-2.90
	Natural Gas	%	0.00	-0.72	0.00	0.00
	Geothermal	%	0.00	0.00	0.00	0.00
	Petroleum	%	-0.48	-0.48	-0.33	-0.33
4	Peak Load	MW	-131.05	-163.14	-55.08	-30.54
7	Annual Electricity Production	MWh	9.01	3.06	-0.47	0.09
12	CO2 Emissions	Tons	-1.81	19.99	0.99	1.00
13	SOx Emissions	Tons	0.01	0.02	0.00	0.00
	NOx Emissions	Tons	0.00	0.01	0.00	0.00
	PM-10 Emissions	Tons	0.00	0.00	0.00	0.00
17	Annual Storage Dispatch	MWh	73.18	58.79	10.29	6.50
18	Average Energy Storage Efficiency	%	103.48	103.63	103.75	103.86
21	Feeder Real Load	MW	1.03	0.35	-0.05	0.01
	Feeder Reactive Load	MVAR	-3.13	-2.96	-0.50	-0.30
29	Distribution Losses	%	0.00	0.01	0.00	0.00
39	CO2 Emissions	Tons	-2.04	19.98	0.99	1.01
40	SOx	Tons	0.01	0.02	0.00	0.00
	NOx	Tons	0.00	0.01	0.00	0.00
	PM-10	Tons	0.00	0.00	0.00	0.00

Table 4.5: Impact metrics for climate region 5

Index	Δ Metric	Units	GC-12.47-1 R5	R5-12.47-1	R5-12.47-2	R5-12.47-3	R5-12.47-4	R5-12.47-5	R5-25.00-1	R5-35.00-1
1	Hourly Customer Electricity Usage	kWh	0.43	2.14	-1.15	0.74	0.18	0.59	-0.40	0.74
2	Monthly Customer Electricity Usage	MWh	0.31	1.57	-0.84	0.54	0.13	0.43	-0.29	0.54
3	Peak Generation	kW	-122.06	-495.49	-91.28	-28.10	-143.12	-92.07	-82.00	-71.50
	Nuclear	%	0.00	0.00	0.00	0.00	0.00	0.32	-0.32	0.00
	Solar	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Bio	%	0.00	0.00	0.00	0.00	0.00	0.02	-0.02	0.00
	Wind	%	0.00	0.00	0.00	0.00	0.00	-0.26	0.26	0.00
	Coal	%	0.00	-2.75	0.00	0.00	0.00	-0.20	0.20	0.00
	Hydroelectric	%	-0.23	-0.63	0.00	0.00	-0.04	-0.15	0.15	0.00
	Natural Gas	%	0.00	0.00	0.00	0.00	0.00	0.39	-0.39	0.00
	Geothermal	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Petroleum	%	-1.86	-1.86	-1.83	-0.27	-1.86	-0.84	1.36	-0.58
4	Peak Load	MW	-122.06	-495.49	-91.28	-28.10	-143.12	-92.07	-82.00	-71.50
7	Annual Electricity Production	MWh	3.07	10.85	-13.23	3.99	-1.63	2.97	-4.27	6.08
12	CO2 Emissions	Tons	-67.37	-446.74	-84.61	-31.67	-111.83	-80.92	-70.66	-63.81
13	SOx Emissions	Tons	-0.06	-0.40	-0.07	-0.03	-0.10	-0.07	-0.06	-0.06
	NOx Emissions	Tons	-0.03	-0.22	-0.04	-0.02	-0.05	-0.04	-0.03	-0.03
	PM-10 Emissions	Tons	-0.01	-0.07	-0.01	0.00	-0.02	-0.01	-0.01	-0.01
17	Annual Storage Dispatch	MWh	118.42	682.66	111.14	57.38	165.75	127.98	106.92	111.18
18	Average Energy Storage Efficiency	%	101.41	101.44	101.35	101.49	101.33	101.47	101.49	101.42
21	Feeder Real Load	MW	0.35	1.24	-1.51	0.46	-0.19	0.34	-0.49	0.69
	Feeder Reactive Load	MVAR	-5.39	-33.91	-5.62	-3.37	-8.07	-6.42	-5.08	-4.92
29	Distribution Losses	%	0.00	0.02	0.02	0.01	0.01	0.01	0.00	0.00
39	CO2 Emissions	Tons	-67.86	-455.22	-87.44	-34.17	-115.28	-83.72	-71.93	-64.82
40	SOx	Tons	-0.06	-0.40	-0.07	-0.03	-0.10	-0.07	-0.06	-0.06
	NOx	Tons	-0.03	-0.22	-0.04	-0.02	-0.05	-0.04	-0.03	-0.03
	PM-10	Tons	-0.01	-0.07	-0.01	-0.01	-0.02	-0.01	-0.01	-0.01

5 Observations and Conclusions

Twelve SGIG projects are investigating the implementation of energy storage, or the deployment of capabilities for future energy storage. Two of the SGIG project proposals specifically mentioned implementing thermal energy storage, in the form of ice energy storage, on commercial loads. The two installations were on larger municipal buildings to evaluate the benefits of thermal energy storage on the system, as well as reductions in customer peak load.

5.1 Thermal Energy Storage Observations and Conclusions

During the simulation of thermal energy storage, many different metrics were recorded and examined. Some of these metrics were known to not be primary drivers for the deployment of thermal energy storage, but were examined for secondary benefits or concerns associated with the use of thermal energy storage. This section will provide observations and conclusions, including necessary caveats, from the analysis. A bulleted summary of these conclusions will be presented in Section 5.2.

5.1.1 Thermal Energy Storage Observations

The primary reason for the deployment of thermal energy storage is to reduce customer peak load on the system. By freezing water during off hours and using it to cool buildings during peak hours, peak energy consumption of the end use customer is reduced. For the purposes of these simulations, thermal energy storage was deployed on 10% to 20% of the commercial building population. In all but one case, a reduction of the feeder peak load was achieved. The only exception was in feeder R1-12.47-1, where feeder peak load increased a minor amount. This feeder only had a single thermal energy storage unit deployed, and this unit was located on a smaller commercial building. This single unit changed the system operating point very slightly, which resulted in a minor system peak increase.

The effectiveness of thermal energy storage to reduce the feeder peak load is dependent on the design of the distribution feeder on which it is deployed. For this analysis, thermal energy storage was randomly placed on a percentage of the commercial buildings in the feeder. This placing was completely arbitrary and coupled with a simplistic schedule for when the device was charging and when it was available for cooling. This implementation was optimized for neither feeder peak load nor customer peak load. As such, the results provide some general sense of what impact thermal energy storage can provide, but a specific implementation will likely be better tuned to a customer-driven or utility-driven deployment.

While thermal energy storage can provide some annual energy reductions in addition to peak load reductions, reductions in annual energy consumption should not be a primary driver for deployment. Three of the feeders showed noticeable decreases in annual energy consumption with storage present, but most showed slight increases in annual energy consumption, or little-to-no change. The change in annual energy consumption is highly influenced by the charging schedules of the thermal energy storage units. As was indicated, charging schedules were not selected to provide any specific feeder or customer peak reduction. The schedules were designed to charge thermal energy storage during late evening and early morning hours (e.g., 10:00 PM to 5:00 AM), and provide discharge capabilities during mid-day to early evening hours (e.g., 10:00 AM to 6:00 PM). These schedules were set for each region, so every region 5 feeder utilized the same basic charging schedule. However, because of varying locations and end-use load behaviors, the charging schedules may be sub-optimal. As with the peak reduction results, further considerations and design criteria, such as proper schedule selection to reduce either a customer or a feeder peak, may yield significantly better results.

Some of the changes in annual energy consumption associated with thermal energy storage can be directly attributed to changes in the distribution system losses. Since thermal energy storage was successful in reducing the peak load, some reduction in system losses is expected. Most of the changes in distribution losses were associated with the series losses of overhead distribution lines and underground cables. With peak power consumption reduced, less current is flowing through these lines and cables, resulting in lower resistive and inductive losses during that peak load period. The impact is enhanced by the fact that series losses are greatest during the peak load times, due to the non-linear relationship of current to losses.

Regardless of where the changes in annual energy consumption occur, they will affect carbon dioxide emissions. Even under the simple generator dispatch scheme utilized, energy changes can shift marginal generation sources and influence the emissions output. For the NO_x, SO_x, and PM-10 emissions, very little change was observed. Despite the minimal impact on these emissions metrics, carbon dioxide still showed significant differences. The deployment of thermal energy storage affects the marginal generation and leads to mixed results on CO_2 emissions. Many feeders had a slight increase in energy consumption, but not all showed an increase in CO_2 emissions. Furthermore, feeders that showed an overall energy decrease may show a CO_2 increase. Many of these unexpected shifts are due to peak load occupying a less CO_2 intense generation source (such natural gas turbines), while the off-peak production is using carbon intensive generation, such as coal. As a result, energy consumption is reduced, but the CO_2 intensity is greater for the generation source used by the energy storage during the off peak hours..

Examination of the different “state-of-charge” levels for the thermal energy storage deployed sheds some significant insights into proper deployment of the technology. In all of the cases simulated, the thermal energy storage on the feeder was never completely depleted (individual units may have been depleted, but at least one unit on the system retained capacity). This may be indicative that the thermal storage is oversized, was not being deployed during an optimal period, or may simply be attached to commercial buildings that do not need that capability. A much more detailed study, including specifics about the feeder of interest, is necessary to determine the optimal benefits of thermal energy storage on a system. This could include specific impacts of thermal energy storage to reduce customer peak and thermal energy storage to reduce customer peak (customer versus utility deployments).

5.1.2 Thermal Energy Storage Conclusions

Thermal energy storage has the potential to influence many aspects of the power system. Its primary benefit is peak load reduction. The penetration levels in the simulations (10% to 20% of commercial buildings) provided peak reduction of between 1% and 4%. However, this penetration level is significantly higher than any of the SGIG projects. To provide similar peak reduction, SGIG participants would need similar levels of deployment.

In addition to the peak load reduction, almost all feeders experienced a corresponding reduction in losses. These loss reductions were associated with overhead lines and underground cables, which represent direct losses in capacity. Whether the deployment of thermal energy storage is customer-peak or feeder-peak driven, these reductions should always be present. Therefore, even in customer-peak deployments, the feeder utility will gain some level of benefit from the thermal energy storage.

The secondary impact characteristics of energy consumption and carbon dioxide were a mixed result for thermal energy storage. Some feeders showed a slight increase in energy consumption, while still others resulted in energy decrease. Emissions results followed similar trends, with emissions often increasing in regions due to a carbon intensive generation source being used to make the ice for thermal storage. Unless deployed in a region where the off-peak generation is less CO_2 intense than on-peak generation, thermal energy storage can actually increase CO_2 emissions. However, it is important to note that CO_2 reductions are not a primary motivator for deploying thermal energy storage.

Thermal energy storage has significant potential for aiding in reducing demands to the system. While the results of the study show it serves to reduce feeder peak load fairly well, a more refined placement scheme and charge/discharge schedule could provide even greater results. Thermal energy storage placed on smaller, single-zone commercial buildings obviously will not provide as much benefit as the same proportion of a larger, multi-zonal building utilizing thermal energy storage. Furthermore, the charging and cooling-mode availability of the thermal energy storage can be tailored to the needs of the particular installation. Many parameters can be adjusted to provide a customer-peak or feeder-peak load reduction and may result in greater impacts than the random population distribution used in these studies.

The results of these simulations showed significant peak reduction benefits to the feeder. However, these reductions were not necessarily enough to justify the penetration levels and implementation considerations associated with thermal energy storage. System level impacts were noticeable in many of the scenarios simulated, but the amount of thermal energy storage was much higher than any proposed deployments in the SGIG projects (one building versus 10% of the commercial buildings on a feeder). However, the peak reduction and energy shifting may be of great interest to individual commercial building operators. While the peak reduction on a system level may not have been significant enough, it may be sufficient to keep a commercial customer out of a higher electricity rate. Furthermore, it allows the cooling capacity of a building to take advantage of the price differential of electricity at different times of the day, if the proper tiered structure for electricity rates exists.

5.2 Observations and Conclusions Summary

Various observations and conclusions resulted from the TES analysis. The previous section detailed some of the findings and their overall messages. This section highlights the major observations and conclusions of the study into thermal energy storage.

5.2.1 Thermal Energy Storage Observations

The analysis presented in this report has shown that the benefits of the TES technologies deployed in the SGIG projects can be quantified and tracked using the SGIG metrics guidebook [2]. From the analysis conducted, and the metrics tracked, the following conclusions and observations can be made about TES technologies:

1) TES technologies can be deployed by a utility or commercial or industrial end-use customer.

2) TES technologies can effectively address peak load issues.

3) In this report TES technologies were deployed at the customer level, but have impacts at the feeder, as well as the transmission system.

5.2.2 Thermal Energy Storage Conclusions

From the analysis of TES, the following conclusions and observations can be made:

1) The primary benefit of thermal energy storage is reducing peak power consumption. The penetration levels in the simulations (10% to 20% of commercial buildings – significantly higher than any deployments in the SGIG proposals) provided between 1% to 4% peak reductions in most of the feeders.

2) While peak reductions can be achieved with thermal energy storage, total annual energy consumed increases in some cases.

3) The deployment of thermal energy storage generally provided a minor reduction in distribution feeder losses.

4) While peak reductions can be achieved with thermal energy storage, total energy consumed increases in some cases.

5) Emissions results, particularly those of carbon dioxide, indicated mixed benefits for deploying thermal energy storage. Carbon dioxide emissions often increased in regions with CO_2 intensive generation because of the shifting of load from on-peak to off-peak time periods.

6) Deployment of thermal energy storage was designed to reduce customer peak, which is not always coincident with the distribution system peak. The idea of peak shaving or "optimal operation" must take into account whether it is from the perspective of the customer, the distribution system operator, or the transmission system operator.

Appendix A: SGIG Program Impact Metrics

An important component of the SGIG projects is the transfer of information from the individual projects to the broader industry audience. The aim of this transfer is to allow individuals, research organizations, and utilities to better understand the performance of the various technologies deployed on the various projects. Due to the large amount of potential data, it is not feasible for each grant recipient to provide all of the available raw data. To address the issue of data collection, the "Guidebook for ARRA Smart Grid Program Metrics and Benefits" [2] was developed as a starting point for the discussion of data collection and impact categories. Specifically, the document contained a table of impact metrics against which each project could be evaluated; it is these metrics that are used in the four technical reports to evaluate the impact of the various technologies. Table A.1 is a complete list of all 74 metrics listed in the Guidebook and is included in this appendix as a reference. Not every metric is used for each technology, only those that are relevant to the specific technology are examined in Section 2.

Table A.1: SGIG program impact metrics from guidebook

#	Metric	Project Value	System Value	Remarks
A 2.1 IMPACT METRICS: AMI and Customer Systems				
Metrics Related Primarily to Economic Benefits				
1	Hourly Customer Electricity Usage	kWh $/kWh	Not Applicable	Hourly electricity consumption information (kWh) and applicable retail tariff rate. Nature of this data will be negotiated with DOE
2	Monthly Customer Electricity Usage	MWh $/kWh	Not Applicable	Monthly electricity consumption information (kWh) and applicable retail tariff rate. The nature of this data will be negotiated with DOE
3	Peak Generation and Mix	MW Mix	MW Mix	Specify intermittent generation by type and amount
4	Peak Load and Mix	MW Mix	MW Mix	Specify controllable load by type
5	Annual Generation Cost	$	$	Total cost of generation to serve load
6	Hourly Generation Cost	$/MWh	$/MWh	Aggregate or market price of energy in each hour
7	Annual Electricity Production	MWh	MWh	Total electricity produced by central generation
8	Ancillary Services Cost	$	$	Total cost of Ancillary services
9	Meter Operations Cost	$	Not Applicable	Includes operations, maintenance, reading and data management
10	Truck Rolls Avoided	#	Not Applicable	Could include trips for meter reading, connection/disconnection, inspection and maintenance
Metrics Related Primarily to Environmental Benefits				

#	Metric	Project Value	System Value	Remarks
11	Meter Operations Vehicle Miles	Miles	Not Applicable	Total miles accumulated related to meter operations
12	CO2 Emissions	Tons	Tons	Could be modeled or estimated
13	Pollutant Emissions (SOx, NOx, PM-10)	Tons	Tons	Could be modeled or estimated
Metrics Related Primarily to AMI System Performance				
14	Meter Data Completeness	%	Not Applicable	Portion of meters that are online and successfully reporting in
15	Meters Reported Daily by 2AM	%	Not Applicable	Portion of meter reads received by 2AM the following day
A 2.2 Impact Metrics: Electric Distribution Systems				
Metrics Related to Economic Benefits				
16	Hourly Customer Electricity Usage*	kWh $/kWh	Not Applicable	Hourly electricity consumption information (kWh) and applicable retail tariff rate.
17	Annual Storage Dispatch*	KWh	Not Applicable	Total number of hours that storage is dispatched for retail load shifting
18	Average Energy Storage Efficiency*	%	Not Applicable	Efficiency of energy storage devices installed
19	Monthly Demand Charges*	$/kW-month	Not Applicable	Average commercial or industrial demand charges
20	Distribution Feeder or Equipment Overload Incidents	#	Not Applicable	The total time during the reporting period that feeder or equipment loads exceeded design ratings
21	Distribution Feeder Load	MW MVAR	Not Applicable	Real and reactive power readings for those feeders involved in the project. Information should be based on hourly loads
22	Deferred Distribution Capacity Investments	$	Not Applicable	The value of the capital project(s) deferred, and the time of the deferral
23	Equipment Failure Incidents	#	Not Applicable	Incidents of equipment failure within the project scope, including reason for failure
24	Distribution Equipment Maintenance Cost	$	Not Applicable	Activity based cost for distribution equipment maintenance during the reporting period
25	Distribution Operations Cost	$	Not Applicable	Activity based cost for distribution operations during the reporting period
26	Distribution Feeder Switching Operations	#	Not Applicable	Activity based cost for feeders switching operations during the reporting period
27	Distribution Capacitor Switching Cost	$	Not Applicable	Activity based cost for capacitor switching operations during the reporting period
28	Distribution Restoration Cost	$	Not Applicable	Total cost for distribution restoration during the reporting period

#	Metric	Project Value	System Value	Remarks
29	Distribution Losses	%	Not Applicable	Losses for the portion of the distribution system involved in the project. Modeled or calculated.
30	Distribution Power Factor	pf	Not Applicable	Power factor for the portion of the distribution system involved in the project. Modeled or calculated.
31	Truck Rolls Avoided	#	Not Applicable	Estimate of the number of times a crew would have been dispatched to perform a distribution operations or maintenance function
Metrics Related Primarily to Reliability Benefits				
32	SAIF	Index	Not Applicable	As defined in IEEE Std 1366-2003, and do not include major events days. Only events involving infrastructure that is part of the project should be included.
33	SAIDI/CAIDI	Index	Not Applicable	
34	MAIFI	Index	Not Applicable	
35	Outrage Response Time	Minutes	Not Applicable	Time between outage occurrence and action initiated
36	Major Event Information	Event Statistics	Not Applicable	Information should including, but not limited to project infrastructure involved (transmission lines, substations and feeders), cause of the event , number of customers affected, total time for restoration, and restoration costs.
37	Number of High Impedance Faults Cleared	#	Not Applicable	Faults cleared that could be designed as high impedance or slow clearing
Metrics Related Primarily to Environmental Benefits				
38	Distribution Operations Vehicle Miles	Miles	Not Applicable	Total miles for distribution operations and maintenance during the reporting period
39	CO_2 Emissions	Tons	Tons	Could be modeled or estimated
40	Pollutant Emissions (SOx, NOx, PM-10)	Tons	Tons	Could be modeled or estimated
A 2.3 Impact Metrics: Electric Transmission Systems				
Metrics Related Primarily to Economic Benefits				
41	Annual Storage Dispatch*	MWh	MWh	Total number of hours that storage is dispatched for wholesale energy markets or Ancillary services
42	Capacity Market Value*	$/MW	$/MW	Capacity value
43	Ancillary Services Prices*	$/MWh	$/MWh	Ancillary service price during hours when Storage was dispatched
44	Annual Generation Cost	Not Applicable	$	Total cost generation to serve load
45	Hourly Generation Cost	Not Applicable	$/MWh	Aggregate or market price of energy in each hour
46	Peak Generation and Mix	Not Applicable	MW Mix	Specify intermittent generation by type and amount

#	Metric	Project Value	System Value	Remarks
47	Peak Load and Mix	Not Applicable	MW Mix	Specify controllable load by type
48	Annual Generation Dispatch	Not Applicable	MW Mix	Total electricity produced by central generation
49	Ancillary Services Cost	Not Applicable	$	Total cost of Ancillary services
50	Congestion Cost	MW	Not Applicable	Total transmission congestion cost during the reporting period
51	Transmission Line or Equipment Overload Incidents	#	Not Applicable	The total time during the reporting period that line loads exceeded design ratings
52	Transmission Line Load	MW MVAR	Not Applicable	Real and reactive power readings for those lines involved in the project. Information should be based on hourly loads
53	Deferred Transmission Capacity Investments	$	Not Applicable	The value of the capital project(s) deferred, and the time of the deferral
54	Equipment Failure Incidents	#	Not Applicable	Incidents of equipment failure within the project scope, including reason for failure
55	Transmission Equipment Maintenance Cost	$	Not Applicable	Activity based cost for transmission equipment maintenance during the reporting period
56	Transmission Operations Cost	$	Not Applicable	Activity based cost for transmission operations during the reporting period
57	Transmission Restoration Cost	$	Not Applicable	Total cost for transmission restoration during the reporting period
58	Transmission Losses	%	Not Applicable	Losses for the portion of the transmission system involved in the project. Could be modeled or calculated.
59	Transmission Power Factor	pf	Not Applicable	Power factor for the portion of the transmission system involved in the project. Could be modeled or calculated.
Metrics Related Primarily to Transmission Reliability				
60	BPS Transmission Related Events Resulting in Loss of Load (NERC ALR 1-4)	#	Not Applicable	BPS Transmission Related Events Resulting in Loss of Load (NERC ALR 1-4)
61	Energy Emergency Alert 3 (NERC ALR 6-2)	#	Not Applicable	Energy Emergency Alert 3 (NERC ALR-6-2)
Metrics Related Primarily to Environmental Benefits				
62	Transmission Operations Vehicle Miles	Miles	Not Applicable	Total mileage for transmission operations and maintenance during the reporting period
63	CO_2 Emissions	tons	tons	Could be modeled or estimated

#	Metric	Project Value	System Value	Remarks
64	Pollutant Emissions (SOx, NOx, PM-10)	tons	tons	Could be modeled or estimated
Metrics Related Primarily to Energy Security Benefits				
65	Number, Type, and Size	Events Cause Load Lost	Not Applicable	Causes could include line trips, generator trips, or other large disturbances
66	Duration	Minutes/ Hours	Not Applicable	
67	PMU Dynamic Data	PMU Data	Not Applicable	From related PMU's
68	Detection	Application	Not Applicable	Application that detected the event
69	Events Prevented	#	Not Applicable	Include reason for prevention
Metrics related primarily to PMU/PDC System Performance				
70	PMU Data Completeness	%	Not Applicable	Portion of PMU that are operational and successfully provided data
71	Network Completeness	%	Not Applicable	Portion of PMUs networked into regional PDCs
72	PMU/PDC Performance	Reliability Quality	Not Applicable	
73	Communications Performance	Availability	Not Applicable	
74	Application Performance	Description	Not Applicable	Usefulness of applications, including reliability improvements, markets and congestion management, operational efficiency

The metrics shown in Table A.1 were developed for field demonstrations and were not originally intended for simulations. To address this issue, definitions of the metrics in Table A.1 as implemented in the analysis will be given. Because the simulations in this report only examine impacts at the distribution level, transmission level impact metrics will not be examined. Of the distribution metrics, many will not be used because they are associated with a monetary cost that would require information from a specific utility; for example, meter operation costs.

The metrics will be presented in two separate places in this report. Appendix E will contain the metric values for each technology on each feeder. These values are individual to a single technology. Section 4.1, 4.2, and 4.3 will show the difference in metric values between the base case and the specific technology, for each feeder.

1) **Hourly customer electricity usage:** Instead of reporting a time series of values for an entire year this metric will report the average hourly end use consumption.

2) **Monthly customer electricity usage:** Instead of reporting a time series of values for an entire year this metric will report the average monthly end use consumption.

3) **Peak generation and mix:** This metric will report the peak generation as well as the percentages for generation composition. This is the generation that is required to supply the demand as measured at the substation. The generation composition will include the breakdown of central generation as well as distributed resources on the distribution system.

4) **Peak load and mix:** This is the maximum annual end use demand as consumed by the end use customers. This is the load that the utilities meter and charge for. The percent of load that is controllable will also be included.

5) **Annual generation cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

6) **Hourly generation cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

7) **Annual electricity production:** This metric reports the total energy that is required to supply the demand as measured at the substation

8) **Ancillary services cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

9) **Meter operations cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

10) **Truck rolls avoided:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

11) **Meter operations vehicle miles:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

12) **CO2 emissions:** This metric measures the CO2 emissions required to supply the electricity to the end use load.

13) **Pollutant emissions:** This metric measures SOx, NOx, and PM-10 emissions required to supply the electricity to the end use load.

14) **Meter data completeness:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

15) **Meter reported daily by 2 a.m.:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

16) **Hourly customer electricity usage:** For the purposes of this work, this metric is identical to metric 1, and will not be used.

17) **Annual storage dispatch:** This metric examines the total number of hours that energy storage is dispatched.

18) **Average energy storage efficiency:** This is the average round trip efficiency for all energy storage units on a feeder.

19) **Monthly demand charge:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

20) **Distribution feeder or equipment overloads incidents:** Because the taxonomy of prototypical feeders is used for analysis there are not overloads included. This is because the average distribution feeder does not normally have overload conditions. As a result, this metric will not be used.

21) **Distribution feeder load:** This metric gives the annual average hourly load as measured at the substation. Both real and reactive powers are examined.

22) **Deferred distribution capacity investment:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

23) **Equipment failure incidents:** Because the conducted analysis uses representative technologies, there is no information associated with equipment failure. The only failures are faults included for the analysis of FDIR. As a result this metric will not be used.

24) **Distribution equipment maintenance cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

25) **Distribution operations cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

26) **Distribution feeder switching operations:** Because this is dependent on the operational procedures and business structure of specific utilities, this metric will not be used in evaluating the simulation results.

27) **Distribution capacitor switching costs:** Because this is dependent on the operational procedures and business structure of specific utilities, this metric will not be used in evaluating the simulation results.

28) **Distribution restoration cost:** Because this is dependent on the business structure of specific utilities, this metric will not be used in evaluating the simulation results.

29) **Distribution losses:** This metric measures the distribution losses; both series and shunt losses are included. Series losses due to overhead lines, underground lines, transformers, and triplex lines are included. Shunt losses due to underground lines and transformers are included. For the purposes of this metric all losses are combined into a single value but some plots will be provided that break the losses into the various components.

30) **Distribution power factor:** The distribution power factor is the power factor as calculated at the substation.

31) **Truck tolls avoided:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

32) **SAIFI:** As defined in IEEE standard 1366, SAIFI is the system average interruption frequency index. SAIFI indicated how often the average customer experiences a sustained interruption and is calculated by dividing the sum of the total number of customers interrupted by the total number of customers served.

33) **SAIDI/CAIDI:** As defined in IEEE standard 1366, SAIDI is the system average interruption duration index. SAIDI indicates the total duration of interruption for the average customers and is calculated by dividing the sum of the customer interruption durations by the total number of customers served. As defined in IEEE standard 1366, CAIDI is the customer average interruption duration index. CAIDI represents the average time required to restore service and is calculated by dividing the sum of the customer interruption durations by the total number of customers interrupted.

34) **MAIFI:** As defined in IEEE standard 1366, MAIFI is the momentary average interruption frequency index. MAIFI is the average frequency of momentary interruptions and is calculated by dividing the sum of the total number of customer momentary interruptions by the total number of customers served.

35) **Outage response time:** When a fault occurs on the system there are several important times. How long to identify the existence of a fault, how long to locate the fault, and how long to repair the fault. The outage response time is the time between the occurrence of the fault and the time to identify the existence of the fault.

36) **Major event information:** Major events generally impact a large geographic area which includes multiple distribution substations and the interconnecting transmission or sub-transmission system. Since this report is looking primarily at individual feeders this metric will not be used.

37) **Number of high impedance faults cleared:** This metric is based on the occurrence of high impedance faults in a specific system. The occurrence of faults is only handled in the fault detection identification and restoration technology; high impedance faults are not specifically examined.

38) **Distribution operations vehicle miles:** Because this is dependent on the operational procedures of specific utilities, this metric will not be used in evaluating the simulation results.

39) **CO2 emissions:** This metric measures the CO2 emissions required to supply the demand as measured at the substations.

40) **Pollutant emissions:** This metric measures the SOx, NOx, and PM-10 emissions required to supply the demand as measured at the substations.

Appendix B: Taxonomy of Prototypical Distribution Feeders

As part of the DOE-OE Modern Grid Initiative (MGI) efforts of 2008, a Taxonomy of Prototypical Distribution Feeders was developed [3]. The feeders within this taxonomy were designed to provide researchers with an openly available set of distribution feeder models which are representative of those seen in the continental United States. To construct these representative feeder models, actual feeder models were obtained from utilities across the country and their fundamental characteristics were examined. A detailed statistical analysis was conducted to determine the optimal subset of feeders that could effectively represent the entire data set. The development of the complete Taxonomy of feeders was an extensive process and is fully documented in the report titled "Modern Grid Initiative Distribution Taxonomy Final Report" [2].

Because climate and energy consumption are closely coupled, the prototypical feeders were divided into five climate regions, Figure B., based on the U.S DOE handbook (1980) providing design guidance for energy-efficient small office buildings [9].

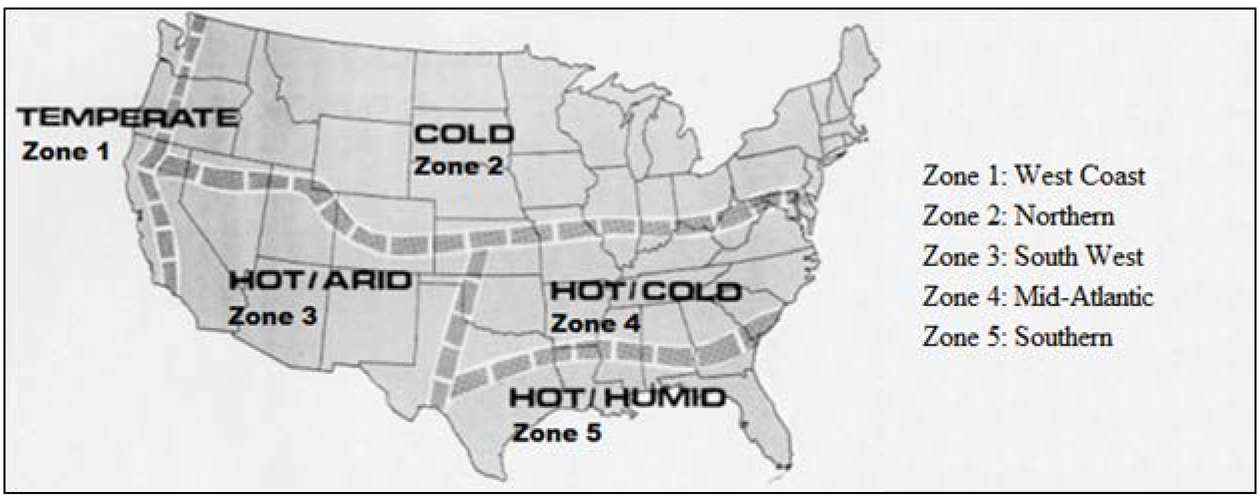

Figure B.1: Climate Zones Used for Development of Prototypical Feeders

Within each of the climate zones, there are a set of feeders that are approximations of the types of feeders that are seen within that zone. Table B.1 gives a summary of the 24 prototypical feeders, including feeder name, base voltage, peak load, and a qualitative description. The peak loading used for the SGIG project analysis is slightly different than the original values from the 2008 report. The difference in peak load due to improved modeling methods used to represent the end-use load will be discussed in further Section B.2.1 and B.2.2.

Table B.1: Summary of prototypical feeders

Feeder	Base kV	Peak kVA	Description
R1-12.47-1	12.5	4,300	Moderate suburban and rural
R1-12.47-2	12.47	2,400	Moderate suburban and light rural
R1-12.47-3	12.47	1,800	Small urban center
R1-12.47-4	12.47	4,900	Heavy suburban
R1-25.00-1	24.9	2,300	Light rural
R2-12.47-1	12.47	6,700	Light urban
R2-12.47-2	12.47	6,700	Moderate suburban
R2-12.47-3	12.47	4,800	Light suburban
R2-25.00-1	24.9	21,300	Moderate urban
R2-35.00-1	34.5	6,900	Light rural
R3-12.47-1	12.47	11,600	Heavy urban
R3-12.47-2	12.47	4,000	Moderate urban
R3-12.47-3	12.47	9,400	Heavy suburban
R4-12.47-1	13.8	6,700	Heavy urban with rural spur
R4-12.47-2	12.5	2,100	Light suburban and moderate urban
R4-25.00-1	24.9	1,000	Light rural
R5-12.47-1	13.8	10,800	Heavy suburban and moderate urban
R5-12.47-2	12.47	4,200	Moderate suburban and heavy urban
R5-12.47-3	13.8	4,800	Moderate rural
R5-12.47-4	12.47	6,200	Moderate suburban and urban
R5-12.47-5	12.47	8,500	Moderate suburban and light urban
R5-25.00-1	22.9	9,300	Heavy suburban and moderate urban
R5-35.00-1	34.5	12,100	Moderate suburban and light urban
GC-12.47-1	12.47	5,400	Single large commercial or industrial

The original prototypical feeders were modeled in detail from the substation to the end-use point of interconnection, but did not include detailed load models. To use these feeders for an accurate analytic assessment of the SGIG projects, it was necessary to model the end-use load in the appropriate level of detail as was done for the 2010 report on Conservation Voltage Reduction [10].

B.1 End-use Load Models

The taxonomy of prototypical feeders accurately represents the electrical infrastructure of the distribution feeders, but not the end-use loads. Since it is the end-use loads that consume the majority of the energy on a distribution feeder, it is critical to accurately represent their operation. For the taxonomy of feeders to be of use, the end-use loads are classified into various categories. In 2010, an analysis of conservation voltage reduction was conducted in GridLAB-D that classified loads as shown in Table B.2 [10]. Because the analysis of the SGIG projects includes technologies other than conservation voltage reduction, a more complete handling of end-use load classifications is necessary and will be discussed in detail in section B.2. This is especially true of technologies such as demand response where the physical characteristics of the buildings are fundamental.

Table B.2: End-use load classifications

Load Class	Description
Residential 1	Pre-1980 <2000 sqft.
Residential 2	Post-1980 <2000 sqft.
Residential 3	Pre-1980 >2000 sqft.
Residential 4	Post-1980 >2000 sqft.
Residential 5	Mobile Homes
Residential 6	Apartment Complex
Commercial 1	>35 kVA
Commercial 2	<35 kVA
Industrial	All Industrial

Regardless of how end-use loads are classified, the component end-use loads are modeled as a combination of ZIP models and multi-state physical models. The ZIP load model and the multi-state model are described in the following sections.

B.1.1 ZIP Loads

ZIP models are two state models, energized and de-energized. When energized there is only a single operational state and the energy consumption can be determined using (B1) for real power, (B2) for reactive power, and (B3) as a constraint [12].

$$P_i = \left[\frac{|V_a^2|}{|V_n^2|} \cdot |S_n| \cdot Z_{\%} \cdot \cos(Z_\theta) + \frac{|V_a|}{|V_n|} \cdot |S_n| \cdot I_{\%} \cdot \cos(I_\theta) + |S_n| \cdot P_{\%} \cdot \cos(P_\theta) \right] \tag{B1}$$

$$Q_i = \left[\frac{|V_a^2|}{|V_n^2|} \cdot |S_n| \cdot Z_{\%} \cdot \sin(Z_\theta) + \frac{|V_a|}{|V_n|} \cdot |S_n| \cdot I_{\%} \cdot \sin(I_\theta) + |S_n| \cdot P_{\%} \cdot \sin(P_\theta) \right] \tag{B2}$$

$$100 = Z_{\%} + I_{\%} + P_{\%} \tag{B3}$$

where:

P_i : real power consumption of the i^th load
Q_i: reactive power consumption of the i^th load
V_a: actual terminal voltage
Vn: nominal terminal voltage
S_n: apparent Power consumption at nominal voltage
$Z_{\%}$: percent of load that is constant impedance
$I_{\%}$: percent of load that is constant current
$P_{\%}$: percent of load that is constant power
Z_θ: phase angle of constant impedance component
I_θ: phase angle of constant current component
P_θ: phase angle of constant power component

In a time-variant load representation, the coefficients of the ZIP model, V_n, S_n, $Z_{\%}$, $I_{\%}$, $P_{\%}$, Z_θ, I_θ, and P_θ, remain constant, but the power consumption, P_i and Q_i, of the i^{th} load varies with the actual terminal voltage, V_a. The ZIP model is similar to the polynomial representation used in many commercial software packages. In the polynomial representation of the ZIP load, the constant coefficient is equivalent to $P_{\%}$, the linear coefficient is equivalent to $I_{\%}$, and the quadratic coefficient is equivalent to $Z_{\%}$. The ZIP model only varies the power consumption as a function of actual terminal voltage, V_a.

In (B1) and (B2), there are 6 constants that define the voltage dependent behavior of the ZIP load: $Z_{\%}, I_{\%}, P_{\%}, Z_\theta, I_\theta$, and P_θ. Because the actual value of the distribution feeder voltage continually changes, it is critical to understand how the energy consumption of end-use loads will vary. Specifically, what are the six constants that accurately reflect various end-use loads? For loads such as a heating element, it is clear that the load is 100% Z, but for more complicated loads such as a Liquid Crystal Display (LCD) or Compact Florescent Light (CFL), the proper ratios are not as apparent.

As part of the 2010 report on conservation voltage reduction a number of laboratory tests were conducted to determine the six constants for various end-use loads; these values have been incorporated into the end-use load models for this study. Figure B.2 is an example of the laboratory testing that was conducted on a 13W compact florescent light bulb.

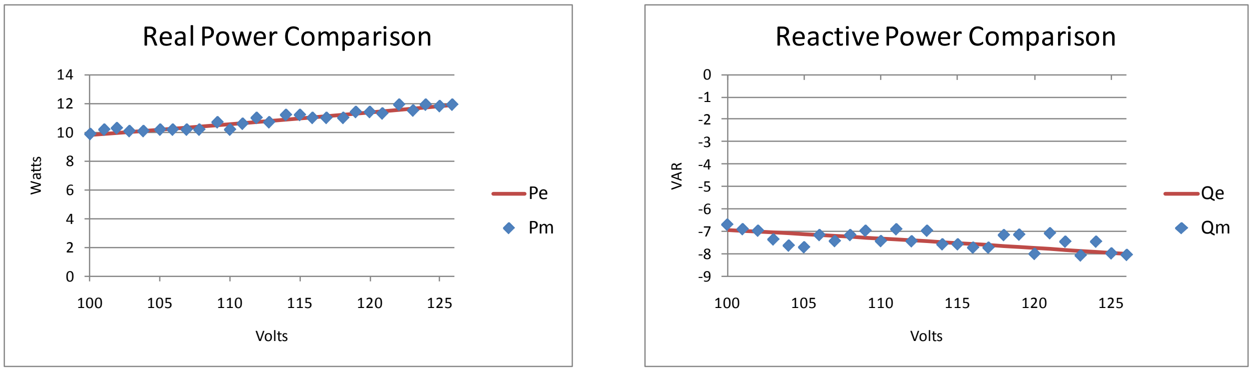

Figure B.2: Voltage dependent energy consumption of 13W CFL

	ZIP Values					
	Z-%	I-%	P-%	Z-pf	I- pf	P-pf
CFL-13W	40.85%	0.67%	58.49%	-0.88	0.42	-0.78

In traditional distribution analysis ZIP models are generally not developed for every individual load, instead models are developed for load classes such as residential, commercial, and industrial. Every load within a given load class then uses the same ZIP values with the exception of the apparent power consumption at nominal voltage, S_n. The value of S_n for each load may change at 1-hour intervals to generate a daily load profile at the feeder level. The use of similar ZIP values for each load class, which only change at 1-hour intervals, is not able to represent coincidental load peaks that occur at the distribution level.

B.1.2 Single-State Detailed Physical Models

When the energy consumption of an end-use load is a function of variables other than terminal voltage, the use of a ZIP model is not adequate. This is true of any load with an external control system or an internal control loop. To illustrate this issue, the air conditioning system of a single family residence will be examined while in the cooling mode. As with the ZIP model, an air conditioning system is a two state model (ON or OFF), but only has a single operational state.

Because a cooling system operates to maintain internal air temperature within a band, parameters such as near term history of operation, time of year, outside air temperature, building construction, and terminal voltage will impact the instantaneous power consumption, as well as the energy consumption. To examine these issues, a physical model of the cooling system and the structure of the building, is constructed using an equivalent thermal parameter (ETP) model [12]. Because the ETP model has been shown to be an accurate representation of residential and small commercial building instantaneous power draw, as well as energy consumption, it will be used for the formulation of the physical model.

Figure B.3 is a diagram showing the heat flow for the ETP model of a single family residence, i.e., a house. While the heating/cooling system can be one of any numerous types, for the purposes of this paper, it is assumed that the system is a heat pump in the cooling mode. In addition to the heat removal of the heat pump while cooling and the heat gain through the building exterior, there are two additional significant flows of heat within a house: incident solar radiation and internal gains from waste heat generated by end-use loads. These sources and sinks of heat constitute the total heat energy exchange in the house. This flow of heat is then divided between the air in the house and the mass of the house, i.e., walls and furniture. A portion of the incident solar energy shining through a window will heat the interior air of the house, while the remaining incident energy will be absorbed by the walls, floors, and furniture. The same division occurs with the waste heat from end-use loads. The internal air temperature of the house is thermally coupled to the internal mass temperature, and the internal air temperature is then thermally coupled to the outside air temperature through the thermal envelope of the house.

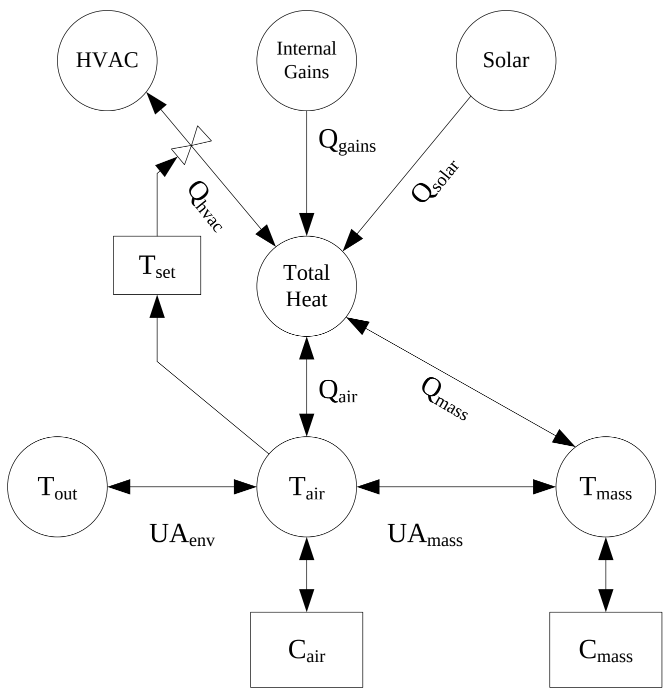

Figure B.3: ETP mode of a residential heating/cooling system

where,

C_{air}:	air heat capacity (Btu/°F)
C_{mass}:	mass heat capacity (Btu/°F)
UA_{env}:	external gain/heat loss coefficient (Btu/°F-h)
UA_{mass}:	internal gain/heat loss coefficient (Btu/°F-h)
T_{out}:	air temperature outside the house (°F)

T_{air}:	air temperature inside the house (°F)
T_{mass}:	mass temperature inside the house (°F)
T_{set}:	temperature set points of HVAC system (°F)
Q_{air}:	heat rate to house air (Btu/h)
Q_{gains}:	heat rate from appliance waste heat (Btu/h),
Q_{hvac}:	heat rate from HVAC system (Btu/h),
Q_{mass}:	heat rate to house mass (Btu/h), and
Q_{solar}:	heat rate from solar gains (Btu/h).

Equation (B4) is the second order differential equation that describes the heat flows shown in Figure B.3 [12]. Its solution determines the time-varying temperature of the house, both air and mass, given the thermal inputs. With the inside air temperature, T_{air}, known, the thermal behavior of the heat pump system in response to the defined thermostatic set point, T_{set}, can be determined.

$$a\frac{d^2T_{air}}{dt^2}+b\frac{dT_{air}}{dt}+cT_{air}=d \tag{B4}$$

Where,

$$a=\frac{C_{mass}\cdot C_{air}}{UA_{mass}}$$

$$b=\frac{C_{mass}\cdot\left(UA_{env}+UA_{mass}\right)}{UA_{mass}}+C_{air}$$

$$c=UA_{env}$$

$$d=Q_{mass}+Q_{air}+\left(UA_{env}\cdot T_{out}\right)$$

With the temperature of the house known from (B4) and the occupant-controlled set point fixed, the operation of the cooling system can be determined. Based on these values, the cooling system will operate long enough to remove the heat necessary to maintain the inside air temperature, T_{air}, within the desired range. The electrical input energy to the motor, $S_{comp\text{-}motor}$, necessary to provide the thermal heat energy, is a function of two elements: the heat flow through the cooling unit, Q_{hvac}, and the electrical losses of the compressor motor, S_{losses}, as shown in (B5) [11]–[12].

$$S_{comp-motor} = \left[Q_{hvac}\left(T_{out}, V_T, COP\right) + S_{losses}\left(V_T\right)\right] \quad \text{(B5)}$$

The coefficient of performance (*COP*) is a scalar value that relates the cooling rate of the heat pump unit to the mechanical power delivered by the compressor as a function of temperature and operation time. A higher value of COP indicates less electrical power is necessary to remove a given amount of heat from the air. V_T is the terminal voltage of the system compressor motor. Additionally, it should be noted that Q_{hvac} is expressed in terms of British thermal units (Btu) consistent with the conventions of the heating/cooling industry in the United States and the derivation of the ETP model of [12], while S_{losses} is expressed in SI units. As a result, the two terms of (B5) must be converted using the conversion of 1.0 Btu/h = 0.2931 W.

Because both of the elements of (B5) are voltage dependent, changes in line voltage will cause a change in power consumption. The cooling system's heat removal rate, Q_{hvac}, can be solved using heat transfer equations based on the available mechanical torque of the compressor [12]. The motor losses, S_{losses}, can be determined using the traditional split phase motor model of [11] and [12]. When (B5) is implemented in a time-series simulation, the result is a model that determines the energy consumption, both real and reactive, of the cooling system as a function of the outside air temperature, the inside air temperature, equipment parameters, terminal voltage, and occupant-controlled set point.

Unlike ZIP models that apply the same values to each load in a given load class, physical models are specific to each individual load. The values of physical models vary on a 1 second or 1 minute basis to capture the true time-variant nature of the end-use load.

The previous example of a physical model has examined a heat pump in the cooling mode, which is one of multiple operational states. Because of the design of heat pumps, their energy consumption varies according to their current operational state. To properly capture the energy consumption, it is necessary to construct a multi-state load model.

B.1.3 Multi-State Detailed Physical Models

A multi-state time-variant load model uses more than one state to describe the energy consumption of an end-use load. Each state is governed either by a ZIP model and/or a physical model, with transitions between states determined by either internal state transition rules or external signals. For example, a typical heat pump has four normal operating states: State 1 (*off*), State 2 (*cooling*), State 3 (*heating-normal*), and State 4 (*heating-emergency*). State 2 operates as described in the previous section, and State 3 follows a similar description but with different values that represent the change in the heating cycle, i.e., heat is added instead of removed. State 4 operates as State 3, except that the COP is 1.0 and the load is a ZIP model. There are other abnormal states such as “stalled compressor motor” or "low refrigerant charge", but they will not be examined in this paper. Additionally, there are numerous heat pump types and many differing thermostatic controllers that are commercially available, but this paper will discuss a "typical" design. Because a heat pump has two heat-flow configurations, the value of T_{set} must be split into a heating set point, T_{low}, and a cooling set point, T_{high}. These set points determine the mode of operation of the heat pump system at any given time: *off*, *cooling*, *heating-normal*, or *heating-emergency*, as shown in Figure B.4.

For a simple single state simulation, the heat pump system would be operating to either heat or cool the house, as discussed in the previous section. For a time-series simulation, the multi-state model captures the transitions between states. While a heat pump system may not transition through all operational states in a single day, it is likely that it will transition through more than one state in any given day. For example, on a mild autumn night, the heat pump may operate to heat the house, then as the sun heats the house during the day, it may be necessary to switch to cooling.

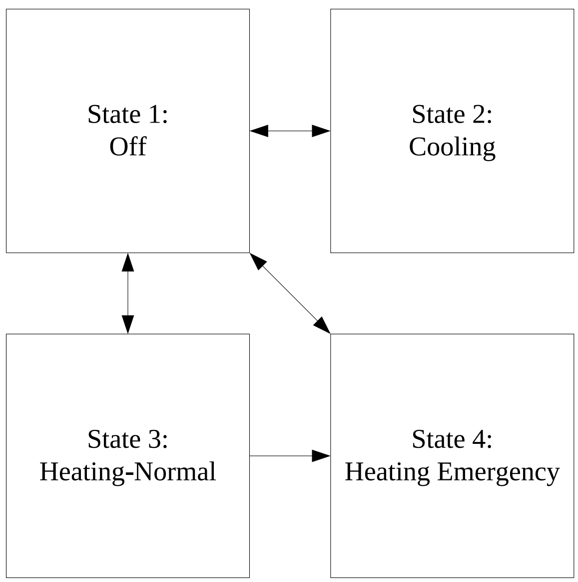

Figure B.4: Multi-state load model

To be in States 2, 3, or 4, the heat pump unit must be turned "on" with defined set points, both occupant-controlled and internal. The occupant-controlled set points are T_{high} and T_{low}. If the internal air temperature T_{air} rises above T_{high} plus a dead band, DB_{high}, then the heat pump will start cooling. If T_{air} decreases below T_{low} minus a dead band, DB_{low} then the heat pump will start heating normally. If T_{out} decreases to a temperature, T_{aux}, where the heat pump efficiency becomes too low to effectively heat the home, the system will start heating in the emergency state using resistive heating elements. In addition to the internal control parameters of T_{aux}, the DB_{low} and DB_{high} are internal parameters that are not occupant-controlled, but are included to prevent the heat pump from cycling excessively. Table B.3 gives the logic for the allowable state transitions shown in Figure B.4.

Table B.3: Heat pump state transition logic

From State	To State	Transition Rule
1	2	$T_{air} > (T_{high} + DB_{high})$
1	3	$T_{air} < (T_{low} - DB_{low})$
1	4	$T_{air} < (T_{low} - DB_{low})$ & $T_{out} < T_{aux}$
2	1	$T_{air} < (T_{high} - DB_{high})$
3	1	$T_{air} > (T_{low} + DB_{low})$
3	4	$T_{out} < T_{aux}$
4	1	$T_{air} > (T_{low} + DB_{low})$

Each of the four discrete states of operation has a different set of characteristics that determine the instantaneous power consumption. In State 1, there is no power draw because the system is off. In State 2 and State 3, there is an electric fan motor plus a compressor motor. Similar to State 3, State 4 provides heating with an associated electric fan for ventilation, but with the difference that heating is provided by resistive heating elements and not a heat pump. The instantaneous power draw of the four states shown in Figure B.4 is given by (B6)-(B9).

State 1: *Off*

$$S_{HVAC} = 0 \tag{B6}$$

State 2: *Cooling*

$$S_{HVAC} = S_{fan-motor} + S_{comp-motor} \tag{B7}$$

State 3: *Heating-Normal*

$$S_{HVAC} = S_{fan-motor} + S_{comp-motor} \tag{B8}$$

State 4: *Heating-Emergency*

$$S_{HVAC} = S_{fan-motor} + \frac{V_T^2}{R_{elements}} \tag{B9}$$

where,

$S_{fan\text{-}motor}$:	apparent power of ventilation fan motor (VA)
$S_{comp\text{-}motor}$:	apparent power of compressor motor (VA)
V_T:	terminal voltage of the heat pump unit (V)
$R_{elements}$:	resistance of the heating coil elements (Ω)

While the power consumption for State 2 and State 3, given by (B7) and (B8) respectively, appear to be the same, there are different internal models for Q_{hvac}, particularly with respect to the COPs. With the instantaneous power draw determined by (B6)-(B9), the time necessary to heat or cool the house to within the occupant-controlled set points is determined by the solution to (B4). The result is that variations in temperature, voltage, and efficiency are translated into a variable duty cycle of the heat pump. This information can then be used to determine the instantaneous power demand and the energy consumption of the heat pump over time.

B.2 Model Extraction and Population

Section B.1 discussed the physical infrastructure of the distribution feeders and gave an overview of the level of detail that is modeled at the end-use. This section describes how the detailed end-use models are populated onto the prototypical distribution feeders.

The taxonomy of prototypical feeders was originally populated with a series of spot loads representing a standard peak load study. Each spot load was classified as residential, commercial, agricultural, or industrial. In this analysis, due to the broad nature of industrial and agricultural loads and the difficulty in accurately representing these loads, each of these loads was re-classified as commercial, leaving only residential and commercial loads. Each load was replaced with building models appropriate to the region of the United States where the prototypical feeder was located. The representative commercial and residential models will be described here.

B.2.1 Residential Loads

At each triplex node, the residential spot load was replaced with a number of residential house models, which under peak conditions approximately matched the original spot load. The number of house models replacing the original peak load depended upon a scaling factor unique to each taxonomy feeder model and was used to calibrate the populated feeder model to the peak load study. For example, if the original spot load was 10 kVA and the feeder scaling factor was determined to be 5 kVA / house, the spot load would be replaced with two house models. In all cases, the number of homes was rounded to the nearest integer, while the residual from the rounding was used as a weighting factor. For example, if the same 10 kVA load was used with a scaling factor of 5.5 kVA / home, the number of homes would be 1.82. The number was rounded to two homes and the difference of 0.18 was used as a weighting factor on the square footage of the homes populated at that location, creating two house models with a slightly lower than the average square footage. The scaling factor was used to calibrate the new feeder model to the peak load study. Multiple annual simulations were run on each feeder until the peak load for the annual simulation approximately equaled that of the peak load study.

The parameters of each home were determined by the climate region the feeder was located in. Data from the Energy Information Administration's (EIA) 2005 Residential Energy Consumption Survey [13] was used to create a population of homes for each feeder which contained the average characteristics from that region. The EIA divides the country into ten regions, while the U.S. DOE Handbook providing design guidance for energy-efficient small office buildings [9], which was used to create the taxonomy feeders, only uses five. Table B.4 shows the weighting factors used to map the characteristics between the two sets of regional data.

Table B.4: Table of weighting factors for mapping regional parameters

Taxonomy Feeder Climate Regions		Building Survey Climate Region Weighting	
1	West Coast	1	Pacific
2	Northern	0.5	Mountain
		1	W N Central
		1	E N Central
		1	Mid Atlantic
		1	New England
3	Southwest	0.5	Mountain
		0.33	W S Central
4	Mid-Atlantic	0.33	W S Central
		0.5	E S Central
		0.5	S Atlantic
5	Southern	0.33	W S Central
		0.5	E S Central
		0.5	S Atlantic

From the EIA data and the weighting factors, a set of key, average building parameters were created as a basis for the population of each feeder. The residential building models were broken into three types: single family homes, apartments, and mobile homes. The age of the home was used to create a set of thermal integrity levels for each housing age and type, from poorly insulated to well insulated, and key parameters were assigned by region and age of home. Table B.5 shows the average thermal integrity properties by age of the single family homes, apartments, and mobile homes. Each of these parameters was then randomized, where appropriate, around the average value with either a normal or uniform distribution to create a diversified population which approximately represents the average household characteristics in that region. More details on the randomizations used can be found in the feeder generator script found on the open source repository [8]. Table B.6, Table B.7, and Table B.8 provide a breakdown of the percentage of single family homes, apartments, and mobile homes, and their corresponding ages, used in creating the randomized population of buildings per region. In addition, other average parameter values were extracted from the EIA documentation, including square footage, cooling and heating set points, heating type, air conditioning penetration, electric water heater penetration, and pool pump penetration. These are listed in Table B.9 through Table B.11.

Table B.5: Residential thermal integrity values by age of home

	R Roof	R Wall	R Floor	Glass Layers	Glass Type	Glazing Treatment	Window Frame	R Door	Air Infiltration	COP High	COP Low
Single Family											
Pre-1940	16	10	10	1	Glass	Clear	Alum.	3	0.75	2.8	2.4
1940-1949	19	11	12	2	Glass	Clear	Alum.	3	0.75	3.0	2.5
1950-1959	19	14	16	2	Glass	Clear	Alum.	3	0.50	3.2	2.6
1960-1969	30	17	19	2	Glass	Clear	TB	3	0.50	3.4	2.8
1970-1979	34	19	20	2	Glass	Clear	TB	3	0.50	3.6	3.0
1980-1989	36	22	22	2	Low-e	Clear	TB	5	0.25	3.8	3.0
1990-2005	48	28	30	3	Low-e	Abs.	Ins.	11	0.25	4.0	3.0
Apartment											
Pre-1960	13	12	9	1	Glass	Clear	Alum.	2	0.75	2.8	1.9
1960-1989	20	12	13	2	Glass	Abs.	TB	3	0.25	3.0	2.0
1990-2005	29	14	13	2	Low-e	Refl.	Ins.	6	0.13	3.2	2.1
Mobile Home											
1960-1989	13	9	12	1	Glass	Clear	Alum.	2	0.75	2.8	1.9
1990-2005	24	12	18	2	Low-e	Clear	TB	3	0.75	3.5	2.2

Note 1: R is in units of °F.sf.h/BTU, air infiltration is in units of air changes / hour, COP is in units of BTU/kWh

Note 2: Low-e refers to low emissivity glass, Abs. refers to absorptive glass, Refl. refers to reflective glass, Alum. refers to an aluminum frame, TB refers to thermal break insulation, Ins. refers to insulated

Table B.6: Percentage of single family homes in total population by age and region

	Pre-1940	1940-1949	1950-1959	1960-1969	1970-1979	1980-1989	1990-2005
Region 1	8.05	7.24	10.90	8.67	13.84	12.64	12.97
Region 2	15.74	7.02	12.90	9.71	9.41	7.44	15.32
Region 3	4.48	2.52	8.83	8.43	11.85	13.15	24.11
Region 4	5.26	3.37	8.06	8.27	10.81	12.49	25.39
Region 5	5.26	3.37	8.06	8.27	10.81	12.49	25.39

Table B.7: Percentage of apartments in total population by age and region

	Pre-1960	1960-1989	1990-2005
Region 1	3.56	12.23	2.56
Region 2	4.81	8.87	3.03
Region 3	1.98	11.59	4.78
Region 4	2.17	10.91	5.02
Region 5	2.17	10.91	5.02

Table B.8: Percentage of mobile homes in total population by age and region

	1960-1989	1990-2005
Region 1	5.54	1.81
Region 2	8.87	3.03
Region 3	5.24	3.02
Region 4	4.91	3.33
Region 5	4.91	3.33

Table B.9: Percentage of key building parameters by region

	Heating Fuel Type			With Air Conditioner	With Electric Water Heater	With Pool Pump*	One-Story Home*
	Non-Electric	Heat Pump	Resistance				
Region 1	70.51	3.21	26.28	43.48	25.45	9.04	68.87
Region 2	89.27	1.77	8.96	75.28	25.15	5.91	52.10
Region 3	67.23	5.59	27.18	52.59	34.80	8.18	77.45
Region 4	44.25	19.83	35.92	96.73	64.28	6.57	70.43
Region 5	44.25	19.83	35.92	96.73	64.28	6.57	70.43

*Note: Percentage with pool pumps and one-story homes was only applied to single family homes.

Table B.10: Percentage of nighttime heating and cooling set points by housing type

	Single Family	Apartment	Mobile Home
Set point (°F)	Cooling		
65-69	9.8	15.5	13.8
70-70	14.0	20.7	17.2
71-73	16.6	10.3	17.2
74-76	30.6	31.0	27.6
77-79	20.6	15.5	13.8
80-85	8.4	6.9	10.3
	Heating		
59-63	14.1	8.5	12.9
64-66	20.4	13.2	17.7
67-69	23.1	14.7	16.1
70-70	16.3	27.9	27.4
71-73	12.0	10.9	8.1
74-79	14.1	24.8	17.7

Table B.11: Average square footage by building type and region

	Single Family	Apartment	Mobile Home
Region 1	2209	820	1054
Region 2	2951	798	1035
Region 3	2370	764	1093
Region 4	2655	901	1069
Region 5	2655	901	1069

Of note is the cooling and heating set points found in Table B.10. Heating and cooling set points bins were chosen randomly and independently, except to require that the heating set point be below the cooling set point. Within each bin a uniform distribution was used to determine the actual nighttime set point for each home. Additionally, data from the surveys showed average daytime versus nighttime offsets. Offsets were uniformly distributed between zero and twice the average offset, and the time at which the offsets occurred was randomized across the population. Figure B.5 provides a few examples of the diversity of cooling set points established through this methodology, while Figure B.6 shows the average cooling set point on a summer day of all the residential homes within the R1-12.47-2 feeder.

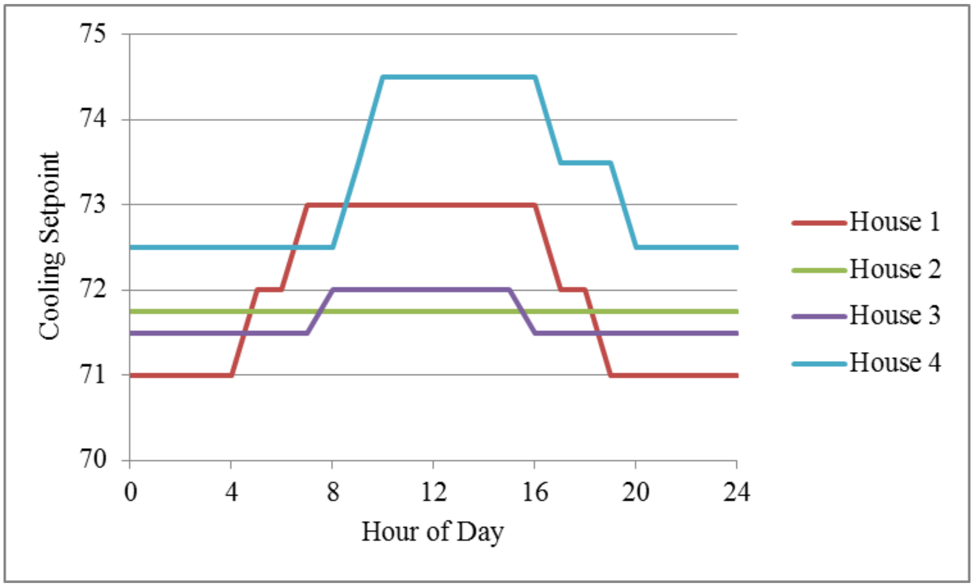

Figure B.5: Exemplary cooling set points diversified with time and daytime and nighttime offsets

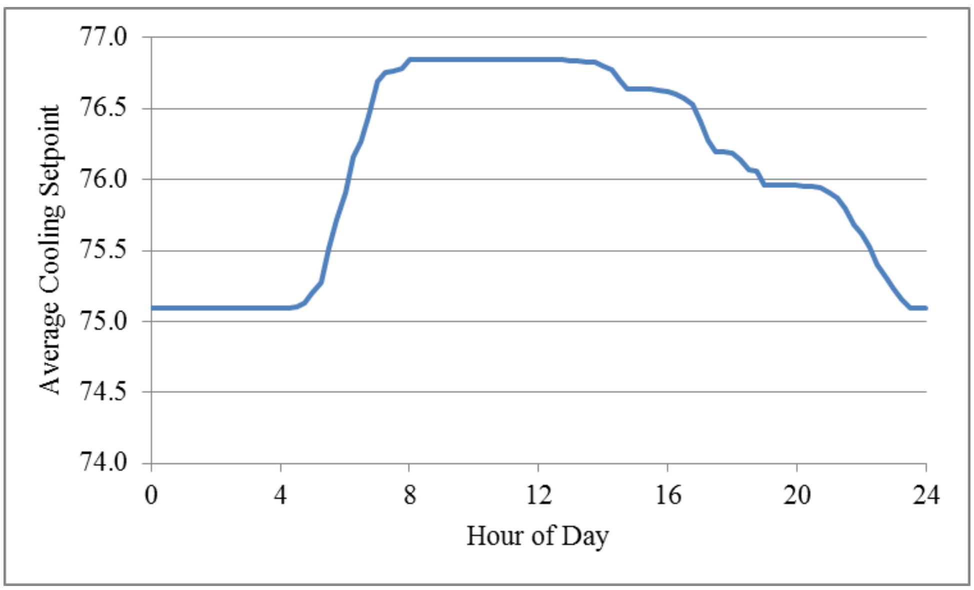

Figure B.6: Average cooling set points of entire population of R1-12.47-2

It is important to note that the populated building models were not designed to represent any particular feeder circuit or city in the United States, but rather as a blended average of large climate regions within the United States. While this will not perfectly capture the behavior of any particular city or utility, it is designed as a representative analysis. Additional methods exist where a utility can provide very specific load data which is much more representative of the local population, and design an analysis which is much more suited to that particular application.

The parameter values, in conjunction with estimated demand, were used to describe the state models of the hot water heater, HVAC system, and pool pump. However, additional loads were represented as scheduled ZIP loads. "Appliances" such as refrigerators and lights were divided into two categories: responsive and unresponsive loads. Responsive loads indicate that the customer is able to modify the behavior of the appliance due to a price signal, while unresponsive loads indicate that the customer is typically not willing or able to modify the behavior without investment in additional technologies (e.g. demand response enabled appliances). Responsive loads included lights, plug loads, clothes washers, clothes dryers, dishwashers, cooking ranges, and microwaves, while unresponsive loads included refrigerator and freezer loads. These were divided in anticipation of demand response studies and the shift of customer behavior that is associated with Time-of-Use or Critical Peak pricing. ELCAP load data [14] was used to create a base hourly load profile for responsive and unresponsive loads, with adjustments made for 20 years of increased efficiency and increased or decreased demand, and included seasonal and weekday versus weekend effects, as shown in Figure B.7 and Figure B.8. Additionally, loads were scaled as a function of square footage using a regression, again using ELCAP data. The proper scalar from the regression is shown in (B10):

$$k = 324.9 * \textit{floor area}^{.442} * 1000 / 8760 \qquad \text{(B10)}$$

The scalar was then randomized +/- 20% over a uniform distribution. While this provided no single home with a load shape representative of a time-series of an actual home, the aggregate load shape was representative of an entire population of homes, and internal loading of each home provided internal heat gains appropriate to that size of home.

Figure B.7: Average energy consumption of responsive loads

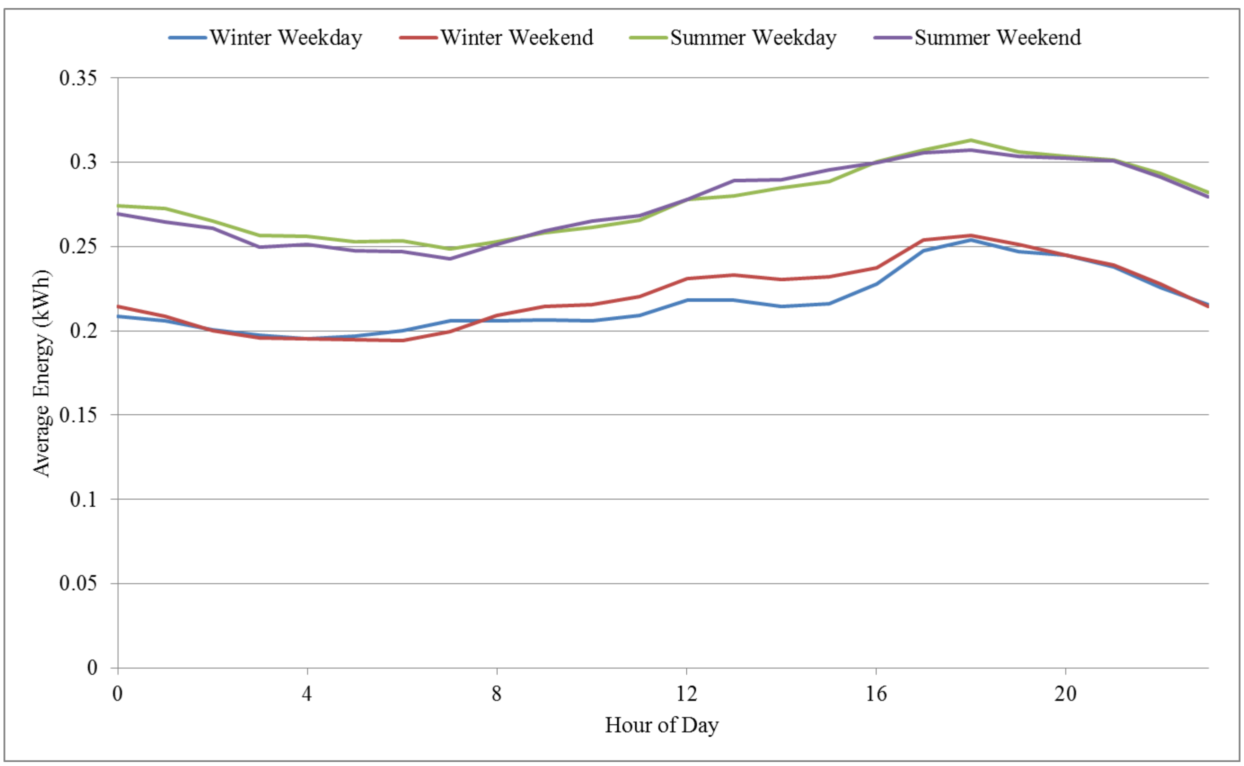

Figure B.8: Average energy consumption of unresponsive loads

B.2.2 Commercial Loads

At this time, a fully implemented, multi-zone commercial building model is not available within GridLAB-D. However, to represent the “zones” of a commercial building, multiple house models were created to represent the commercial load. These loads were created using very generic commercial building characteristics and load patterns. The commercial loads (and the re-classified industrial and agricultural loads) were divided into three types: office buildings, large retail “box” buildings, and small retail strip malls. The key characteristics of these models were developed through federally-supported building codes and end-use metering studies, and are not based on regional differences as the residential models were [15]-[16]. Population of the prototypical feeders and the three types of buildings was performed by size of the original load and the number of phases the load was attached to. Similar to the residential loading, a scalar was used to calibrate the loading on each feeder model, modifying the number of loads and size of each load.

Office buildings were represented by a three-story, fifteen-zone model as shown in Figure B.9. These replaced loads within the taxonomy feeder that were three-phase and “larger”, as defined by the scaling factor. The average square footage was 40,000 sf., with a uniform deviation of 50%, while maintaining the geometrical relationship of each zone. Each of the zones has identical parameter values, except square footage, aspect ratio, external wall area, external floor area, and external ceiling area. Assumptions are made in this model to better represent the zonal attributes of a commercial building. It is assumed that the adjacent zone has approximately the same air and mass temperature as the current zone, so that there is no heat transfer across the boundaries. This means that the internal wall, ceiling, or floor areas do not lose or gain heat from adjacent zones, and can therefore be ignored when defining the thermal envelope of the building. For example, Zone 5 on the second floor in Figure B.9 will have an external wall area of 0 sf., an external floor area of 0 sf., and an external ceiling area of 0 sf. This zone would only have heat added (or removed) through end-use loads and the HVAC system. Zone 2 on the third floor will have an external wall area equal to one-half its total wall area, and external floor area also equal to 0 sf., and an external ceiling area equal to its floor area, allowing additional heat flows across the external boundaries. By defining each zone within the constraints of the geometrical model, then defining where heat transfer across boundaries is allowed and not allowed, a zonal model can be roughly represented. Notice that Figure B.9 contains a variable ‘x’. This variable would be adjusted by the randomly chosen square footage so that $3*1.5*x^2$ equaled the total square footage, while all other parameters except for the widths of Zones 1-4 adjusted within the geometrical constraints. The other building type zones were defined in a similar manner. Table B.12 shows the key parameters used to define the office building zones. Additionally, since the office building is considered a larger, single owner, customer billing was performed as an aggregate of all the “zones”.

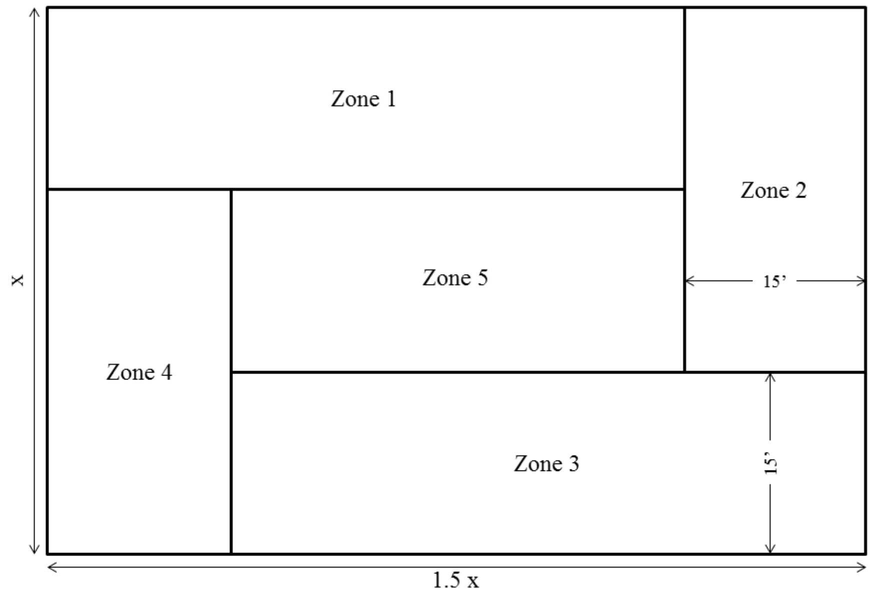

Figure B.9: Office zonal floor plan representing 1 of 3 identical floors

Table B.12: Key parameters for commercial buildings

	Office	Big Box	Strip Mall
Square Footage	40,000 +/- 50%	20,000 +/- 50%	2400 +/ 30%
Ceiling Height	13	14	12
Air Infiltration	0.69	1.5	1.76
R Roof	19	19	19
R Wall	18.3	18.3	18.3
R Floor	46	46	40
R Door	3	3	3
Glazing Layers	2	2	2
Glass Type	Glass	Glass	Glass
Glazing Treatment*	Low S	Low S	Low S
Window Frame	None	None	None
No. of Doors*	0	0 / 1 / 24	1
Window to Wall Ratio	0 / 0.33	0 / 0.76	0.03 / 0.05
Internal Gains (W/sf)	3.24	3.6	3.6
Cooling COP	3 +/- 20%	3 +/- 20%	3 +/- 20%

*Note: Low S refers to low solar glazing.

*Note: Number of doors refers to the number of doors externally exposed, and is translated into a wall area used by the doors - 24 doors refers to the surface area used by 24 doors. Office accounts for door area in the window area.

Big box retail buildings were represented as a one-story, six-zone model as shown in Figure B.10. and were used to replace "larger" two-phase loads and "smaller" three-phase loads, as defined by the scaling factor. The overall square footage was defined as 20,000 sf., with a uniform deviation of 50%. Table B.12 shows the key parameters used to define the retail big box building zones. Again, this building was considered a single occupant and customer billing was performed on the aggregate of all the "zones".

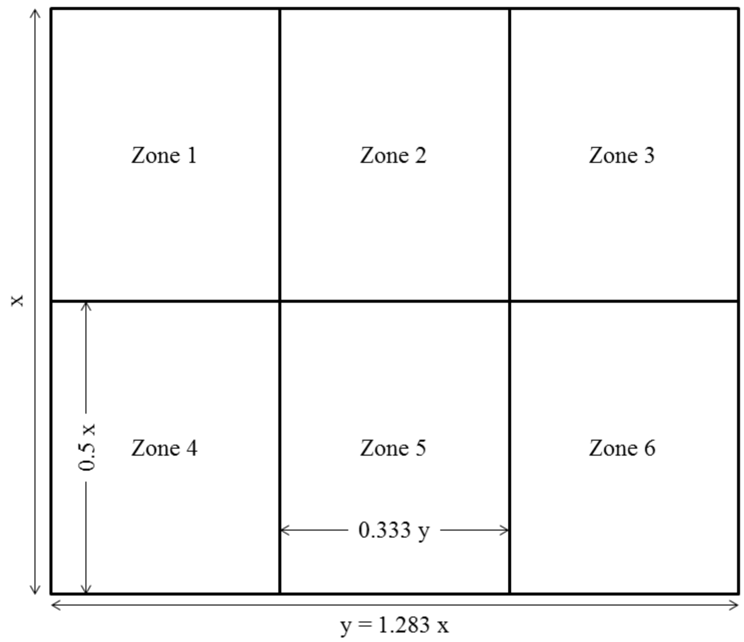

Figure B.10: Retail "big box" zonal floor plan

A retail strip mall model was used to represent all other loads, including all one-phase loads and "smaller" two- or three-phase loads. These were represented by one-story, single-zone models connected in series as shown in Figure B.11. Individual zones were defined as 1200 or 2400 sf., with a uniform deviation of 30%. Table B.12 shows the key parameters used to define the retail strip mall building zones. In this case, ownership was considered on a per-zone basis, so customer billing was also performed on a per-zone basis.

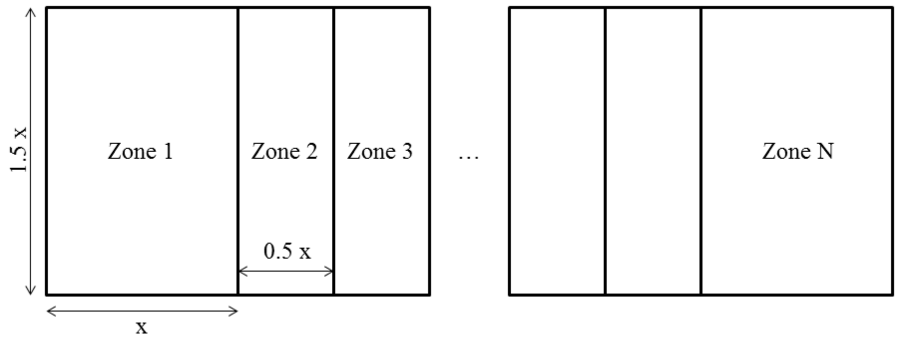

Figure B.11: Retail strip mall zonal floor plan with N zones depending upon scaling factor

Additionally, it was assumed that all commercial buildings had both heating and cooling systems and heating was always represented by a gas heating unit rather than a heat pump or resistive heat unit. Again, internal loads are very important drivers for both heating and cooling of the space, displacing heating load while adding cooling load. Commercial building load is highly occupant driven, and is typically very recurring. Data from end-use metering projects was used to create average end-use load shapes for weekdays and weekends [17]. Again, certain loads were slightly scaled up or down to reflect changes in efficiencies or standard usage. Weekdays are assumed to be Mon-Fri for office buildings, Mon.-Sun. for big box buildings, and Mon.-Sat. for strip malls. Average load shapes are shown in Figure B.12 through Figure B.15. Notice that the y-axis is in units of W/sf. The load shape applied to each zone is scaled as a function of square footage then randomized on a zonal basis by +/- 20% over a uniform distribution. In addition to the magnitude randomization, the load shape was also randomly "skewed" in time. Each of the zones within the building were considered to be on the same schedule, however, across the population of buildings, not all started and ended at the same time. The load shapes were temporally shifted from those shown in Figure B.12 through Figure B.15 in 30-minute blocks using a normal distribution of average of 0 minutes and standard deviation of 30 minutes. This produced a more diversified load across the entire population.

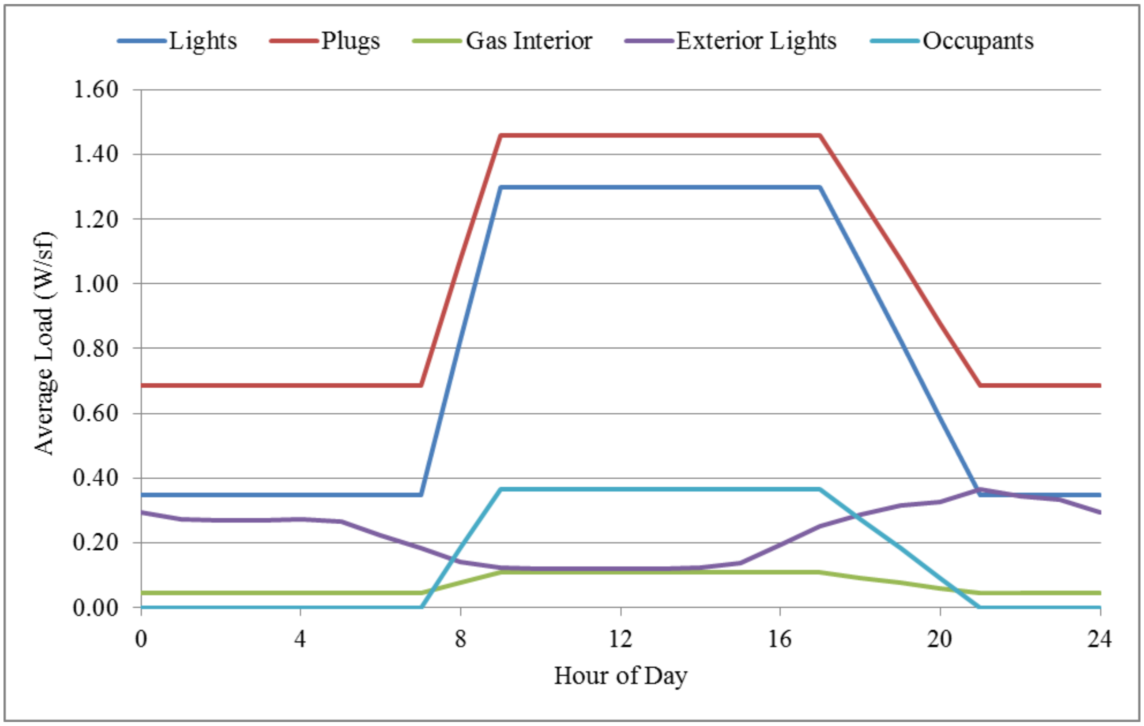

Figure B.12: Average office end-use load shape (weekday)

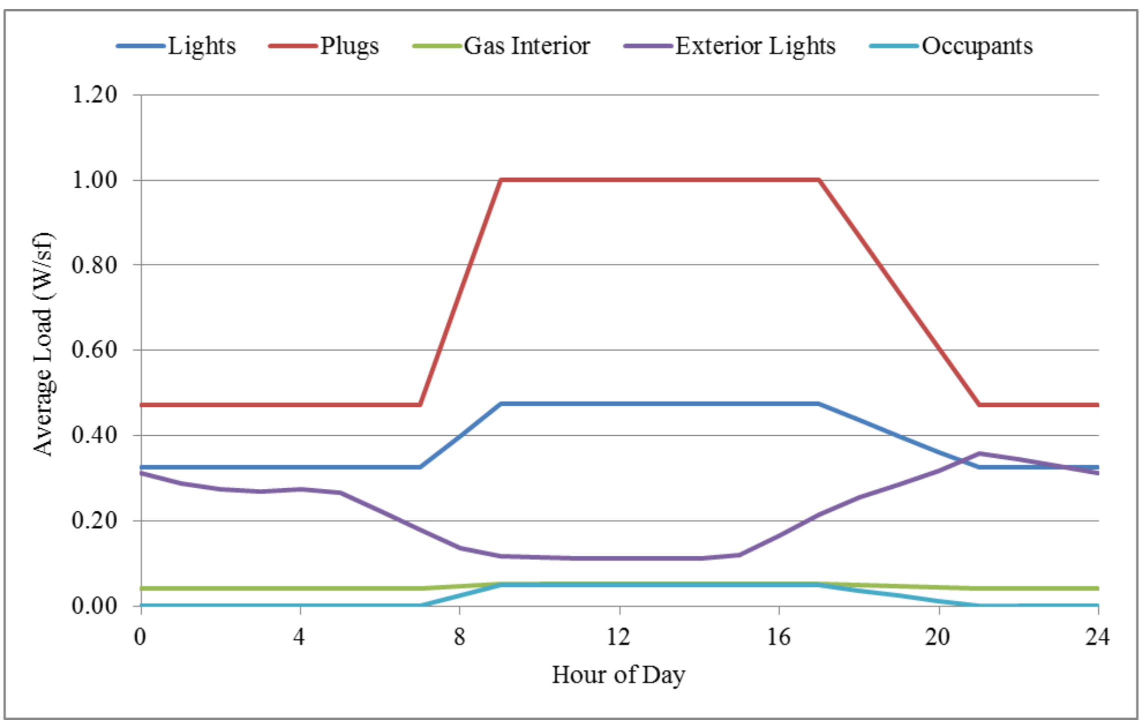

Figure B.13: Average office end-use load shape (weekend)

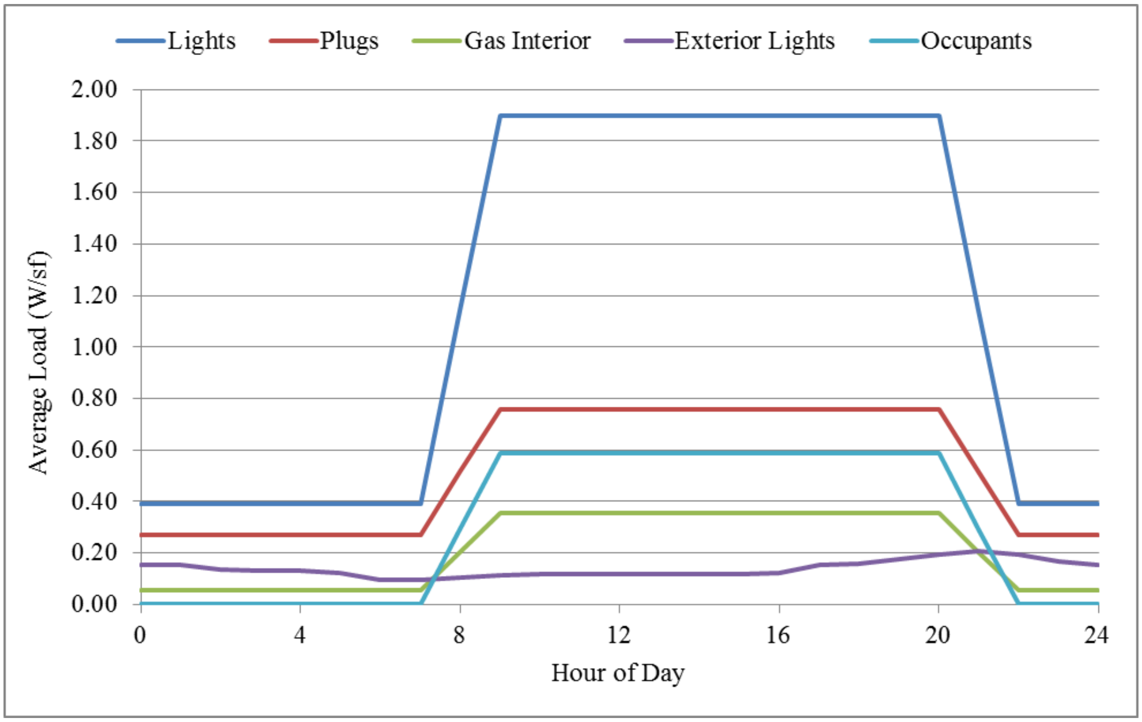

Figure B.14: Average big box and strip mall end-use load shape (weekday)

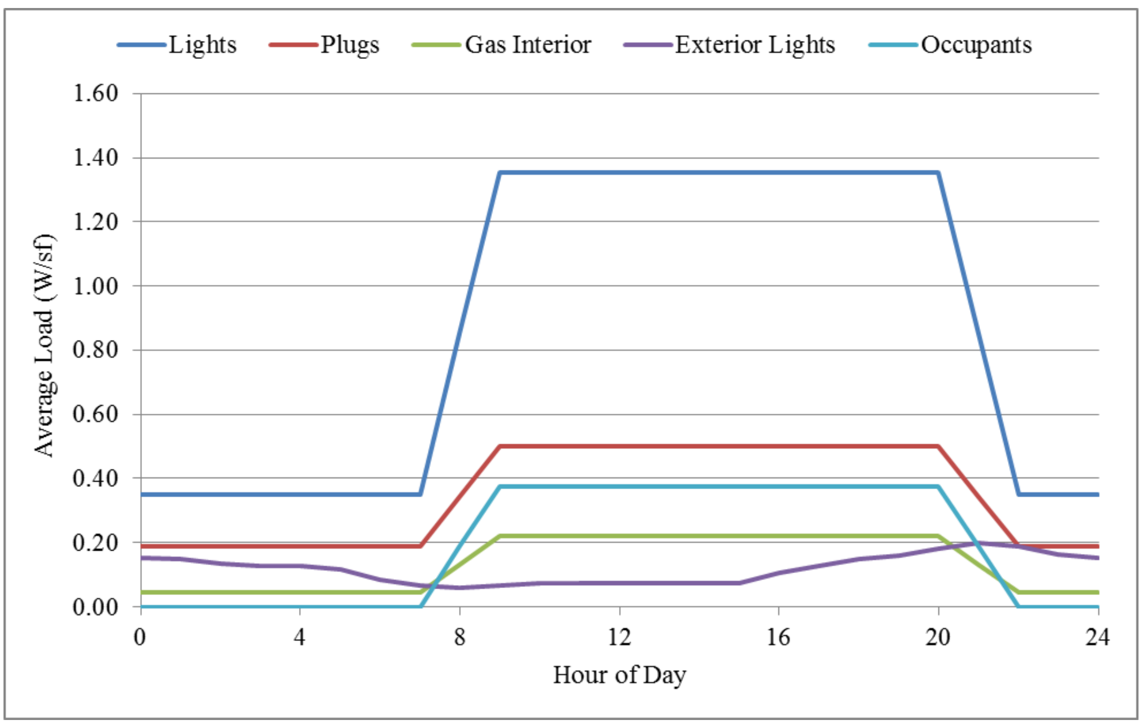

Figure B.15: Average big box and strip mall end-use load shape (weekend)

Finally, there were a number of loads on the prototypical feeders that were far smaller than could be described by a building model at peak load, often less than 1 kVA. While there are a number of options for representation of these loads, such as traffic lights or a small espresso stand, it was determined that without data to indicate what these loads represented they would be best represented by street lighting loads. These small loads were converted to a scheduled one-, two-, or three-phase load, depending on the original load and the full rated load was applied during dark hours and zero load was applied during daylight hours. While it is understood that this is not an accurate representation of true street light loading and operation, the loads were small enough and infrequent enough that a simple scheduled load had little to no effect on the overall operation of the feeder circuits.

B.3 Taxonomy Feeder Emission Profiles

Increasing operational efficiency of the electrical power system can lead to a reduction in pollutant emissions. Peak load reduction or peak shifting has been shown to reduce emissions, mainly due to reducing the need to use "peaker" units. These are typically older, less efficient generators, designed for quick start-up and shutdown, and are often single cycle natural gas turbine generators or petroleum fired plants. Reduction in overall energy consumption or shifting of production to more efficient energy sources can also reduce emissions by reducing the amount of fuel burned for electricity production. Solutions for the amount of emissions created are traditionally performed at the transmission level, using optimal power flow and economic dispatch, and are typically not well-suited for distribution level simulation. The following section is a brief description of how GridLAB-D estimates emissions impacts at the distribution level.

To capture the emissions level benefits to the system, generation mixes were assumed in each region and the nine most heavily consumed fuels for electrical generation in the U.S. were used. In each region, the fuels are dispatched in order from first to last by capacity factor, as shown in Table B.13. Exceptions are made for a number of the renewable resources, such as wind, solar, and biomass, as they are assumed to be dispatched when available. The level of penetration by each fuel type was determined for each region by month as shown in Table B.14 – Table B.18. These values were determined from the EIA's Annual Electric Generator Report [13], utilizing state-by-state breakdowns of annual energy production.

Table B.13: Dispatch order of fuel by region

Region	1	2	3	4	5
Order of dispatch	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear
	Solar	Solar	Solar	Solar	Solar
	Biomass	Biomass	Biomass	Biomass	Biomass
	Wind	Wind	Wind	Wind	Wind
	Hydroelectric	Coal	Coal	Coal	Natural Gas
	Natural Gas	Natural Gas	Natural Gas	Natural Gas	Coal
	Coal	Hydroelectric	Hydroelectric	Hydroelectric	Hydroelectric
	Geothermal	Geothermal	Geothermal	Geothermal	Geothermal
	Petroleum	Petroleum	Petroleum	Petroleum	Petroleum

Table B.14: Percent of energy consumed, broken down by fuel type and month in region 1

Region 1	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Nuclear	9.86	8.68	11.47	13.08	10.63	9.73	10.68	8.93	10.09	8.5	9.83	10.41
Solar	0.01	0.08	0.18	0.23	0.25	0.24	0.25	0.24	0.21	0.15	0.09	0.04
Biomass	0.58	0.78	0.77	0.72	0.73	0.73	0.67	0.65	0.72	0.82	0.81	0.73
Wind	2.37	1.86	4.39	4.57	4.63	5.44	4.07	4.66	3.55	3.64	3.17	1.44
Hydroelectric	43.43	37.29	38.84	49.88	56.78	58.39	36.88	29.63	26.32	31.09	36.02	36.29
Natural Gas	34.61	41.6	34.96	25.6	22.89	21.1	41.38	48.31	51.24	45.88	42.02	42.13
Coal	5.44	5.77	5.42	2.14	0.45	0.86	2.88	4.09	4.38	5.97	4	5.14
Geothermal	3.29	3.49	3.51	3.35	3.29	3.1	2.84	3.09	3.11	3.54	3.63	3.35
Petroleum	0.43	0.45	0.45	0.43	0.35	0.41	0.36	0.38	0.39	0.4	0.44	0.47

Table B.15: Percent of energy consumed, broken down by fuel type and month in region 2

Region 2	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Nuclear	26.47	26.9	27.74	25.27	28.52	27.95	26.33	24.75	27.04	25.09	25.63	25.42
Solar	0	0	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0	0
Biomass	0.64	0.72	0.82	0.9	0.92	0.84	0.82	0.76	0.83	0.85	0.89	0.75
Wind	2.23	2.71	2.9	3.34	2.79	1.7	1.41	1.6	1.73	2.82	3.22	2.99
Coal	49.62	49.36	46.7	46.31	44.39	45.54	47.18	46.33	46.05	49.04	49.05	50.69
Natural Gas	12.31	13.49	14.19	14.67	13.43	14.47	16.33	19.87	17.97	15.73	14.51	13.22
Hydroelectric	6.11	5.99	6.92	9.11	9.51	9.05	7.42	6.08	5.98	6.13	6.34	6.43
Geothermal	0.07	0.07	0.08	0.08	0.08	0.07	0.07	0.07	0.08	0.07	0.08	0.08
Petroleum	2.55	0.74	0.64	0.32	0.34	0.37	0.43	0.6	0.33	0.27	0.28	0.43

Table B.16: Percent of energy consumed, broken down by fuel type and month in region 3

Region 3	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Nuclear	9.82	8.88	10.24	11.6	10.83	9.72	8.65	8.5	7.13	8.62	9.63	9.38
Solar	0.01	0.05	0.13	0.16	0.17	0.13	0.13	0.14	0.13	0.1	0.06	0.03
Biomass	0.22	0.28	0.29	0.29	0.25	0.25	0.23	0.21	0.25	0.27	0.29	0.26
Wind	2.13	3.08	3.26	3.77	2.8	2.45	2.05	2.2	2.34	3.55	3.02	2.77
Coal	50.18	43.95	41.77	42.34	43.59	41.52	40.24	41.42	43.7	47.9	49.94	46.58
Natural Gas	32.79	37.12	37.34	33.17	33.92	37.88	41.67	41.48	40.32	33.07	31.29	34.43
Hydroelectric	2.89	4.75	4.95	6.72	6.68	6.4	5.58	4.59	4.47	4.74	3.76	4.6
Geothermal	1.63	1.62	1.7	1.67	1.53	1.4	1.25	1.26	1.42	1.52	1.79	1.7
Petroleum	0.32	0.26	0.32	0.28	0.24	0.25	0.2	0.2	0.22	0.24	0.22	0.24

Table B.17: Percent of energy consumed, broken down by fuel type and month in region 4

Region 4	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Nuclear	23.16	23.97	23.95	24.4	24.92	22.45	23.15	21.91	23.58	24.33	23.99	22.77
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0.21	0.19	0.21	0.25	0.21	0.18	0.18	0.18	0.21	0.22	0.22	0.18
Wind	0.69	0.88	1.03	1.16	0.78	0.64	0.53	0.6	0.59	1.13	1.18	1.04
Coal	61.55	60.14	57.45	58.24	57.41	56.92	56.89	57.14	56.06	58.36	58.48	59.96
Natural Gas	9.98	11.44	12.86	11.25	11.38	16.04	16.75	17.49	16.14	10.51	9.83	10.19
Hydroelectric	3.37	2.67	3.71	4.21	4.73	3.32	2.05	2.2	3.09	5.09	5.96	5.51
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Petroleum	1.04	0.71	0.8	0.49	0.56	0.45	0.45	0.48	0.36	0.36	0.34	0.36

Table B.18: Percent of energy consumed, broken down by fuel type and month in region 5

Region 5	Jan	Feb	Mar	April	May	June	July	Aug	Sept	Oct	Nov	Dec
Nuclear	18.26	18.55	18.53	17.36	14.67	13.53	13.74	13.85	13.65	12.7	14.94	16.41
Solar	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0.46	0.45	0.48	0.46	0.3	0.31	0.31	0.33	0.34	0.39	0.46	0.46
Wind	2.14	2.6	2.7	2.95	1.91	1.74	1.44	1.48	1.43	2.52	2.63	2.26
Natural Gas	38.8	41.01	45.26	44.78	47.26	51.29	51.75	51.68	51.03	47.55	43.83	41.73
Coal	37.3	34.53	29.66	30.82	32.04	30.37	30.38	30.17	30.72	33.46	35.06	35.97
Hydroelectric	1.42	0.86	1.57	1.51	1.61	0.78	0.58	0.63	0.99	1.75	2.12	2.35
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0
Petroleum	1.62	2	1.79	2.12	2.2	1.96	1.8	1.86	1.84	1.62	0.95	0.82

At each 15-minute measurement interval, the energy consumed over the previous interval is used to determine the amount of energy delivered by each fuel source. The peak load of the base case for each month is used to scale the percentages. Figure B.16 shows an example of how this is performed in GridLAB-D using June in Region 3. It can be seen that the peak load for that month would utilize all the generation fuels at the levels shown in Table B.16. At the shown 15-minute period, the base case load is approximately 95% of the peak for June for this particular feeder. During the same 15-minute period, the representative technology case is only 87% of the base case peak feeder loading. This results in a reduction of generation by approximately 3% for hydroelectric and 5% for natural gas. This calculation is performed at every 15-minute interval to determine the energy consumed by each fuel type over the course of the entire annual simulation of 1-minute intervals.

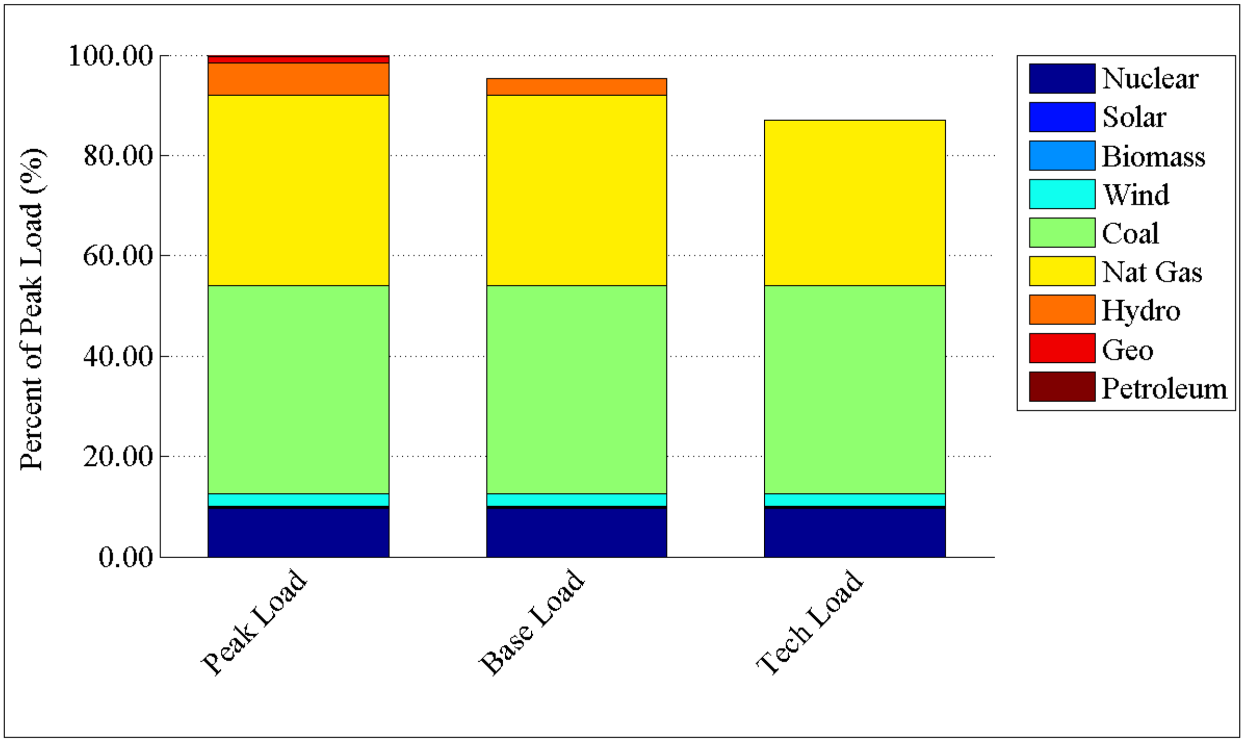

Figure B.16: Interval comparing fuel dispatch for peak load, base case load, and a technology-modified load

Assumed average thermal efficiencies are then used to convert the energy delivered to the amount of fuel used, where applicable. The values used are shown in Table B.19. Finally, assumed average values for conversion efficiencies are used to convert from fuel used to emissions levels for carbon dioxide, sulfur dioxide, and nitrous oxides. The conversion values assumed are shown in Table B.20. These values are not indicative of any single plant, but rather broad averages across the U.S. While this is a very simplified means of dispatching and assigning generation, ignoring complex issues such as inefficiencies due to warm-up cycles, maintenance periods, and economic or optimal dispatching, it should provide a general indication of how changes in operation of a distribution circuit can reduce pollutant emissions.

Table B.19: Average thermal efficiencies by fuel type

	MBTUs / MWh
Nuclear	10.46
Solar	N/A
Biomass	12.93
Wind	N/A
Natural Gas	8.16
Coal	10.41
Hydroelectric	N/A
Geothermal	21.02
Petroleum	11

Table B.20: Pollutant production per BTU of fuel (lbs./MBTU)

	CO2	SO2	NOx	PM-10
Nuclear	0	0	0	0.017157
Solar	0	0	0	0.03
Biomass	195	0	0.08	0.0232
Wind	0	0	0	0
Natural Gas	117.08	0.001	0.0075	0
Coal	205.57	0.1	0.06	0
Hydroelectric	0	0	0	0
Geothermal	120	0.2	0	0
Petroleum	225.13	0.1	0.04	0

B.4 Taxonomy Feeder Descriptions

The previous sections have described the details of how each of the prototypical feeders is populated with end-use loads. This section is a reproduction of the individual prototypical feeder descriptions from [3] which describes the characteristics of the primary distribution system.

B.4.1 Feeder 1: GC-12.47-1

This feeder is representative of a single large commercial or industrial load, such as a very large shopping mall or a small lumber mill. These feeders may supply the load through a single large transformer or a group of smaller units. While there may be a couple of smaller loads the behavior of the feeder is primarily determined by the single large customer. This is a 12.47 kV feeder with a peak load of approximately 5,400 kVA.

B.4.2 Feeder 2: R1-12.47-1

This feeder is a representation of a moderately populated suburban and rural area. This is composed mainly of single family residences with small amounts of light commercial. Approximately 60% of the circuit-feet are overhead and 40% are underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.5 kV feeder with a peak load of approximately 4,300 kVA.

B.4.3 Feeder 3: R1-12.47-2

This feeder is a representation of a moderately populated suburban and lightly populated rural area. This is composed mainly of single family residences with small amounts of light commercial. Approximately 70% of the circuit-feet are overhead and 30% underground. It would not be expected that this feeder is connected to adjacent feeders through normally open switches. Even though there are not adjacent feeders for transferring the load, the total feeder loading is low because of the sparse rural loading. In this model an urban substation is feeding a rural load through a long primary circuit. The majority of the load is located relatively distant with respect to the substation. This is a 12.47 kV feeder with a peak load of approximately 2,400 kVA.

B.4.4 Feeder 4: R1-12.47-3

This feeder is a representation of a moderately populated urban area. This is composed mainly of mid-sized commercial loads with some residences, mostly multi-family. Approximately 85% of the circuit-feet are overhead and 15% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. Since this is a small urban core the loading of the feeder is well below 60%. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 1,800 kVA.

B.4.5 Feeder 5: R1-12.47-4

This feeder is a representation of a heavily populated suburban area. This is composed mainly of single family homes and heavy commercial loads. None of the circuit-feet are overhead and 100% are underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,900 kVA.

B.4.6 Feeder 6: R1-25.00-1

This feeder is a representation of a lightly populated rural area. This is composed of a mixture of residential, light commercial, industrial, and agricultural loads. Approximately 60% of the circuit-feet are overhead and 40% underground. It would be expected that this feeder is not connected to adjacent feeders through normally open switches. Due to rural location and low population density the feeder is not heavily loaded. The low population density and wide are covered are why this feeder is operated at 24.9 kV. The majority of the load is located relatively distant with respect to the substation. This is a 24.9 kV feeder with a peak load of approximately 2,300 kVA.

B.4.7 Feeder 7: R2-12.47-1

This feeder is a representation of a lightly populated urban area. This is composed of single family homes, moderate commercial loads, light industrial loads, and some agricultural loads. This feeder supplies a college and an airport. Approximately 25% of the circuit-feet are overhead and 75% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 6,700 kVA.

B.4.8 Feeder 8: R2-12.47-2

This feeder is a representation of a moderately populated suburban area. This is composed mainly of single family homes with some light commercial loads. Approximately 80% of the circuit-feet are overhead and 20% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 6,700 kVA.

B.4.9 Feeder 9: R2-12.47-3

This feeder is a representation of a lightly populated suburban area. This is composed of single family homes, light commercial loads, light industrial loads, and some agricultural loads. Approximately 20% of the circuit-feet are overhead and 80% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,800 kVA.

B.4.10 Feeder 10: R2-25.00-1

This feeder is a representation of a moderately populated suburban area. This is composed mainly of single family homes with some light and moderate commercial loads. Approximately 60% of the circuit-feet are overhead and 40% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. This is a heavily loaded feeder, well over 60%, with the majority of the load is located relatively near the substation. This is a 24.9 kV feeder with a peak load of approximately 21,300 kVA.

B.4.11 Feeder 11: R2-35.00-1

This feeder is a representation of a lightly populated rural area. This is composed mainly of single family homes with some light and moderate commercial loads. Approximately 90% of the circuit-feet are overhead and 10% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. But due to the long distances significant portions of the load cannot be shifted to adjacent feeders. In this model a single substation is serving a large geographic area, this is the reason for the higher voltage level; voltage regulators are used on this system. The majority of the load is located relatively distant with respect to the substation. This is a 34.5 kV feeder with a peak load of approximately 6,900 kVA.

B.4.12 Feeder 12: R3-12.47-1

This feeder is a representation of a heavily populated urban area. This is composed of single family homes, heavy commercial loads, and a small amount of light industrial loads. Approximately 25% of the circuit-feet are overhead and 75% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. Due to the heavy commercial loads it would be expected that this feeder would be loaded to a high percentage of its rating. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 11,600 kVA.

B.4.13 Feeder 13: R3-12.47-2

This feeder is a representation of a moderately populated urban area. This is composed of single family homes, light commercial loads, and a small amount of light industrial loads. Approximately 33% of the circuit-feet are overhead and 67% underground. It would be expected that this feeder is connected to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 60% to ensure the ability to transfer load from other feeders, and vice versa. The majority of the load is located relatively near the substation. This is a 12.47 kV feeder with a peak load of approximately 4,000 kVA.

B.4.14 Feeder 14: R3-12.47-3

This feeder is a representation of a heavily populated suburban area. This is composed mainly of single family homes with some light agricultural loads. Approximately 75% of the circuit-feet are overhead and 25% underground. It would be expected that this feeder has limited connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 75% to ensure the ability to transfer some loads from other feeders, and vice versa. Due to the low density of suburban loads the majority of the load is located relatively distant with respect to the substation. This is a 12.45 kV feeder with a peak load of approximately 9,400 kVA.

B.4.15 Feeder 15: R4-12.47-1

This feeder is a representation of a heavily populated urban area with the primary feeder extending into a lightly populated rural area. In the urban areas the load is composed of moderate commercial loads with single and multi-family residences. On the rural spur the load is primarily single family residences. Approximately 92% of the circuit-feet are overhead and 8% underground. This feeder has connections to adjacent feeders in the urban area, but limited connections in the rural areas. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the urban load is located near the substation while the rural load is located at a substantial distance. This is a 13.8 kV feeder with a peak load of approximately 6,700 kVA.

B.4.16 Feeder 16: R4-12.47-2

This feeder is a representation of a lightly populated suburban area with a moderately populated urban area. The lightly populated suburban area is composed mostly of single family residences. The commercial complex is a single facility. Approximately 92% of the circuit-feet are overhead and 8% underground. This feeder has connections to adjacent feeders in the commercial complex, but limited connections in the rural areas. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the suburban load is located near the substation while the commercial load is located at a substantial distance. This is a 12.5 kV feeder with a peak load of approximately 2,100 kVA.

B.4.17 Feeder 17: R4-25.00-1

This feeder is a representation of a lightly populated rural area. The load is composed of single family residences with some light commercial. Approximately 88% of the circuit-feet are overhead and 12% underground. This feeder has connections to adjacent feeders. This combined with the low load density ensures the ability to transfer most of the loads from other feeders, and vice versa. Most of the load is located at a substantial distance from the substation, as is common for higher voltages in rural areas. This is a 24.9 kV feeder with a peak load of approximately 1,000 kVA.

B.4.18 Feeder 18: R5-12.47-1

This feeder is a representation of a heavily populated suburban area and a moderate urban center. This is composed mainly of single family homes and moderate commercial loads. Approximately 95% of the circuit-feet are overhead and 5% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most loads from other feeders, and vice versa. The suburban load is near the substation while the commercial load is at the end of the feeder. This is a 13.8 kV feeder with a peak load of approximately 10,800 kVA.

B.4.19 Feeder 19: R5-12.47-2

This feeder is a representation of a moderate suburban area with a heavy urban area. This is composed mainly of heavy commercial and single family residences. Approximately 38% of the circuit-feet are overhead and 62% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most loads from other feeders, and vice versa. The heavy commercial load is near the substation while the single family residences are at the end of the feeder. This is a 12.47 kV feeder with a peak load of approximately 4,200 kVA.

B.4.20 Feeder 20: R5-12.47-3

This feeder is a representation of a moderately populated rural area. This is composed mainly of single family residences with some light commercial. Approximately 92% of the circuit-feet are overhead and 8% underground. It would be expected that this feeder has limited connections to adjacent feeders through normally open switches. Due to the low load density of the large rural area the feeder is less than 50% loaded. The majority of the load is located relatively distant with respect to the substation. Voltage regulators are used on this feeder. This is a 13.8 kV feeder with a peak load of approximately 4,800 kVA.

B.4.21 Feeder 21: R5-12.47-4

This feeder is a representation of a moderately populated suburban and urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 37% of the circuit-feet are overhead and 63% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. Most of the commercial load is near the substation and the residential load is spread out along the length of the entire feeder. This is a 12.47 kV feeder with a peak load of approximately 6,200 kVA.

B.4.22 Feeder 22: R5-12.47-5

This feeder is a representation of a moderately populated suburban area with a lightly populated urban area. This is composed mainly of single family residences with some light commercial loads. Approximately 48% of the circuit-feet are overhead and 52% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder. The primary feeder extends a significant distance before there is any significant load, an express configuration. This is a configuration that can be seen in a well-established area when a new feeder must be routed through an existing area in order to reach areas of new load growth. This is a 12.47 kV feeder with a peak load of approximately 8,500 kVA.

B.4.23 Feeder 23: R5-25.00-1

This feeder is a representation of a heavily populated suburban area with a moderately populated urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 35% of the circuit-feet are overhead and 65% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 66% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder with the moderate commercial center near the substation. This is a 22.9 kV feeder with a peak load of approximately 9,300 kVA.

B.4.24 Feeder 24: R5-35.00-1

This feeder is a representation of a moderately populated suburban area with a lightly populated urban area. This is composed mainly of single family residences with some moderate commercial loads. Approximately 10% of the circuit-feet are overhead and 90% underground. It would be expected that this feeder has connections to adjacent feeders through normally open switches. For this reason it would be common to limit the feeder loading to 50% to ensure the ability to transfer most of the loads from other feeders, and vice versa. The residential load is spread out across the entire length of the feeder with the moderate commercial center near the substation. This feeder is representative of a substation that is built in a “green field” where significant load growth is expected. The first feeders must go a significant distance before they reach the load, over time the load moves towards the substation and past it. This is a 34.5 kV feeder with a peak load of approximately 12,100 kVA.

Appendix C: Simulation Technology and Methodology

Simulations of the different project technologies and programs were accomplished using the GridLAB-D software. GridLAB-D provides an agent-based multi-disciplinary environment for the examination and evaluation of emerging technologies. By providing a multi-disciplinary simulation environment, it is possible to bring together diverse teams of experts from multiple fields of study to holistically examine complex systems.

GridLAB-D has been developed through funding from the Department of Energy, Office of Electricity. Through $5.5 million of direct funding and supporting projects from DOE-OE, GridLAB-D has developed significant capabilities for analyzing smart grid deployments. The capabilities center on the functionality needed to simulate a distribution feeder power flow and attached loads. The development has included: unbalanced three-phase power flow solvers; detailed end-use models, particularly of a residential home's thermal integrity, HVAC cycles and water heater cycles; and a transactive market that supports double auction bidding. Different combinations of these capabilities enabled simulations of the various technologies and programs evaluated in this report.

GridLAB-D conducts time-series simulations with variable time steps. The solution at each time step is a quasi-steady state solution for each of the modules. Convergence is achieved within each module and convergence across modules is coordinated via the GridLAB core as illustrated in Figure C..

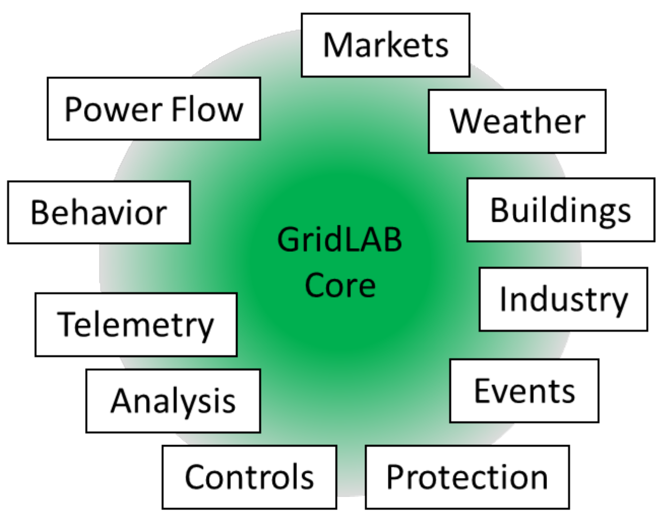

Figure C.1: GridLAB-D architecture

Time steps are also coordinated by the GridLAB-D core. This is necessary because the various modules in the simulation will generally have different time step requirements. At the end of a time step, every object in the model returns a 'sync' time that indicates how long the object will remain constant without outside influence. The GridLAB core then examines every object and determines what the smallest sync time is; this then becomes length of the next step. This process is performed at every time step so that the system has a variable step size. For a given state variable an example of the variable step sizes are shown in Figure C.2.

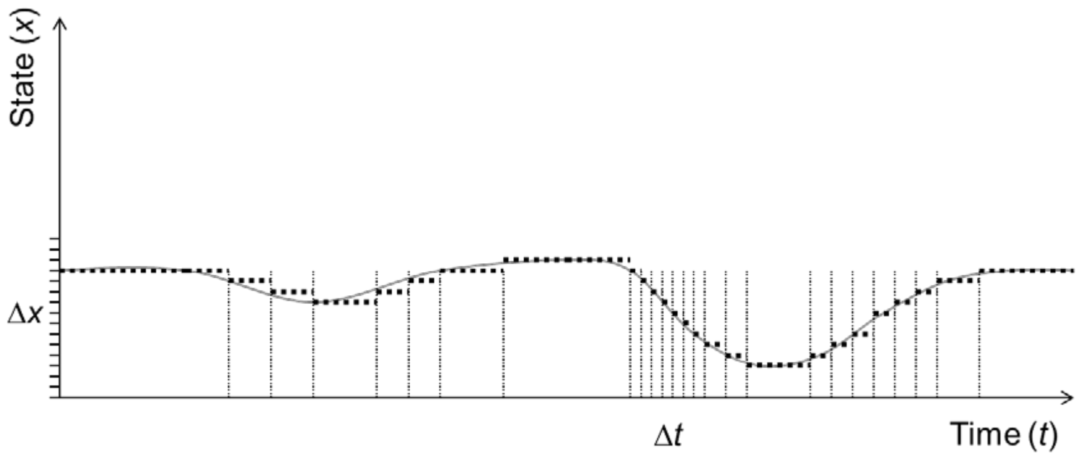

Figure C.2: Variable step sizes in GridLAB-D simulation

When analyzing operations at the distribution level, the major dynamics of interest are mid-term and occur on the order of minutes to hours. For the purposes of this analysis, a minimum time step of one minute was enforced. For operations that occur at intervals of less than one minute, such as a 45-second delay on a voltage regulator, the operation is aggregated up to the one minute time step; multiple operations cannot occur during the enforced minimum of one minute. Because of the large number of objects and the forced minimum, the simulation proceeded at one-minute time steps for the majority of the simulations. As a result, there are approximately 500,000 time steps in an annual simulation of a single prototypical feeder.

Since the simulations for the SGIG analysis are being conducted over a one year period the minimum step size has been set to one minute. Even with a minimum one minute step size there is the possibility of 525,600 time steps in a single simulation. If a one second minimum step size were used there would be no significant increase in accuracy because most of the dynamic behavior has a time constant greater than one minute. Additionally, the number of time steps would increase by a factor of sixty resulting in significantly more computing time.

Appendix D: Plots for Individual Feeder Results

This section presents the individual plots for each feeder simulated. The plots and interpretations are similar to those presented for R3-12.47-3 in Section 3.1.

D.1 Detailed Thermal Energy Storage Plots for GC-12.47-1_R1

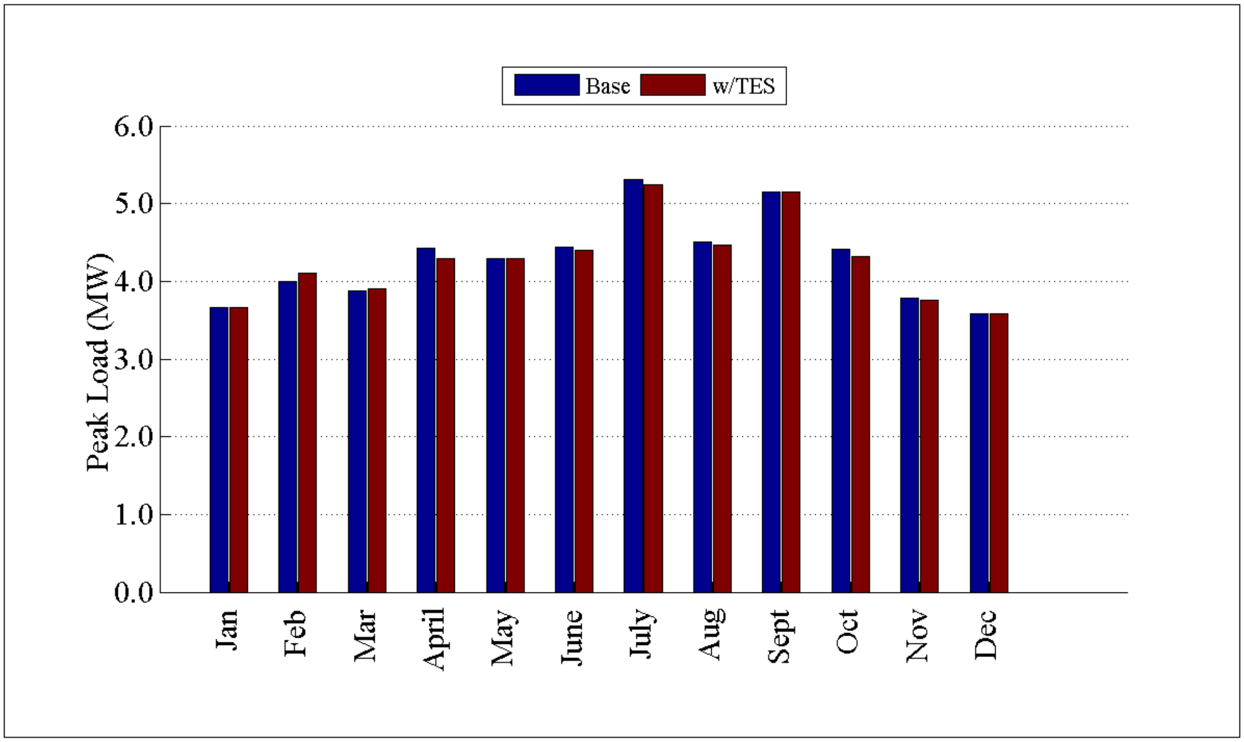

Figure D.1: Peak load by month of GC-12.47-1-r1 feeder

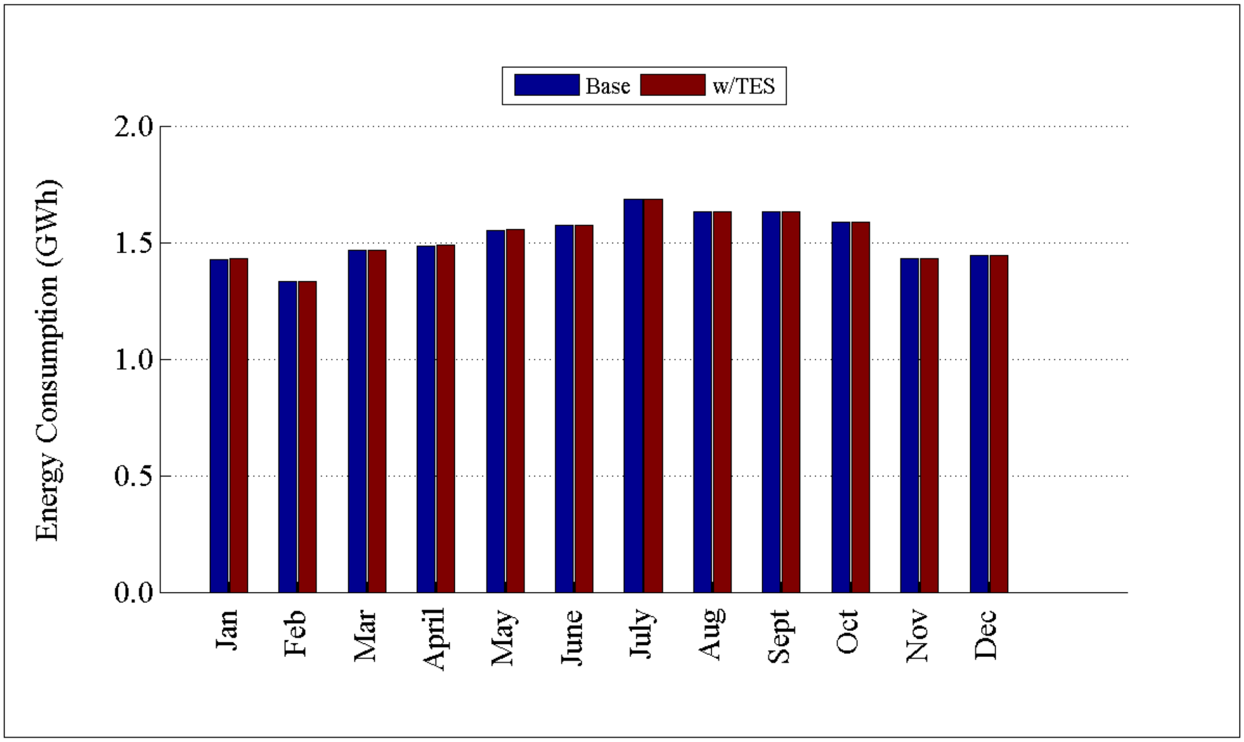

Figure D.2: Monthly energy consumption for GC-12.47-1-r1 feeder

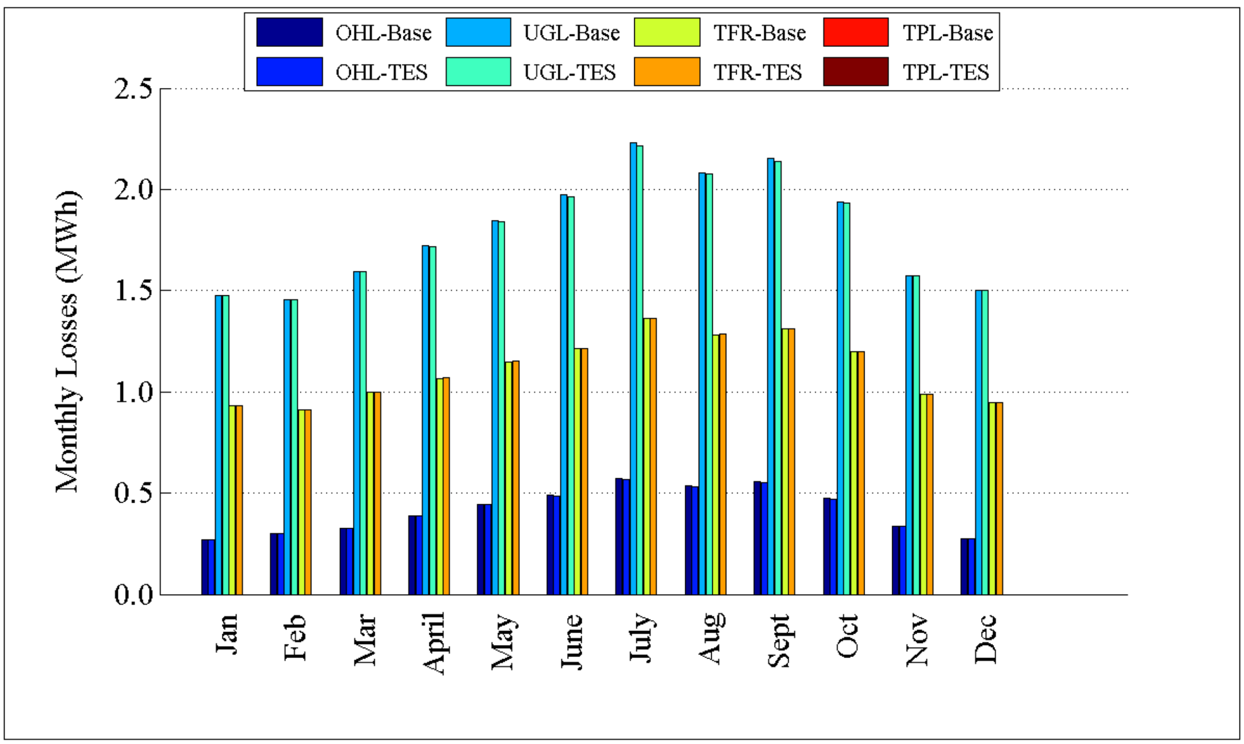

Figure D.3: Distribution system losses by month for GC-12.47-1-r1 feeder

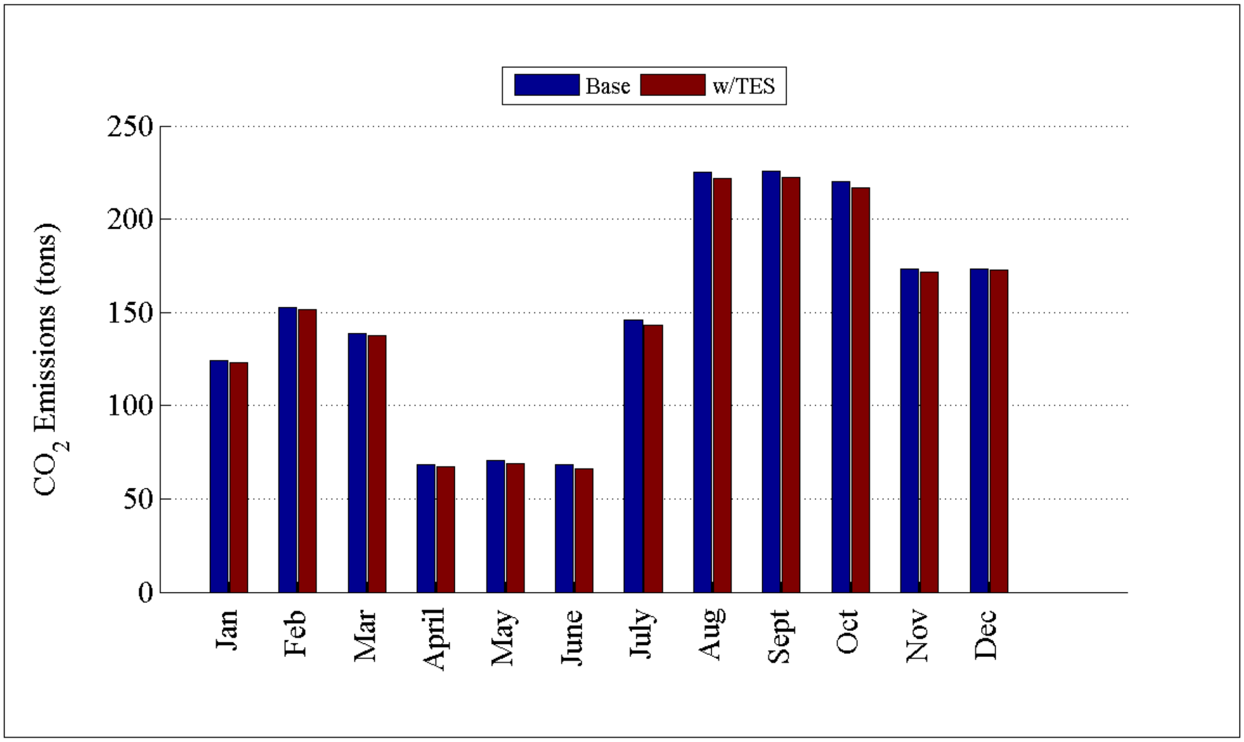

Figure D.4: CO_2 emissions by month for GC-12.47-1-r1

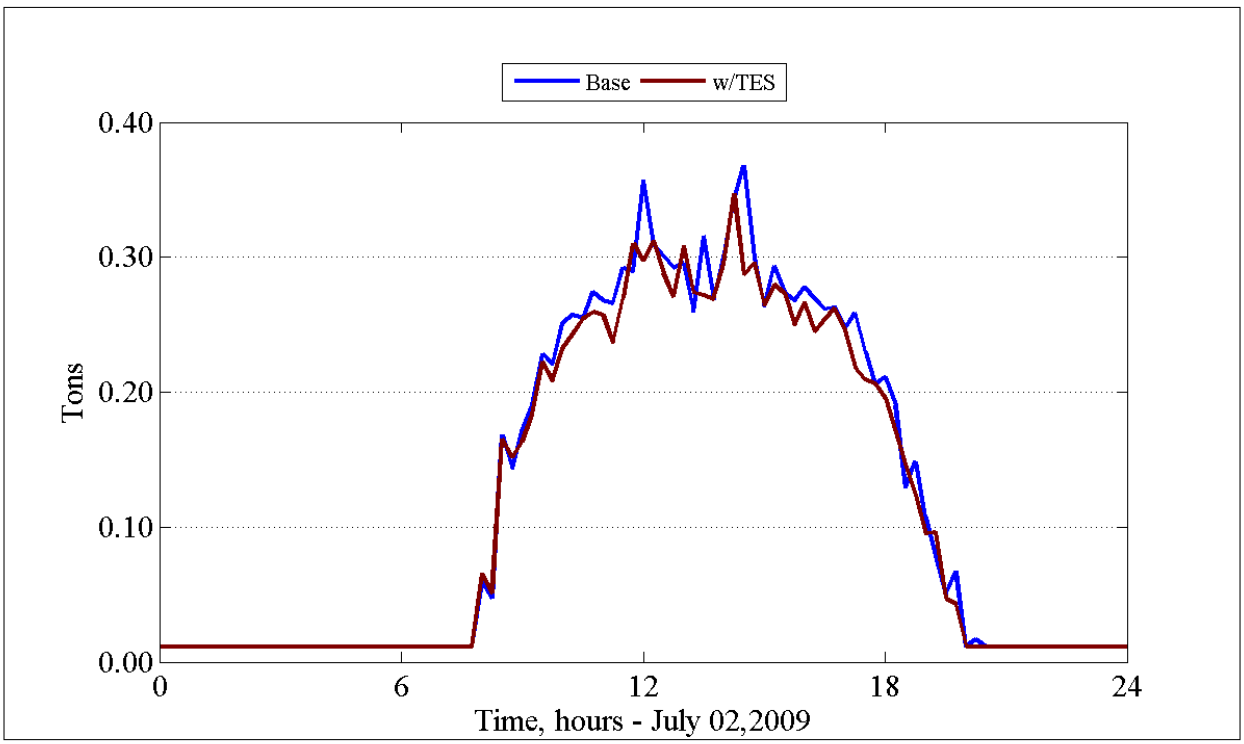

Figure D.5: Carbon dioxide emissions for peak day of GC-12.47-1-r1

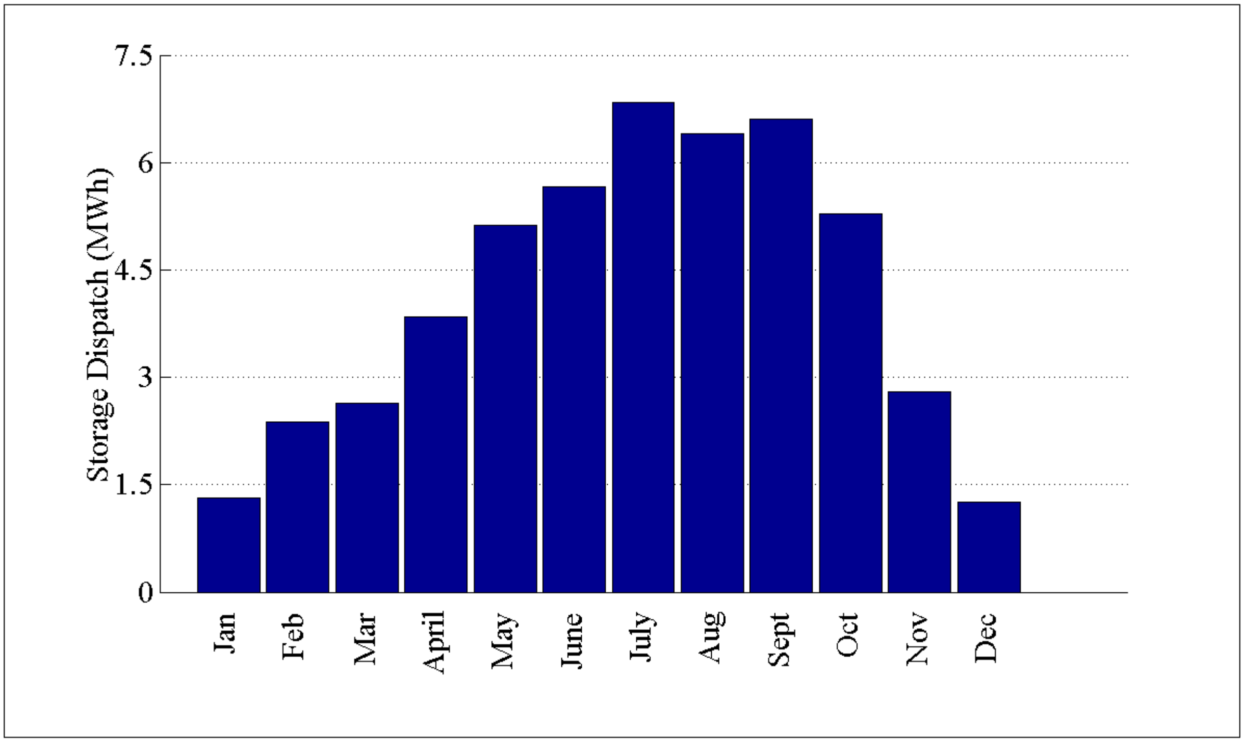

Figure D.6: Monthly storage dispatch energy for GC-12.47-1-r1

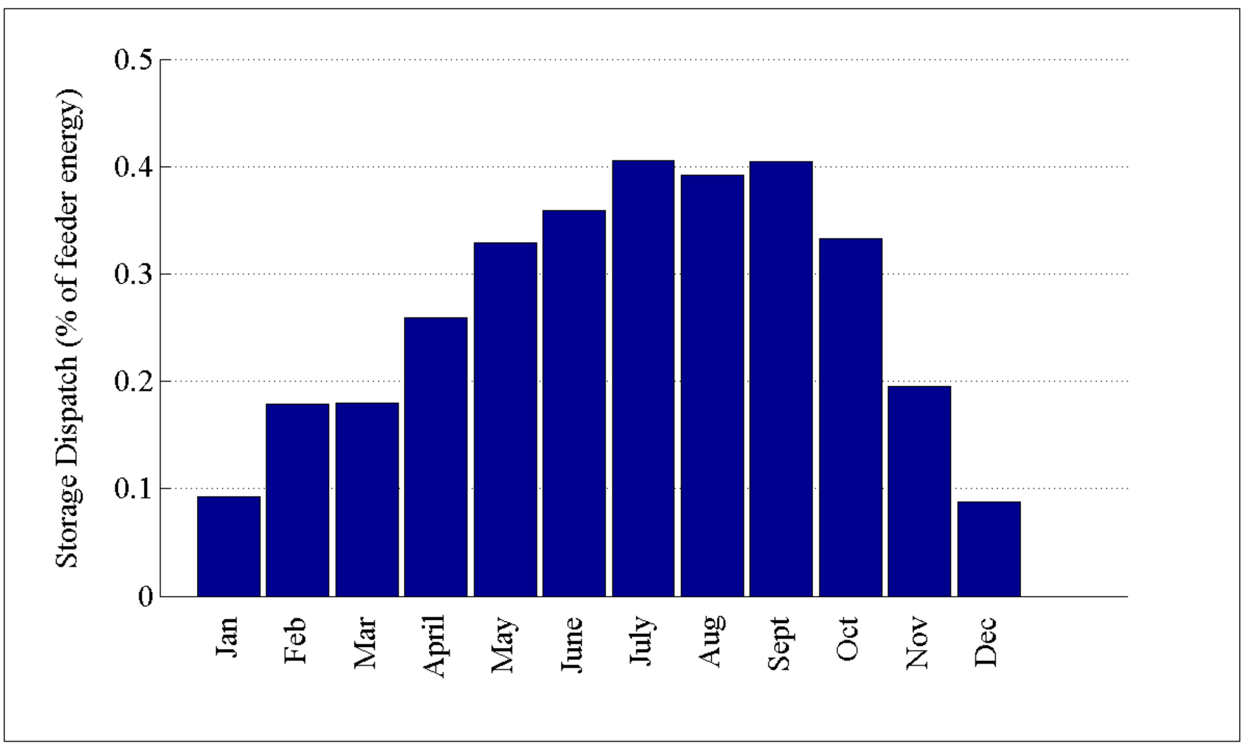

Figure D.7: Monthly storage dispatch energy percentage for GC-12.47-1-r1

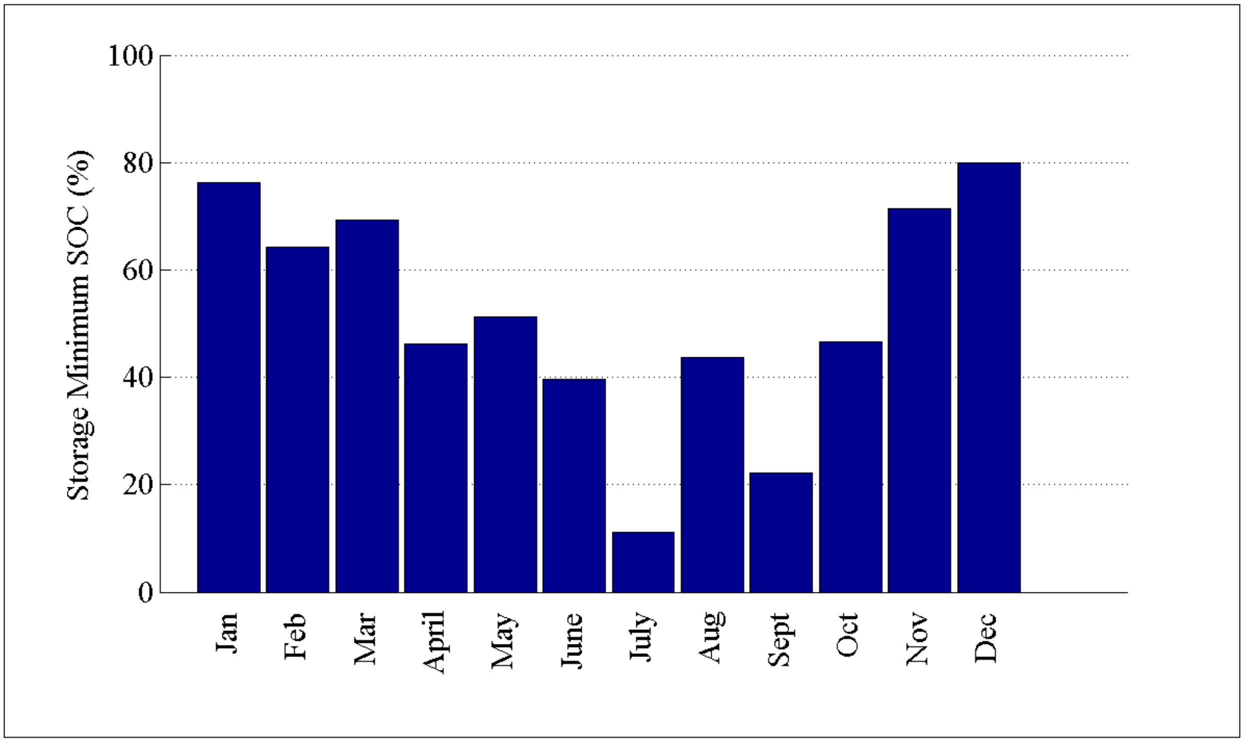

Figure D.8: Minimum state of charge for thermal energy storage on GC-12.47-1-r1

D.2 Detailed Thermal Energy Storage Plots for R1-12.47-1

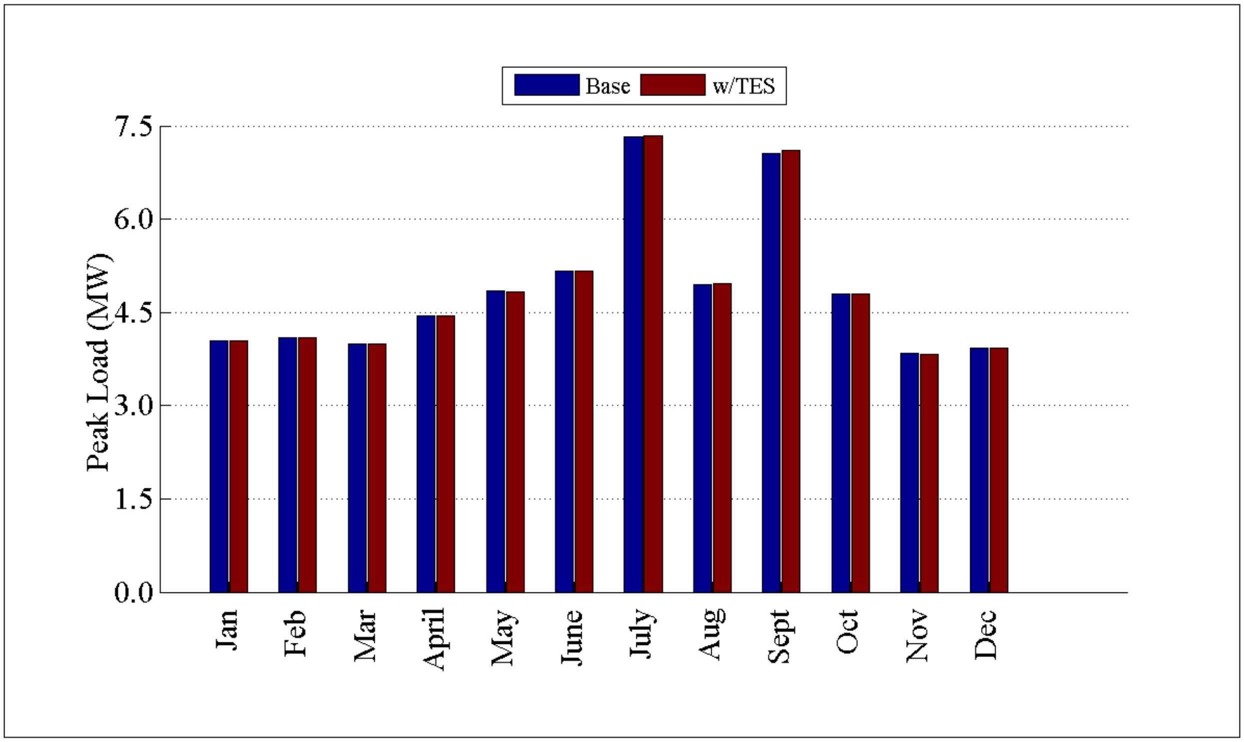

Figure D.9: Peak load by month of R1-12.47-1 feeder

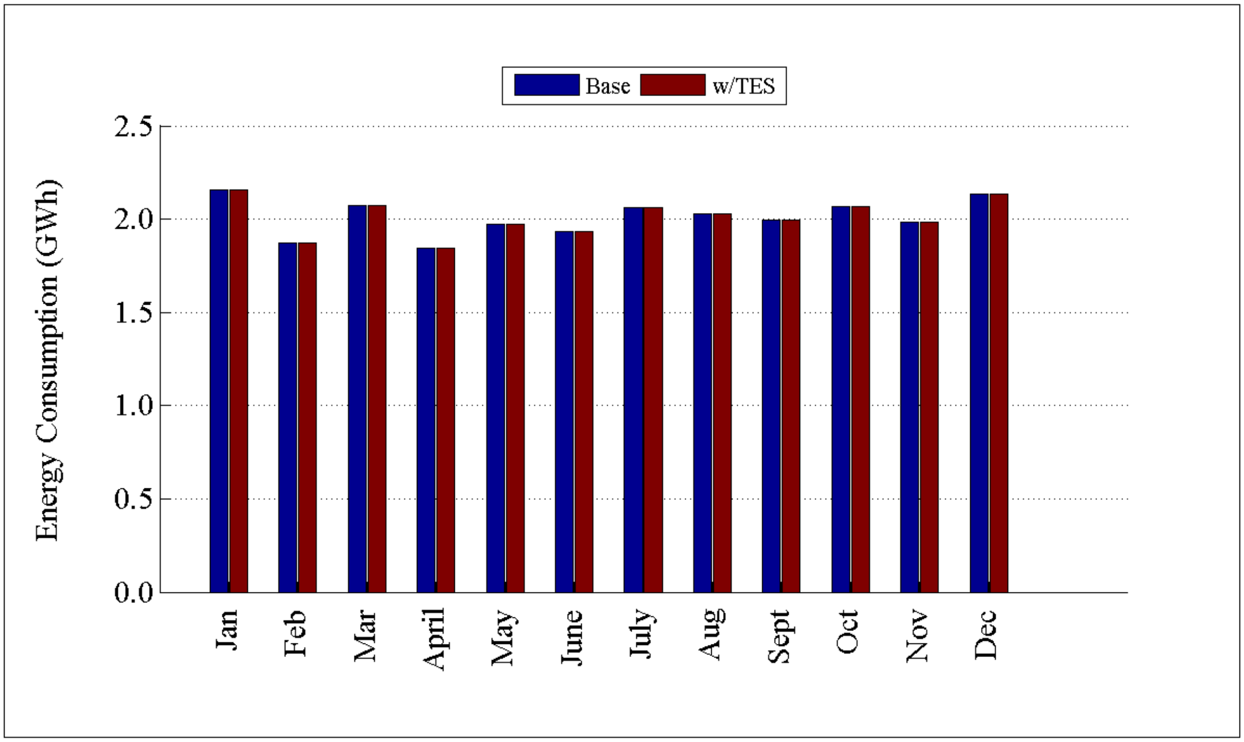

Figure D.10: Monthly energy consumption for R1-12.47-1 feeder

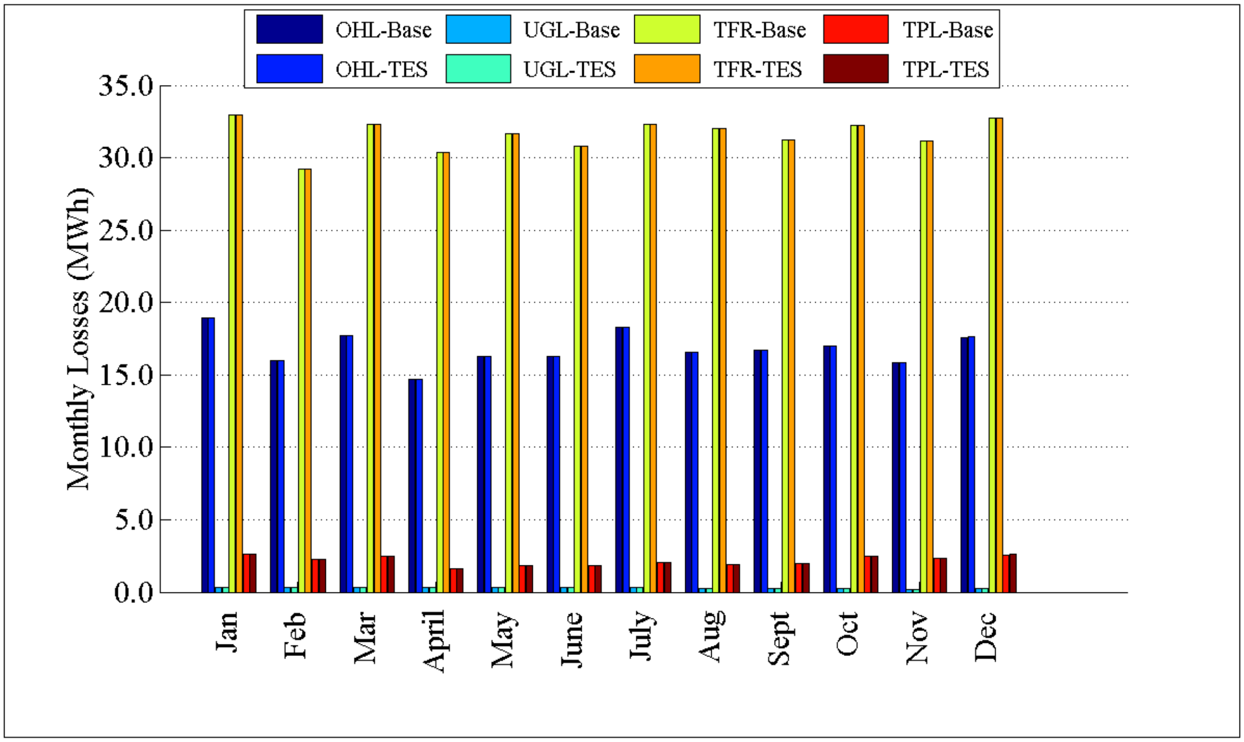

Figure D.11: Distribution system losses by month for R1-12.47-1

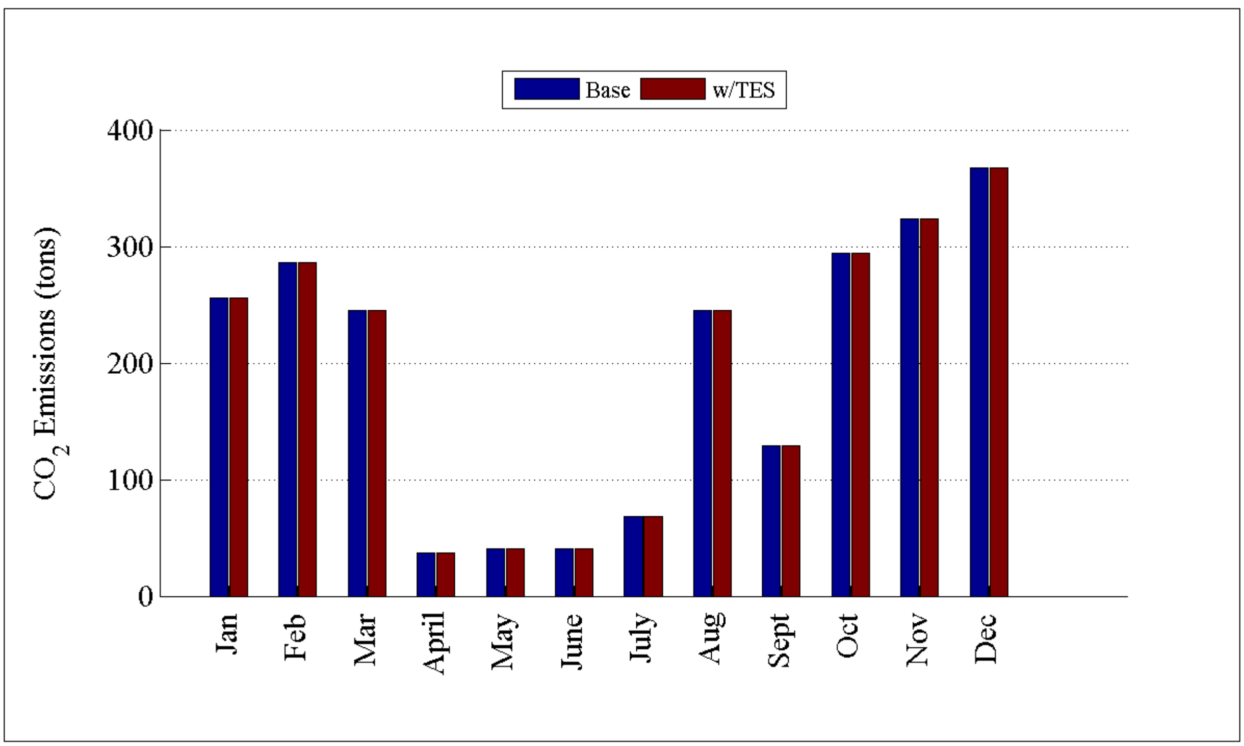

Figure D.12: CO_2 emissions by month for R1-12.47-1

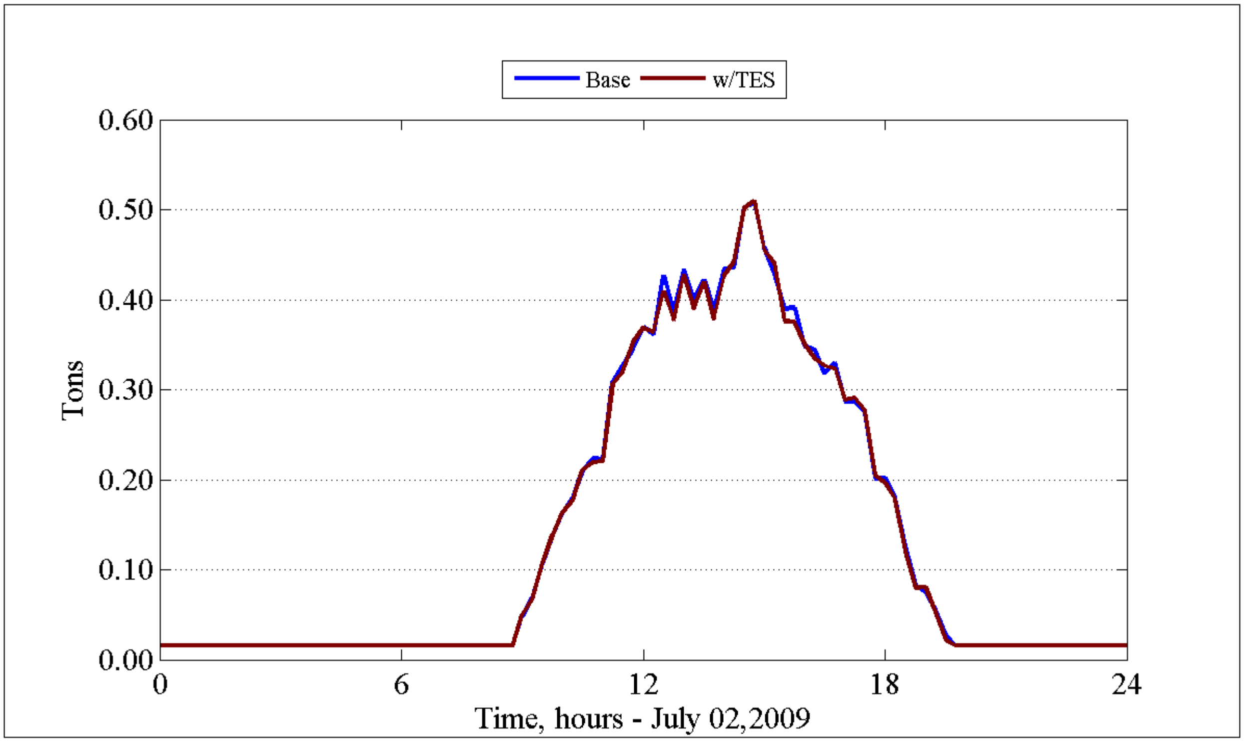

Figure D.13: Carbon dioxide emissions for peak day of R1-12.47-1

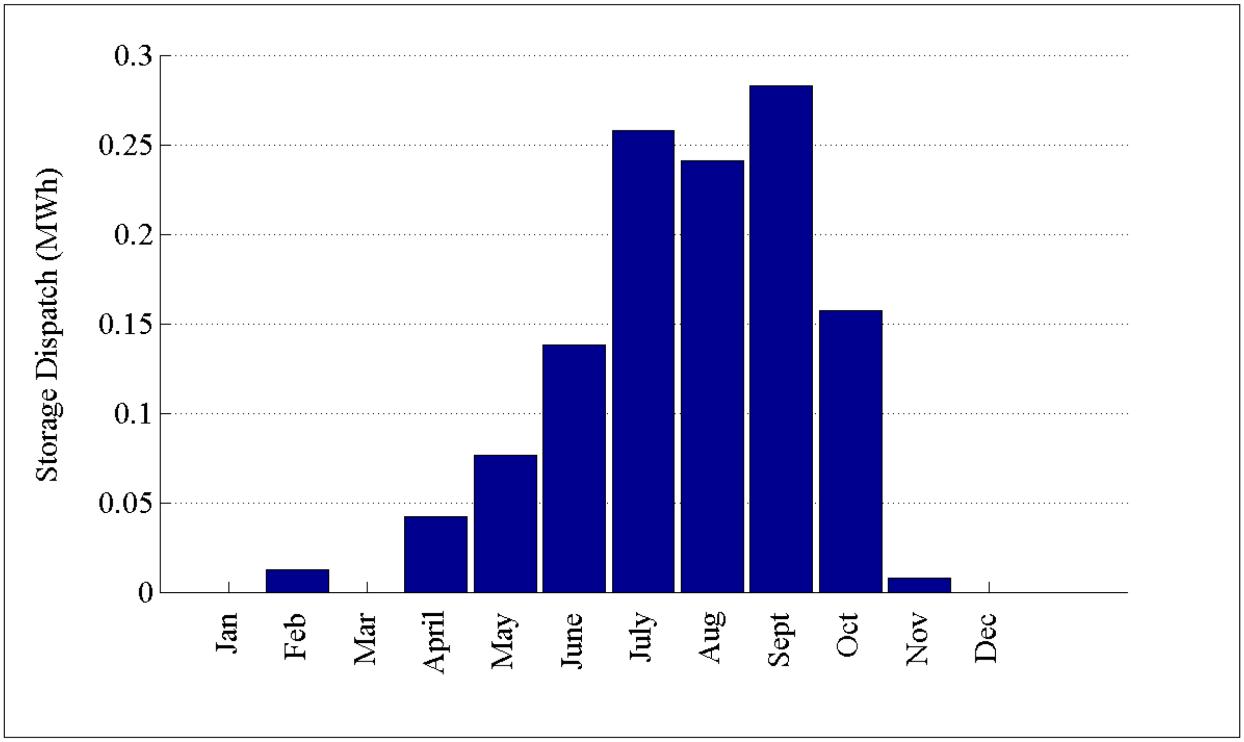

Figure D.14: Monthly storage dispatch energy for R1-12.47-1

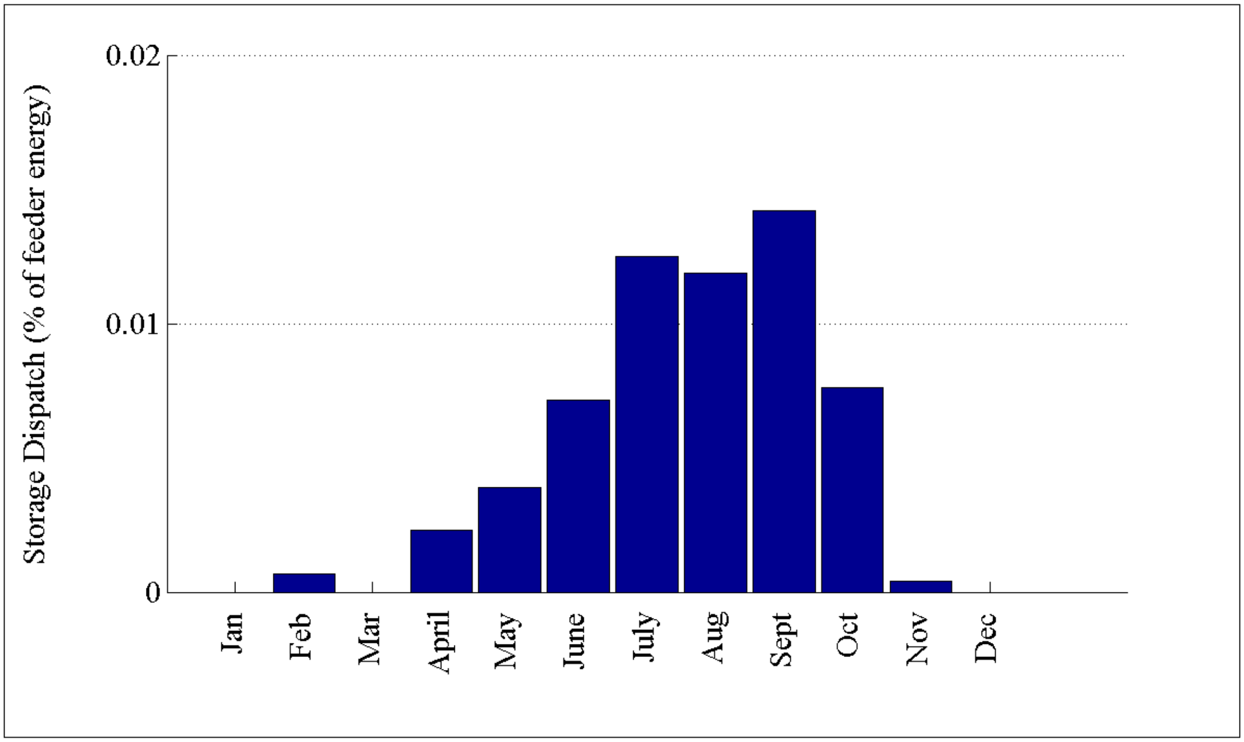

Figure D.15: Monthly storage dispatch energy percentage for R1-12.47-1

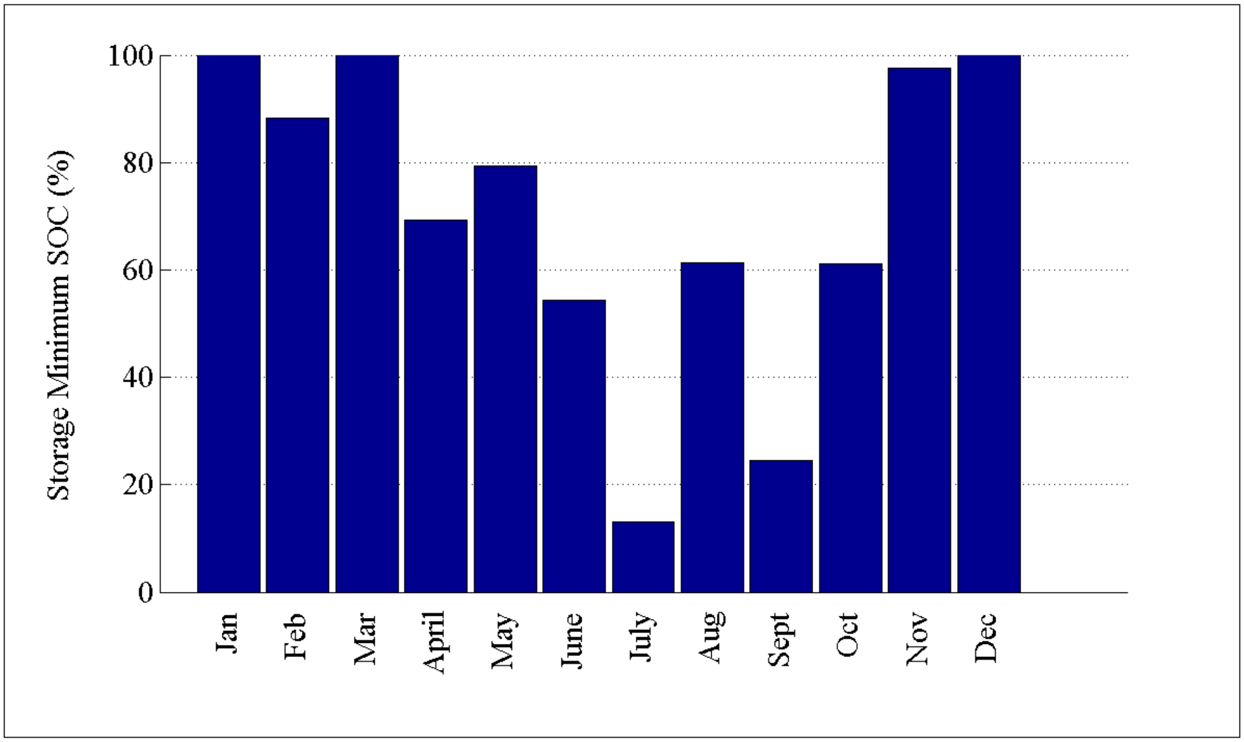

Figure D.16: Minimum state of charge for thermal energy storage on R1-12.47-1

D.3 Detailed Thermal Energy Storage Plots for R1-12.47-2

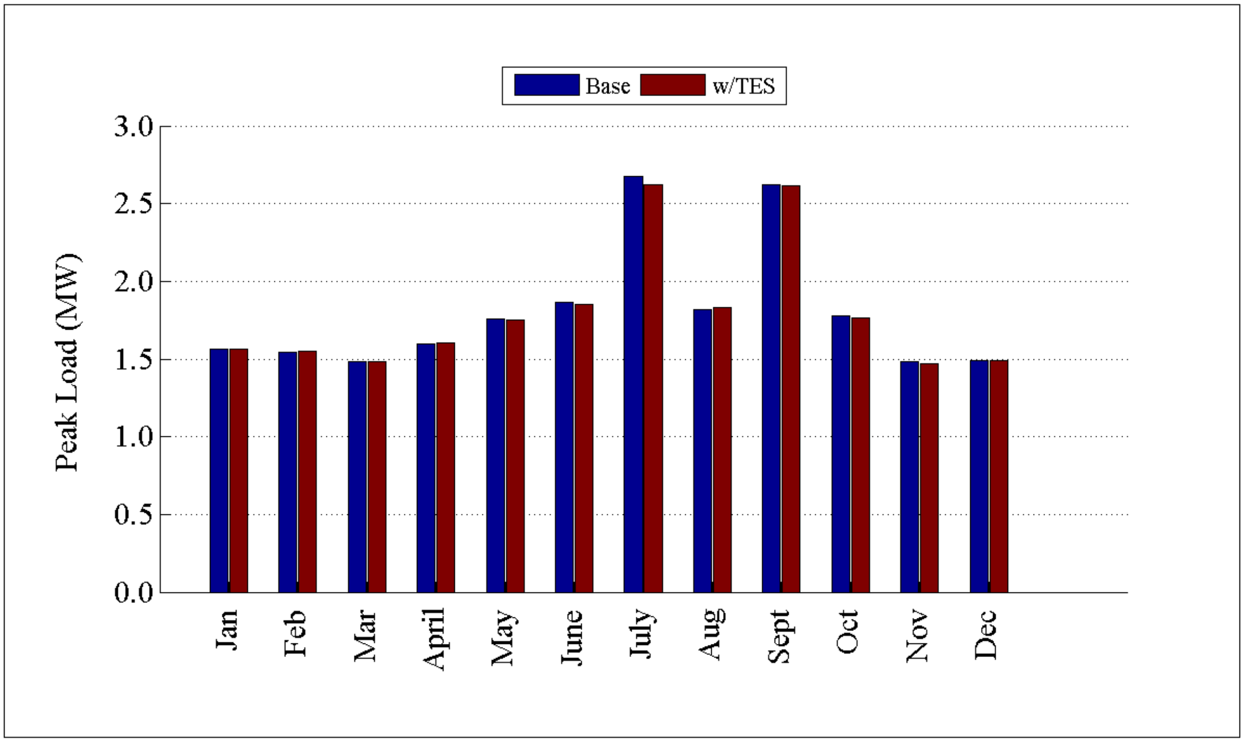

Figure D.17: Peak load by month of R1-12.47-2 feeder

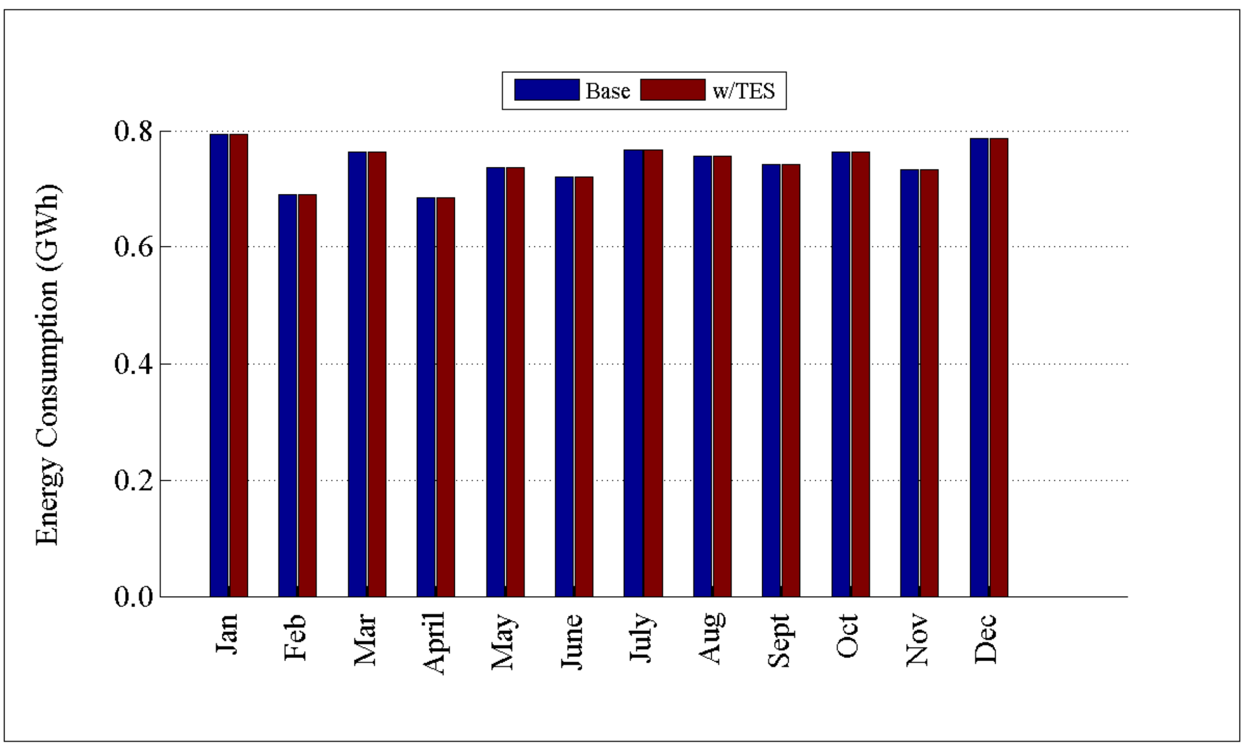

Figure D.18: Monthly energy consumption for R1-12.47-2 feeder

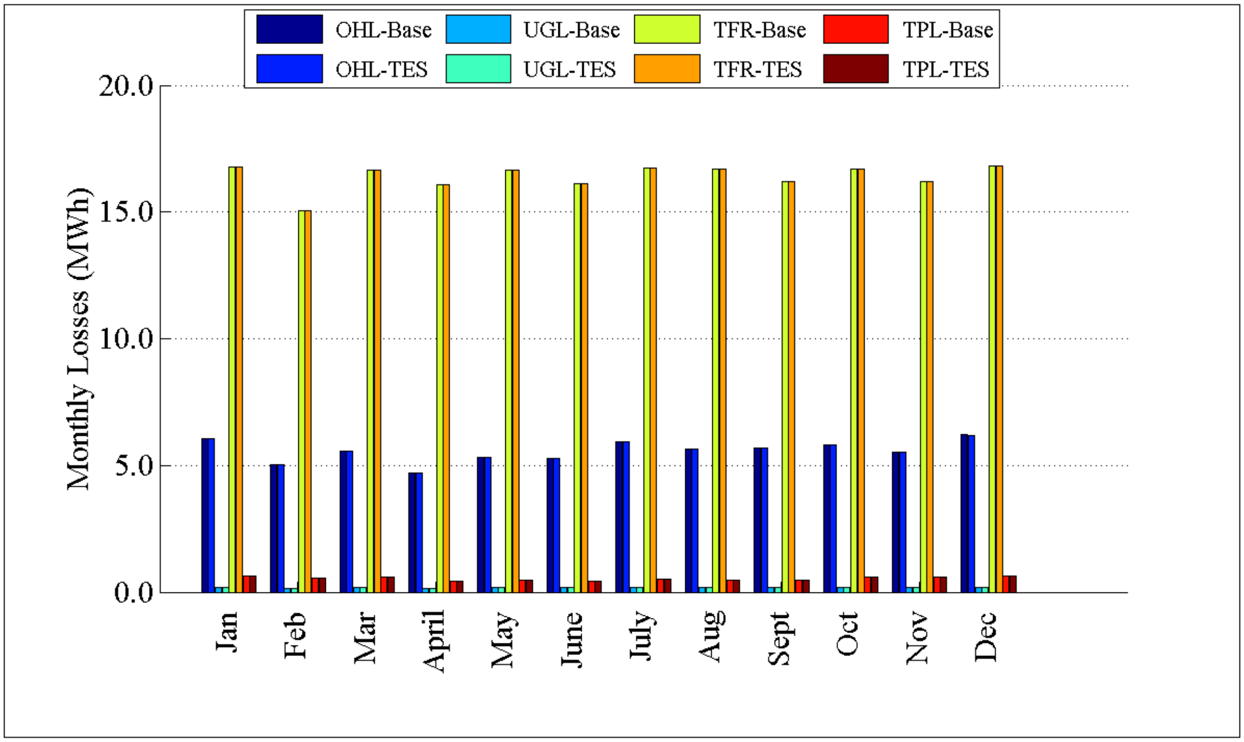

Figure D.19: Distribution system losses by month for R1-12.47-2

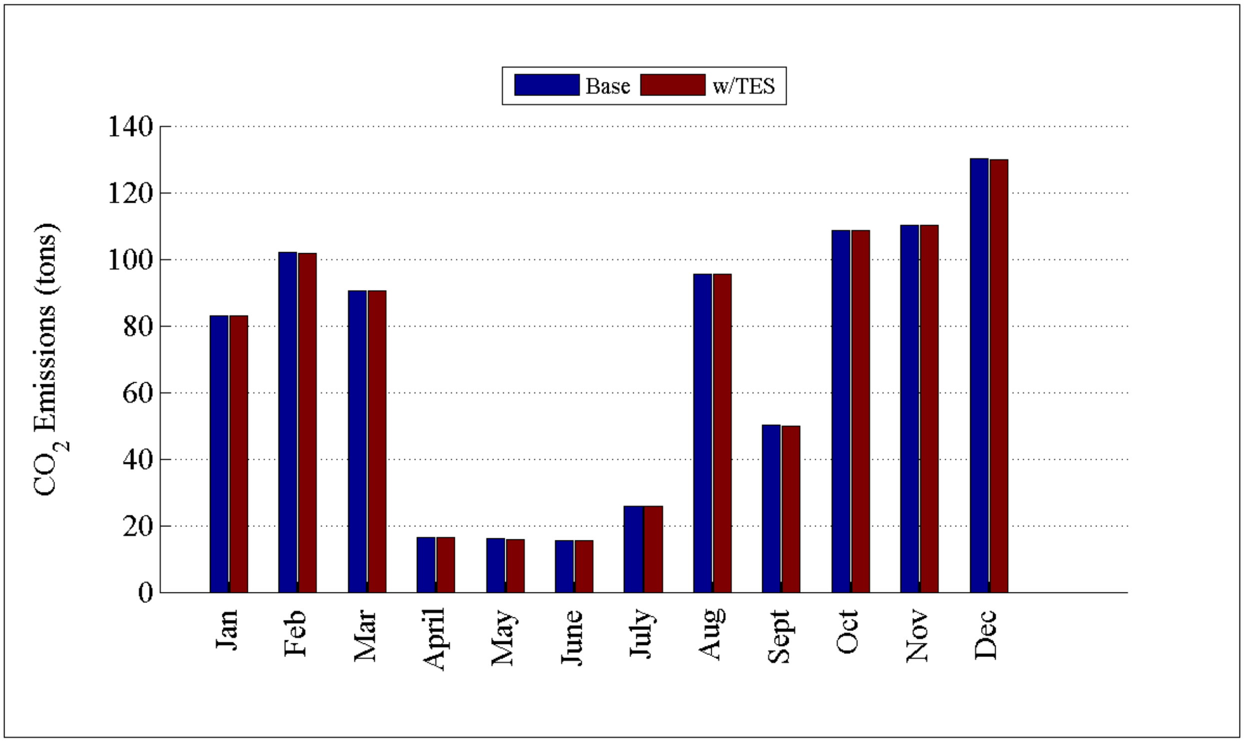

Figure D.20: CO_2 emissions by month for R1-12.47-2

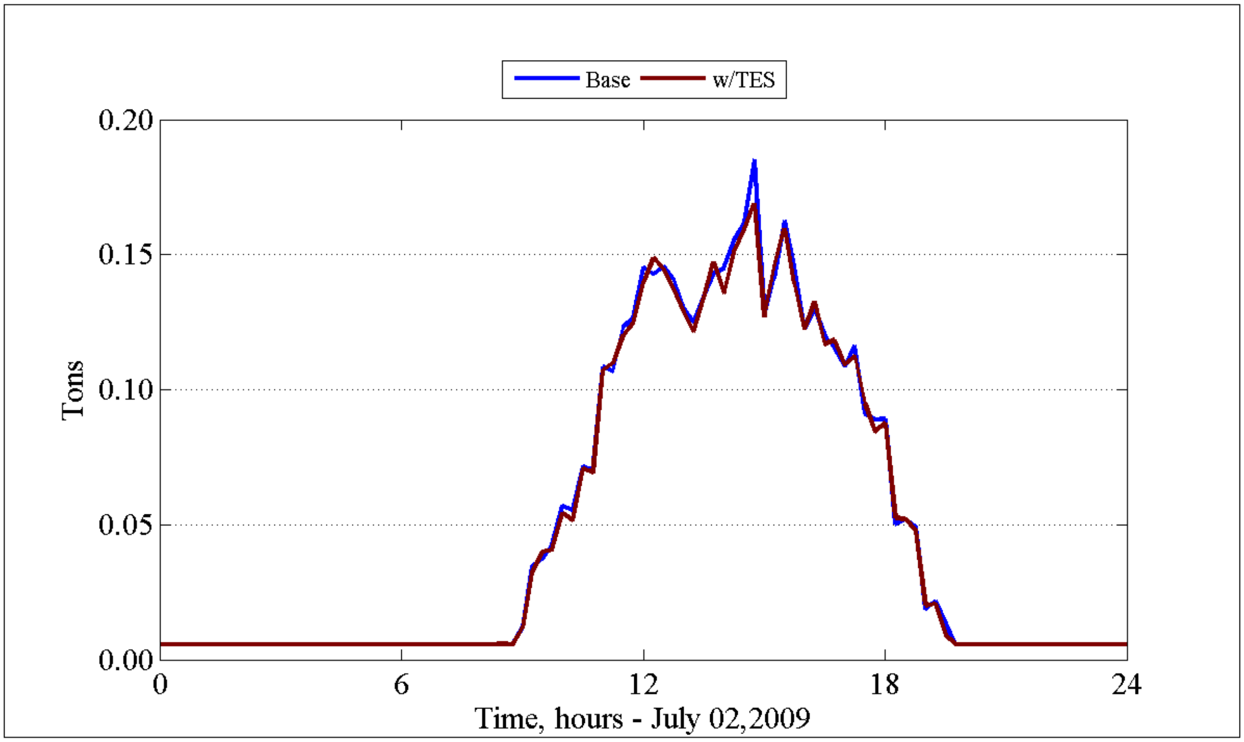

Figure D.21: Carbon dioxide emissions for peak day of R1-12.47-2

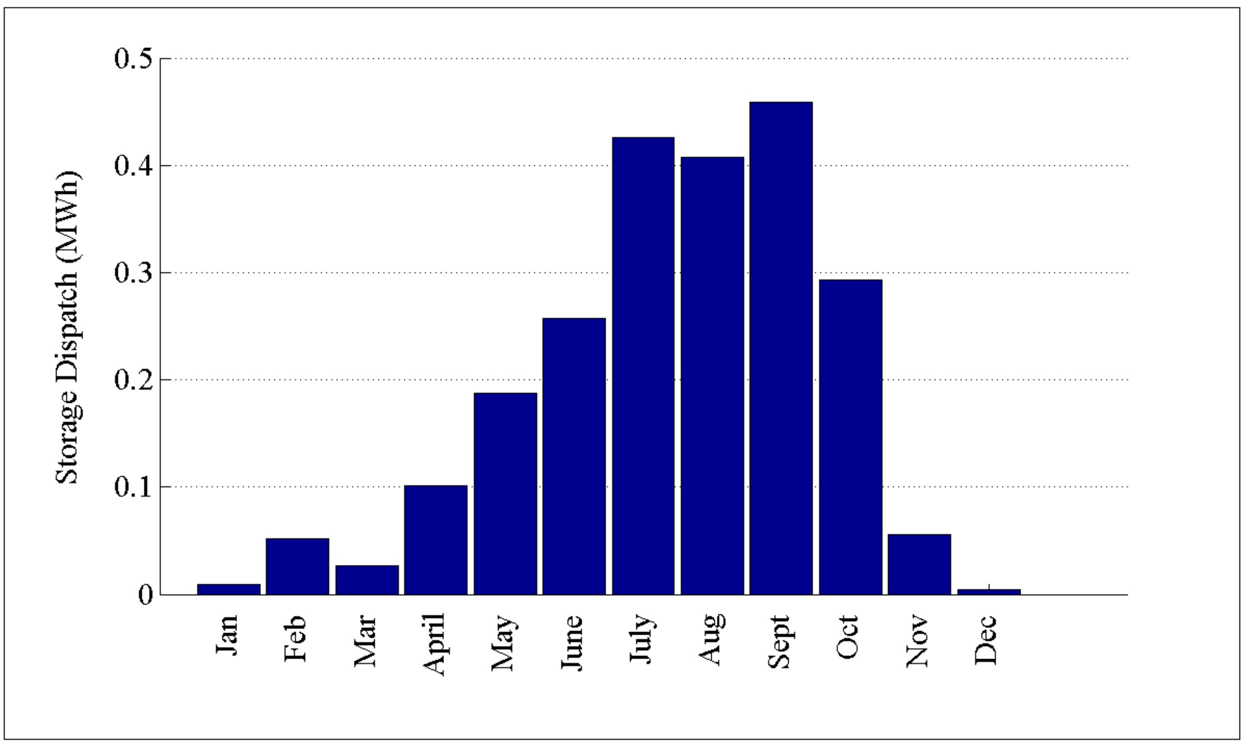

Figure D.22: Monthly storage dispatch energy for R1-12.47-2

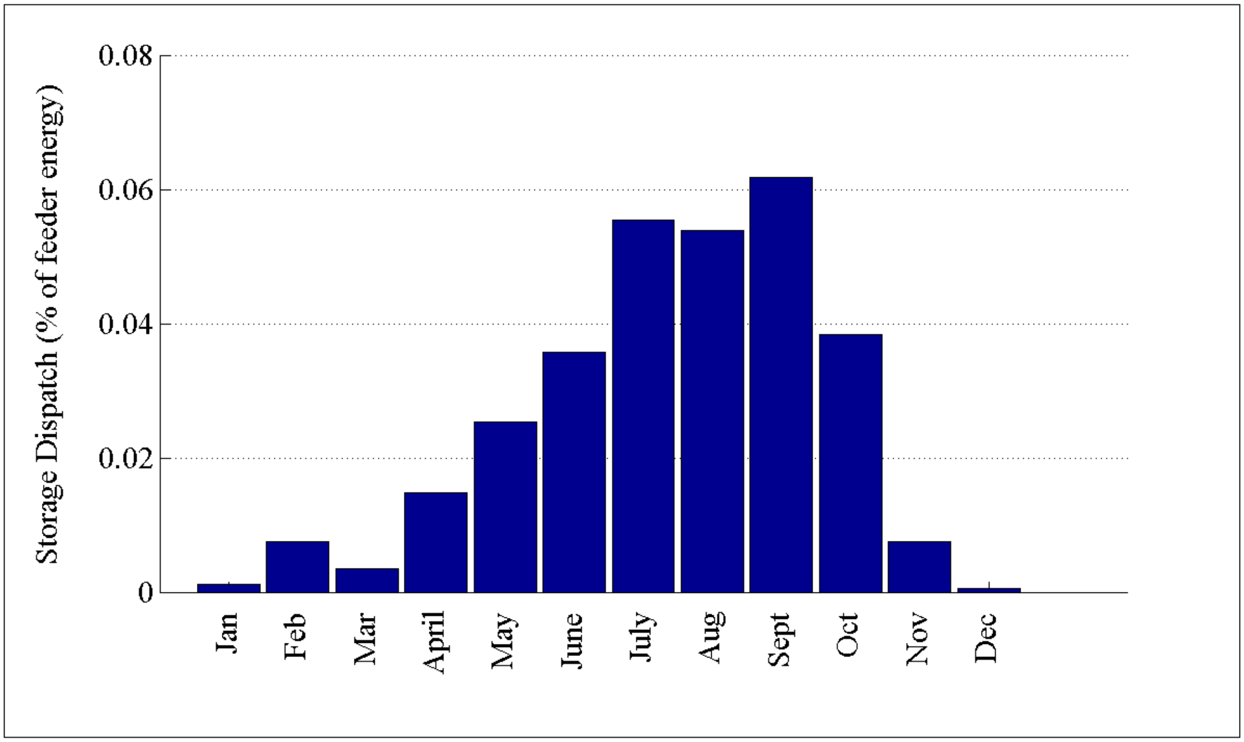

Figure D.23: Monthly storage dispatch energy percentage for R1-12.47-2

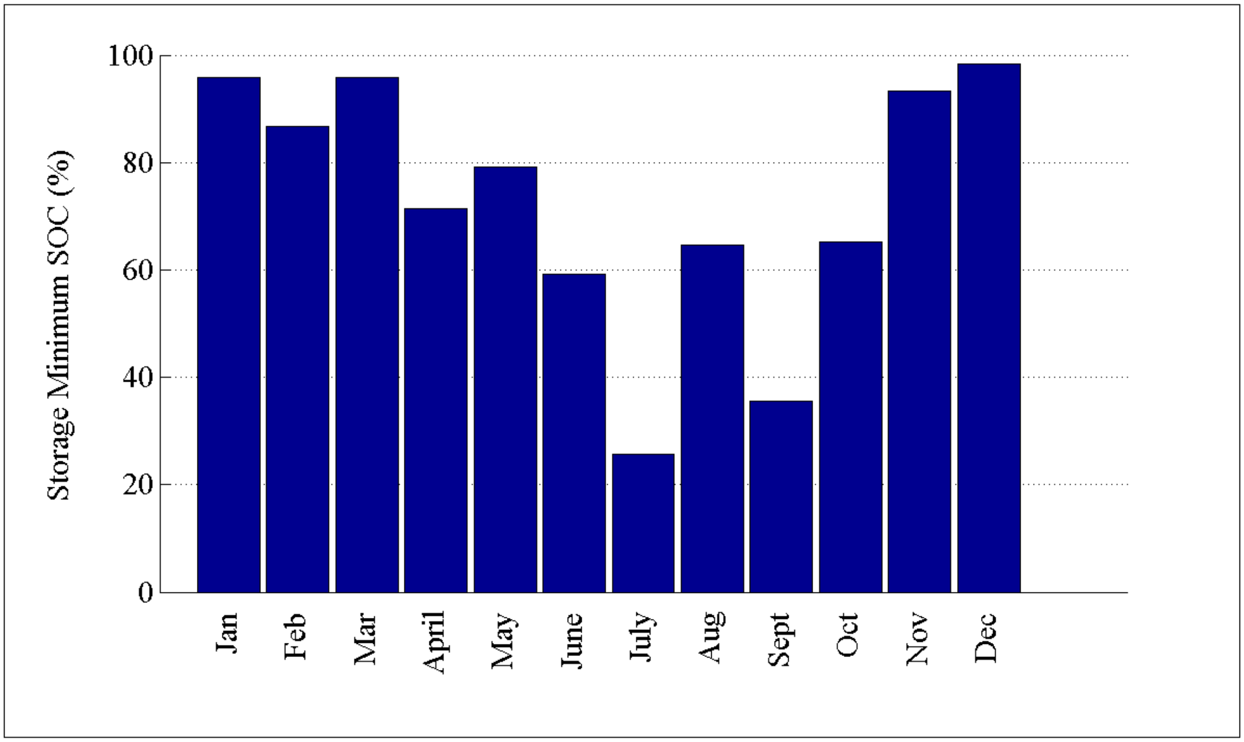

Figure D.24: Minimum state of charge for thermal energy storage on R1-12.47-2

D.4 Detailed Thermal Energy Storage Plots for R1-12.47-3

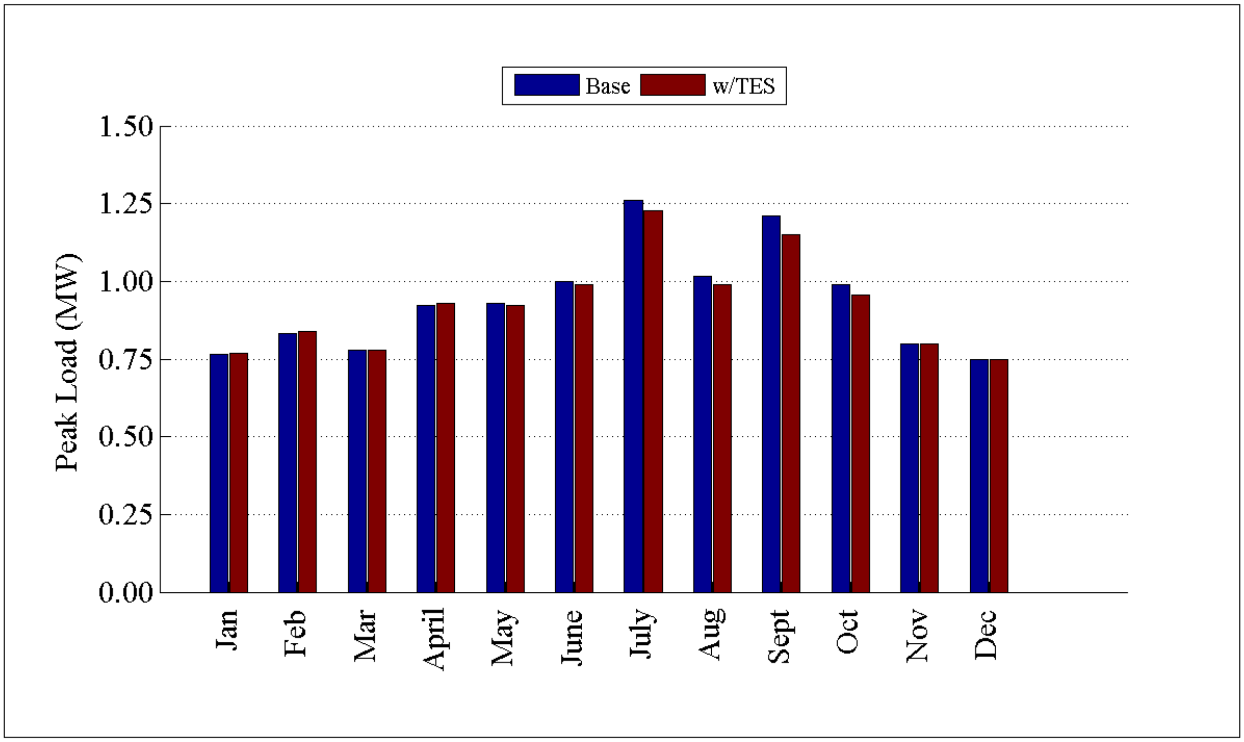

Figure D.25: Peak load by month of R1-12.47-3 feeder

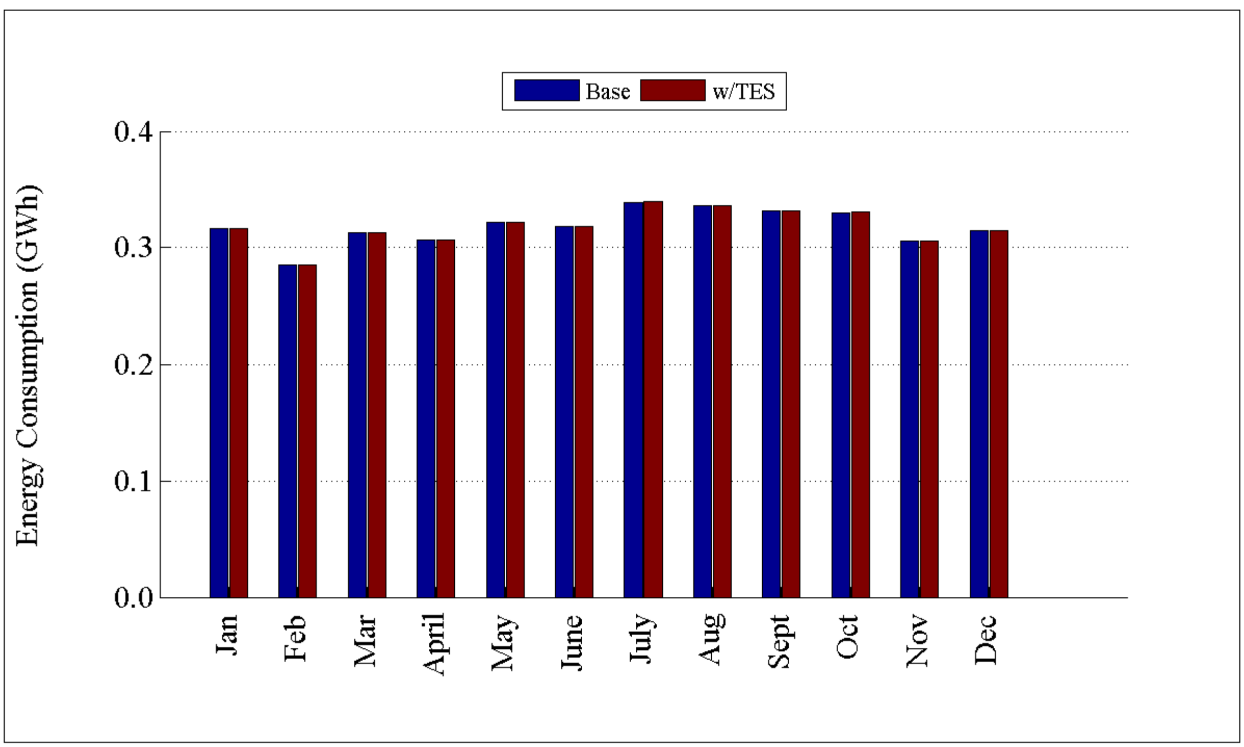

Figure D.26: Monthly energy consumption for R1-12.47-3 feeder

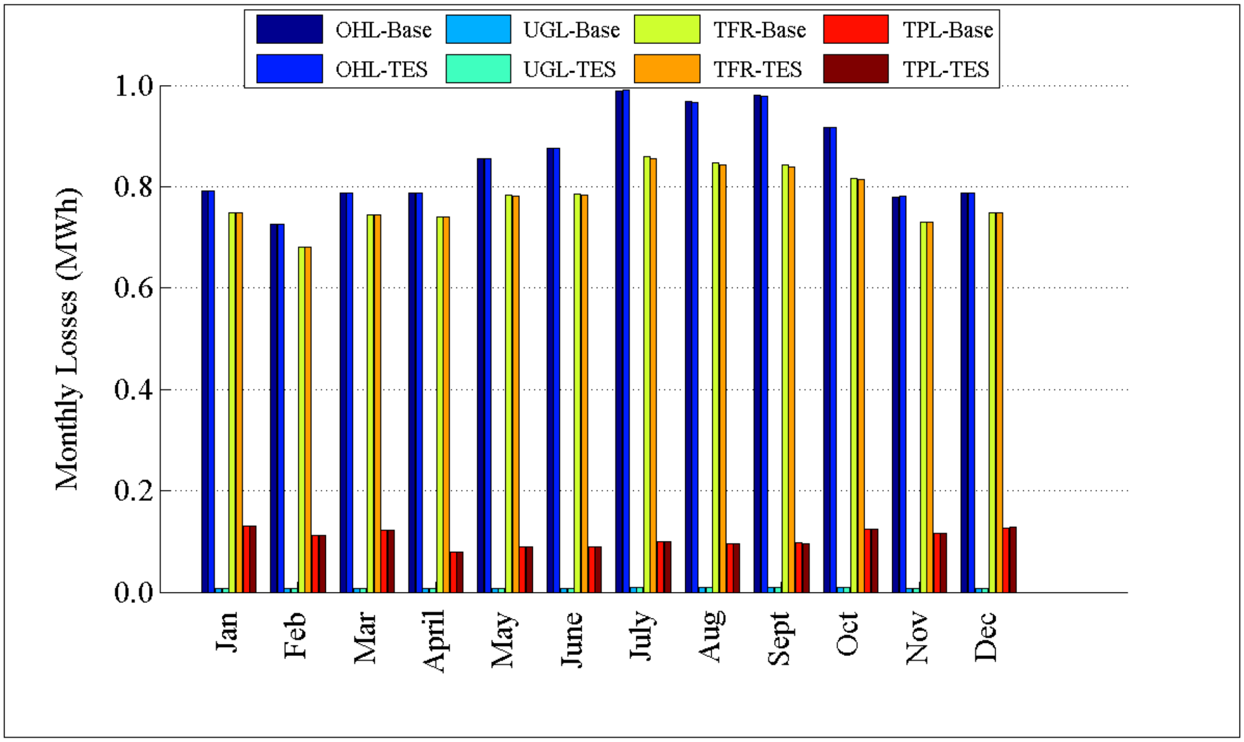

Figure D.27: Distribution system losses by month for R1-12.47-3

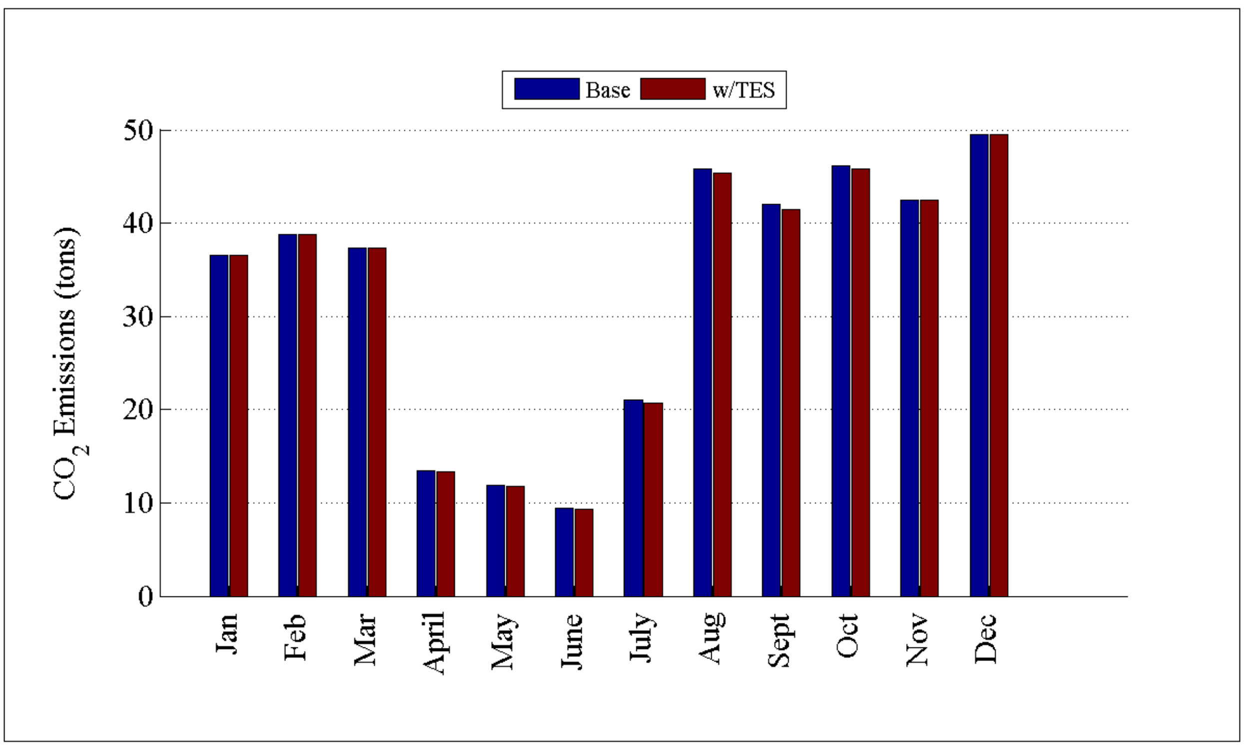

Figure D.28: CO_2 emissions by month for R1-12.47-3

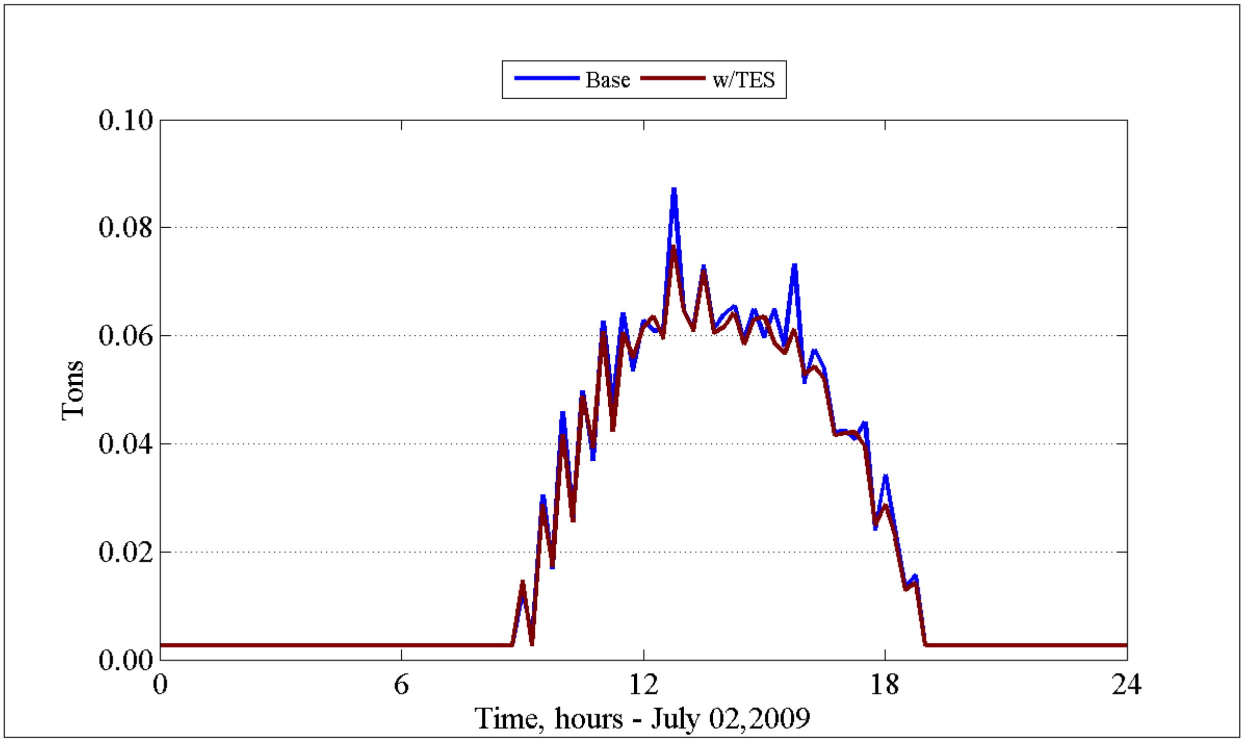

Figure D.29: Carbon dioxide emissions for peak day of R1-12.47-3

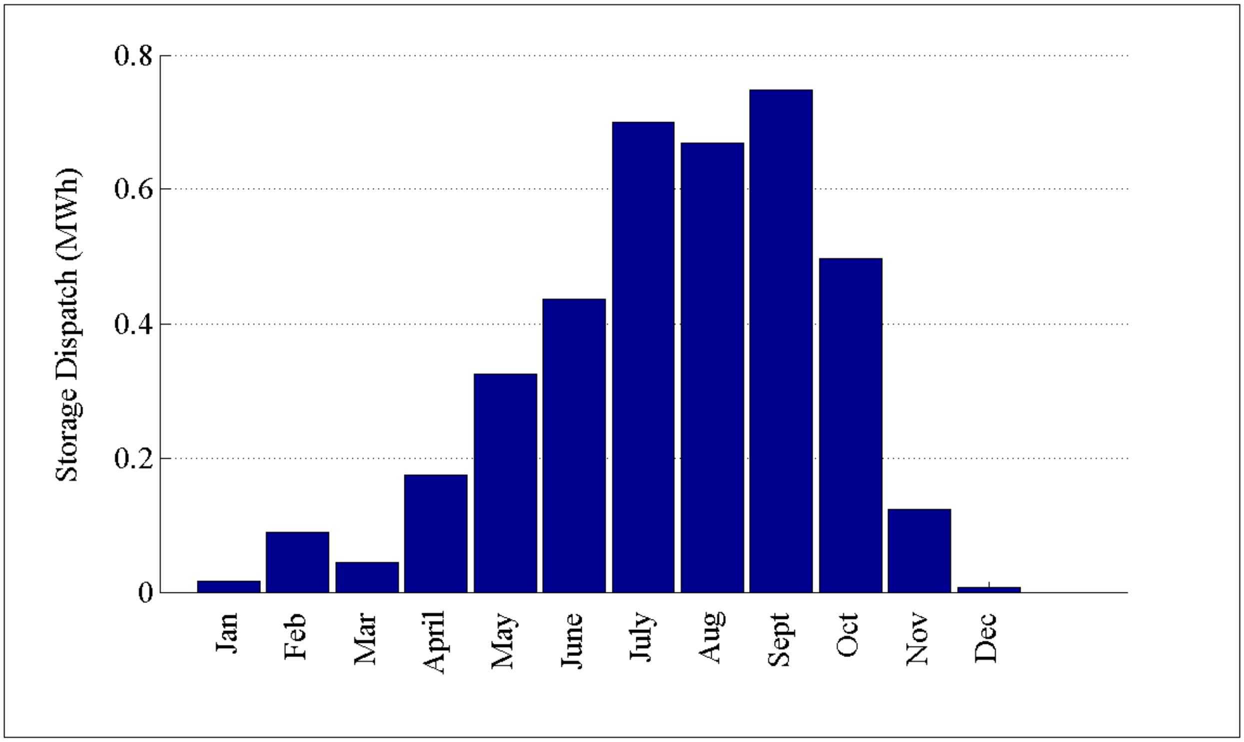

Figure D.30: Monthly storage dispatch energy for R1-12.47-3

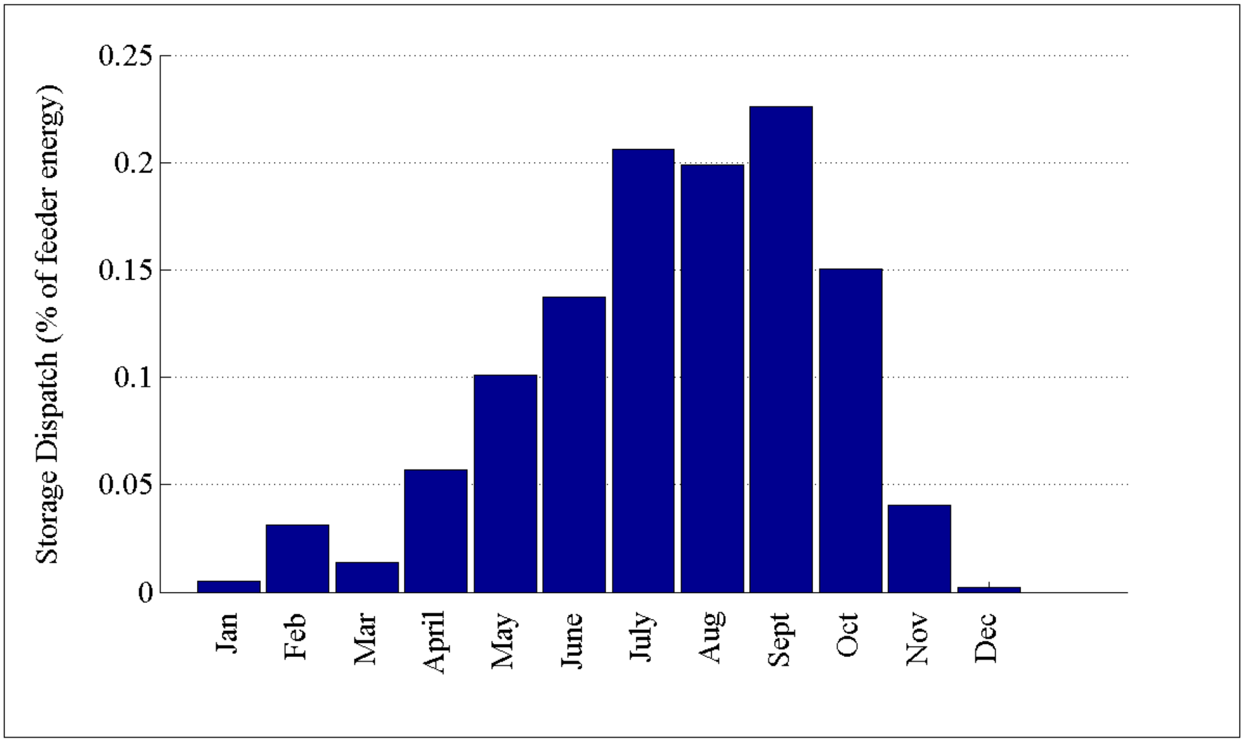

Figure D.31: Monthly storage dispatch energy percentage for R1-12.47-3

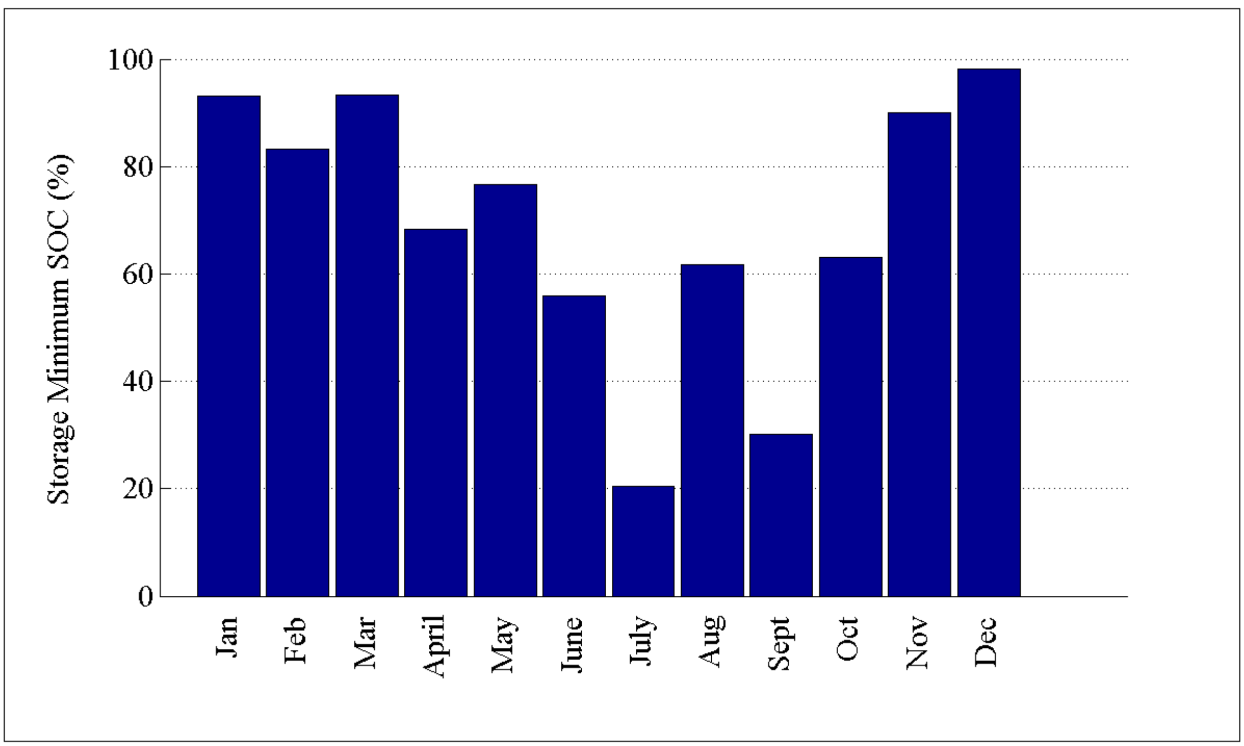

Figure D.32: Minimum state of charge for thermal energy storage on R1-12.47-3

D.5 Detailed Thermal Energy Storage Plots for R1-12.47-4

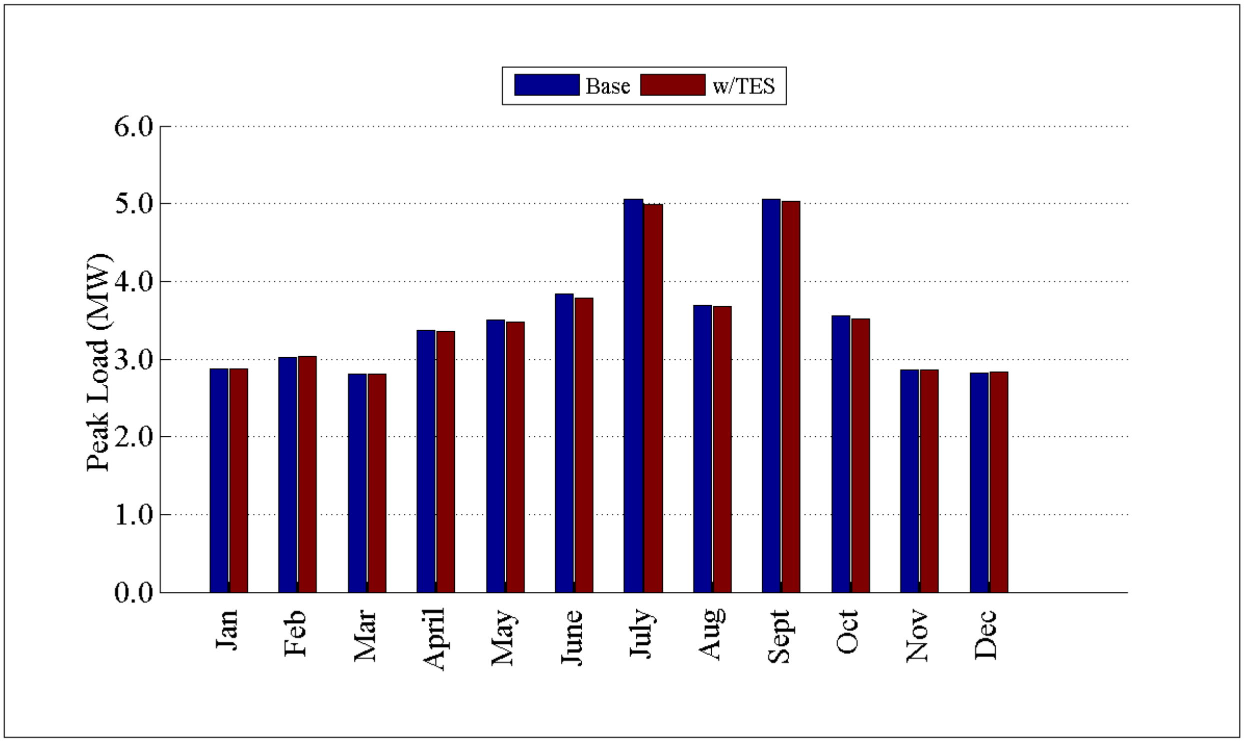

Figure D.33: Peak load by month of R1-12.47-4 feeder

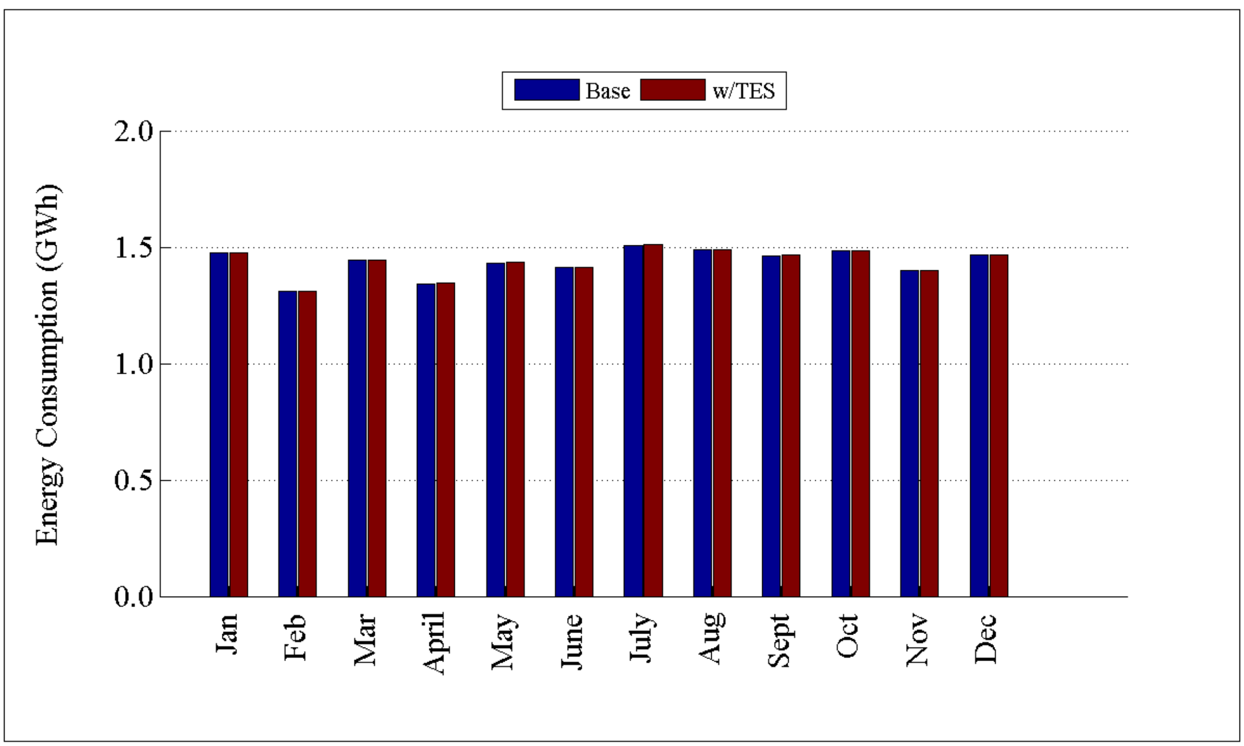

Figure D.34: Monthly energy consumption for R1-12.47-4 feeder

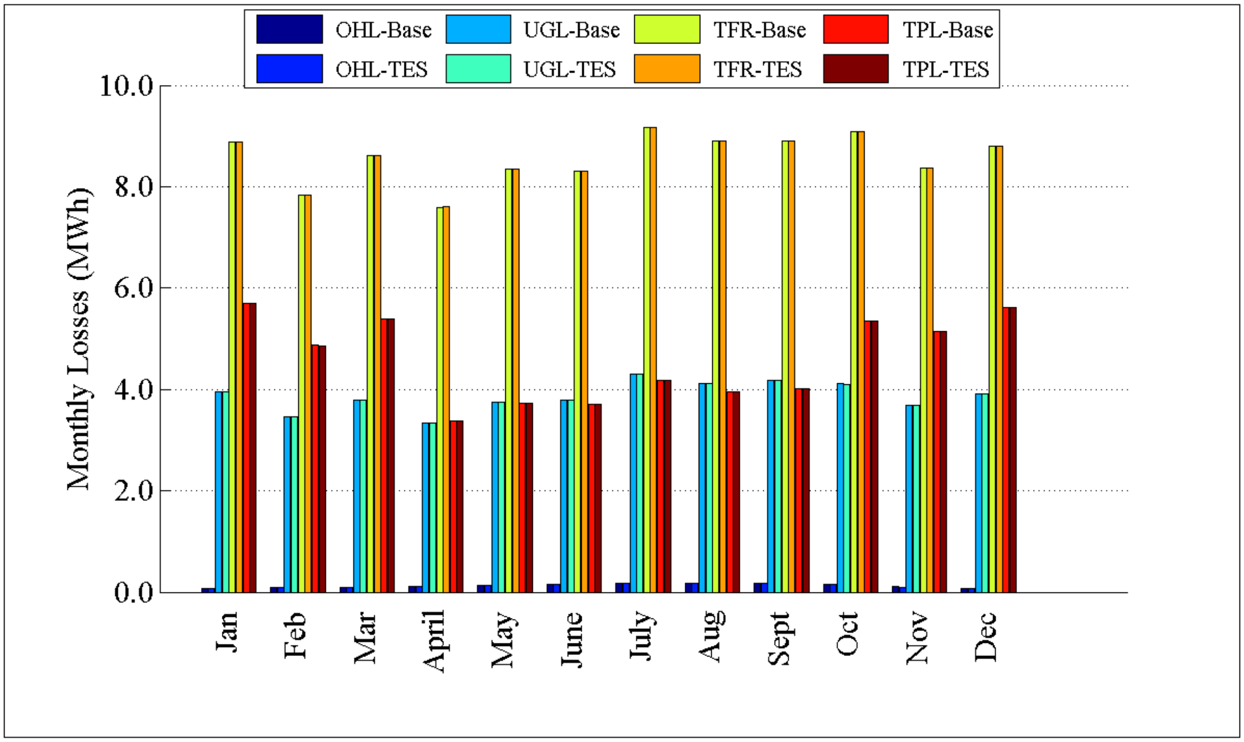

Figure D.35: Distribution system losses by month for R1-12.47-4

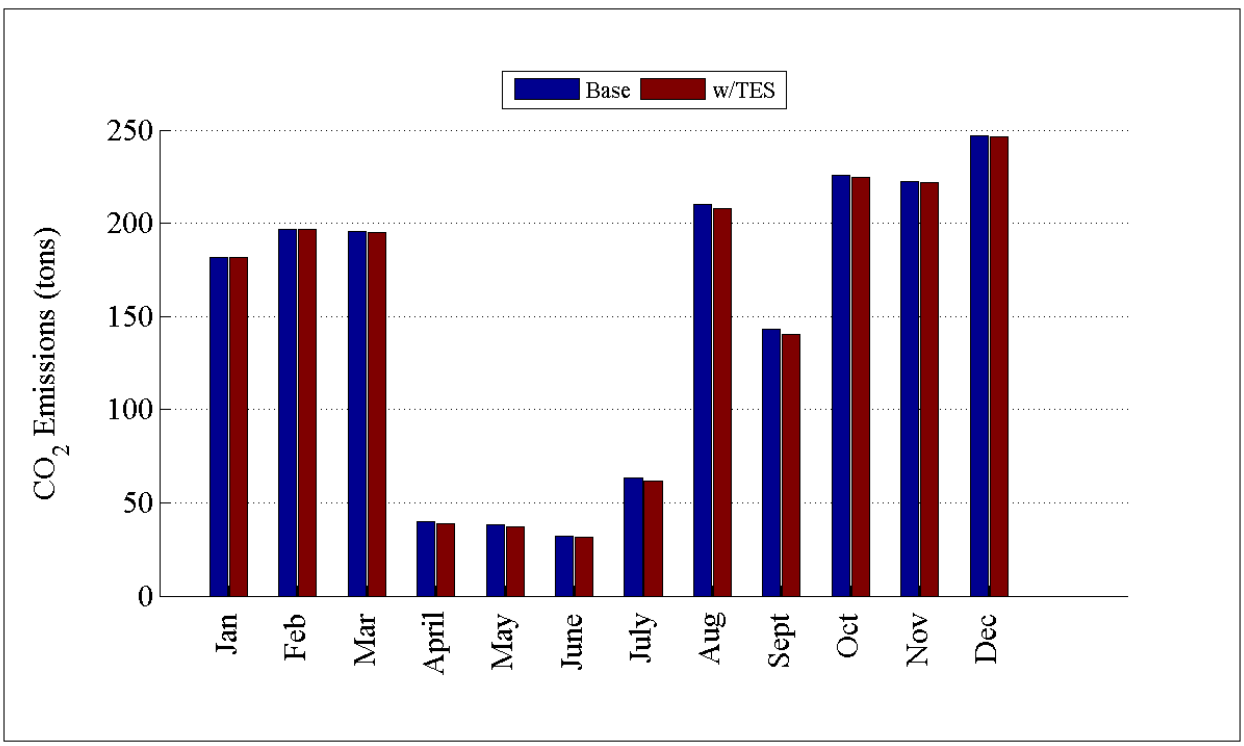

Figure D.36: CO_2 emissions by month for R1-12.47-4

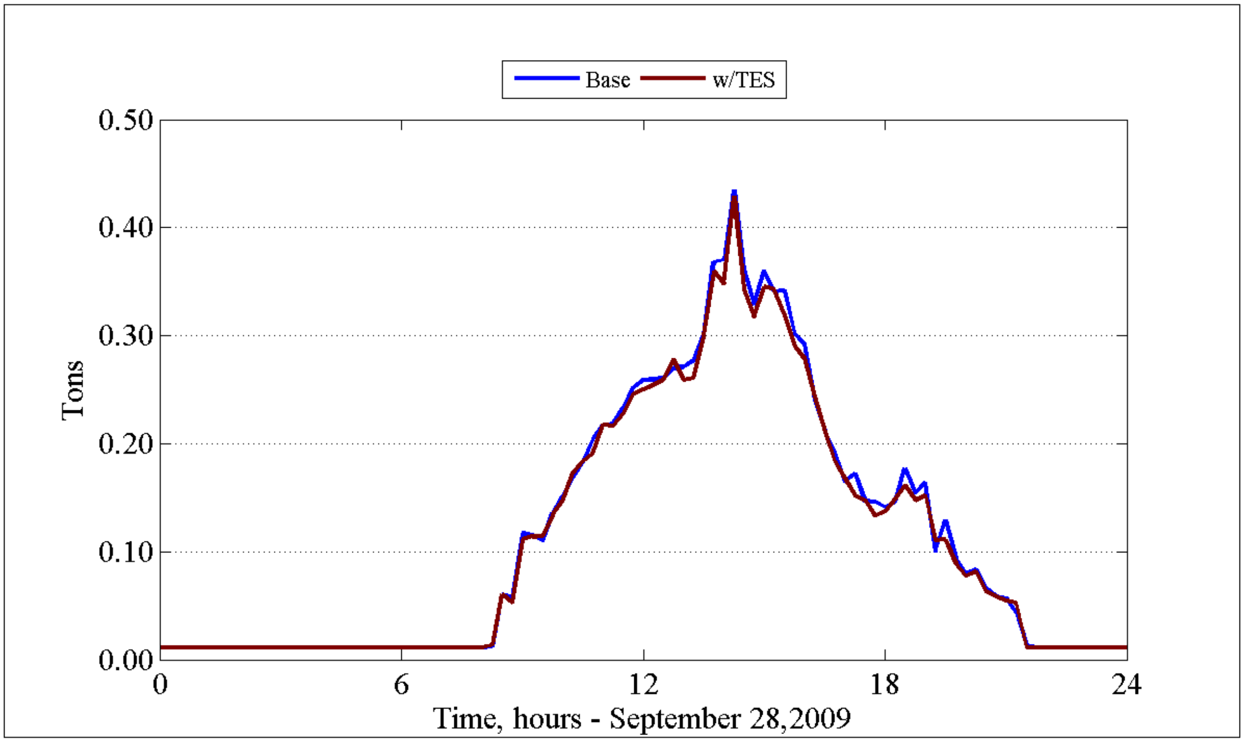

Figure D.37: Carbon dioxide emissions for peak day of R1-12.47-4

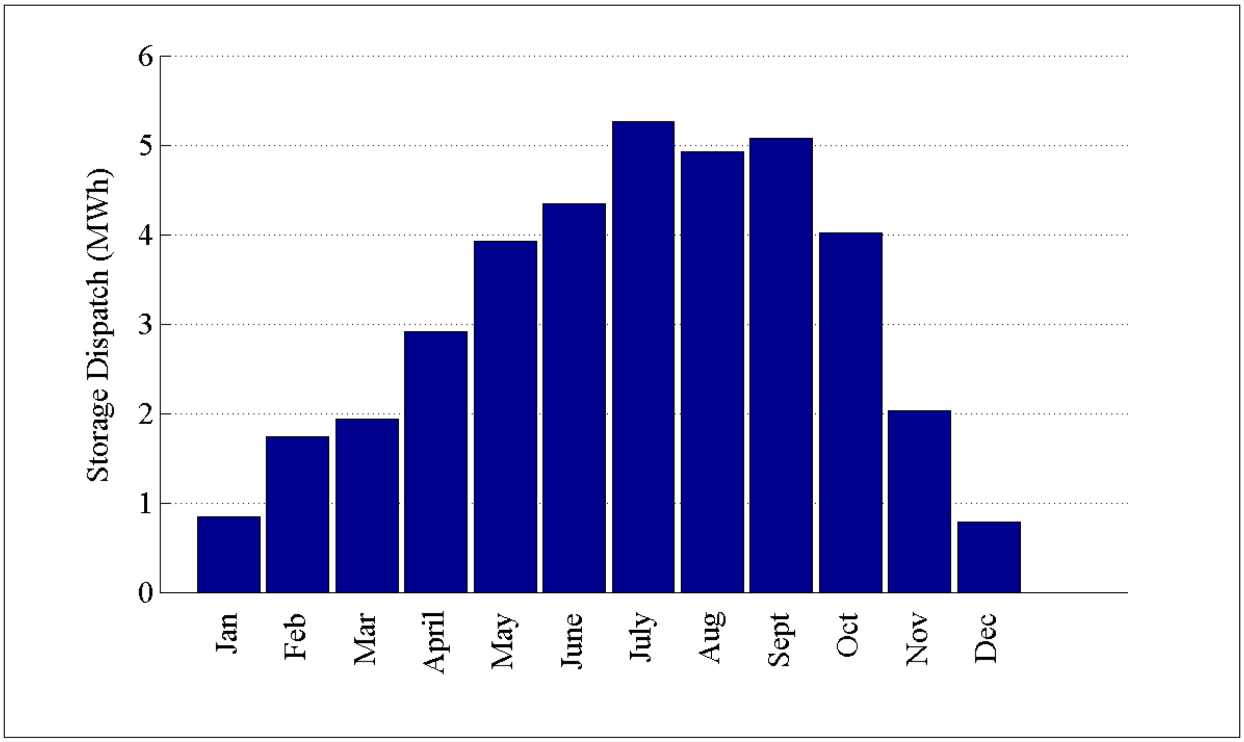

Figure D.38: Monthly storage dispatch energy for R1-12.47-4

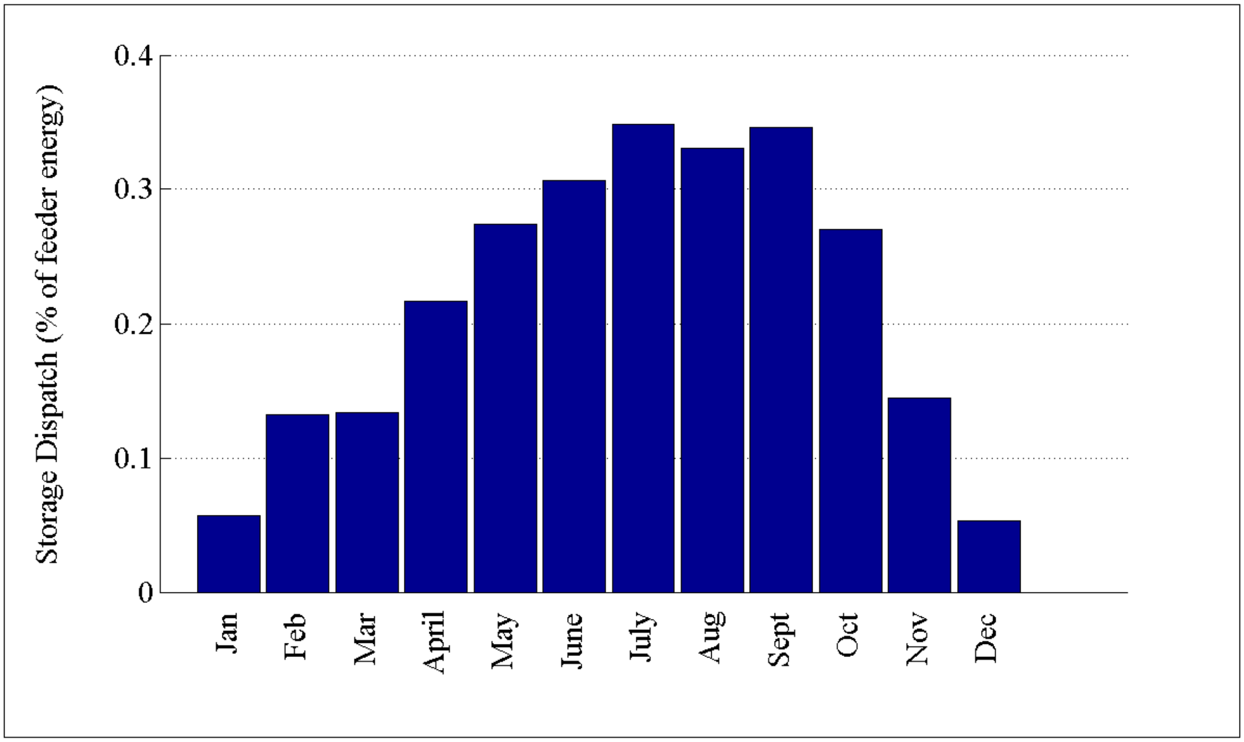

Figure D.39: Monthly storage dispatch energy percentage for R1-12.47-4

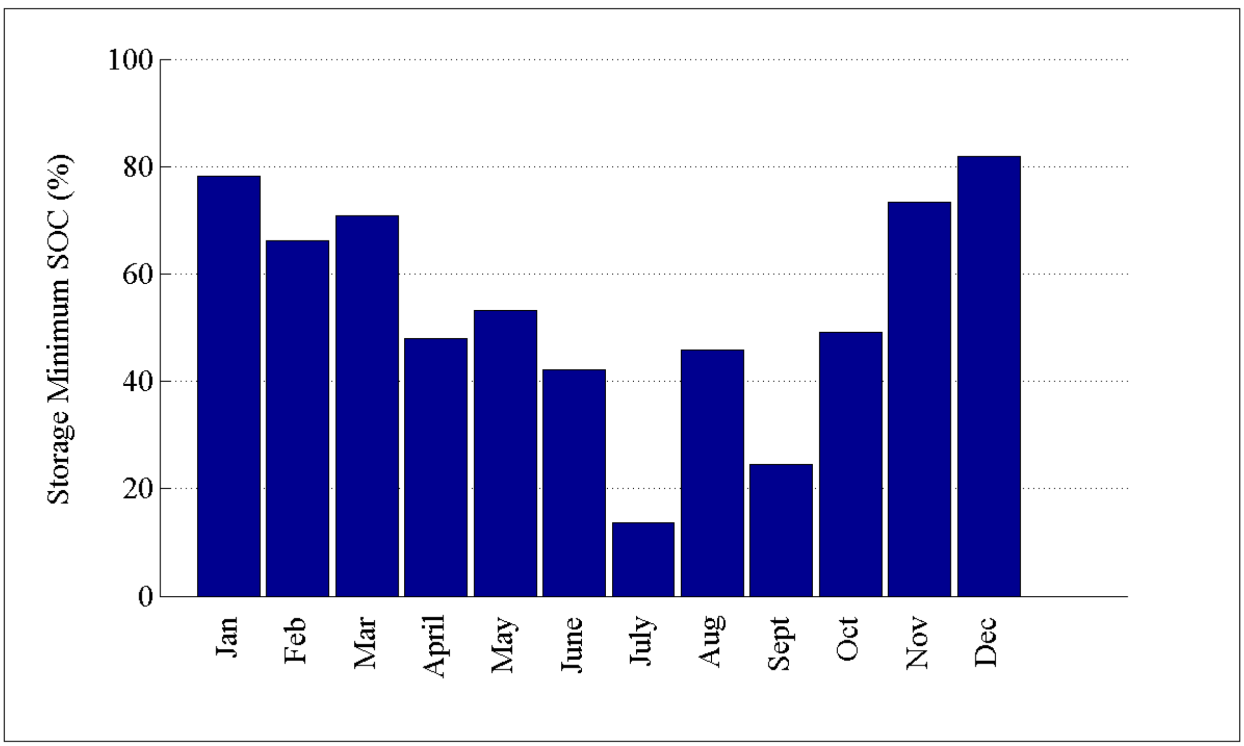

Figure D.40: Minimum state of charge for thermal energy storage on R1-12.47-4

D.6 Detailed Thermal Energy Storage Plots for R1-25.00-1

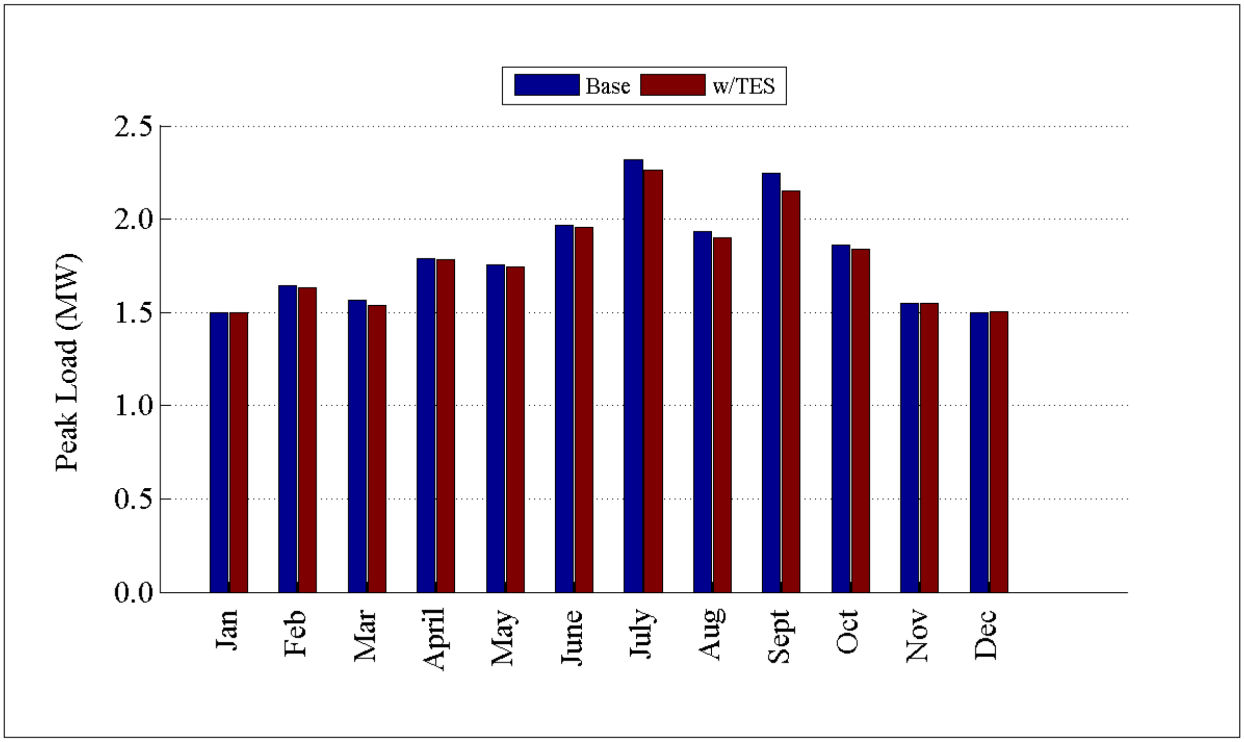

Figure D.41: Peak load by month of R1-25.00-1 feeder

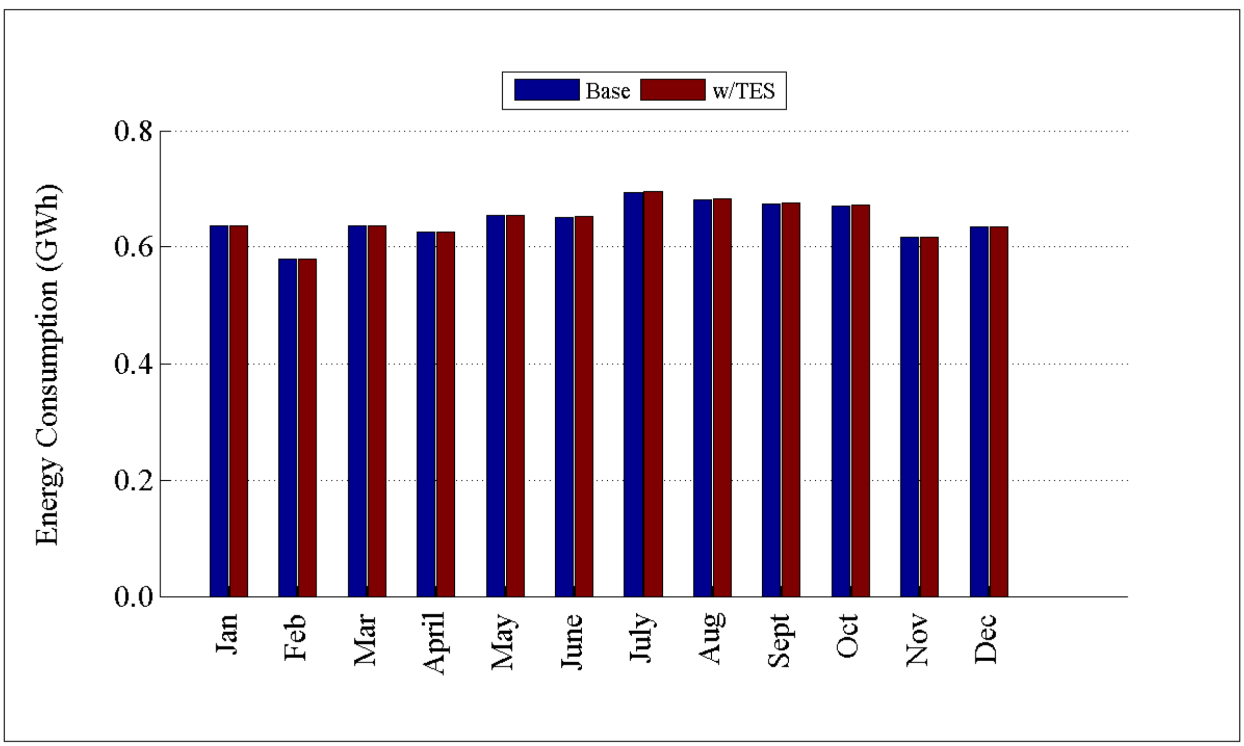

Figure D.42: Monthly energy consumption for R1-25.00-1 feeder

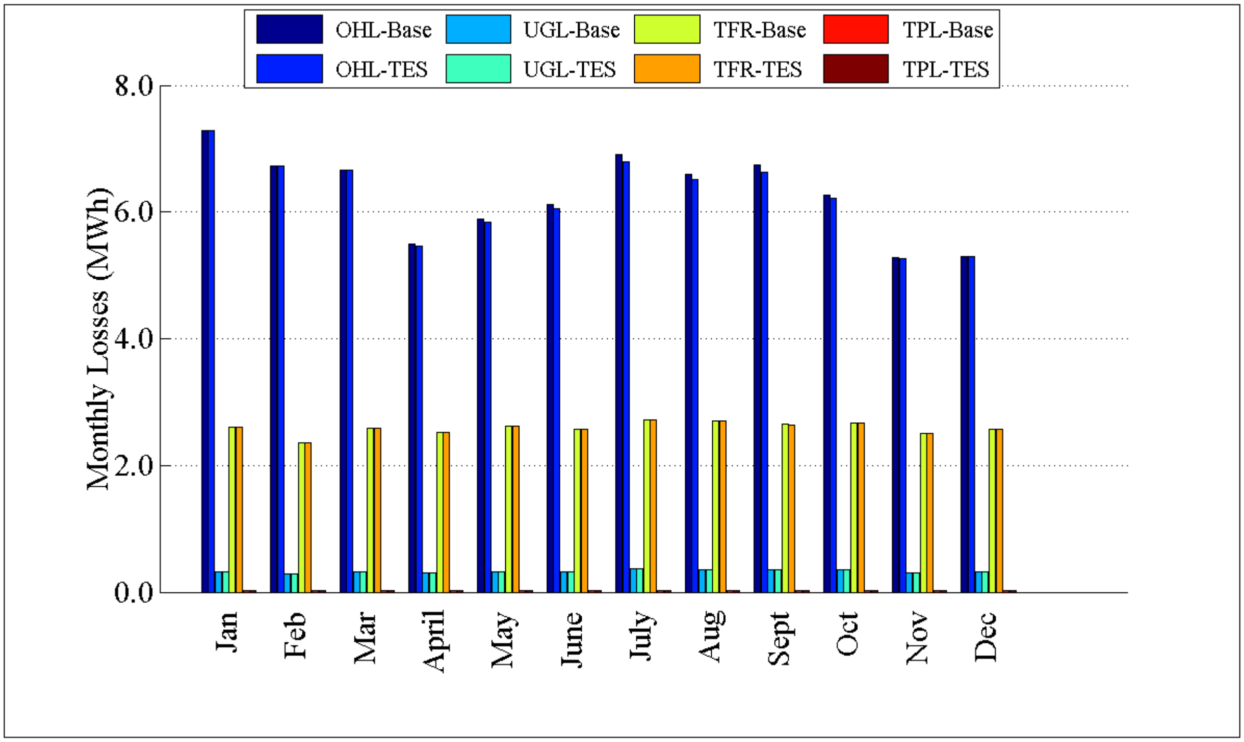

Figure D.43: Distribution system losses by month for R1-25.00-1

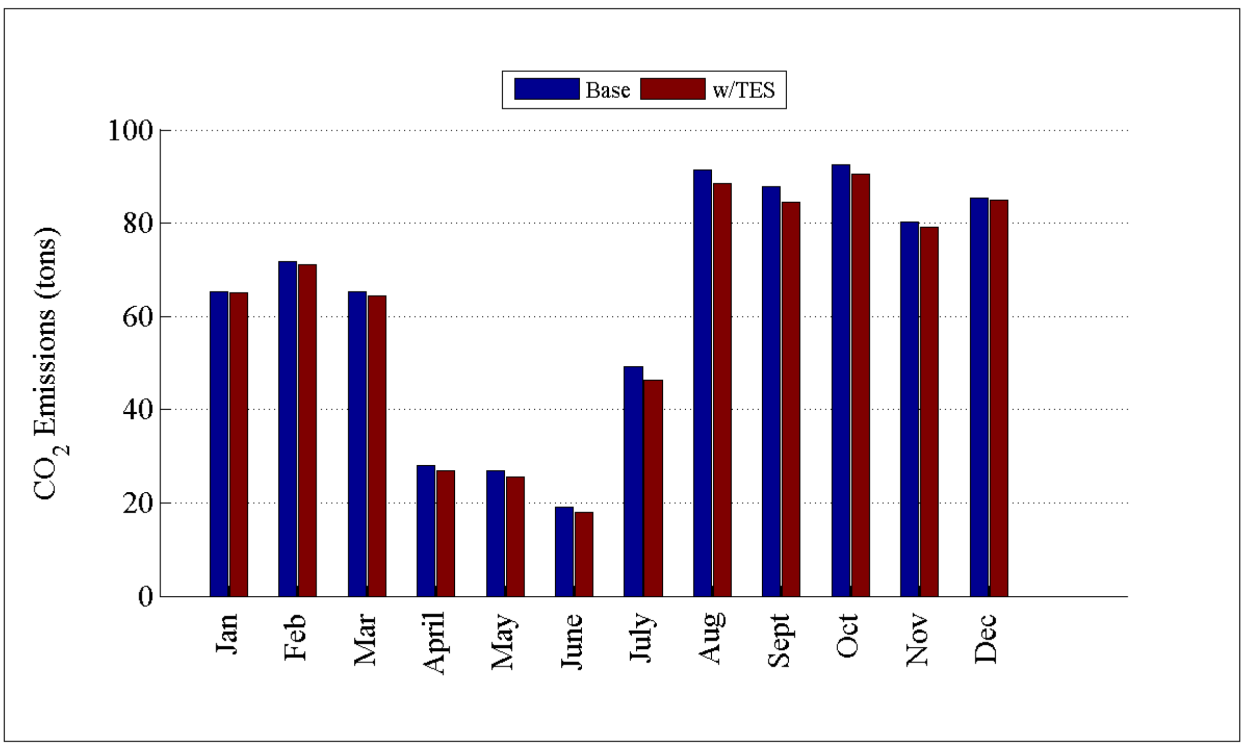

Figure D.44: CO_2 emissions by month for R1-25.00-1

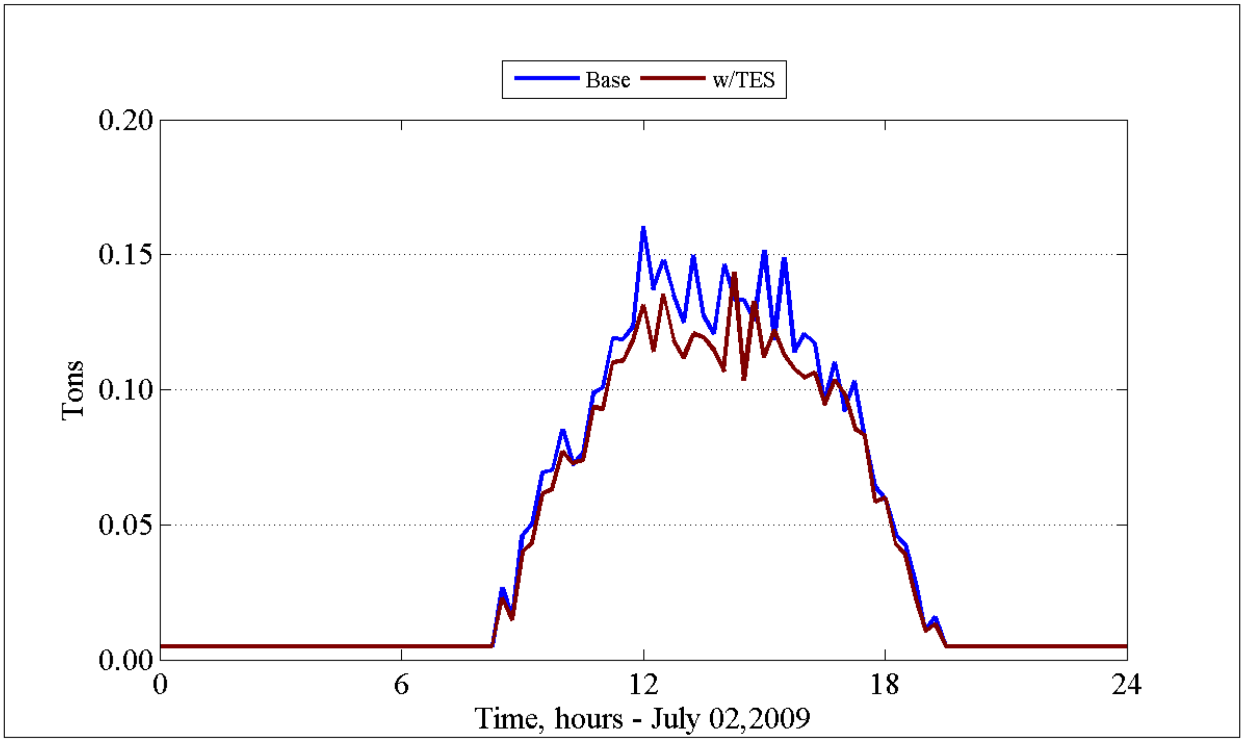

Figure D.45: Carbon dioxide emissions for peak day of R1-25.00-1

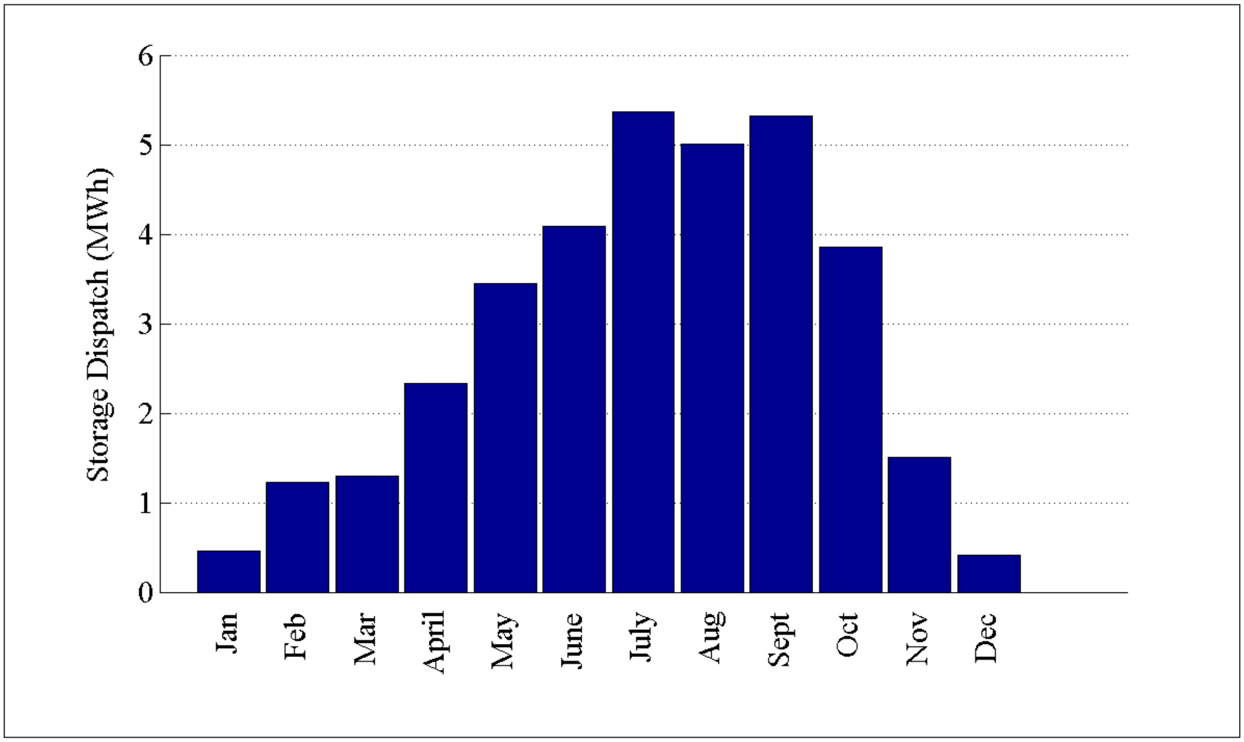

Figure D.46: Monthly storage dispatch energy for R1-25.00-1

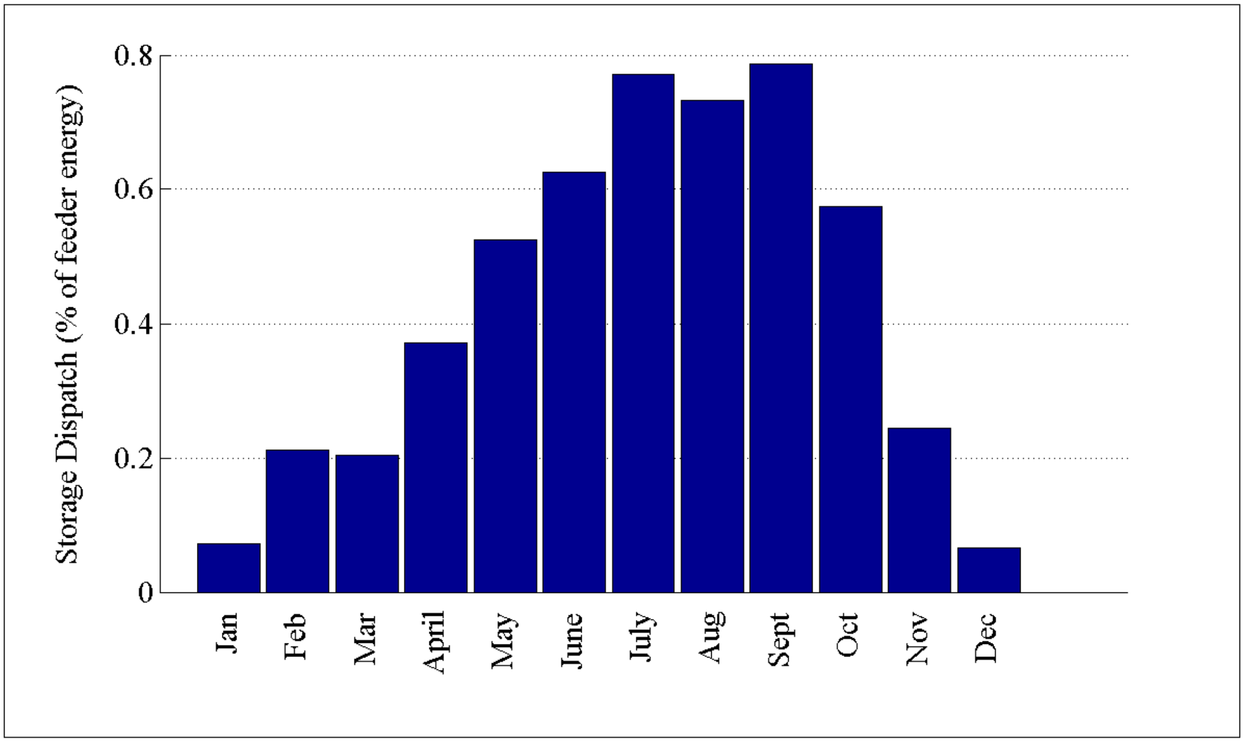

Figure D.47: Monthly storage dispatch energy percentage for R1-25.00-1

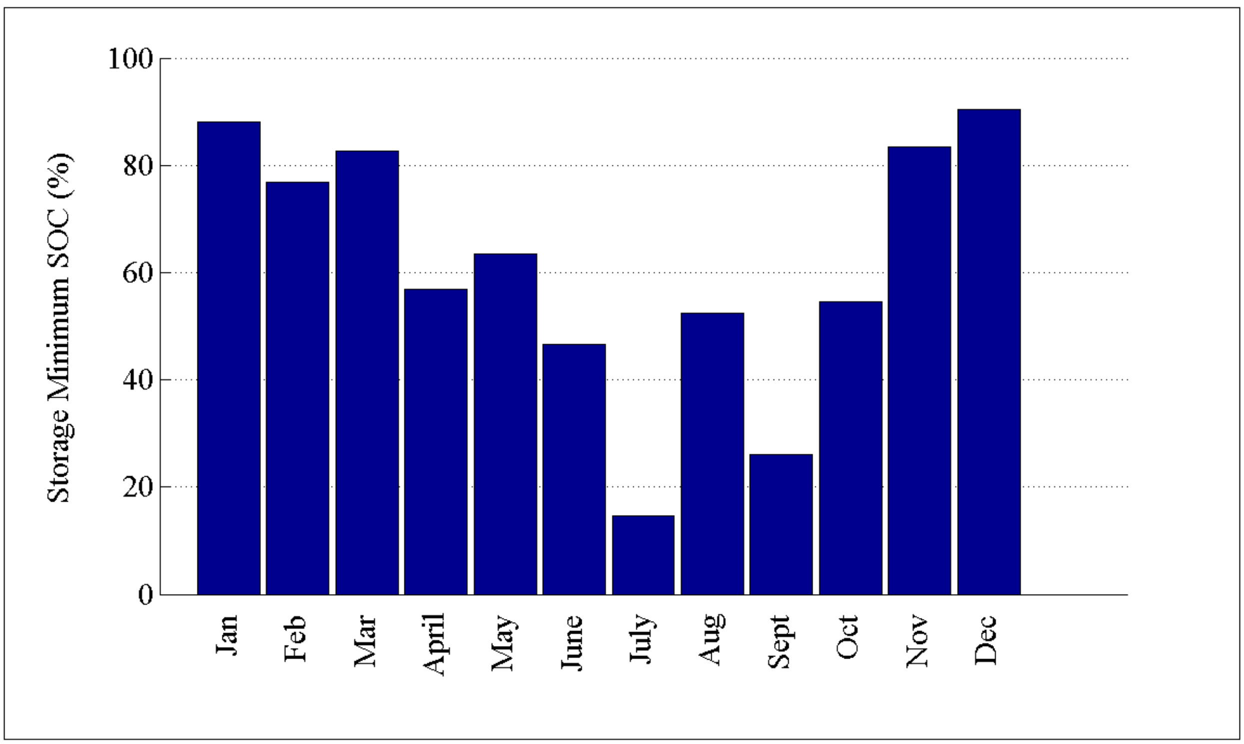

Figure D.48: Minimum state of charge for thermal energy storage on R1-25.00-1

D.7 Detailed Thermal Energy Storage Plots for GC-12.47-1_R2

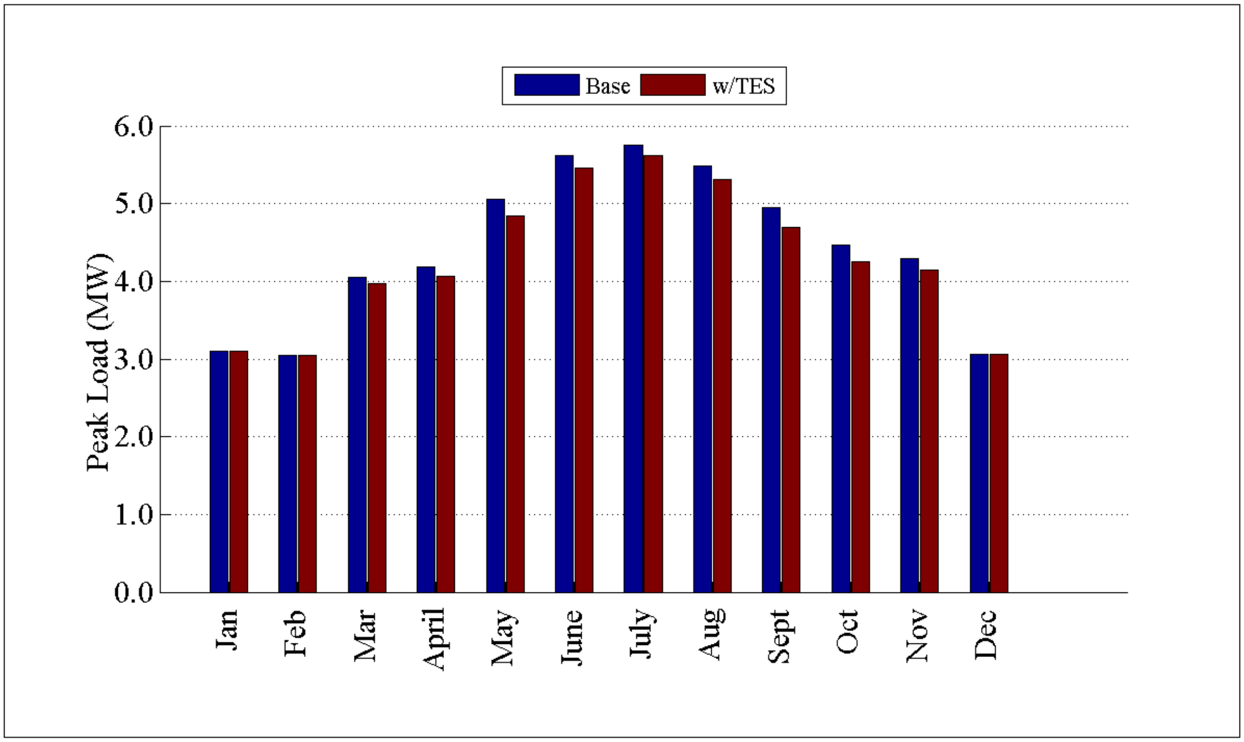

Figure D.49: Peak load by month of GC-12.47-1-r2 feeder

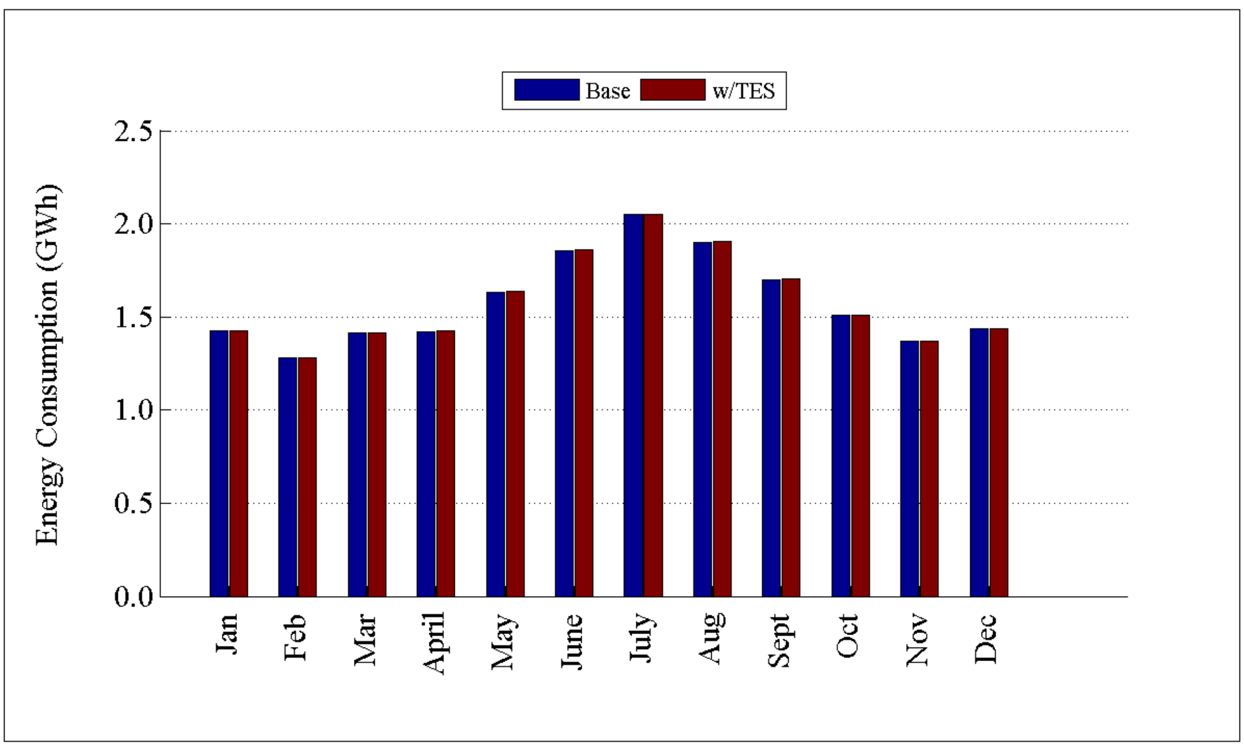

Figure D.50: Monthly energy consumption for GC-12.47-1-r2 feeder

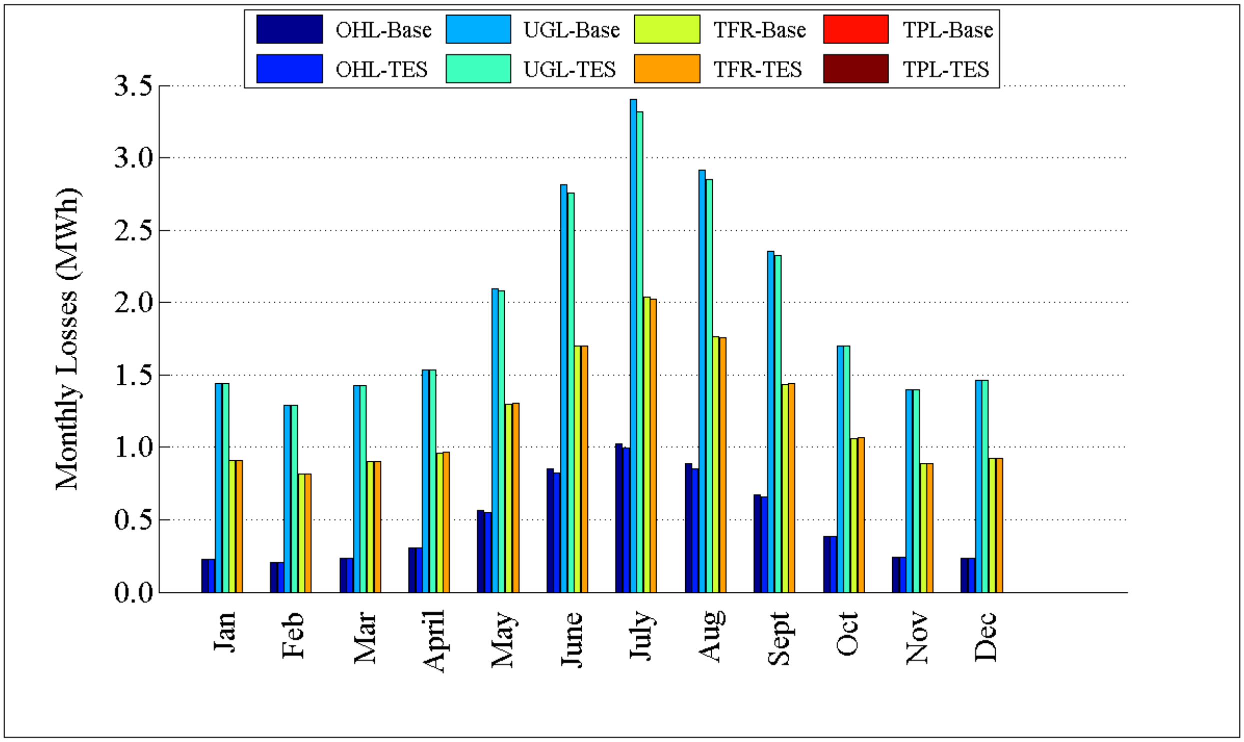

Figure D.51: Distribution system losses by month for GC-12.47-1-r2

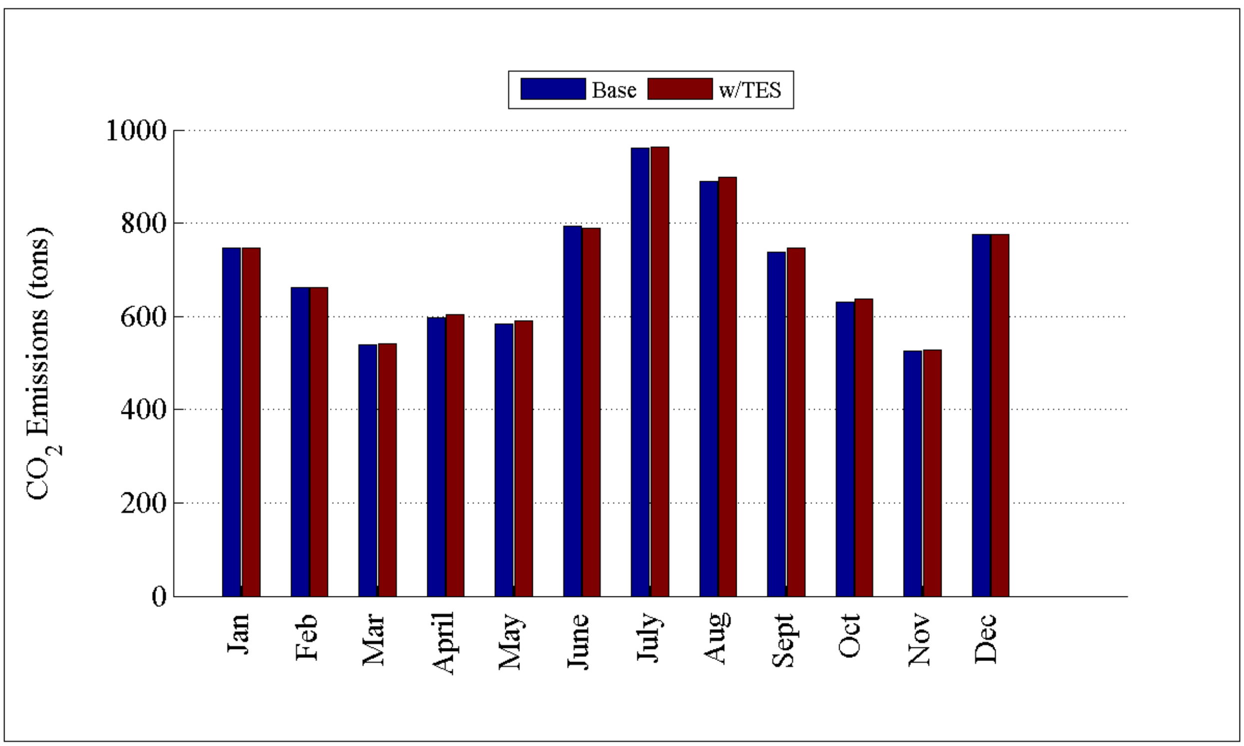

Figure D.52: CO_2 emissions by month for GC-12.47-1-r2

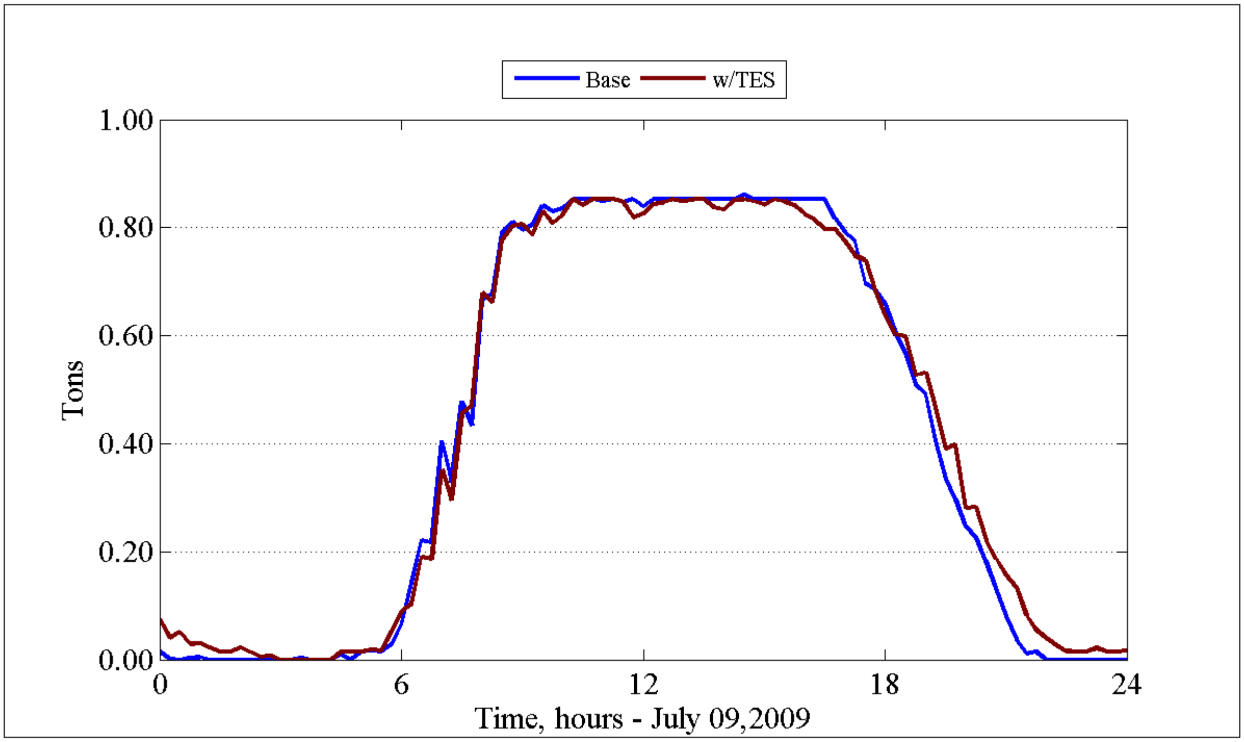

Figure D.53: Carbon dioxide emissions for peak day of GC-12.47-1-r2

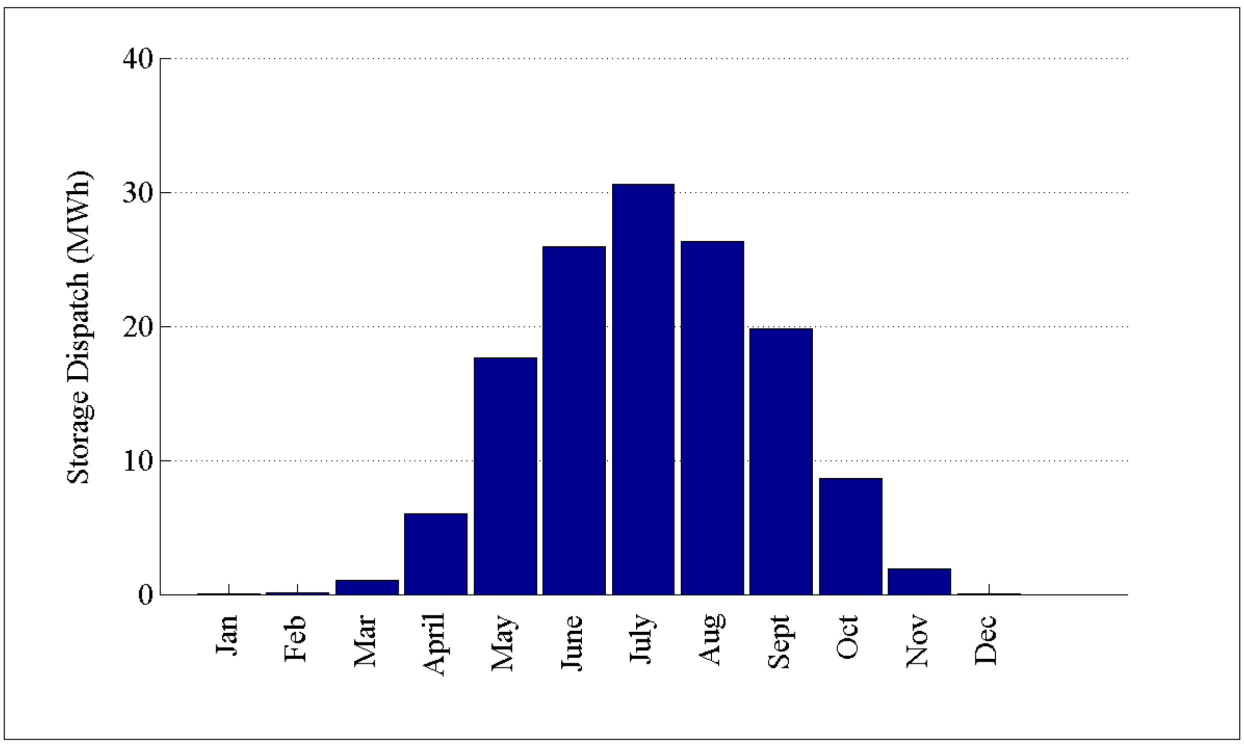

Figure D.54: Monthly storage dispatch energy for GC-12.47-1-r2

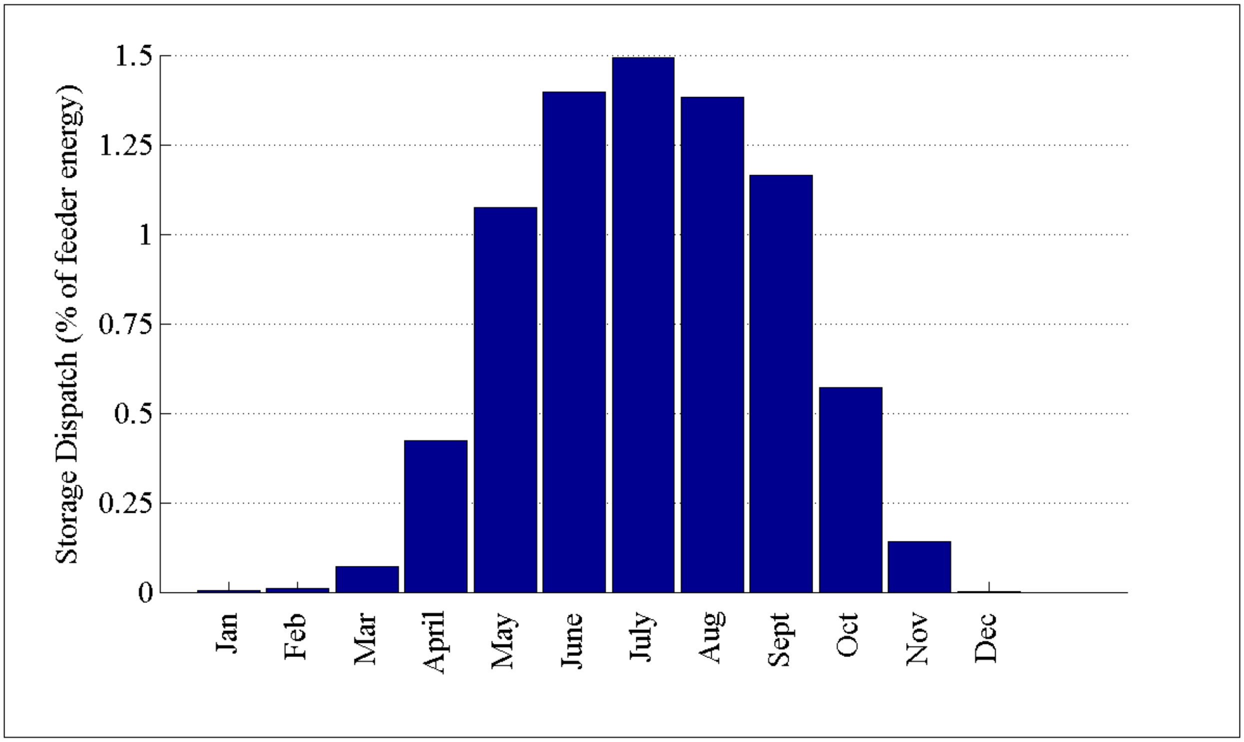

Figure D.55: Monthly storage dispatch energy percentage for GC-12.47-1-r2

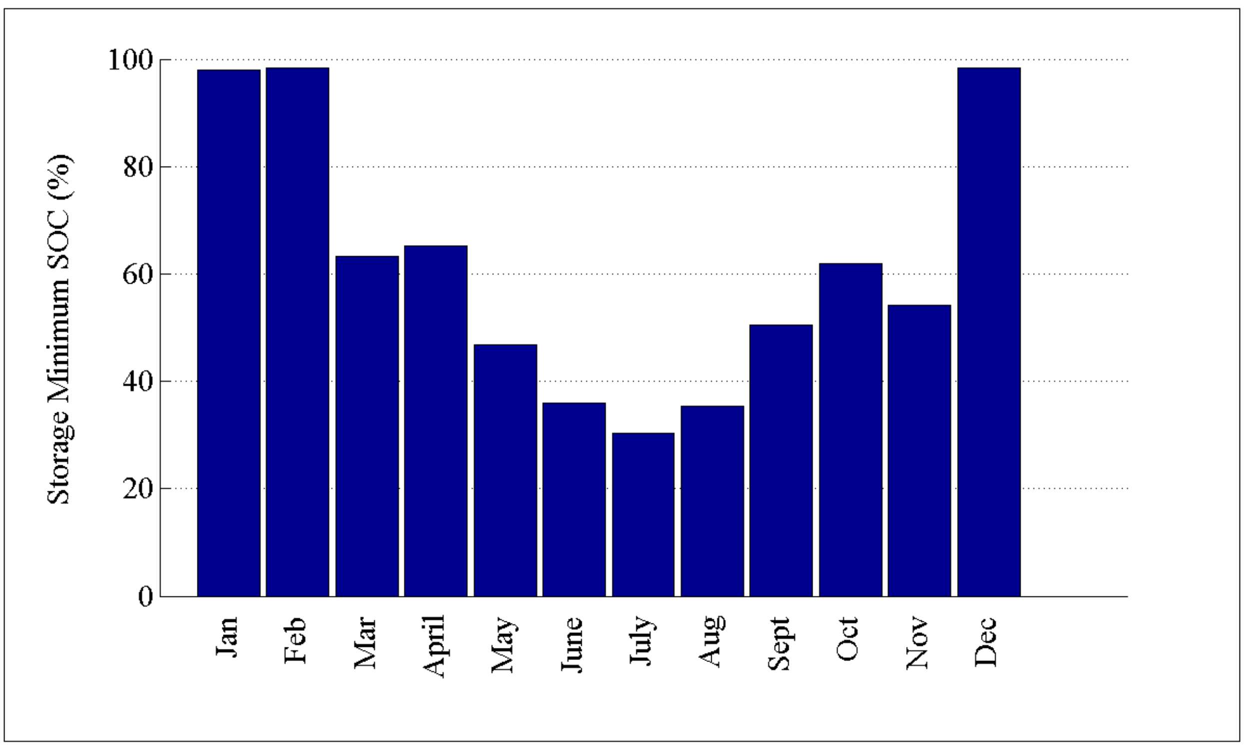

Figure D.56: Minimum state of charge for thermal energy storage on GC-12.47-1-r2

D.8 Detailed Thermal Energy Storage Plots for R2-12.47-1

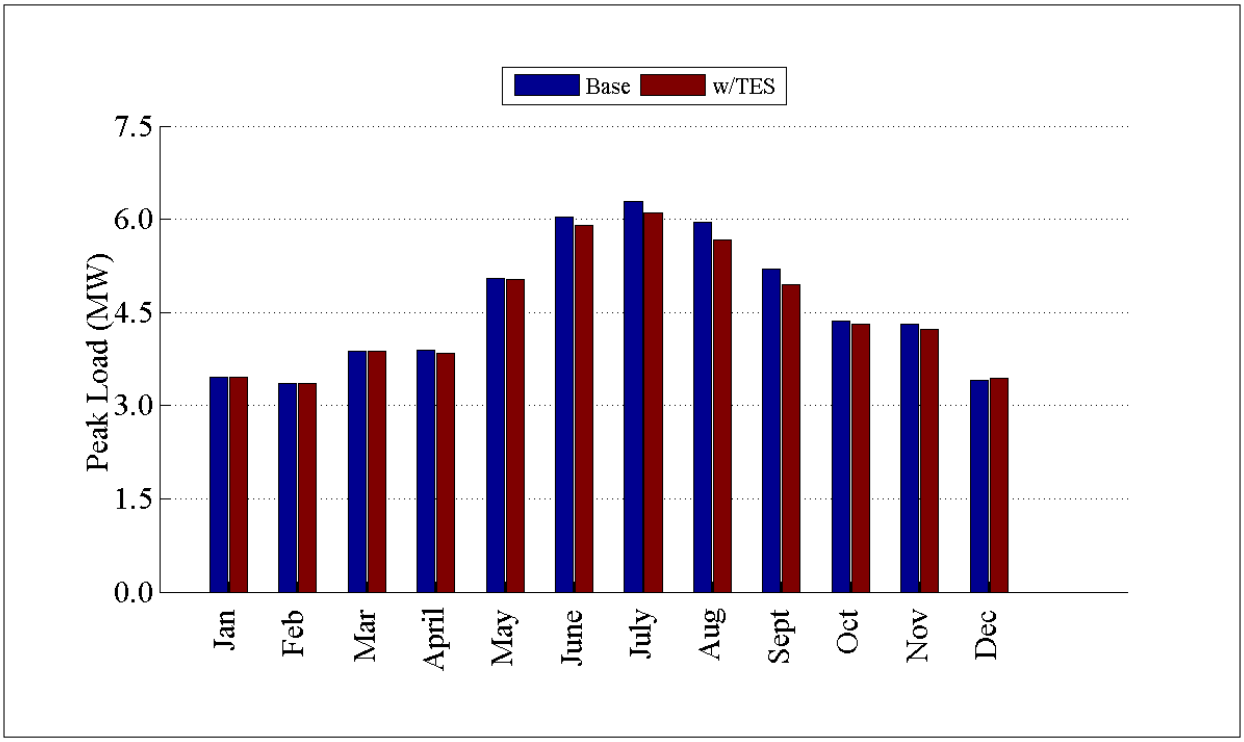

Figure D.57: Peak load by month of R2-12.47-1 feeder

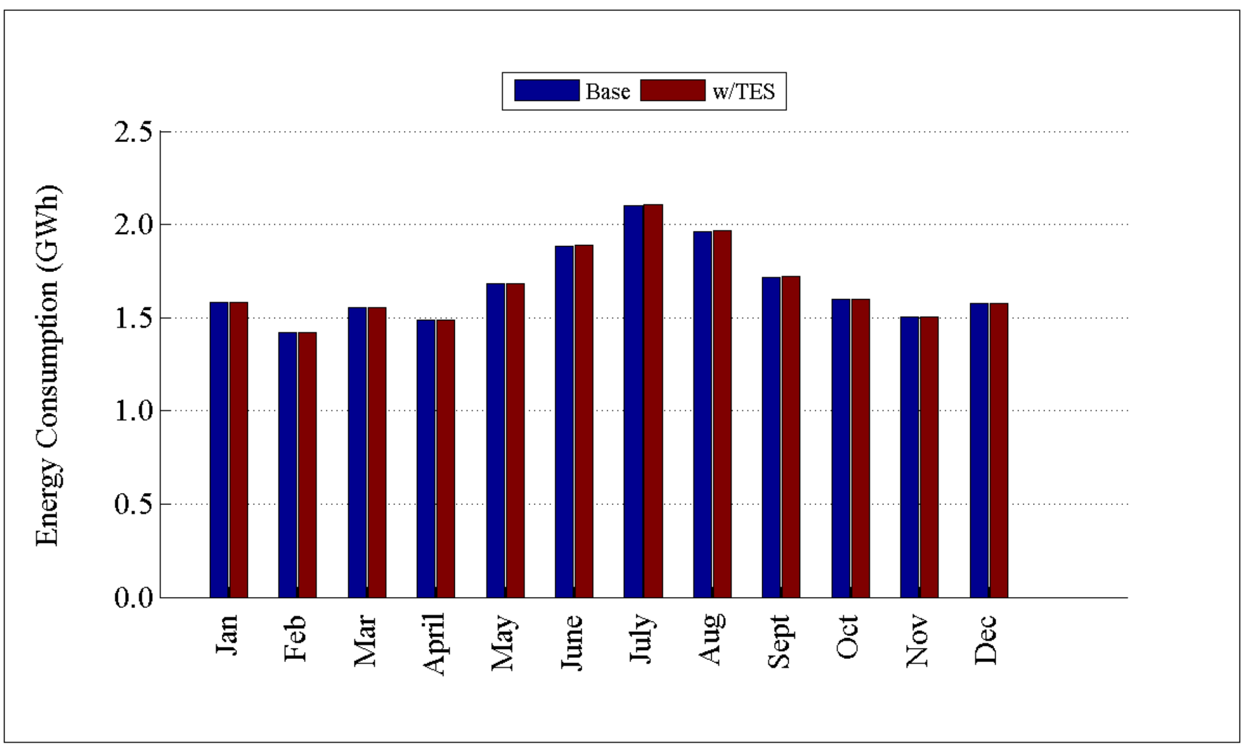

Figure D.58: Monthly energy consumption for R2-12.47-1 feeder

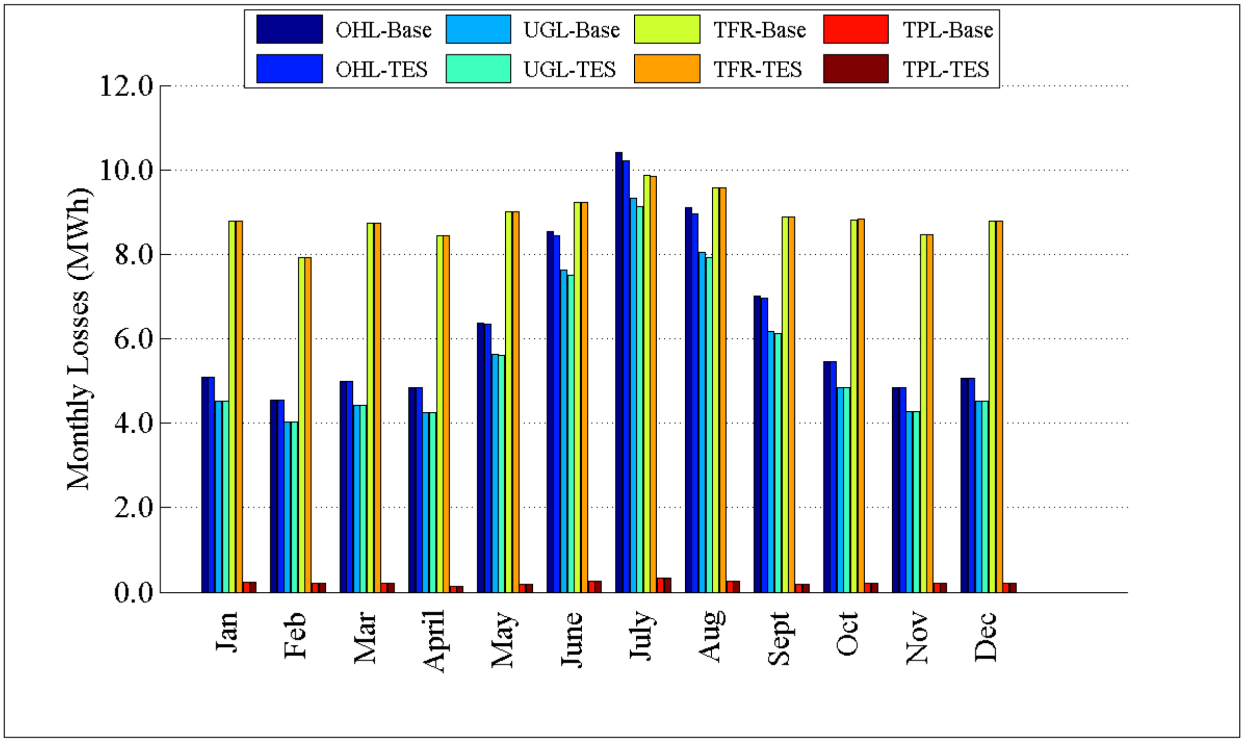

Figure D.59: Distribution system losses by month for R2-12.47-1

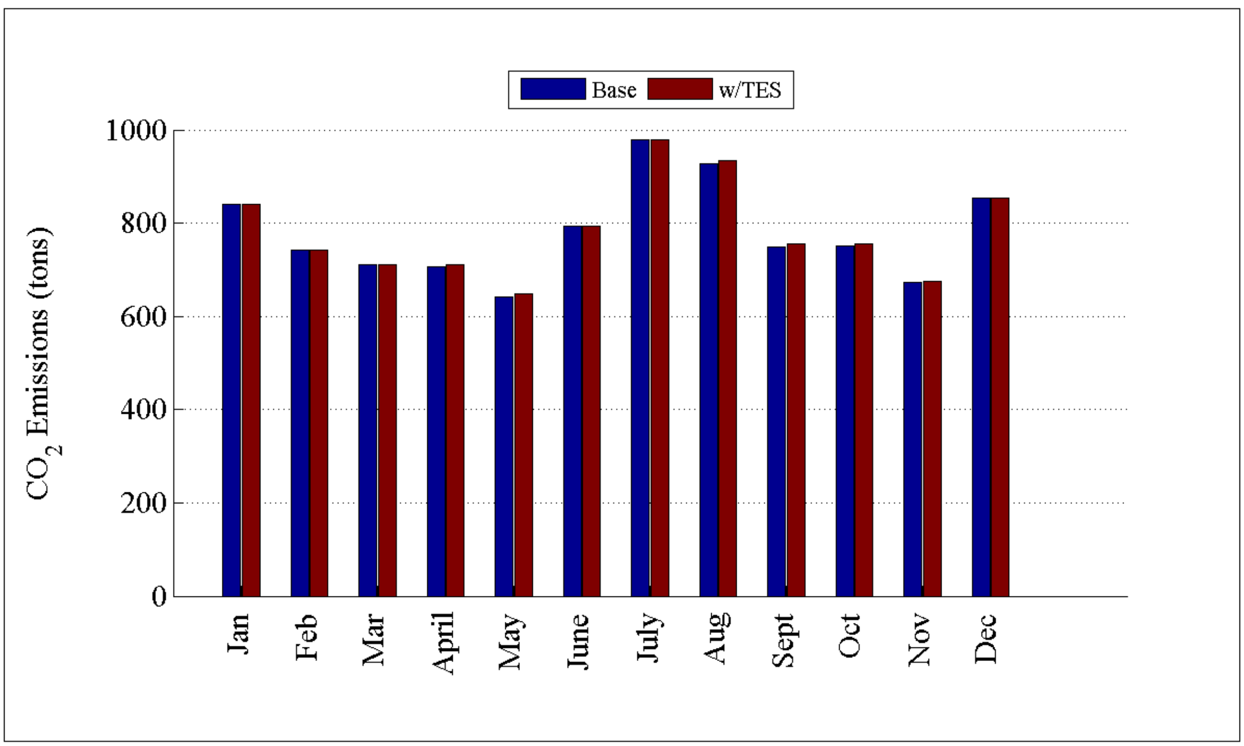

Figure D.60: CO_2 emissions by month for R2-12.47-1

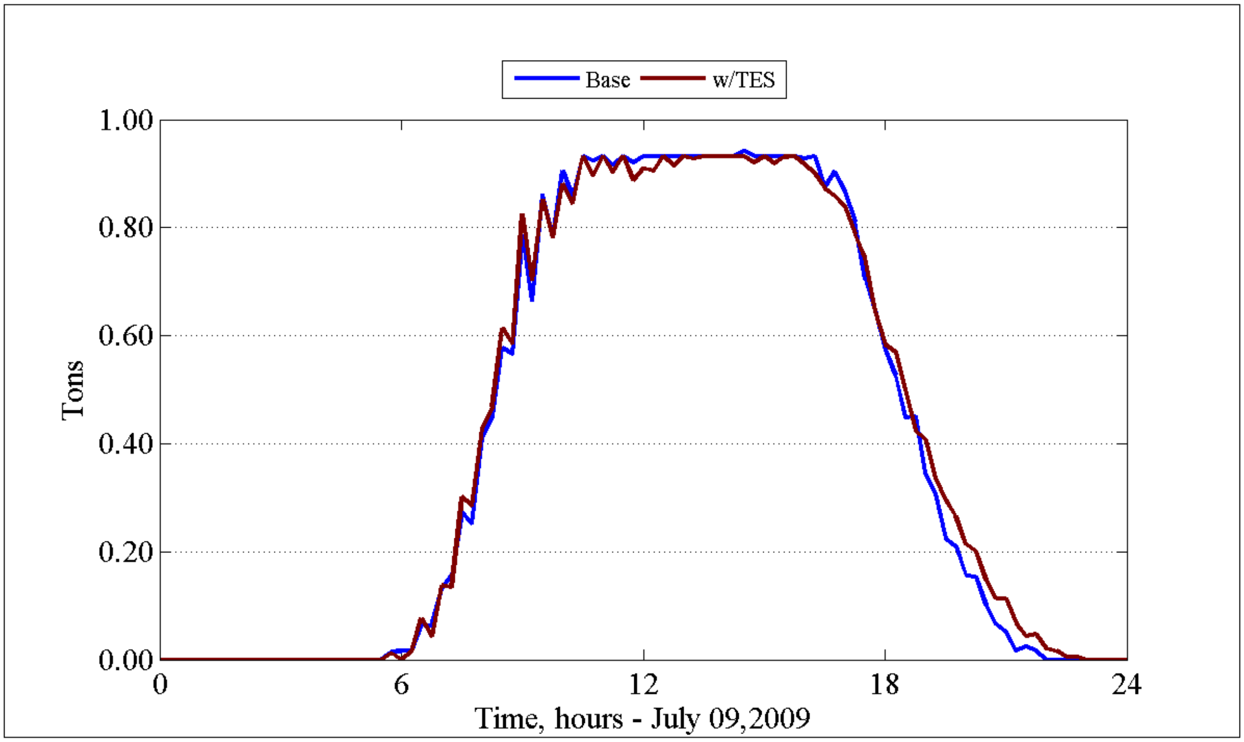

Figure D.61: Carbon dioxide emissions for peak day of R2-12.47-1

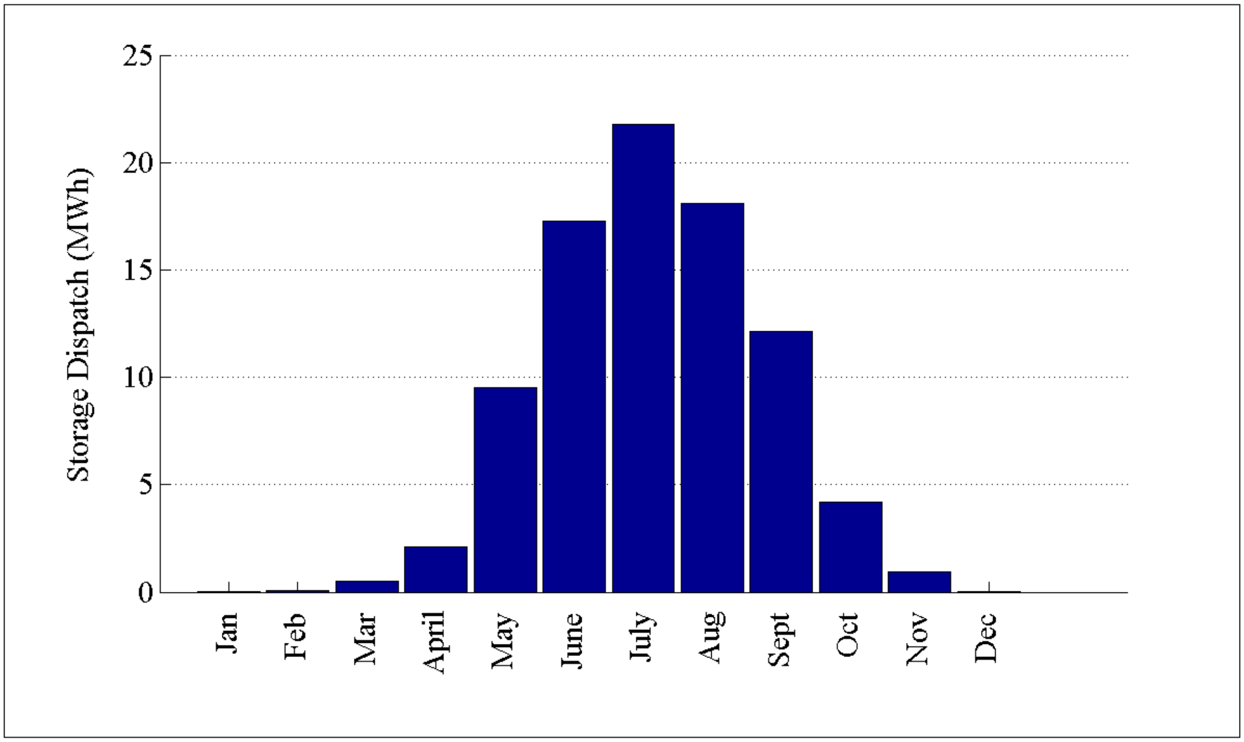

Figure D.62: Monthly storage dispatch energy for R2-12.47-1

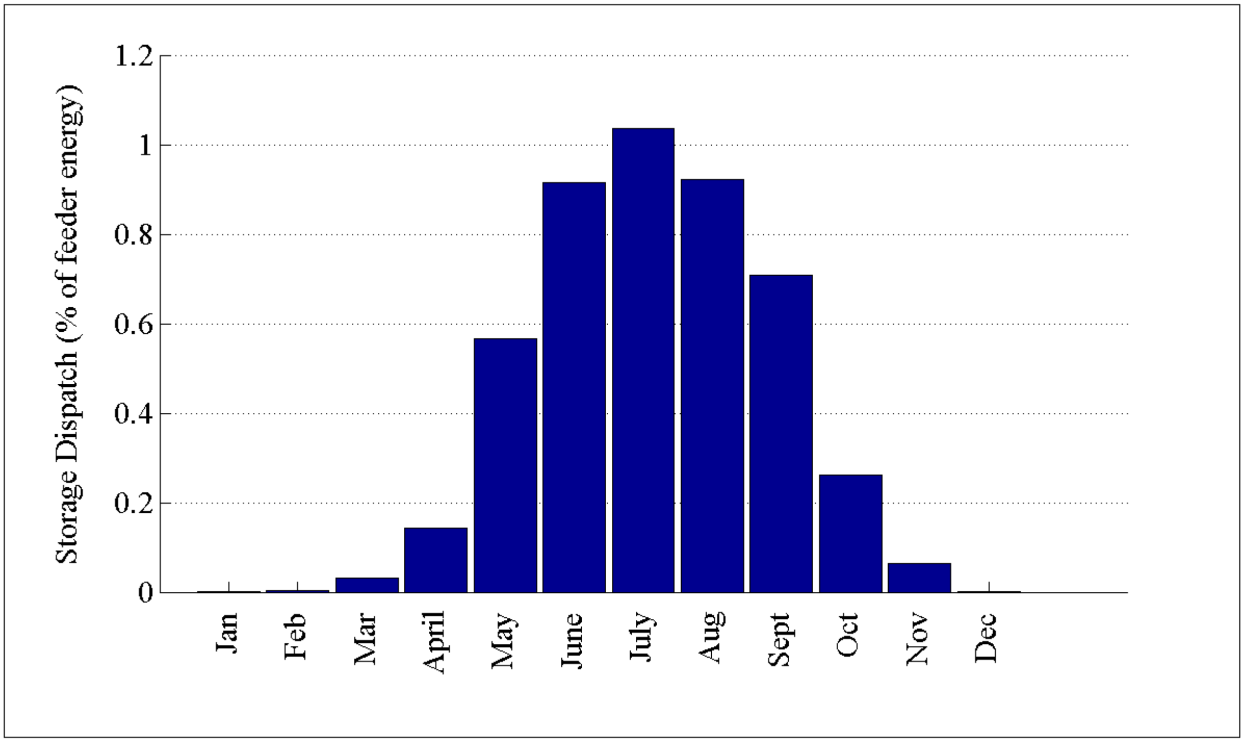

Figure D.63: Monthly storage dispatch energy percentage for R2-12.47-1

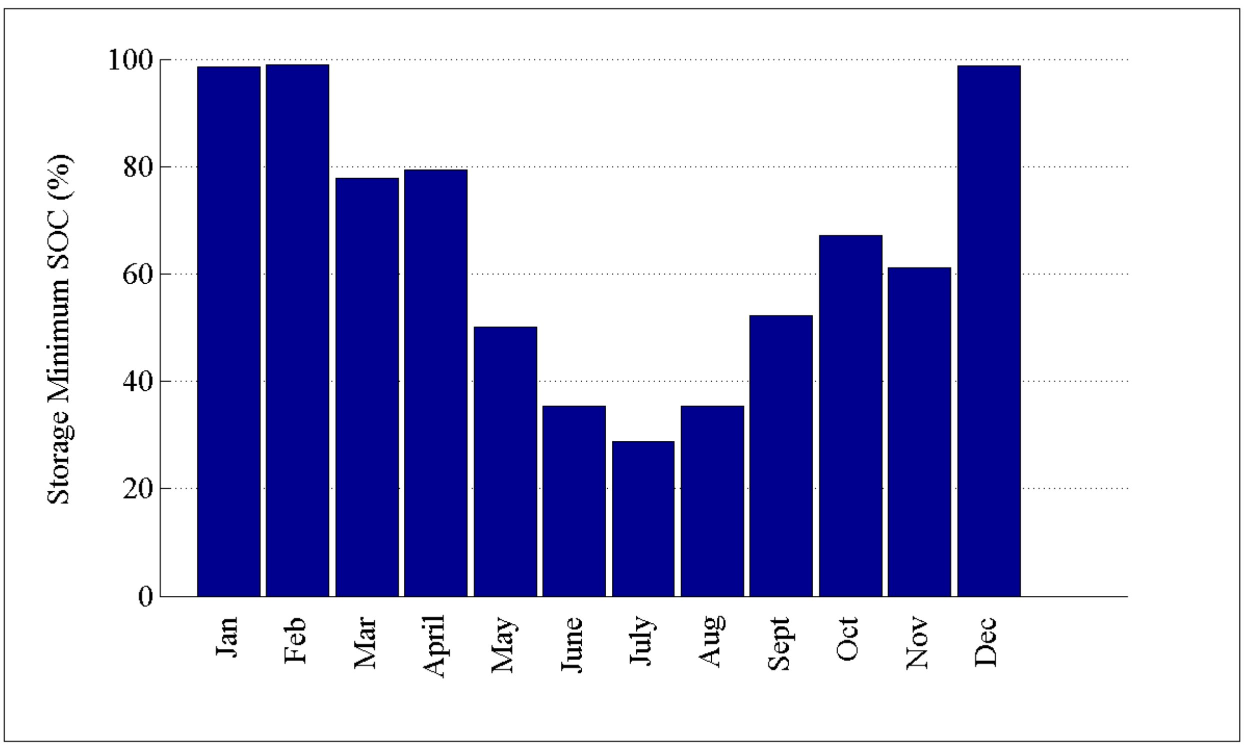

Figure D.64: Minimum state of charge for thermal energy storage on R2-12.47-1

D.9 Detailed Thermal Energy Storage Plots for R2-12.47-2

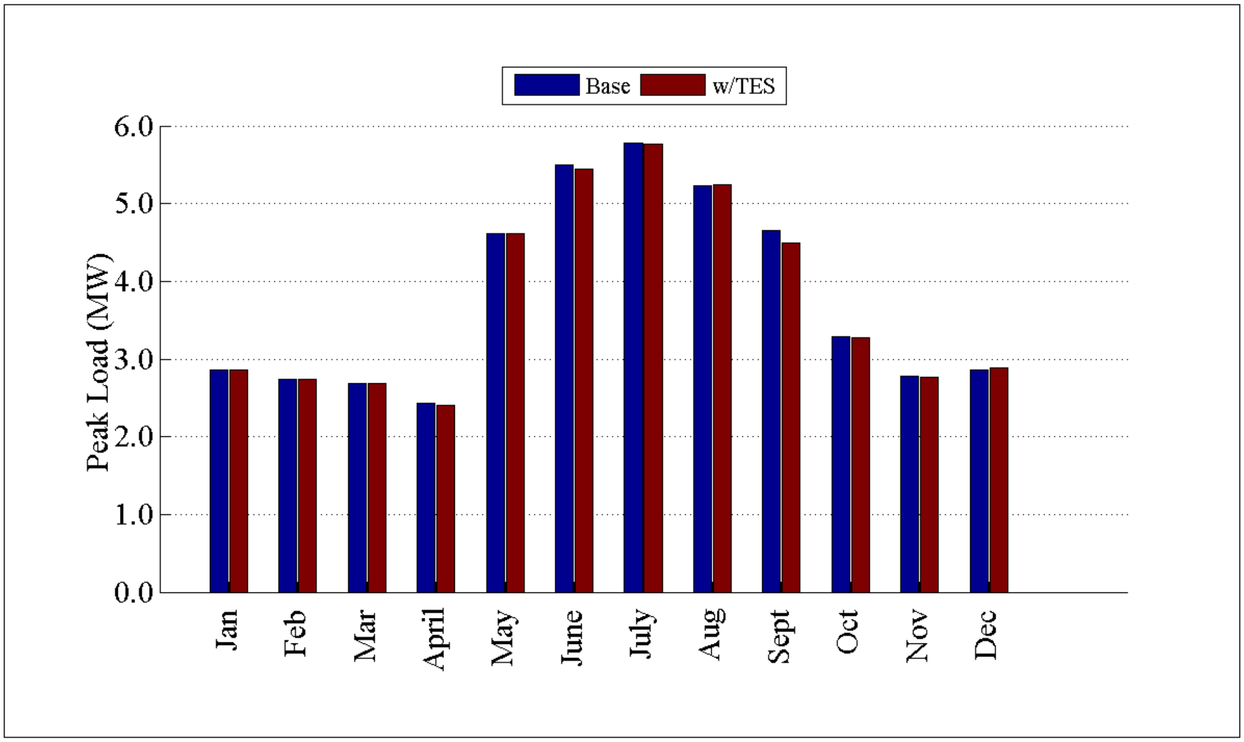

Figure D.65: Peak load by month of R2-12.47-2 feeder

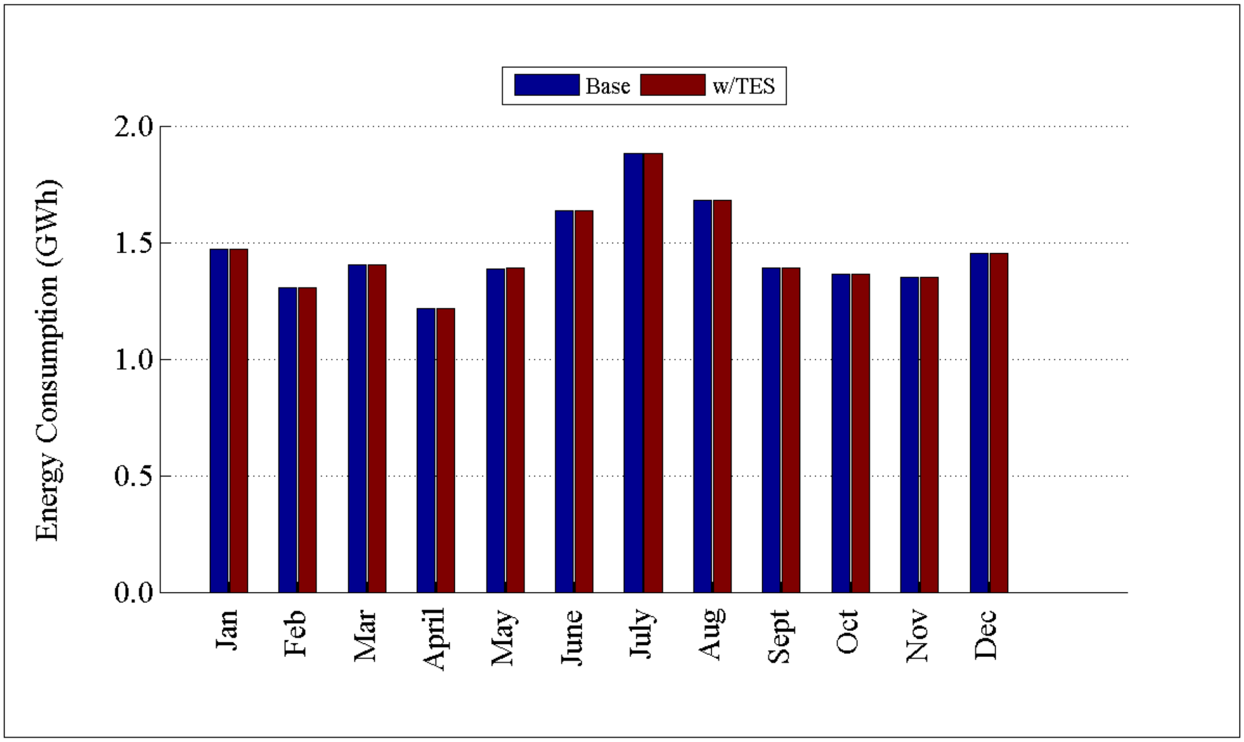

Figure D.66: Monthly energy consumption for R2-12.47-2 feeder

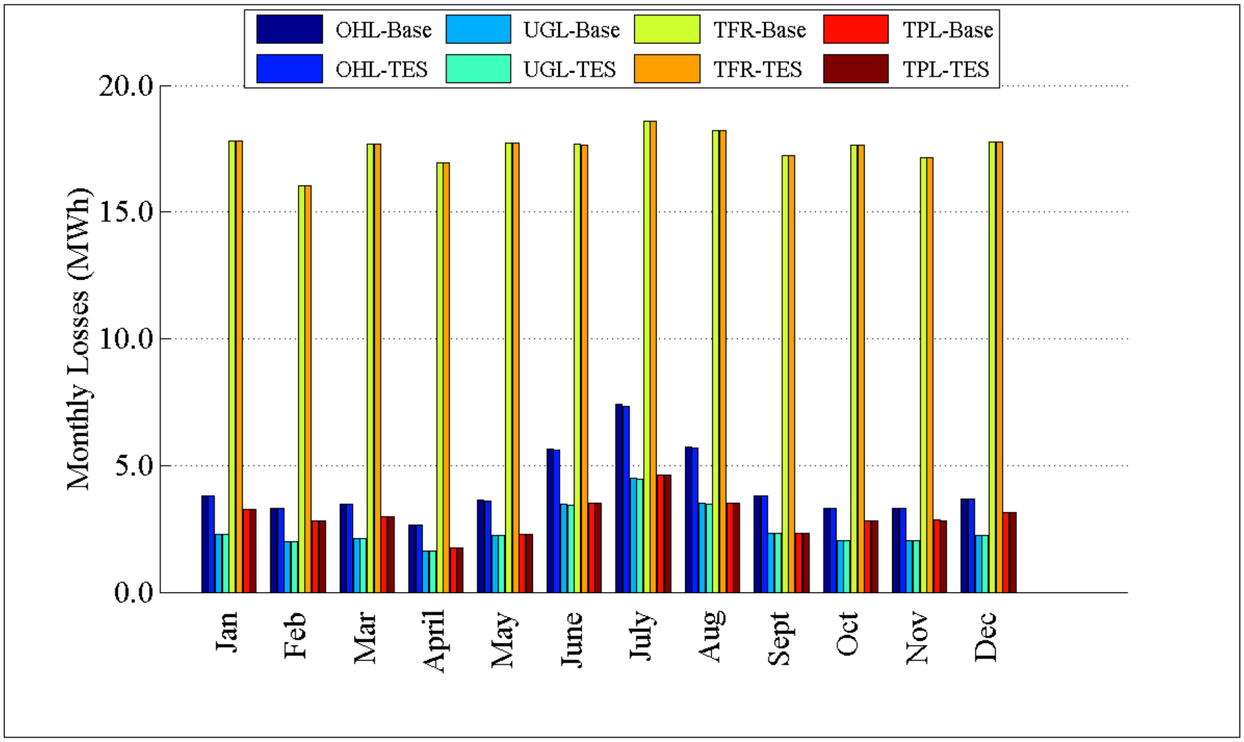

Figure D.67: Distribution system losses by month for R2-12.47-2

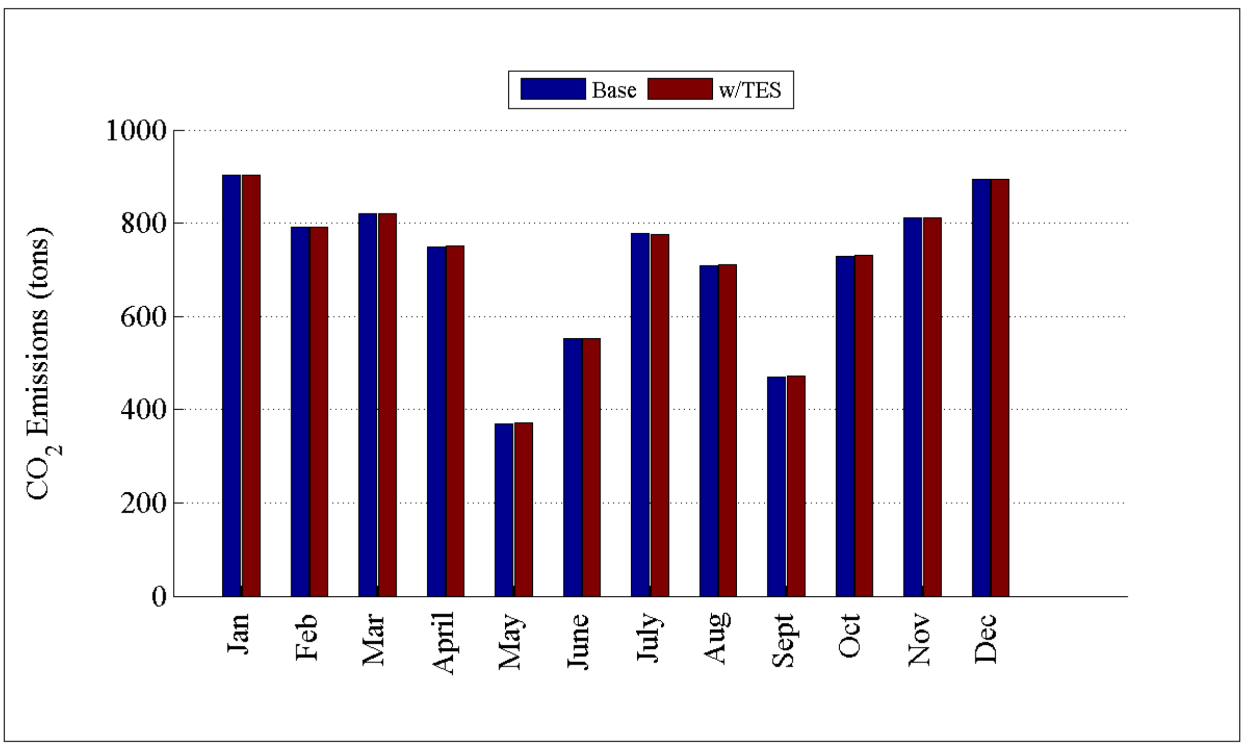

Figure D.68: CO_2 emissions by month for R2-12.47-2

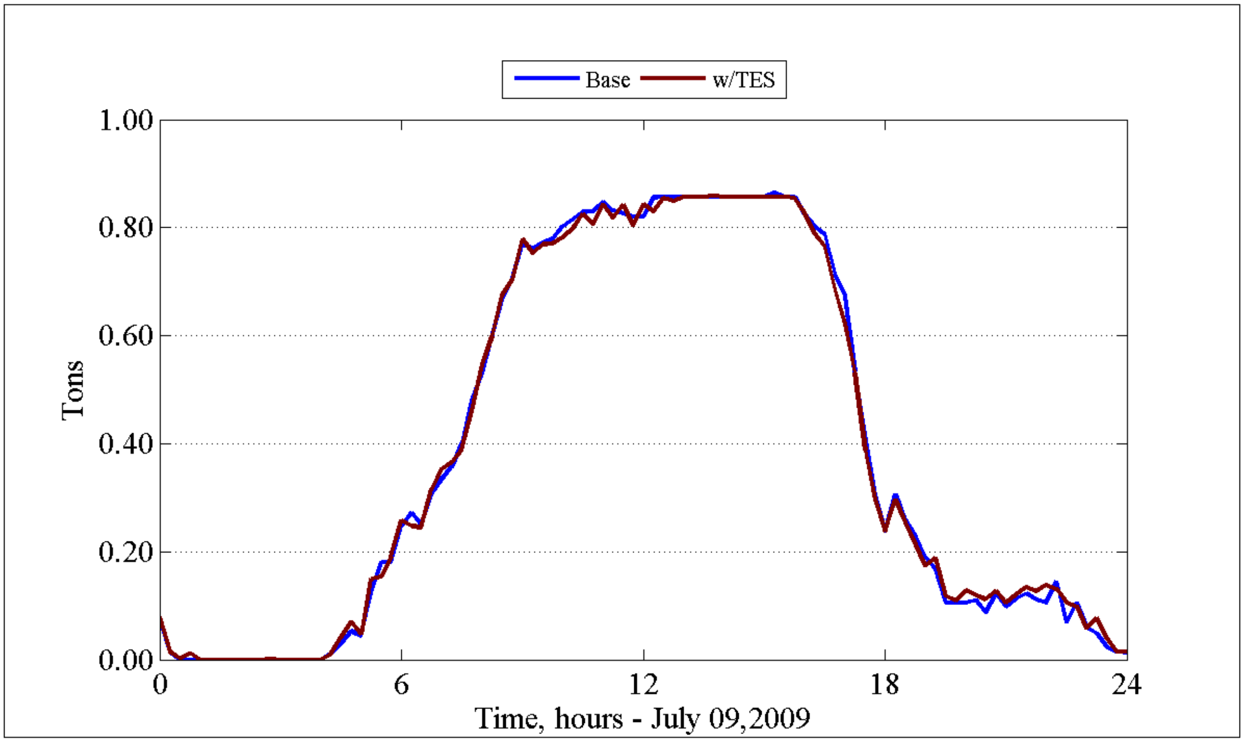

Figure D.69: Carbon dioxide emissions for peak day of R2-12.47-2

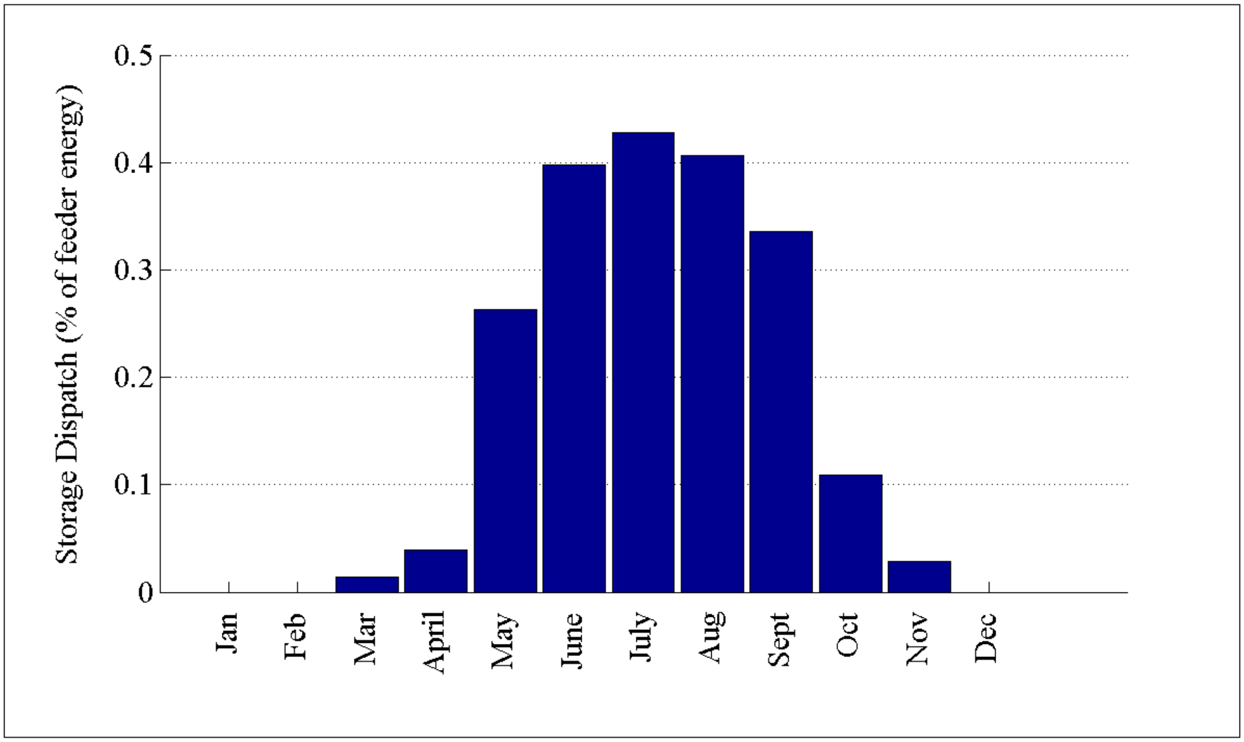

Figure D.70: Monthly storage dispatch energy for R2-12.47-2

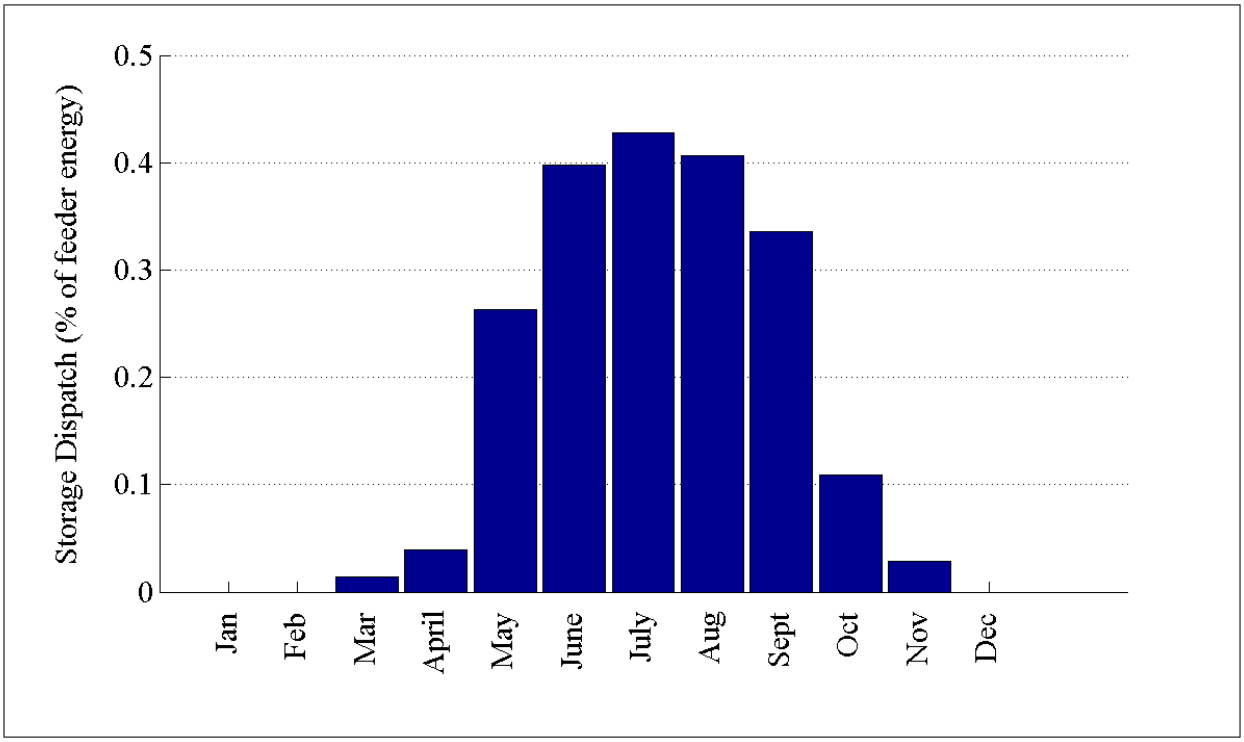

Figure D.71: Monthly storage dispatch energy percentage for R2-12.47-2

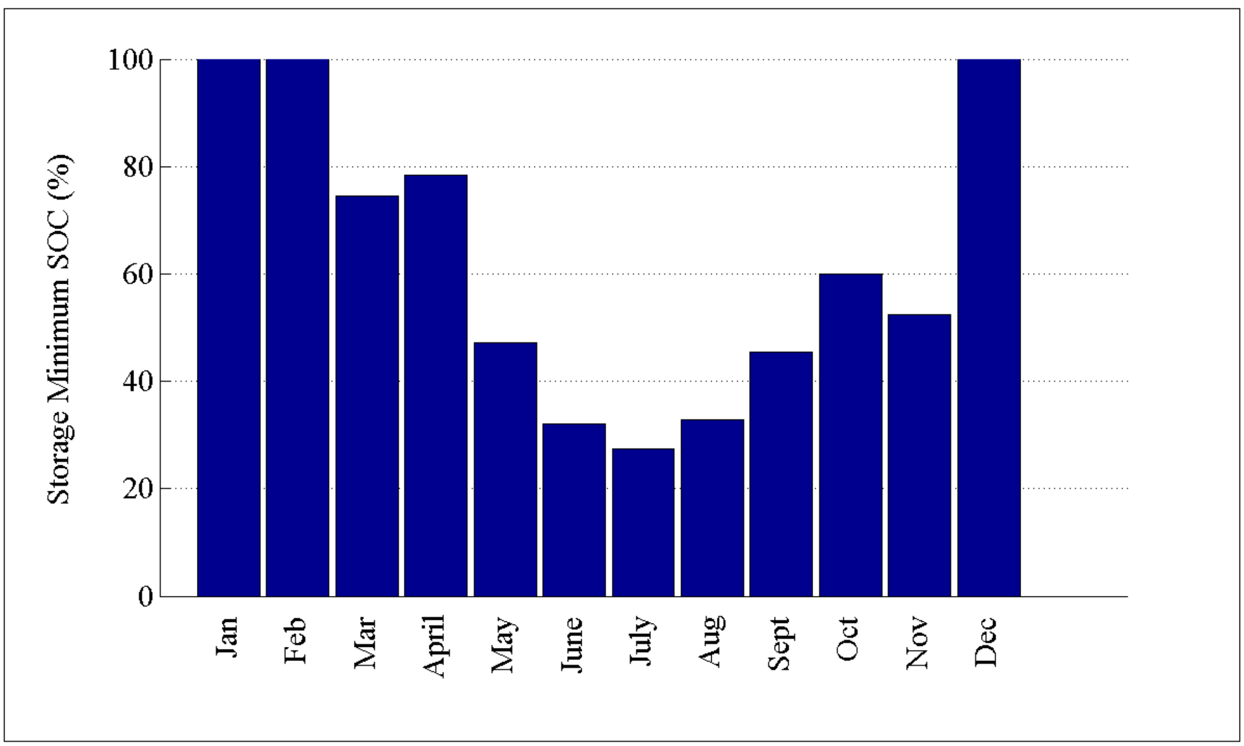

Figure D.72: Minimum state of charge for thermal energy storage on R2-12.47-2

D.10 Detailed Thermal Energy Storage Plots for R2-12.47-3

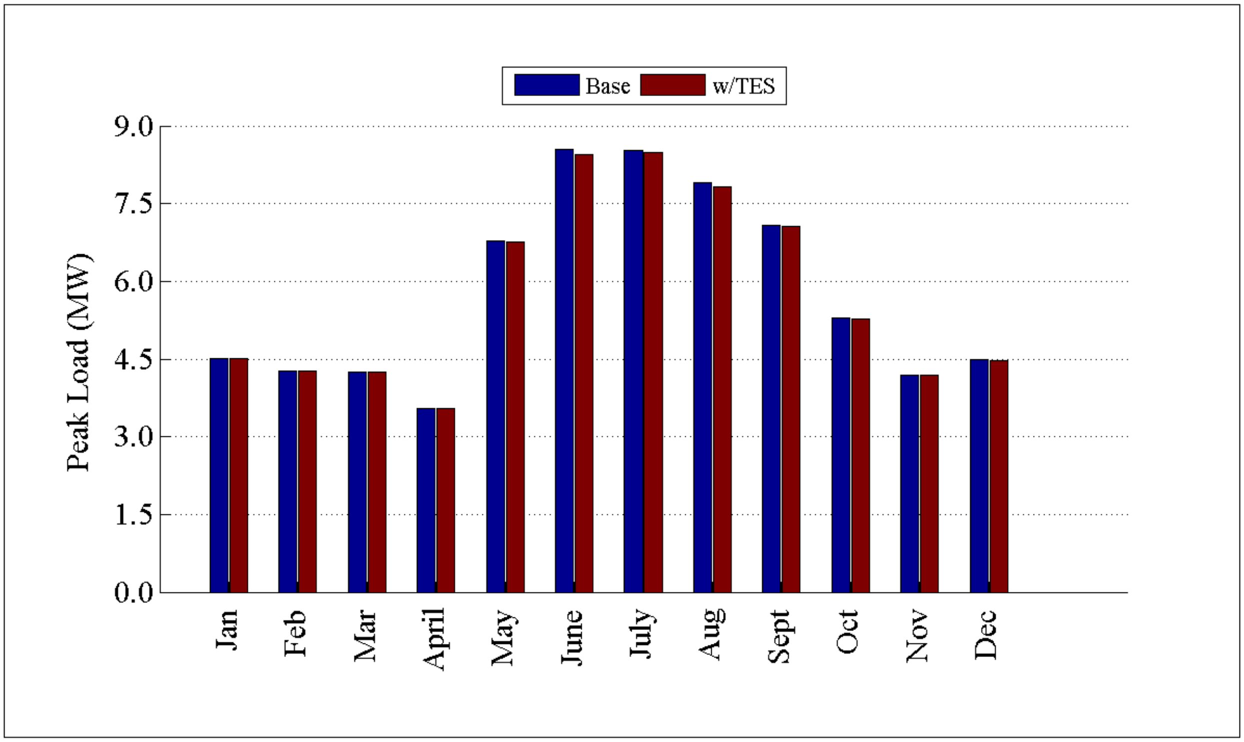

Figure D.73: Peak load by month of R2-12.47-3 feeder

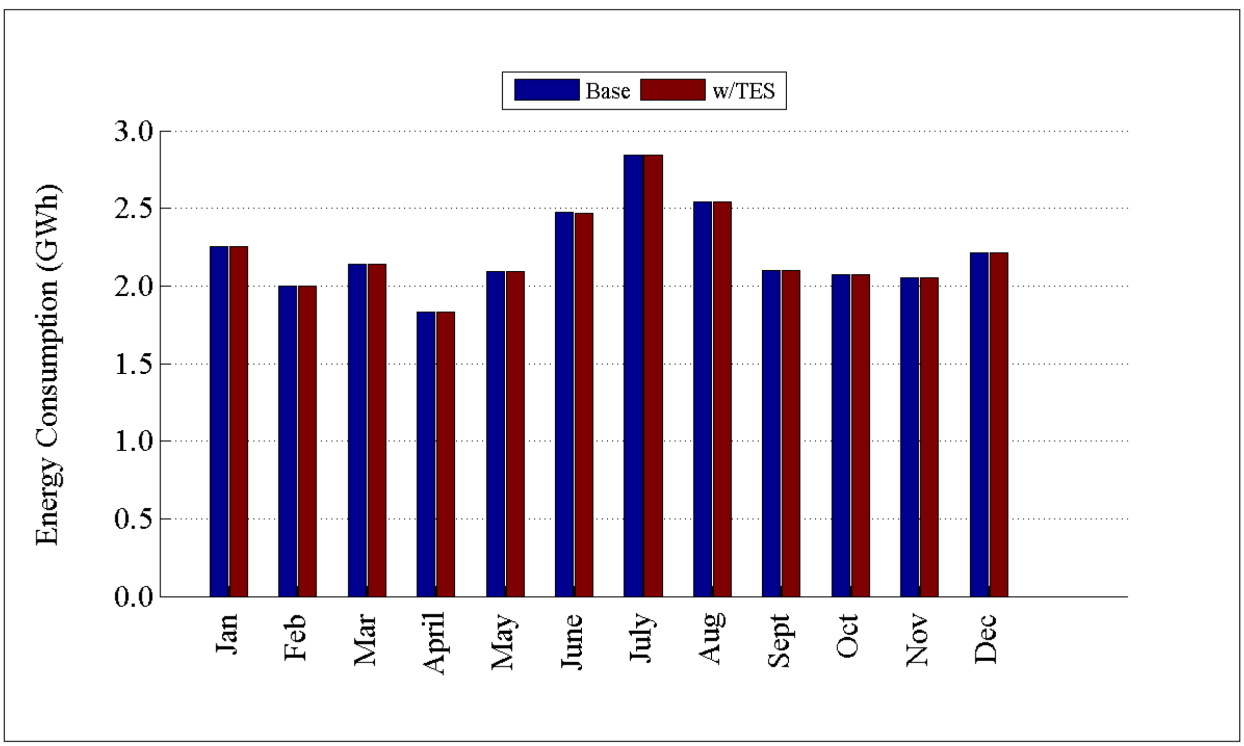

Figure D.74: Monthly energy consumption for R2-12.47-3 feeder

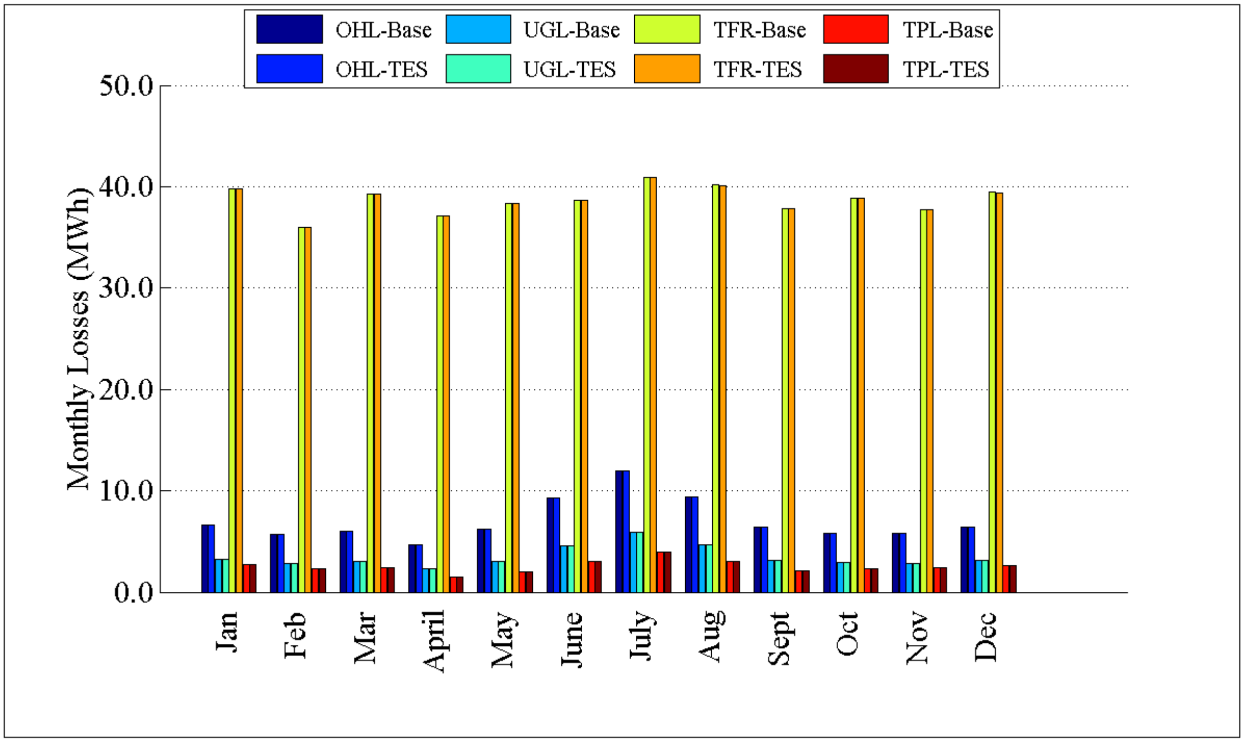

Figure D.75: Distribution system losses by month for R2-12.47-3

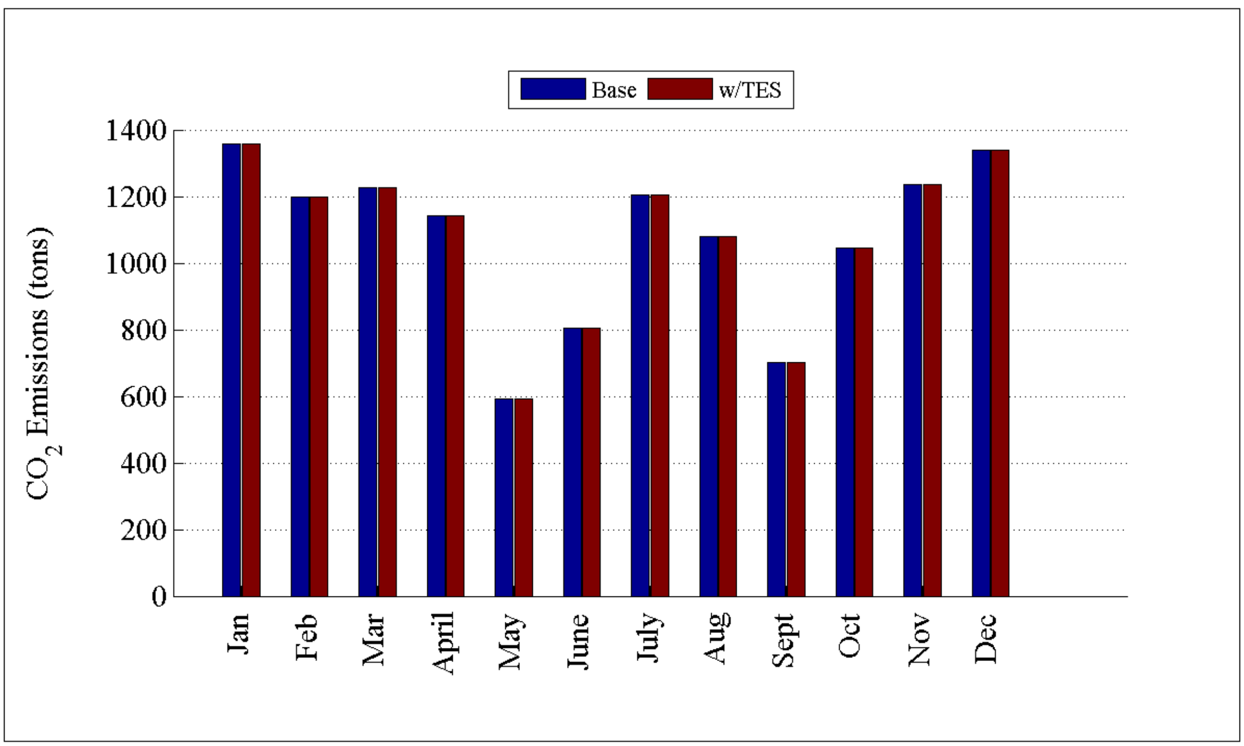

Figure D.76: CO_2 emissions by month for R2-12.47-3

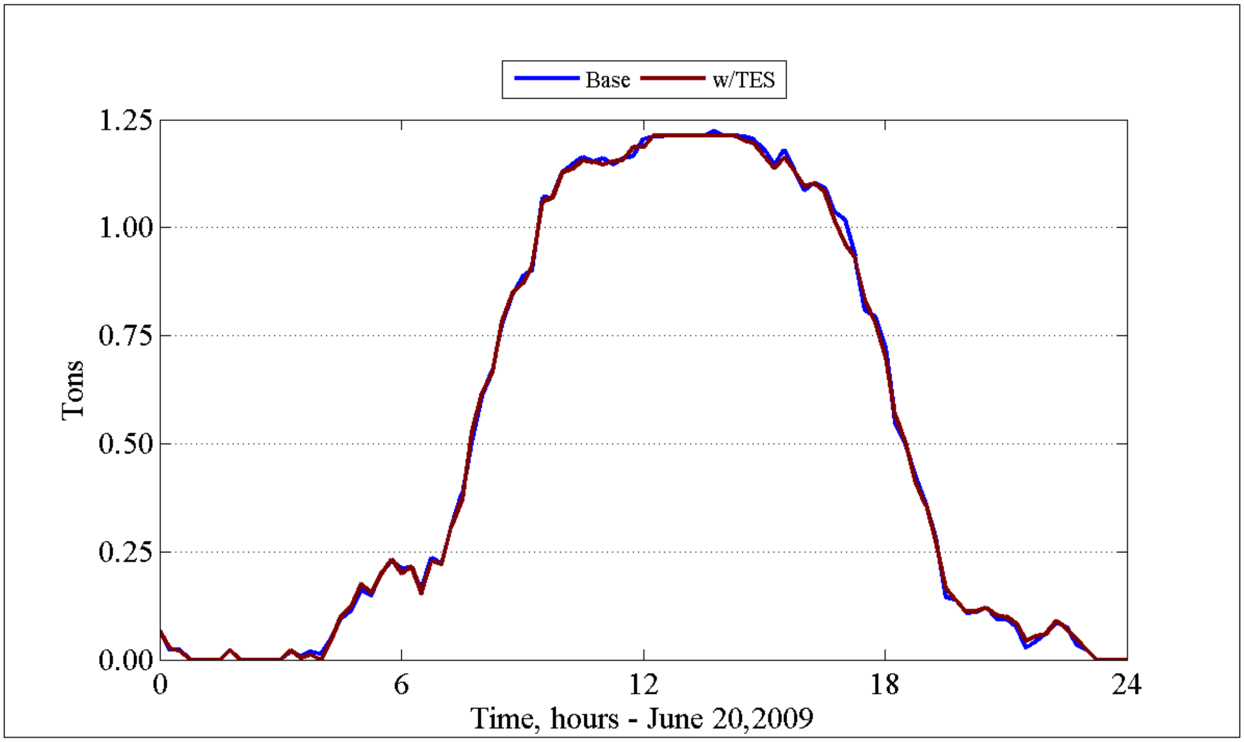

Figure D.77: Carbon dioxide emissions for peak day of R2-12.47-3

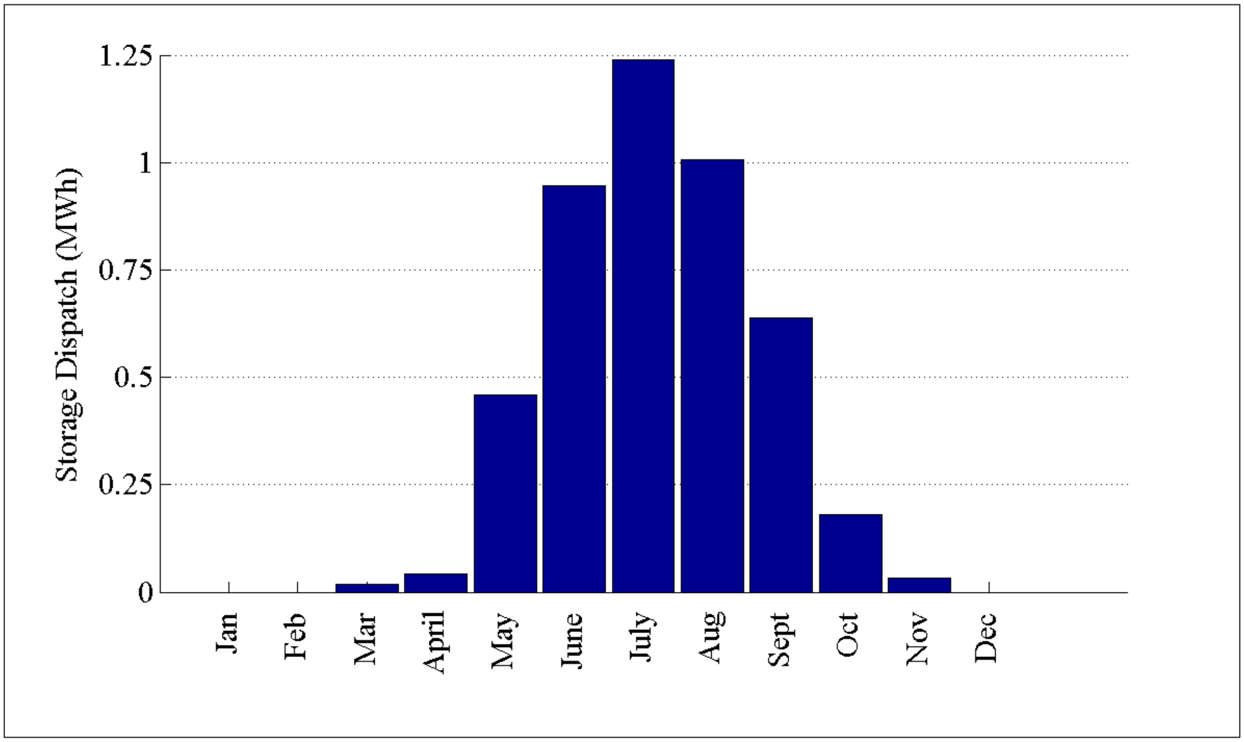

Figure D.78: Monthly storage dispatch energy for R2-12.47-3

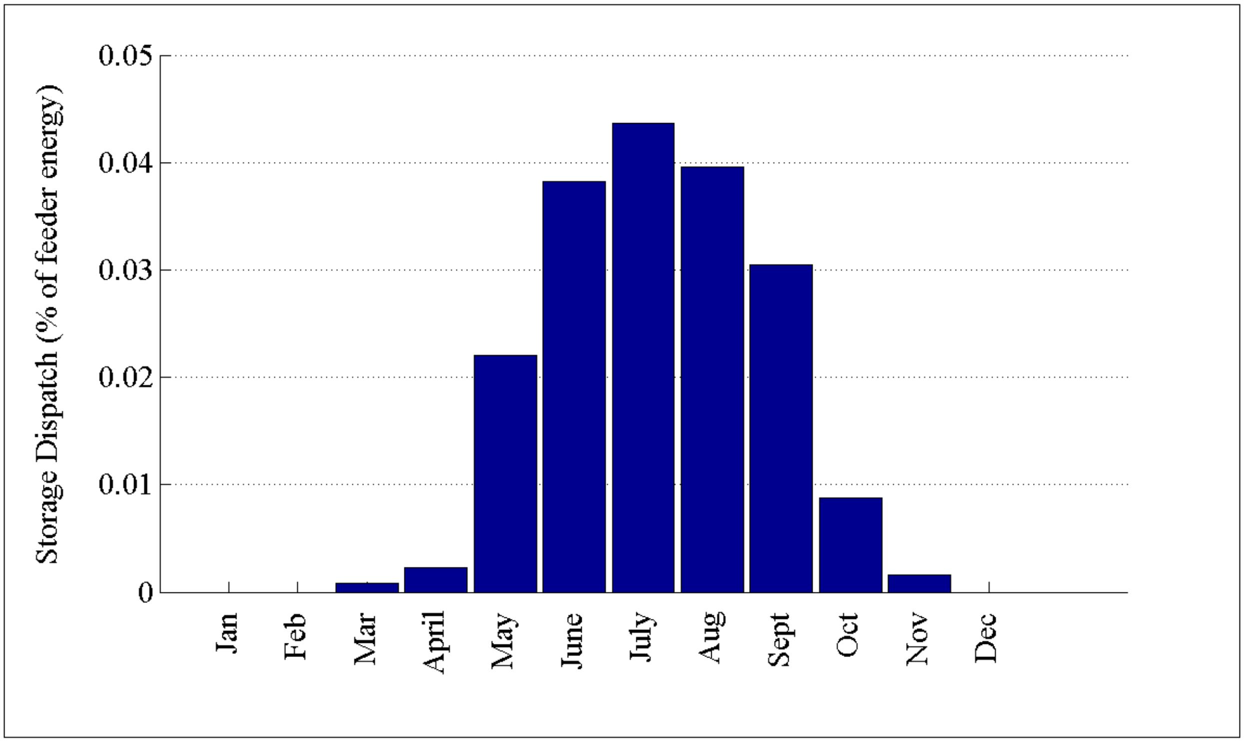

Figure D.79: Monthly storage dispatch energy percentage for R2-12.47-3

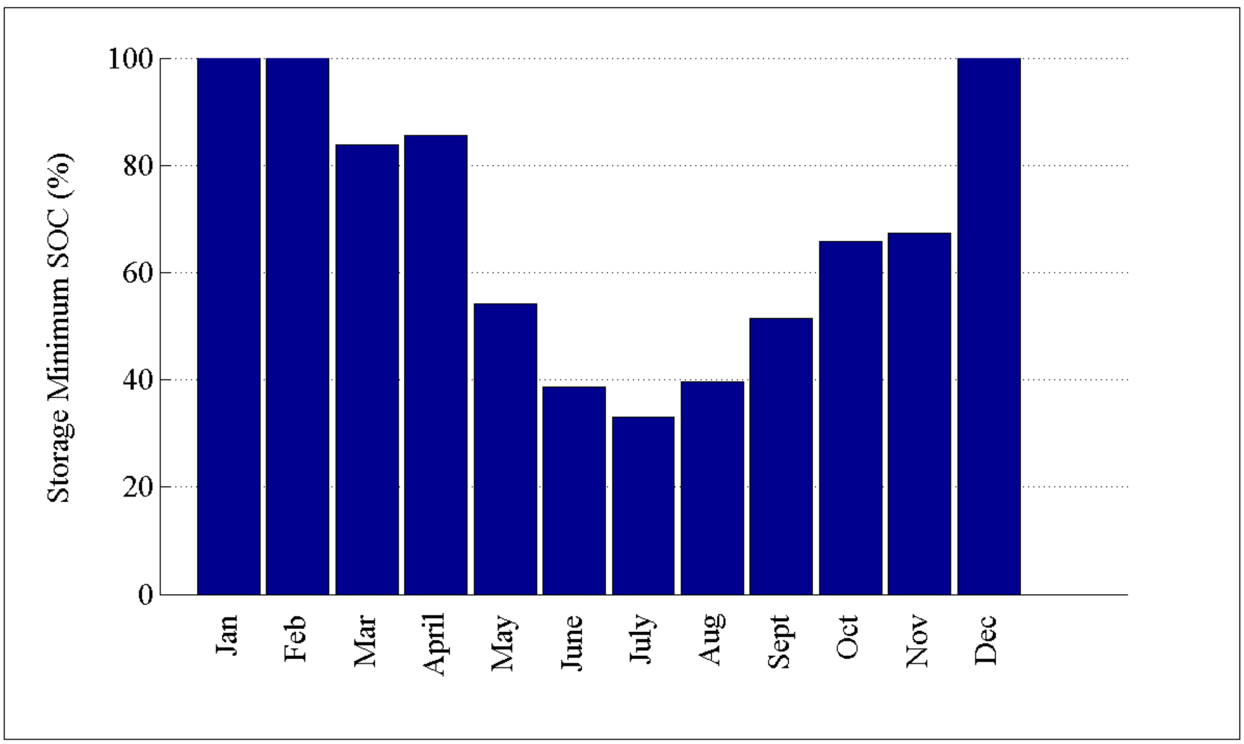

Figure D.80: Minimum state of charge for thermal energy storage on R2-12.47-3

D.11 Detailed Thermal Energy Storage Plots for R2-25.00-1

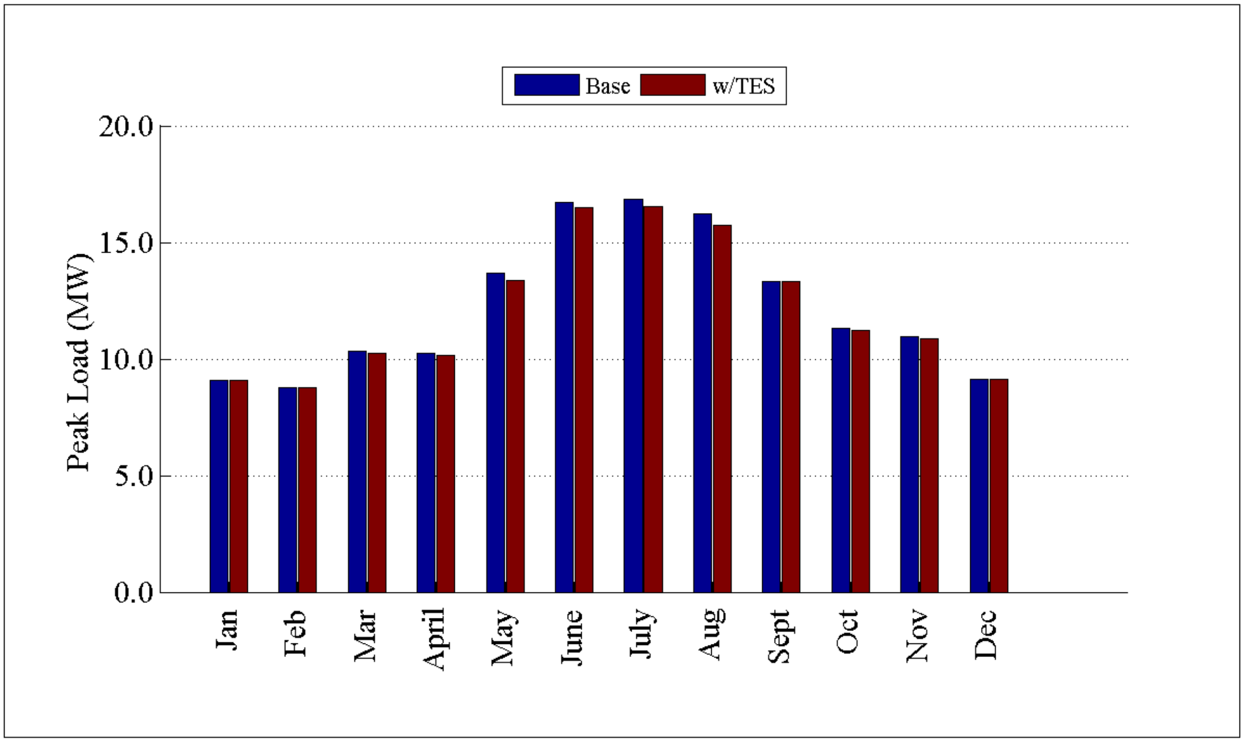

Figure D.81: Peak load by month of R2-25.00-1 feeder

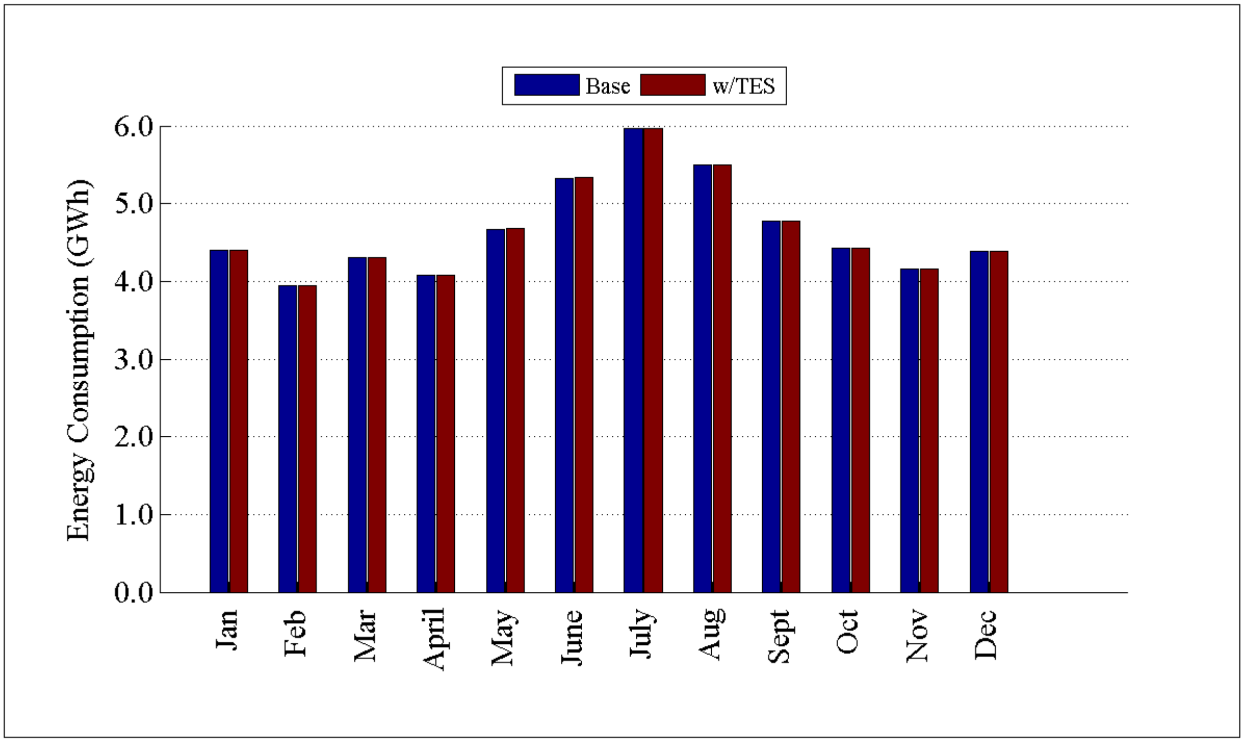

Figure D.82: Monthly energy consumption for R2-25.00-1 feeder

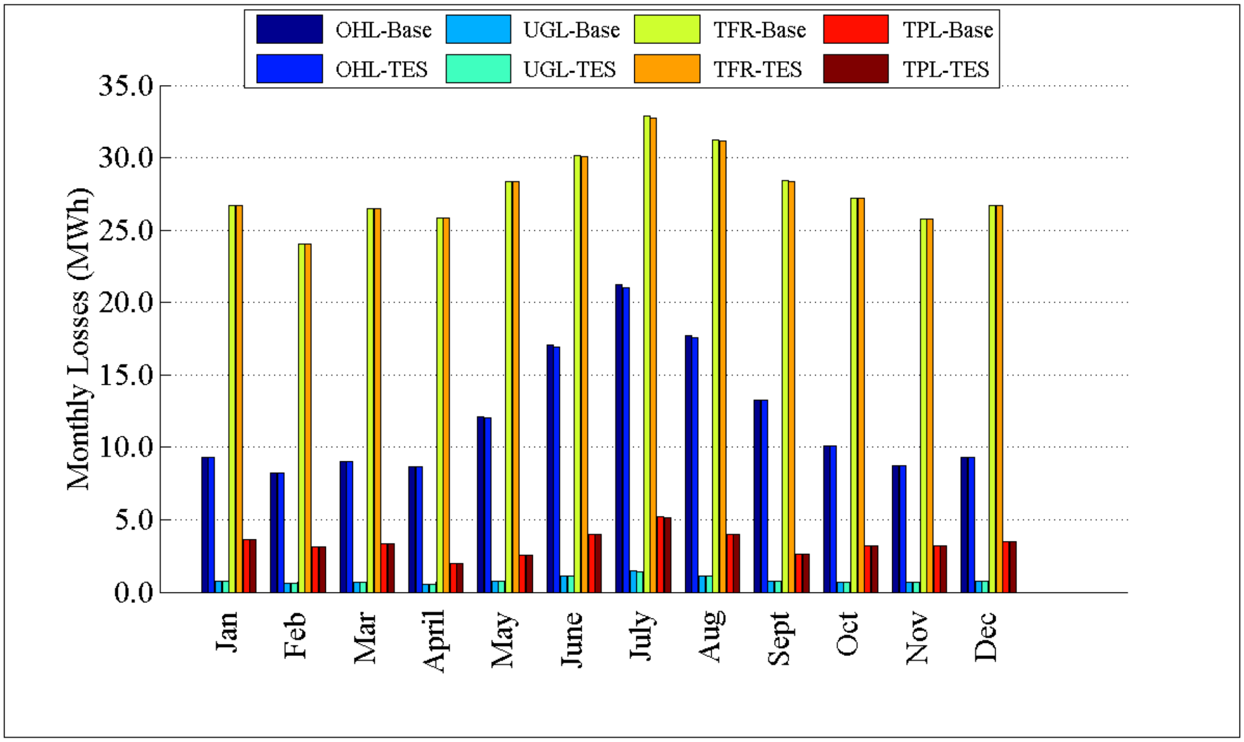

Figure D.83: Distribution system losses by month for R2-25.00-1

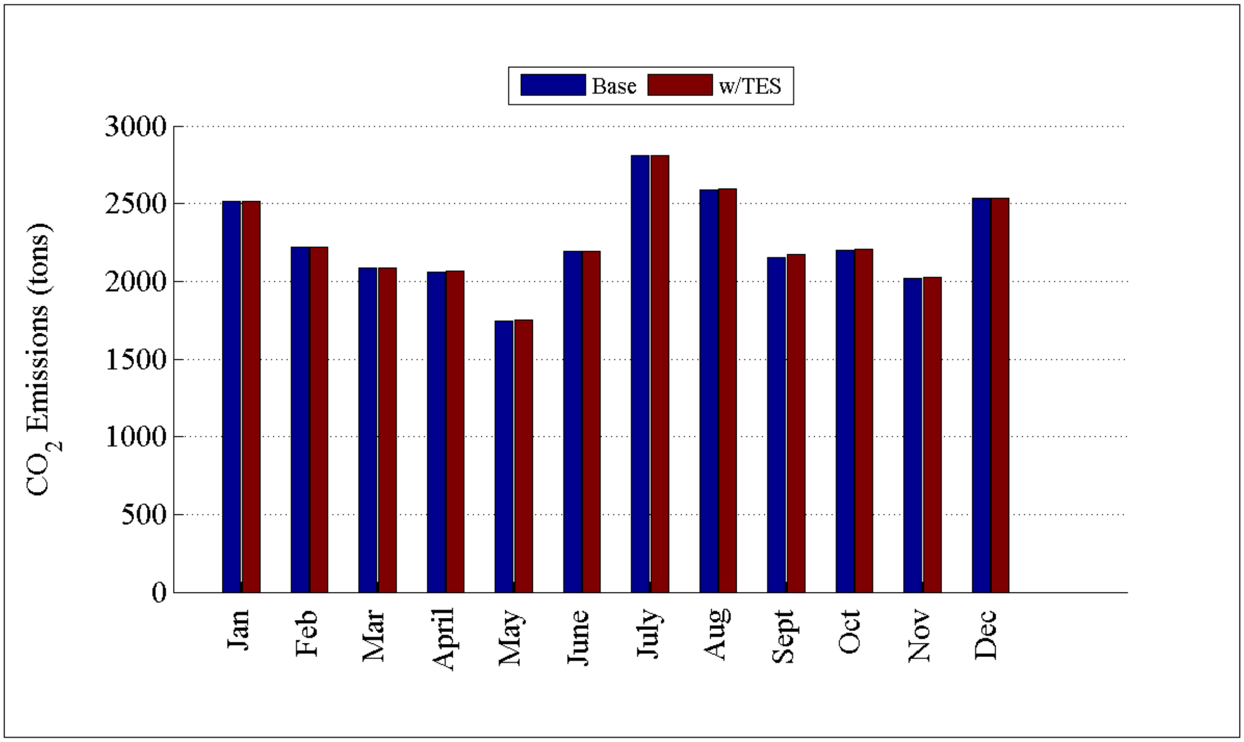

Figure D.84: CO_2 emissions by month for R2-25.00-1

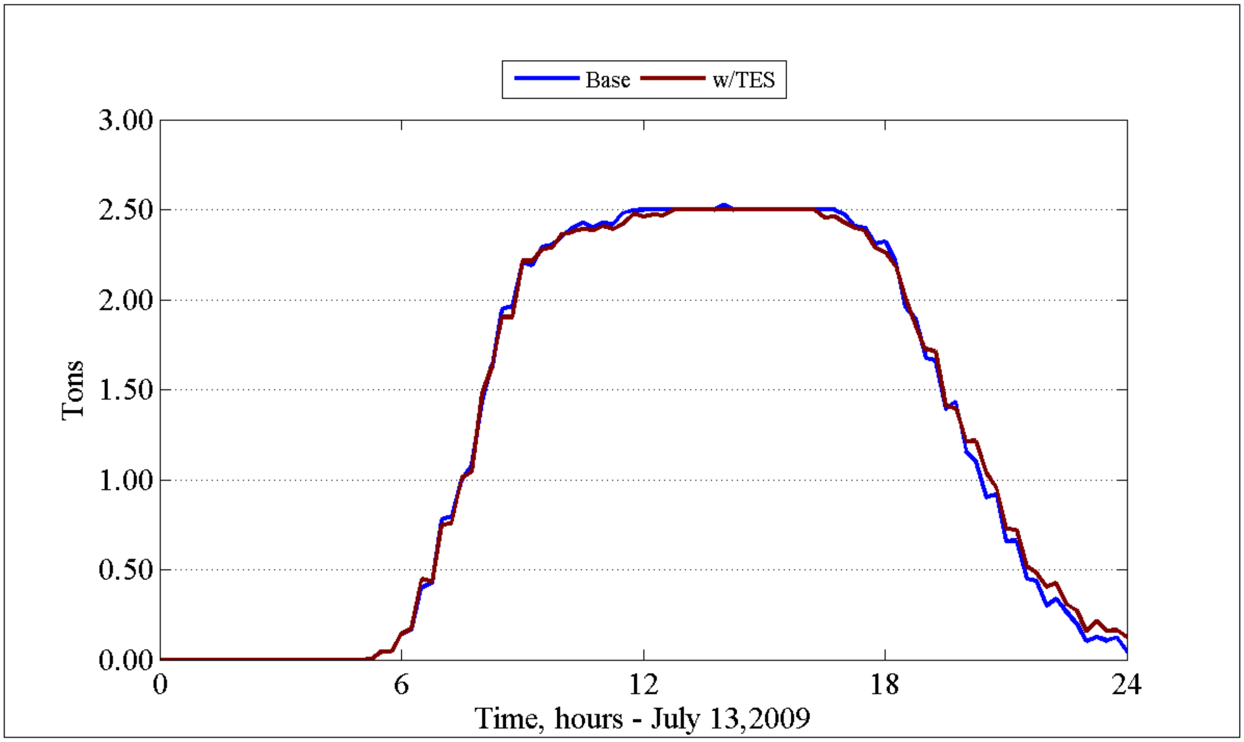

Figure D.85: Carbon dioxide emissions for peak day of R2-25.00-1

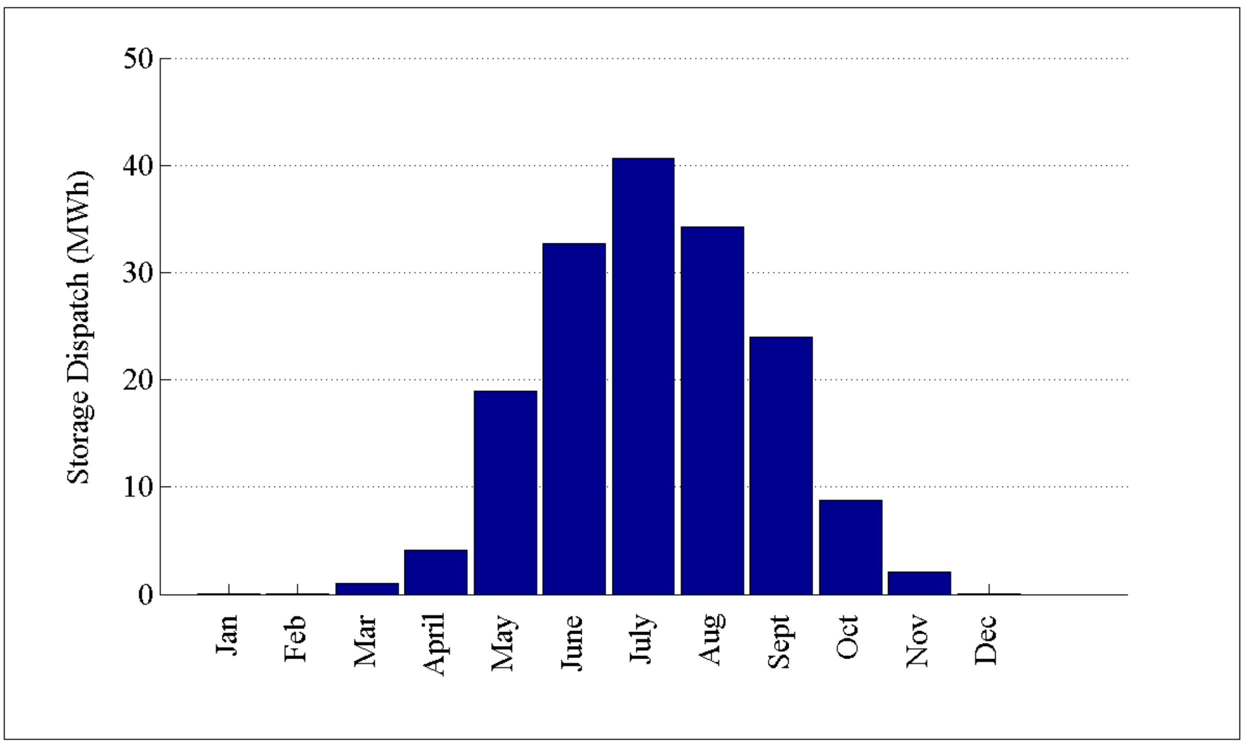

Figure D.86: Monthly storage dispatch energy for R2-25.00-1

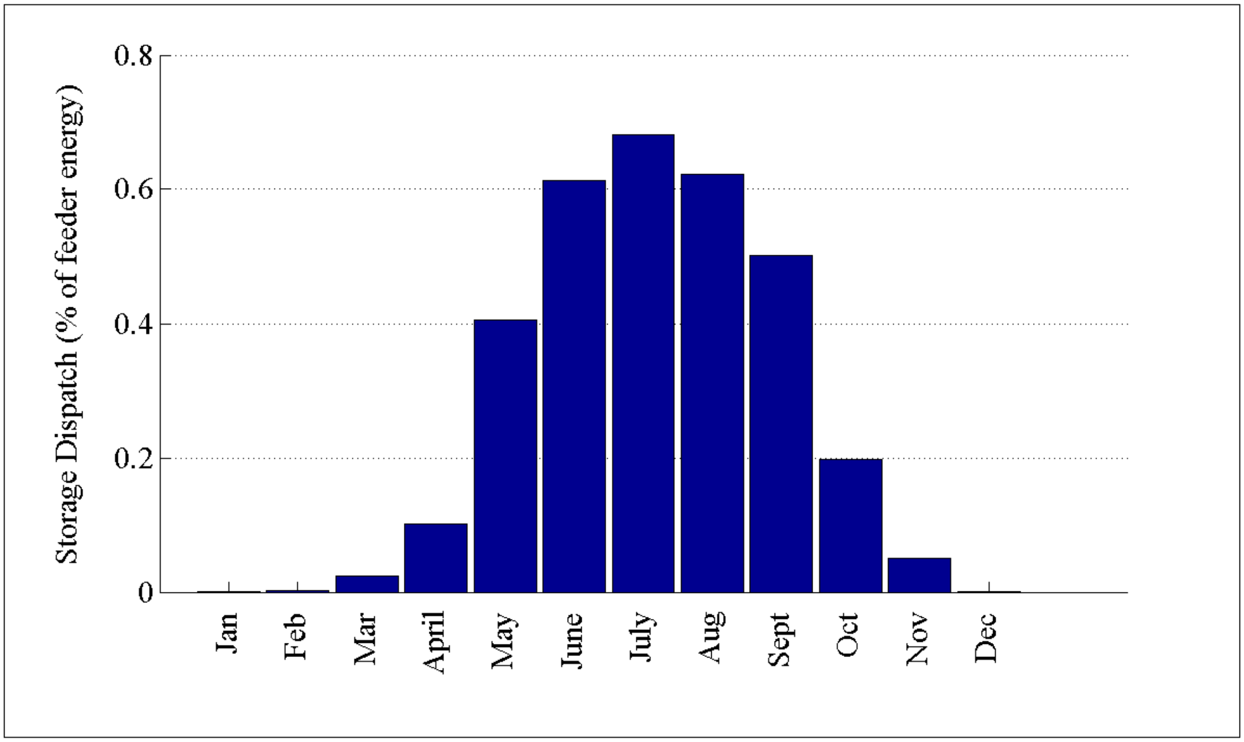

Figure D.87: Monthly storage dispatch energy percentage for R2-25.00-1

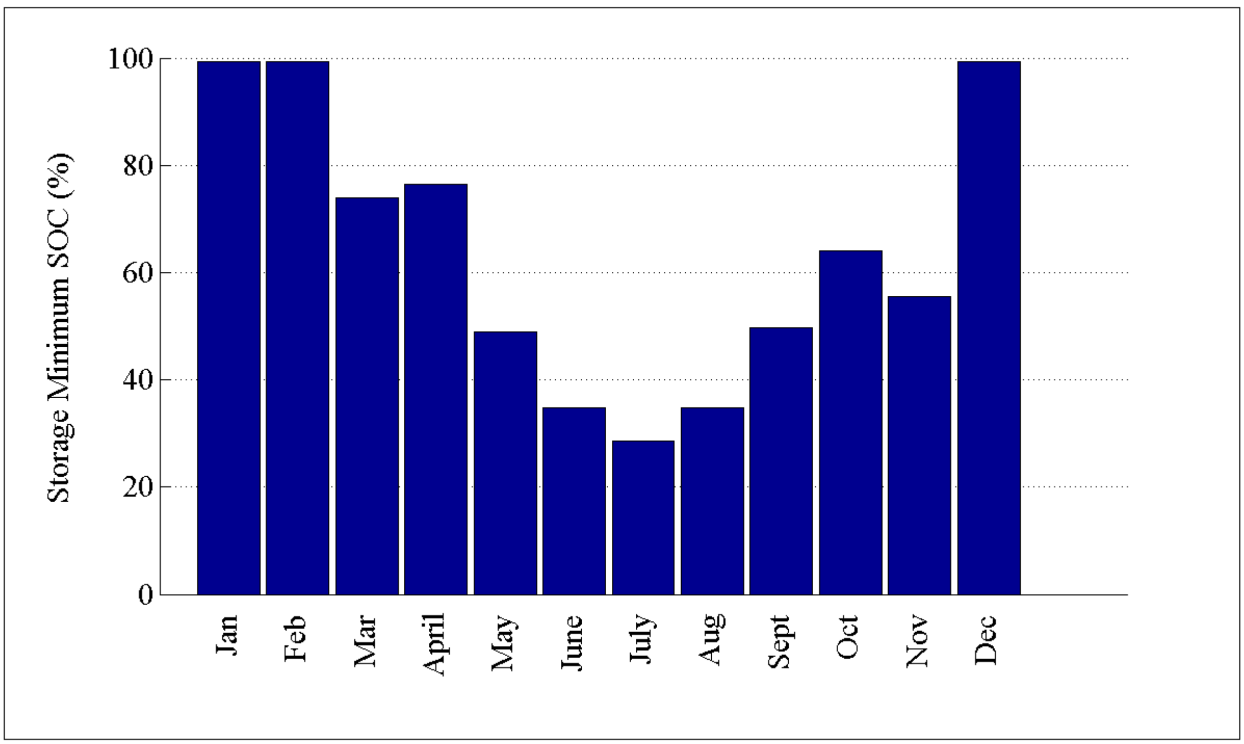

Figure D.88: Minimum state of charge for thermal energy storage on R2-25.00-1

D.12 Detailed Thermal Energy Storage Plots for R2-35.00-1

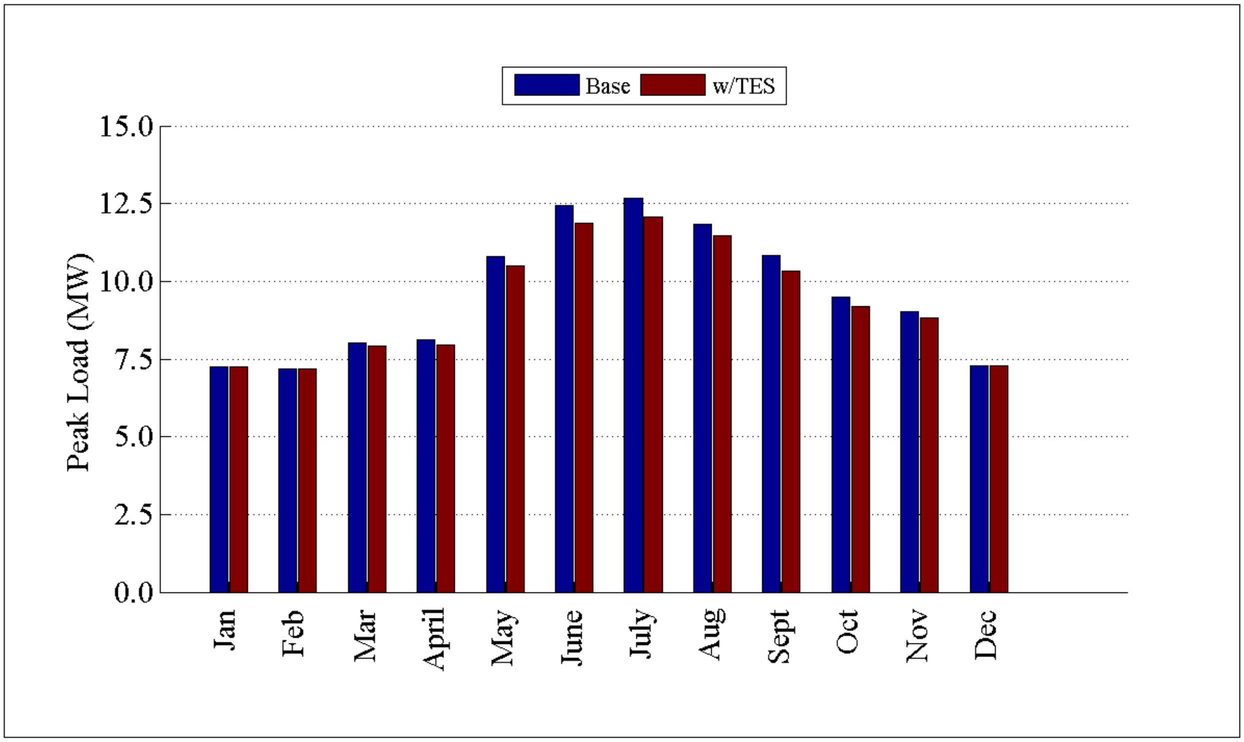

Figure D.89: Peak load by month of R2-35.00-1 feeder

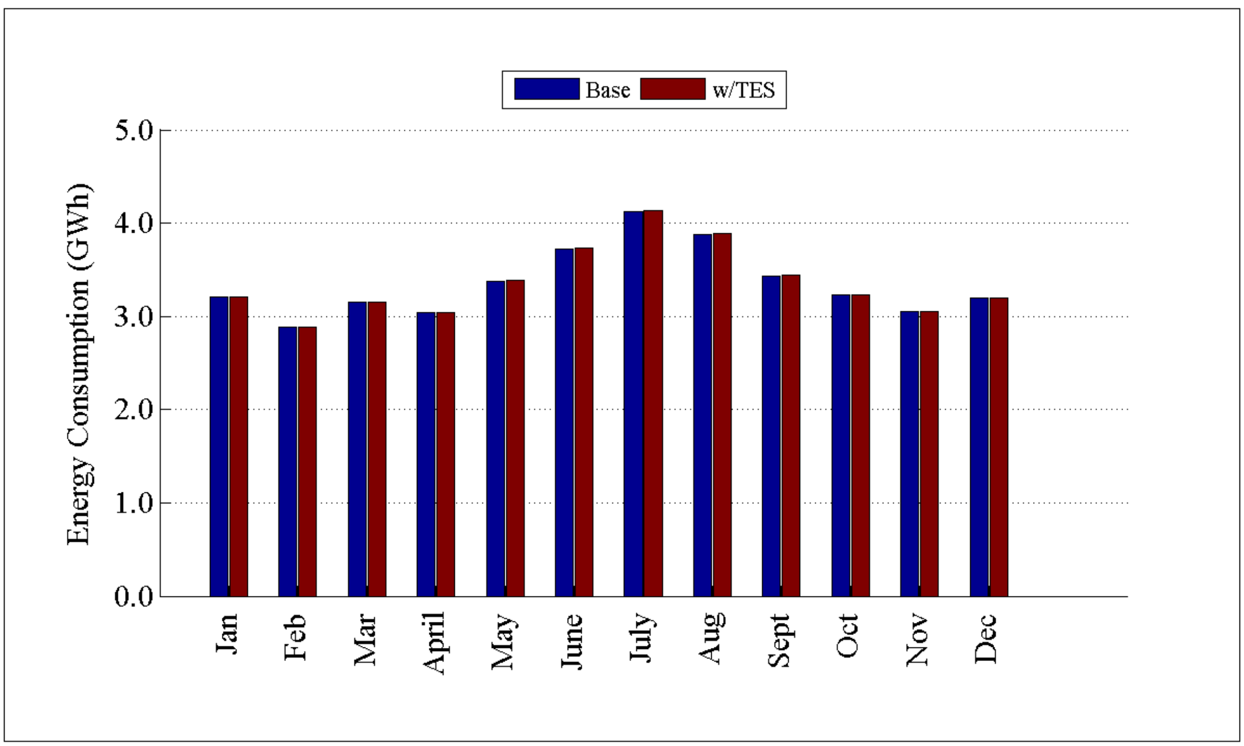

Figure D.90: Monthly energy consumption for R2-35.00-1 feeder

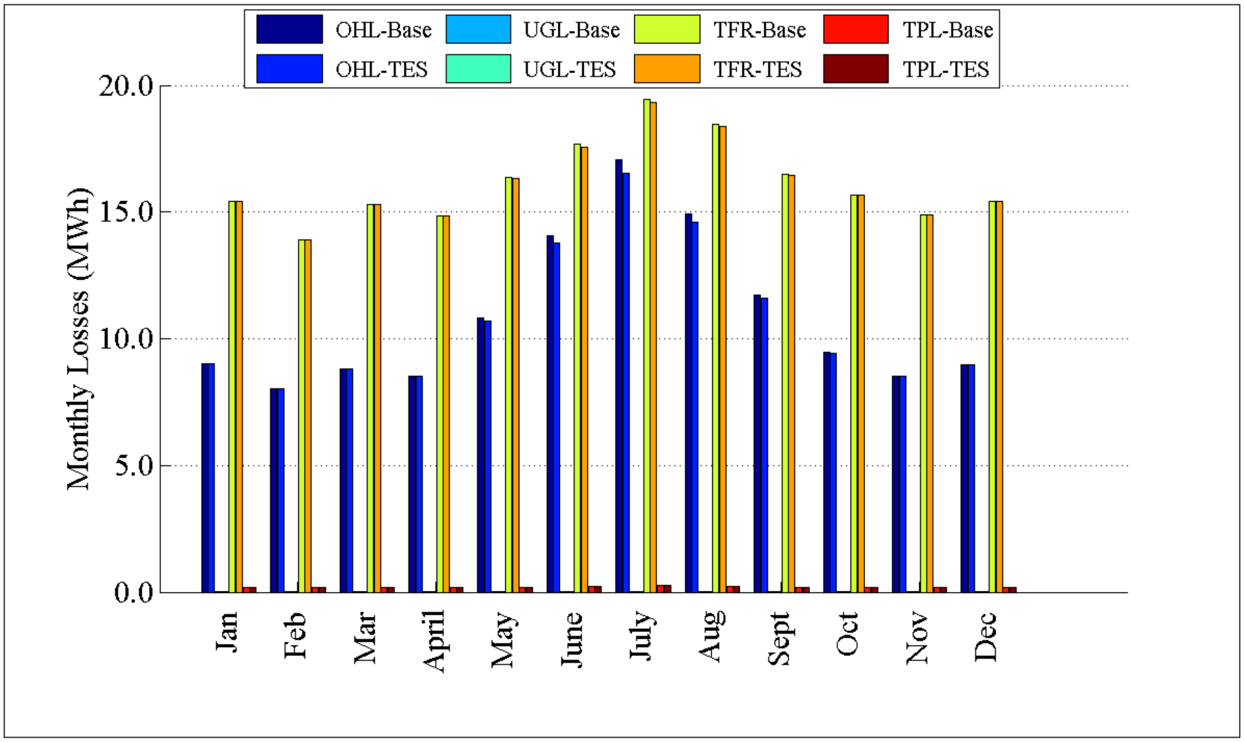

Figure D.91: Distribution system losses by month for R2-35.00-1

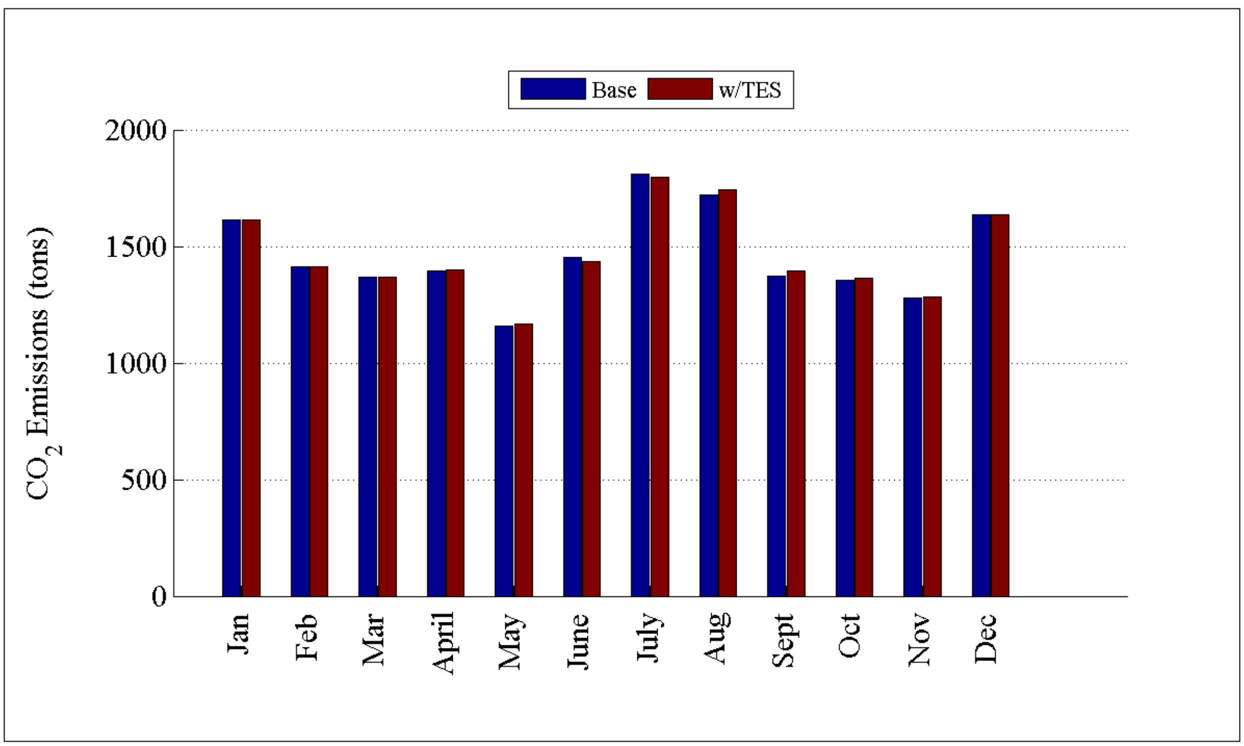

Figure D.92: CO_2 emissions by month for R2-35.00-1

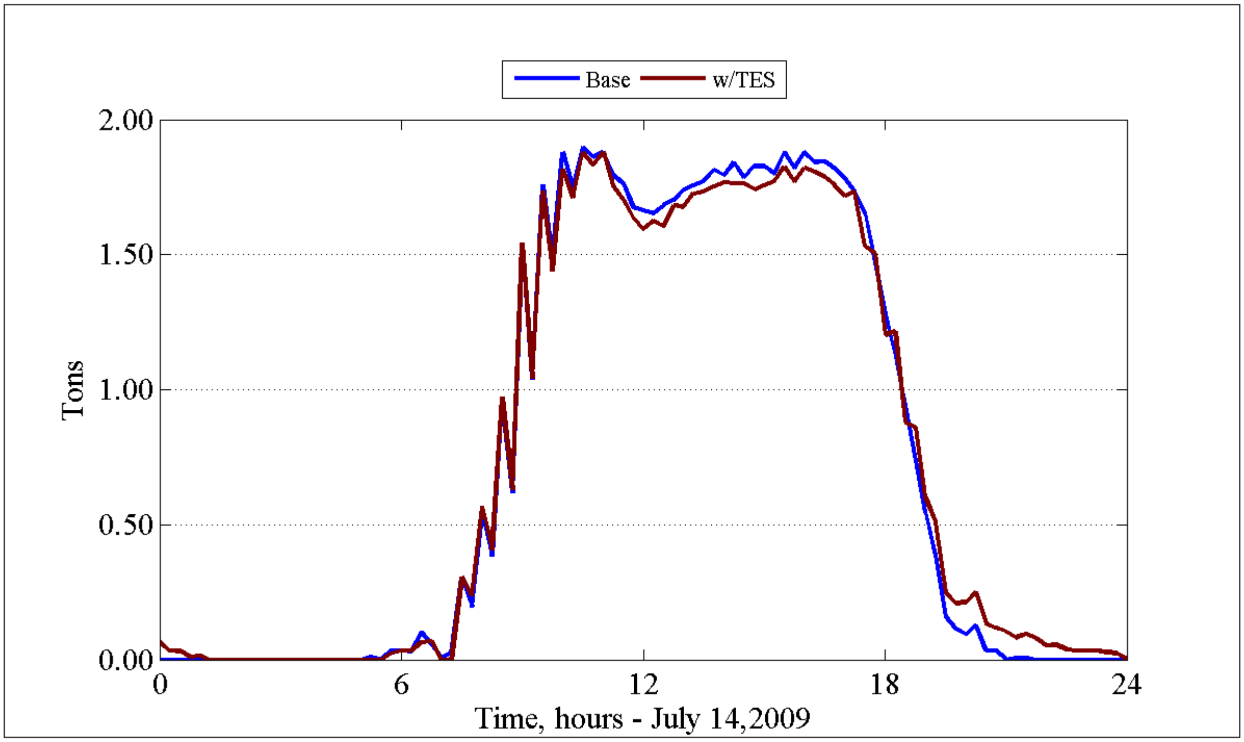

Figure D.93: Carbon dioxide emissions for peak day of R2-35.00-1

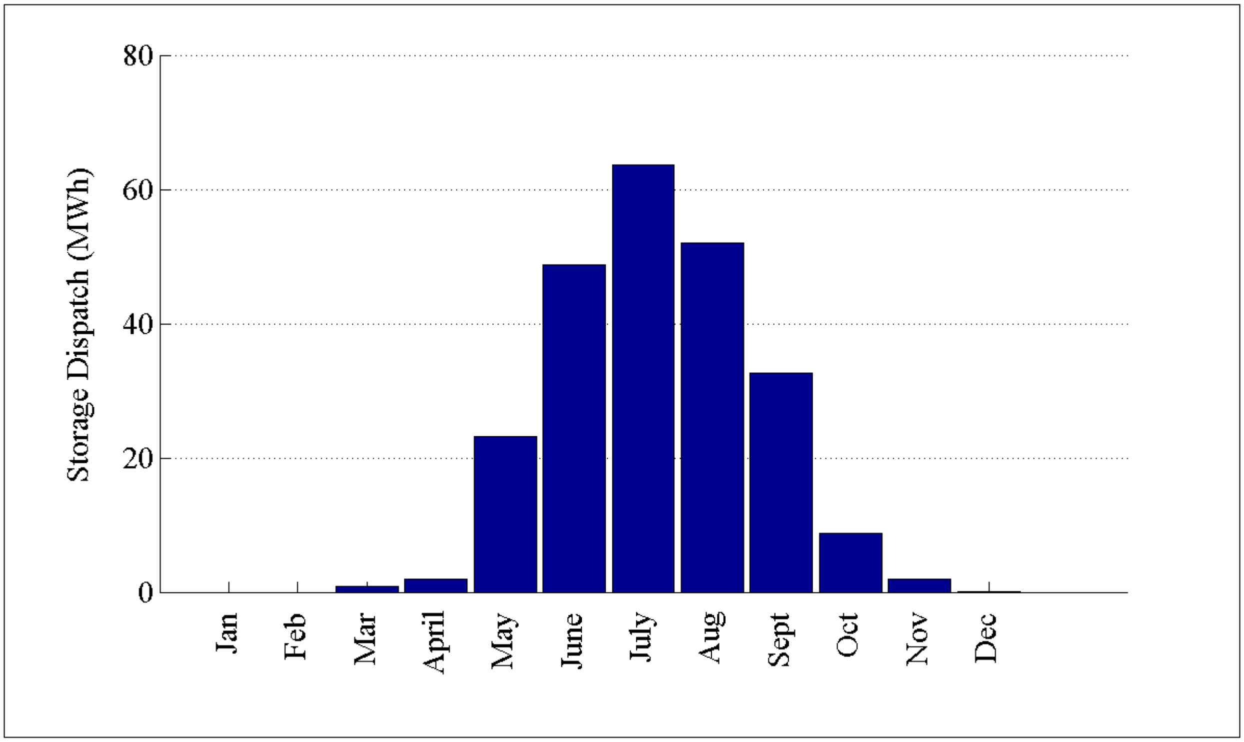

Figure D.94: Monthly storage dispatch energy for R2-35.00-1

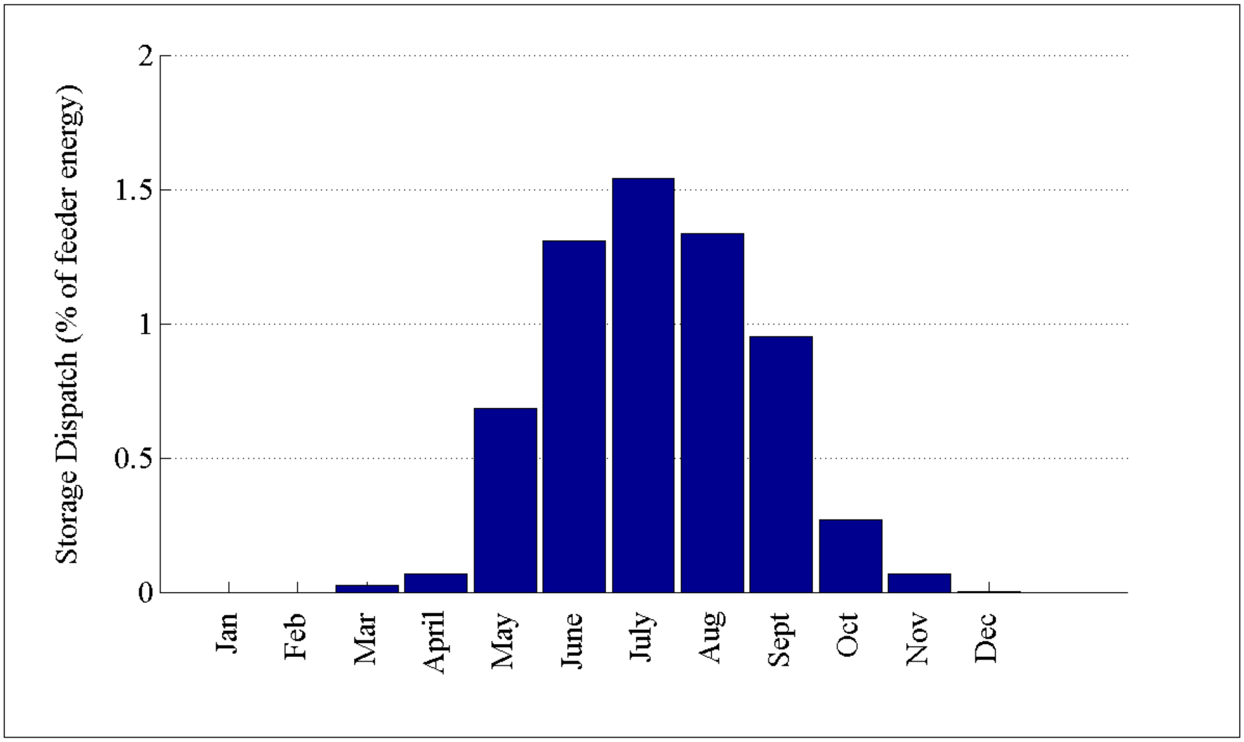

Figure D.95: Monthly storage dispatch energy percentage for R2-35.00-1

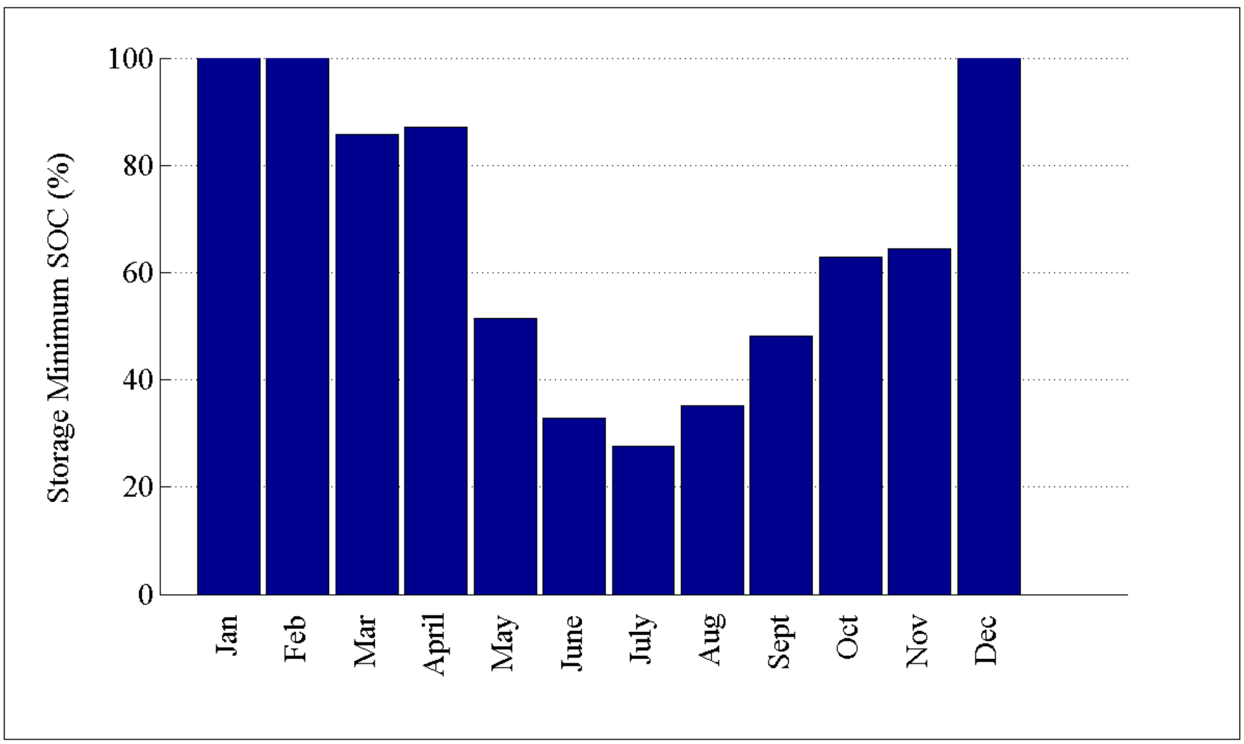

Figure D.96: Minimum state of charge for thermal energy storage on R2-35.00-1

D.13 Detailed Thermal Energy Storage Plots for GC-12.47-1_R3

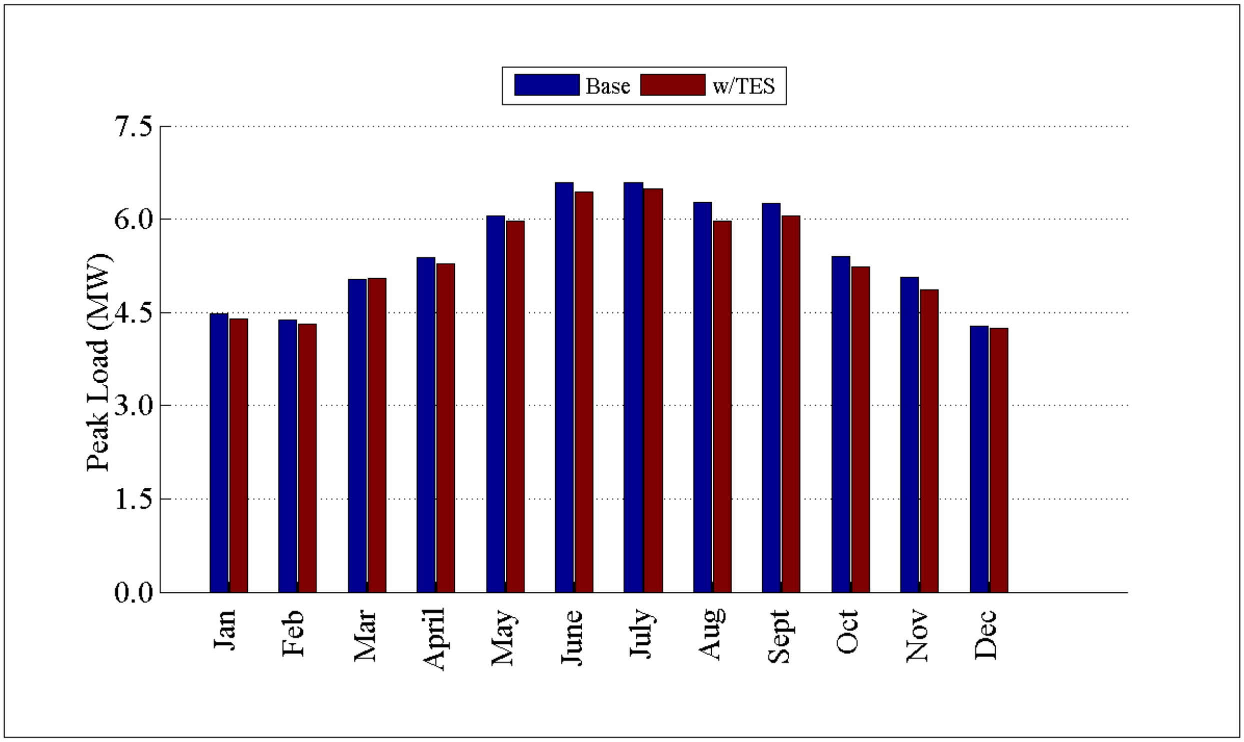

Figure D.97: Peak load by month of GC-12.47-1-r3 feeder

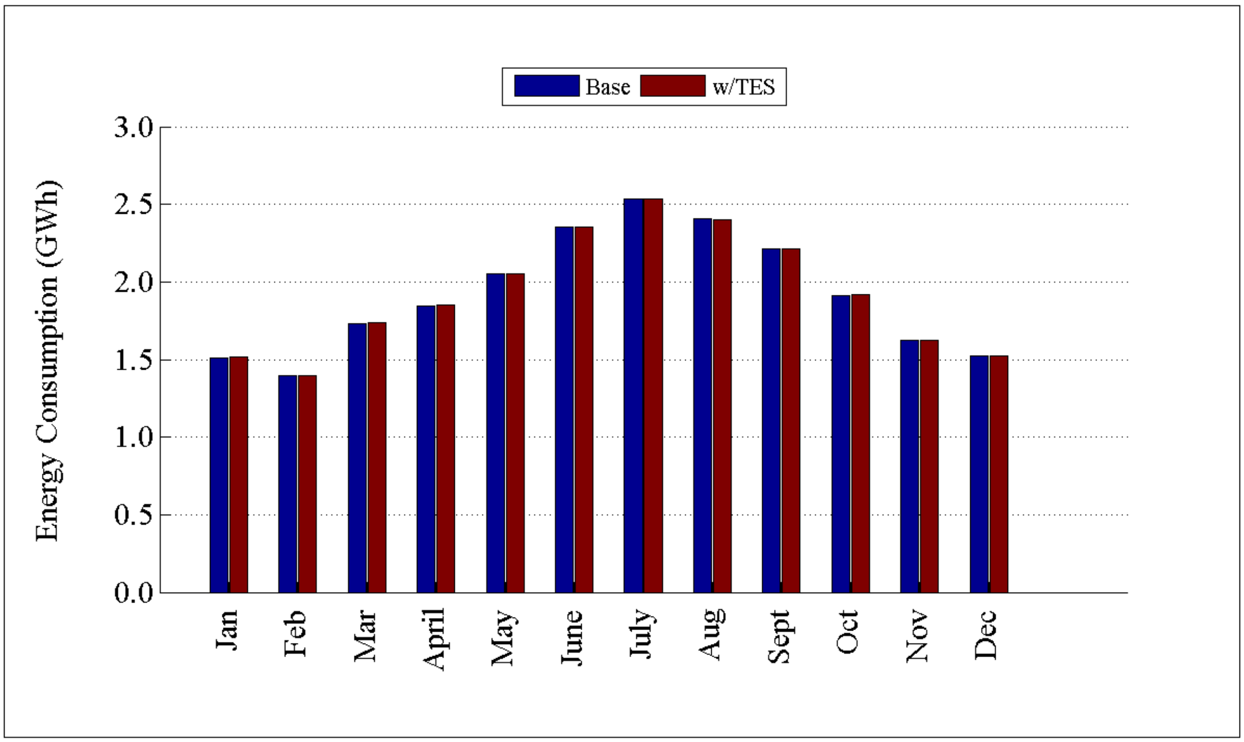

Figure D.98: Monthly energy consumption for GC-12.47-1-r3 feeder

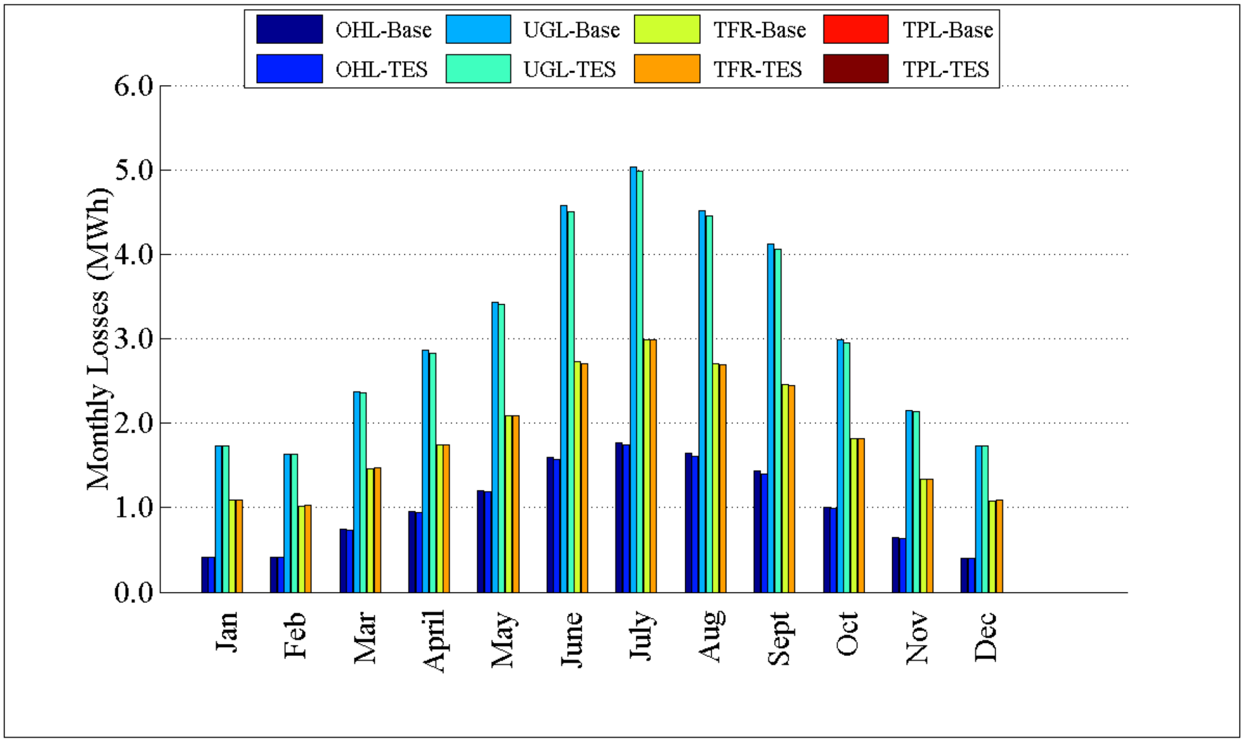

Figure D.99: Distribution system losses by month for GC-12.47-1-r3

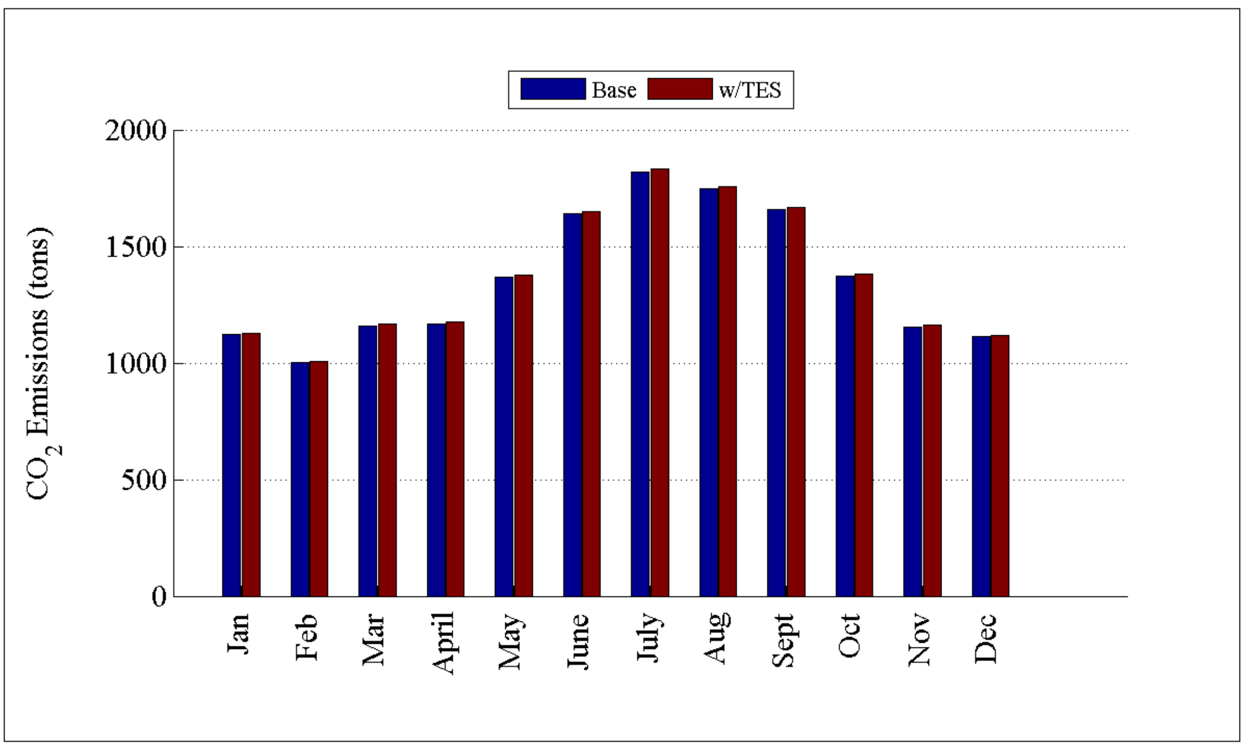

Figure D.100: CO_2 emissions by month for GC-12.47-1-r3

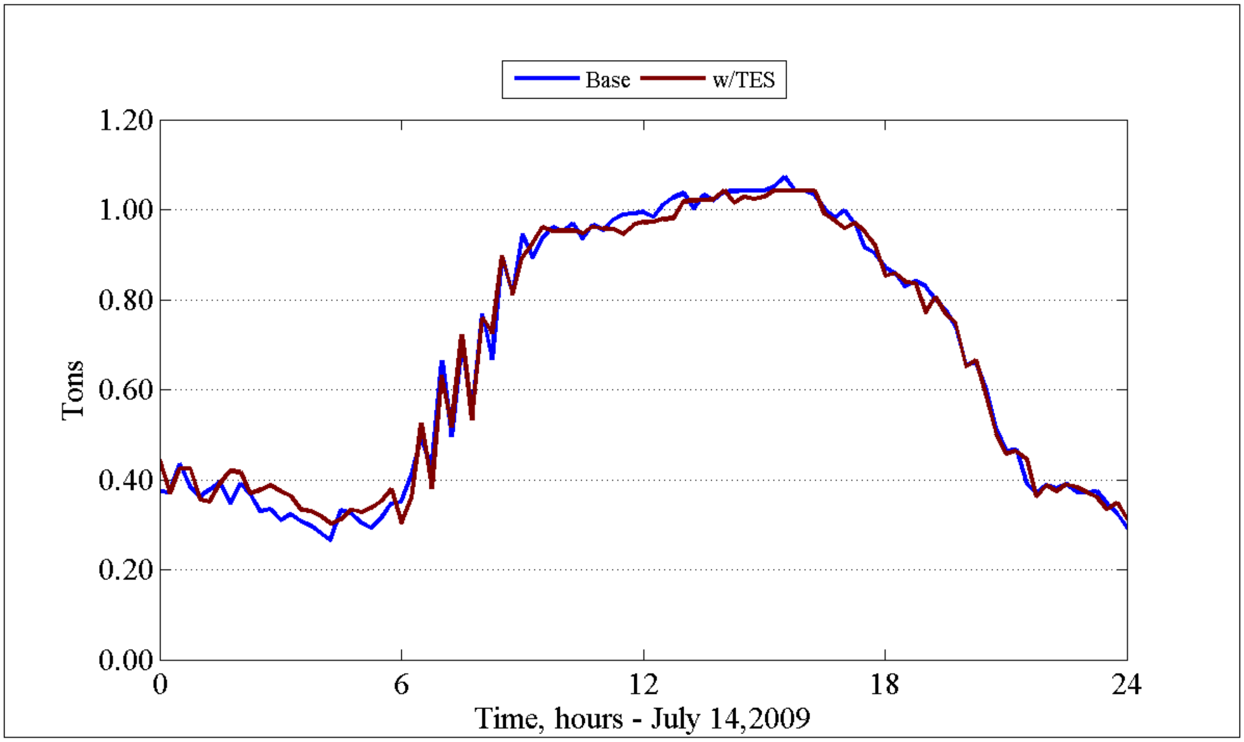

Figure D.101: Carbon dioxide emissions for peak day of GC-12.47-1-r3

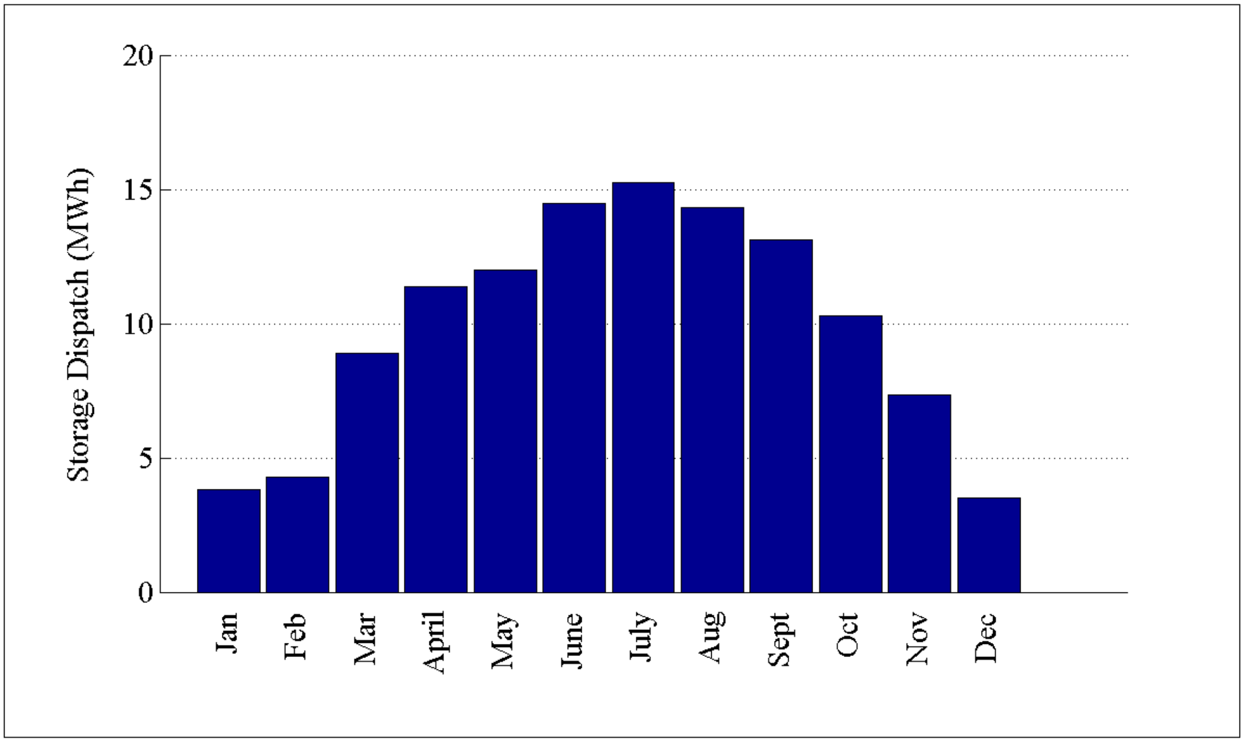

Figure D.102: Monthly storage dispatch energy for GC-12.47-1-r3

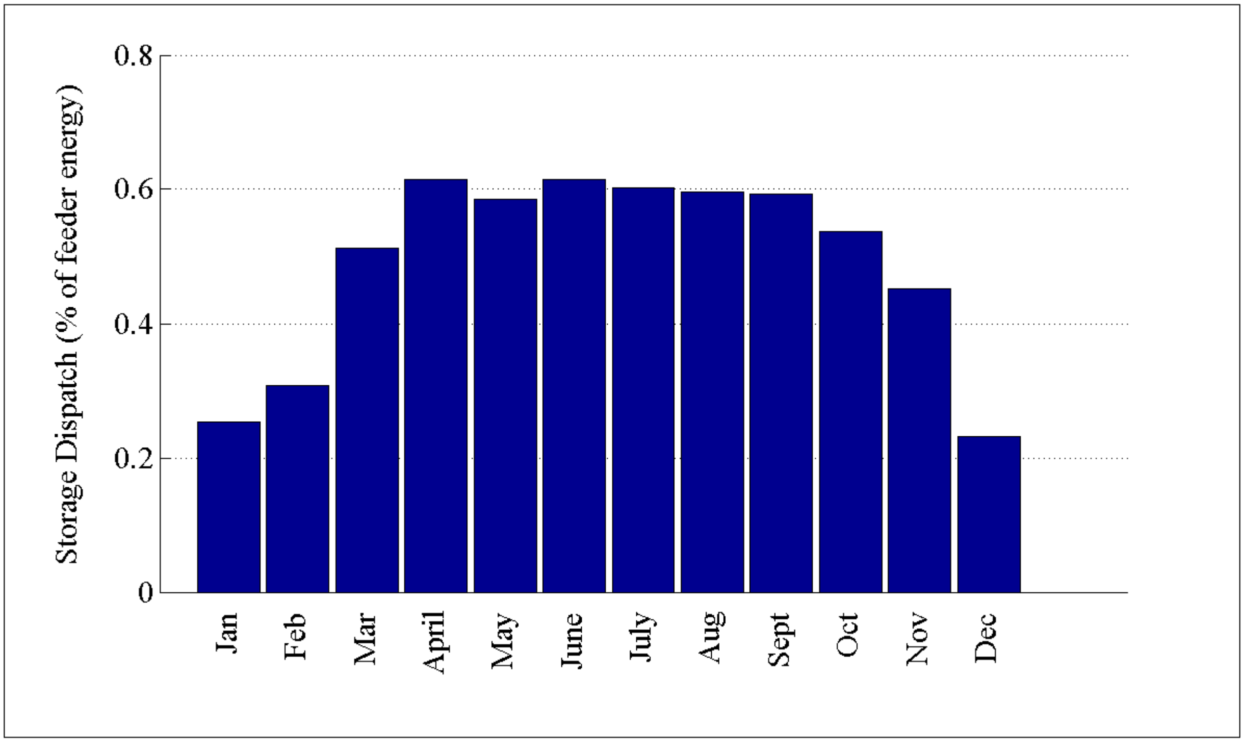

Figure D.103: Monthly storage dispatch energy percentage for GC-12.47-1-r3

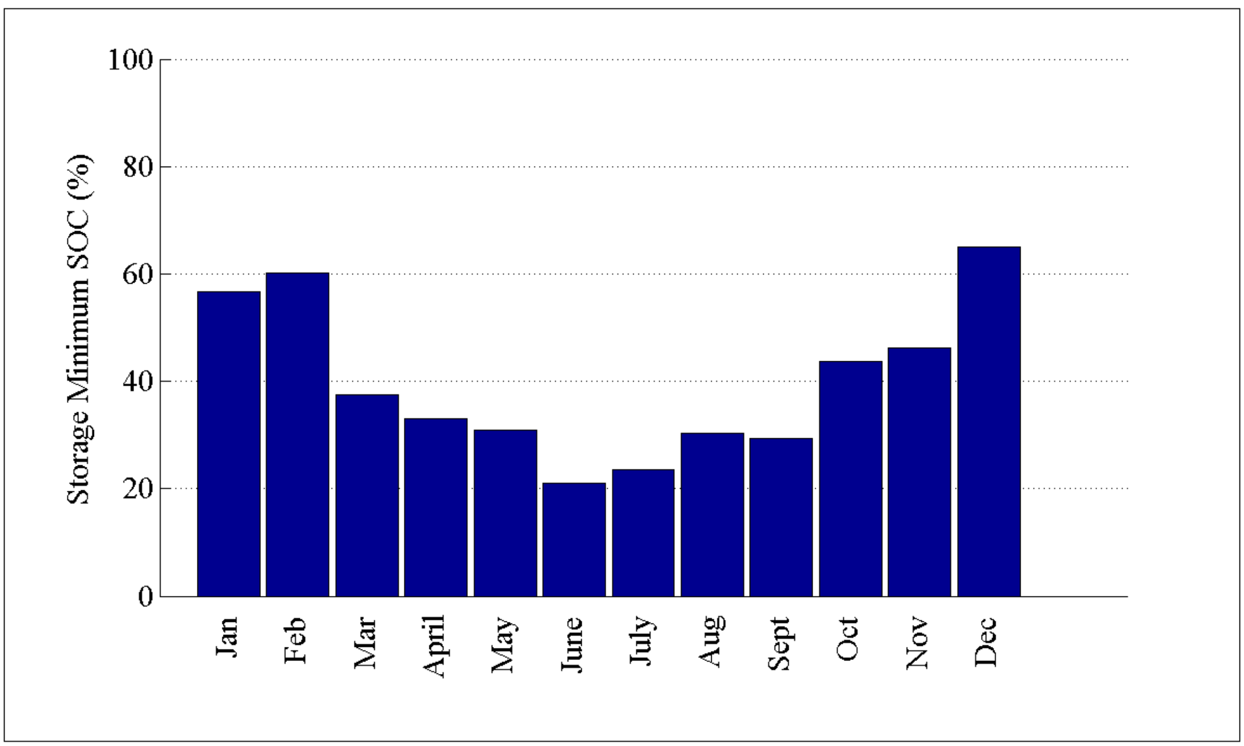

Figure D.104: Minimum state of charge for thermal energy storage on GC-12.47-1-r3

D.14 Detailed Thermal Energy Storage Plots for R3-12.47-1

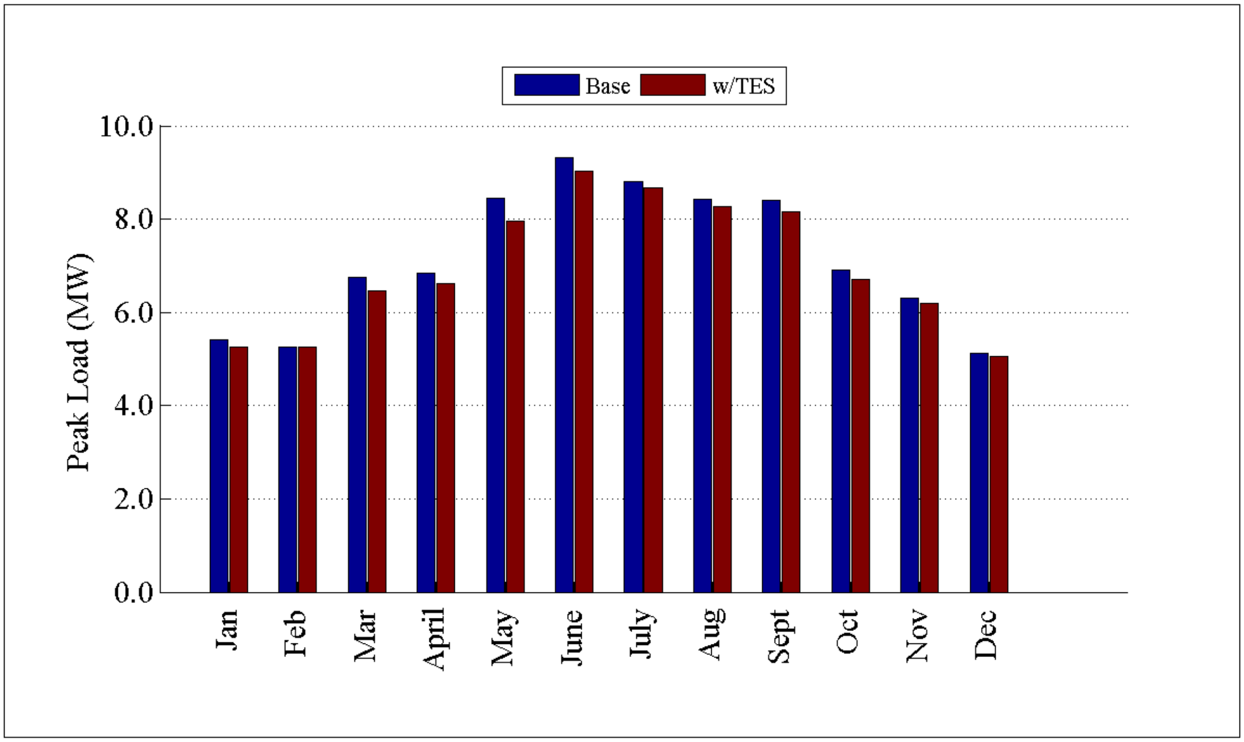

Figure D.105: Peak load by month of R3-12.47-1 feeder

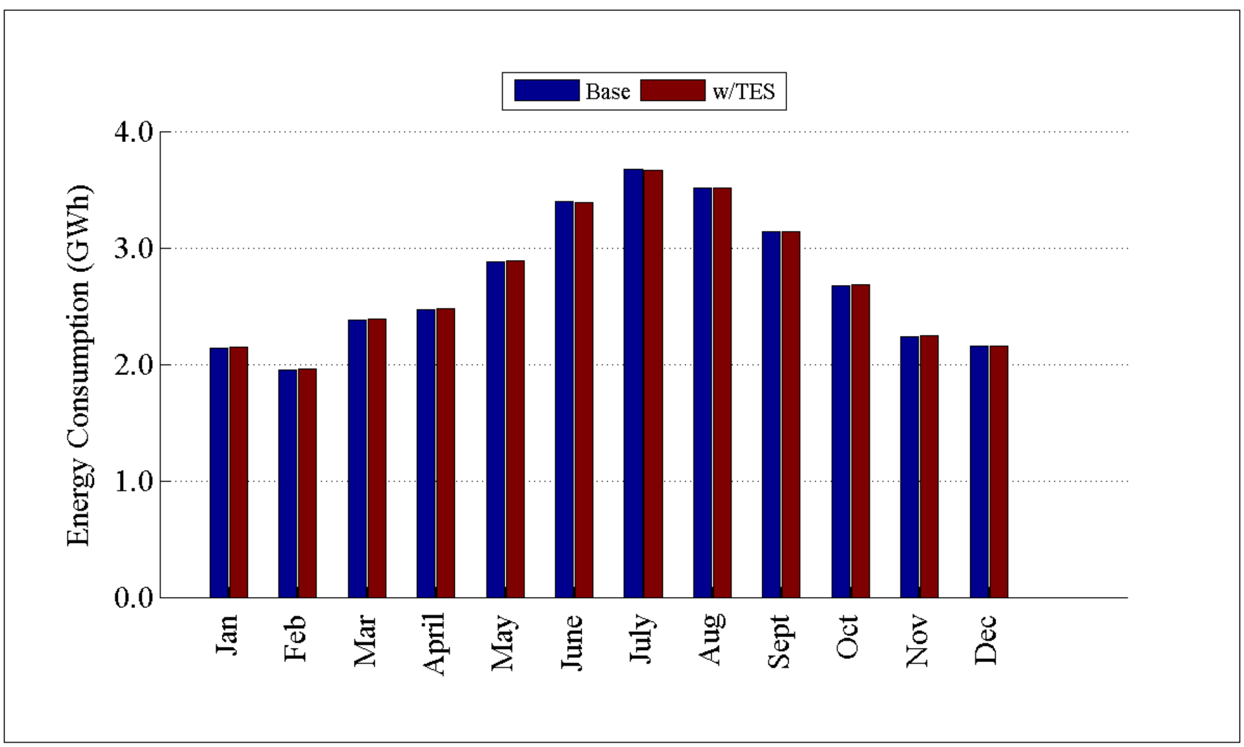

Figure D.106: Monthly energy consumption for R3-12.47-1 feeder

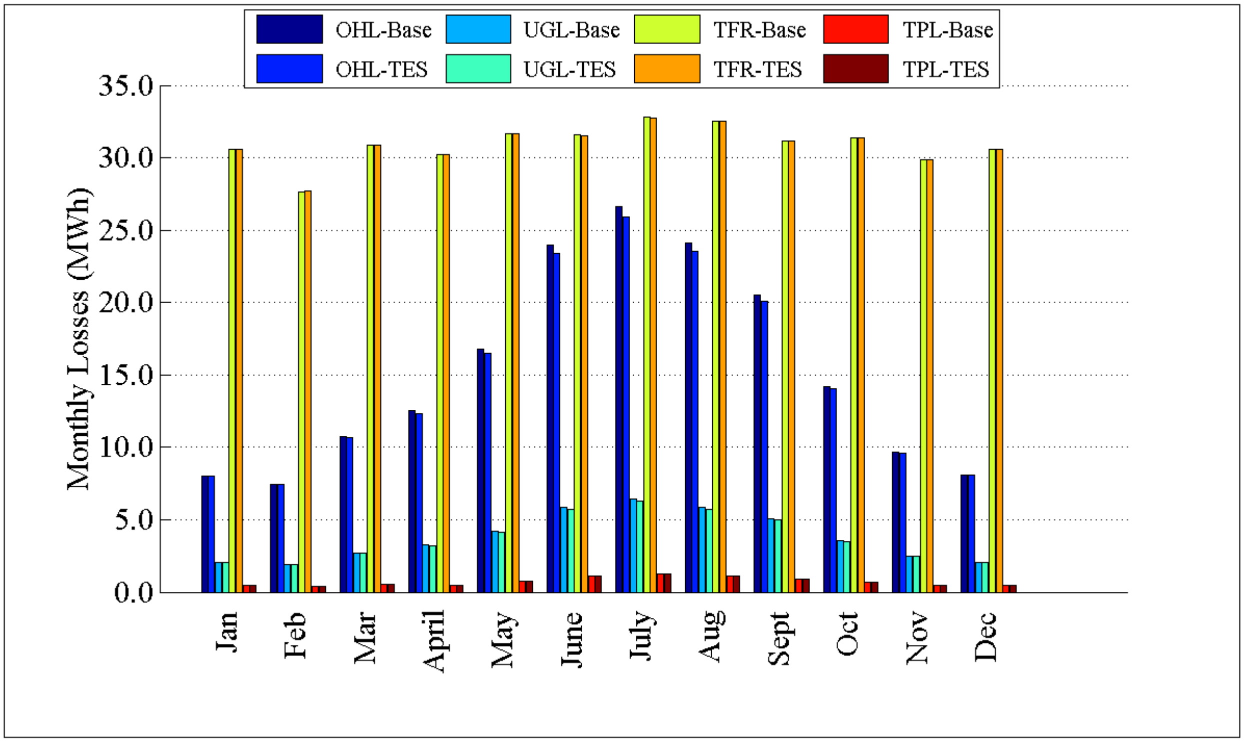

Figure D.107: Distribution system losses by month for R3-12.47-1

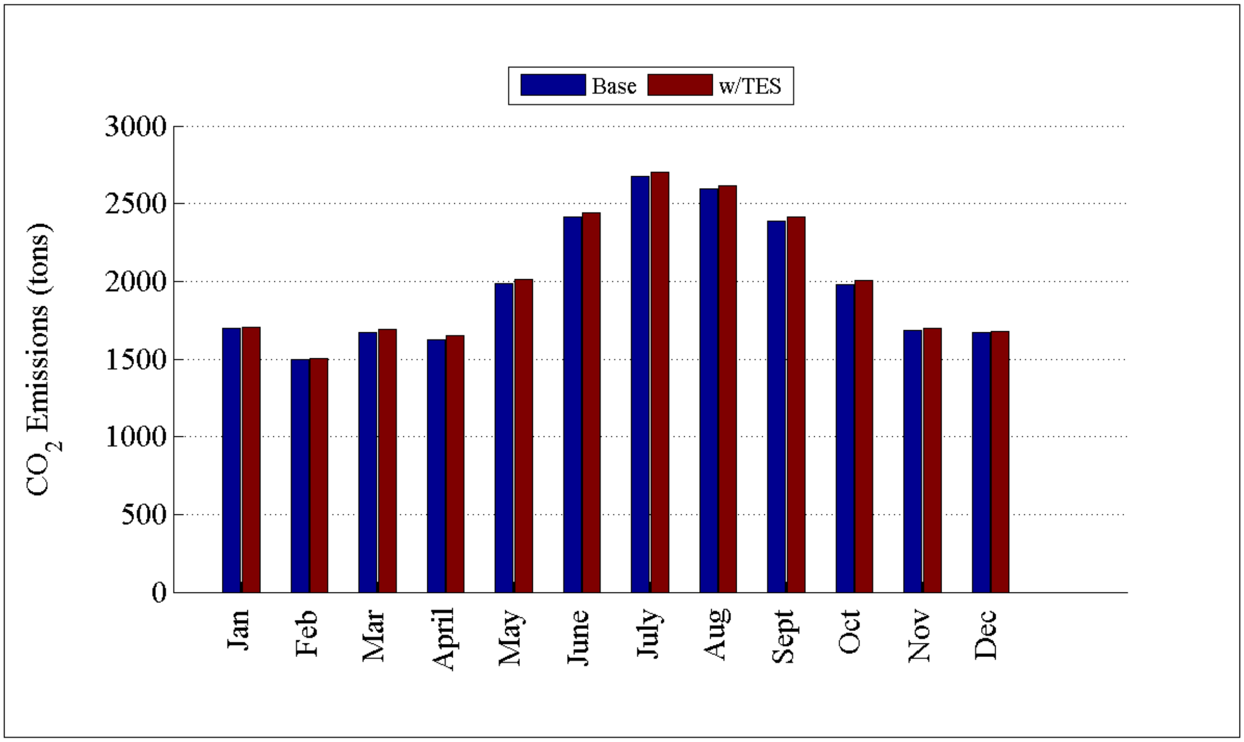

Figure D.108: CO_2 emissions by month for R3-12.47-1

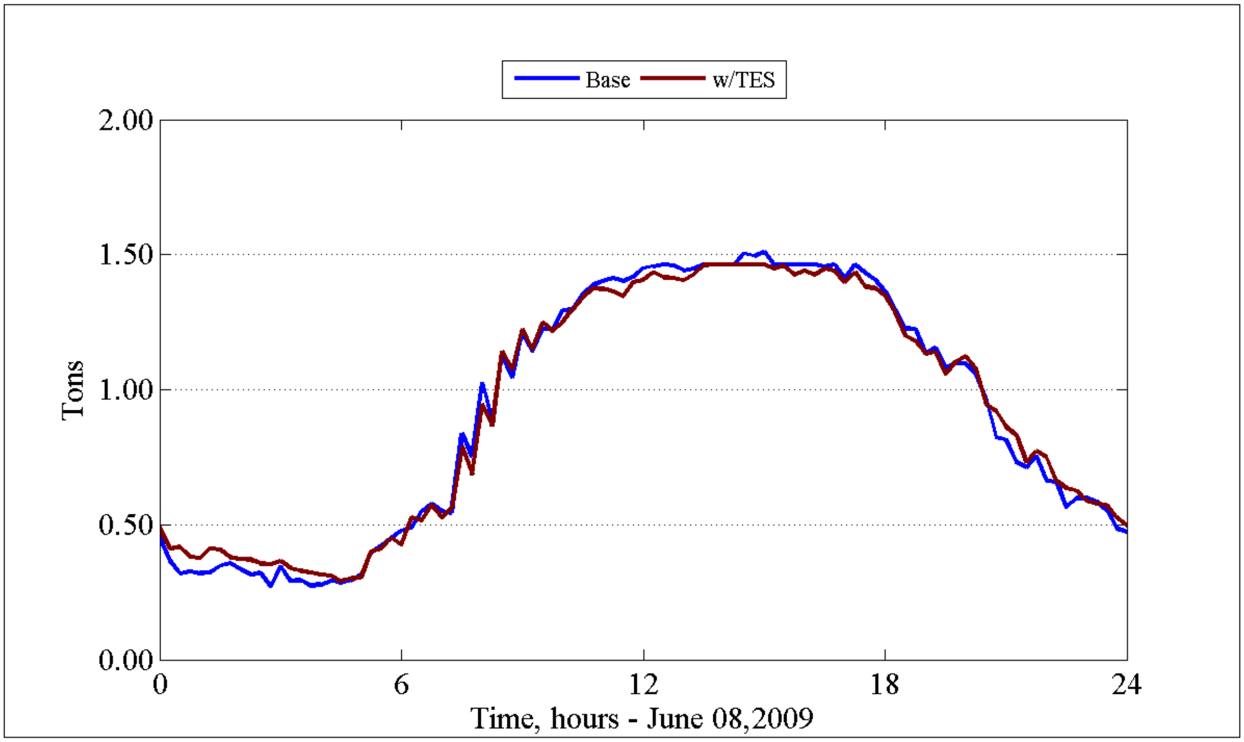

Figure D.109: Carbon dioxide emissions for peak day of R3-12.47-1

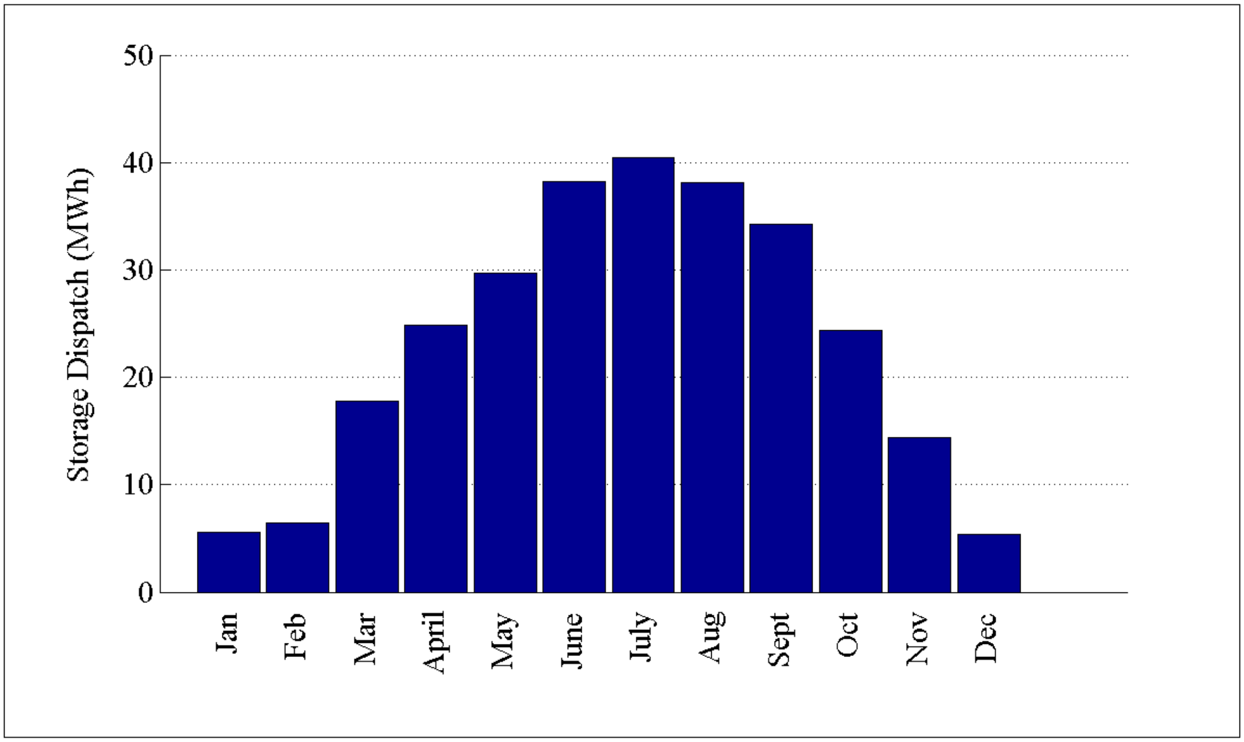

Figure D.110: Monthly storage dispatch energy for R3-12.47-1

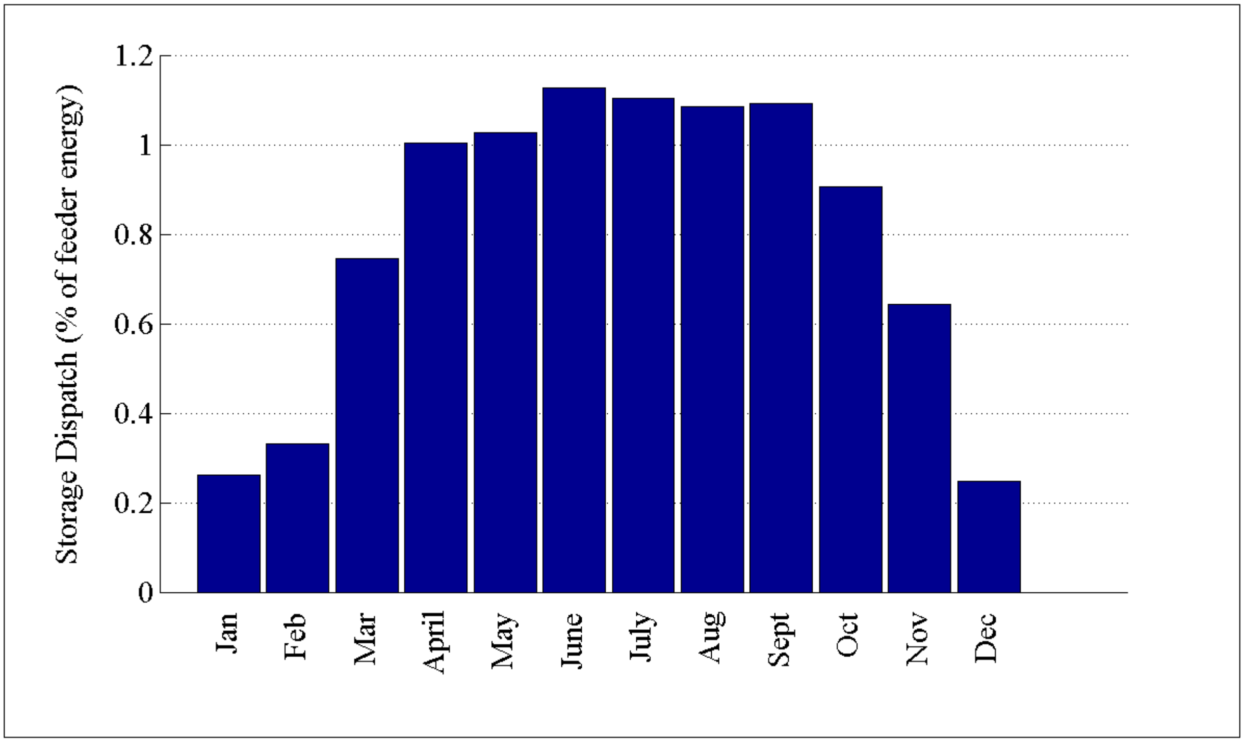

Figure D.111: Monthly storage dispatch energy percentage for R3-12.47-1

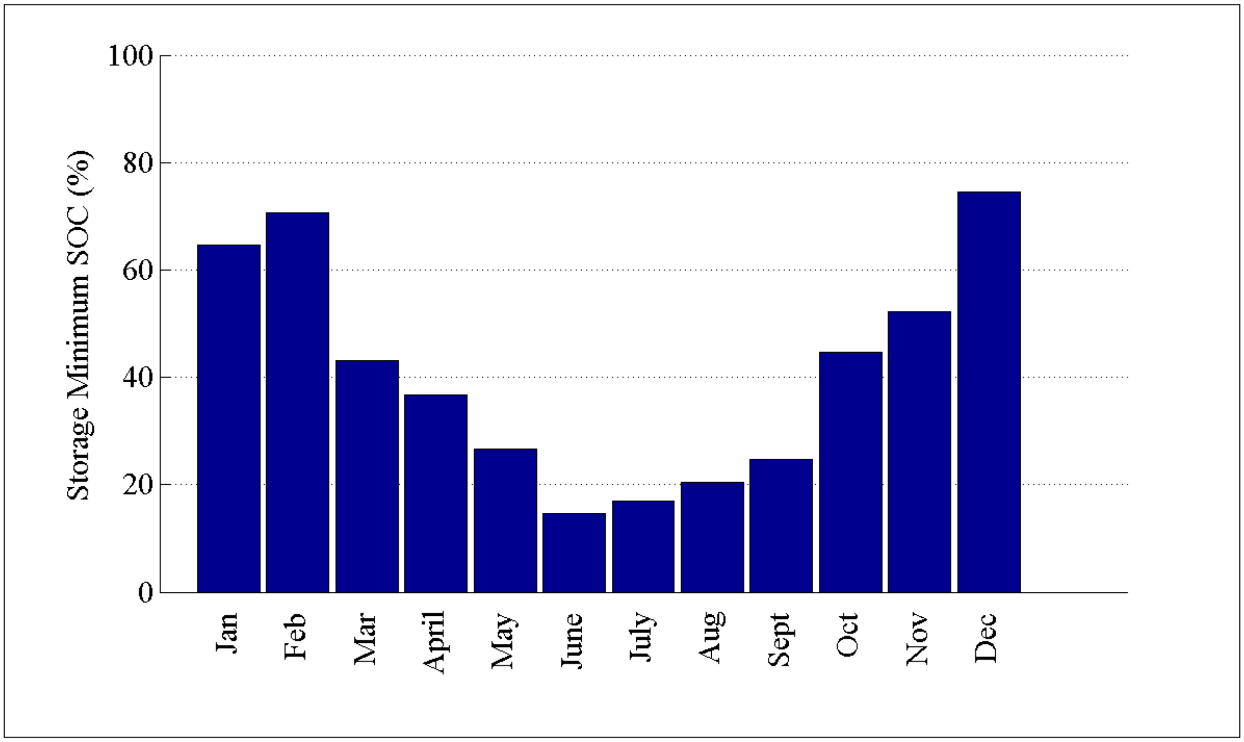

Figure D.112: Minimum state of charge for thermal energy storage on R3-12.47-1

D.15 Detailed Thermal Energy Storage Plots for R3-12.47-2

The plots for R3-12.47-2 were presented as part of the detailed feeder analysis in Section 3.1.

D.16 Detailed Thermal Energy Storage Plots for R3-12.47-3

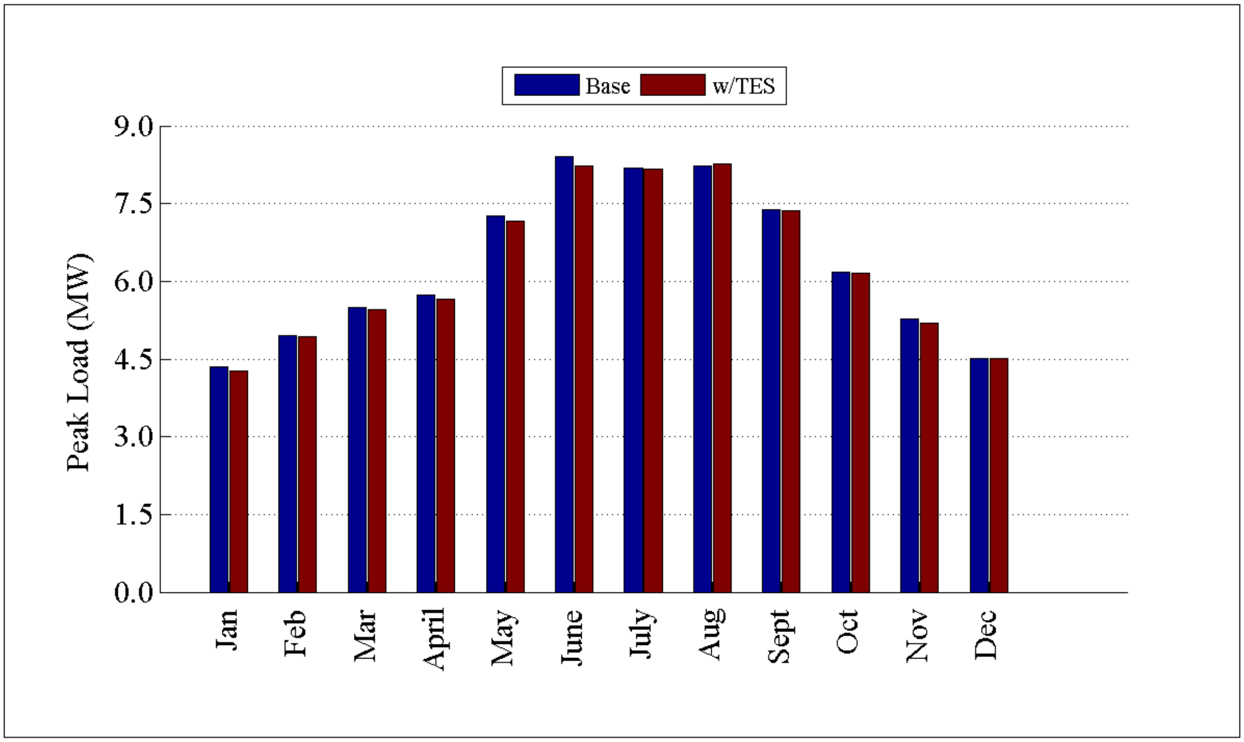

Figure D.113: Peak load by month of R3-12.47-3 feeder

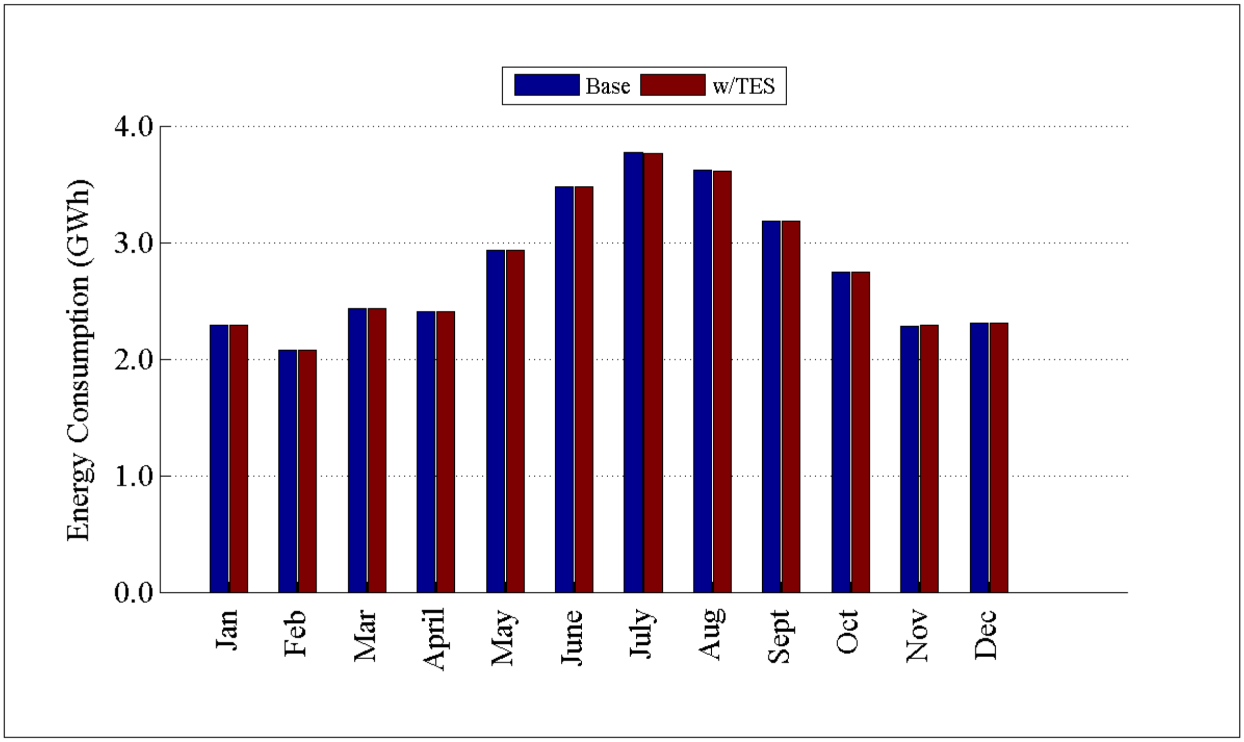

Figure D.114: Monthly energy consumption for R3-12.47-3 feeder

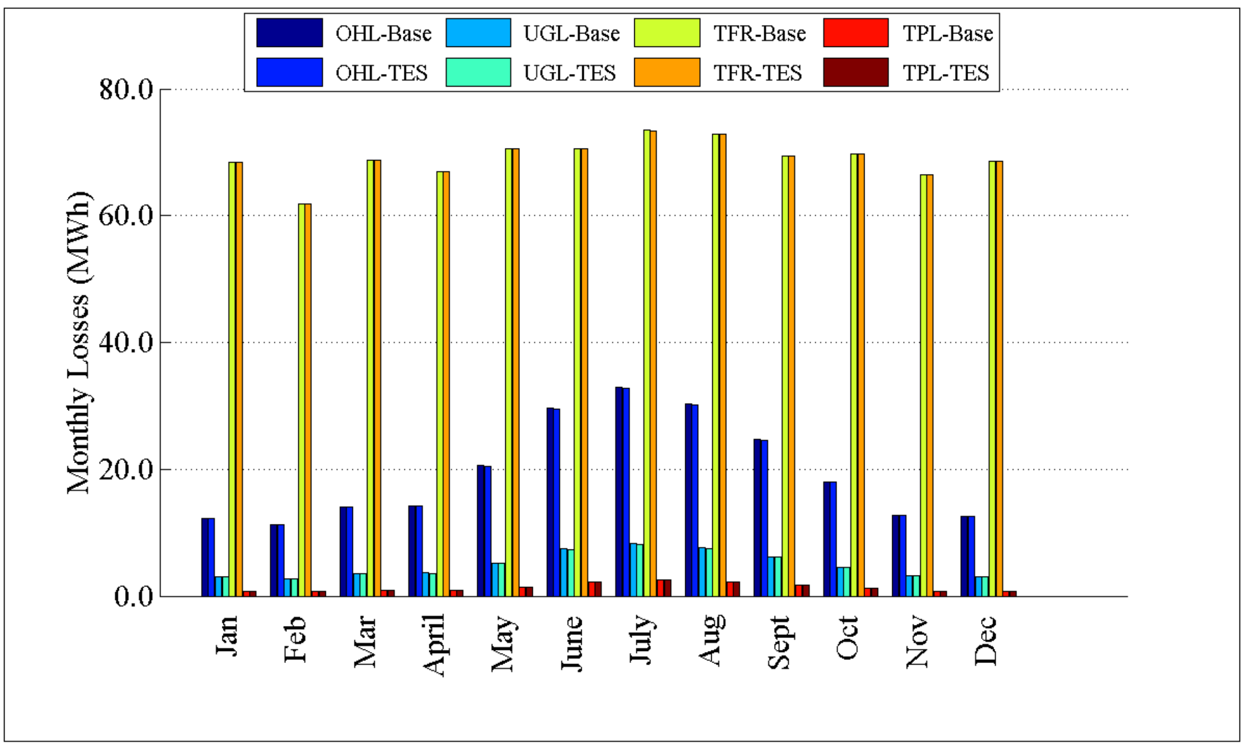

Figure D.115: Distribution system losses by month for R3-12.47-3

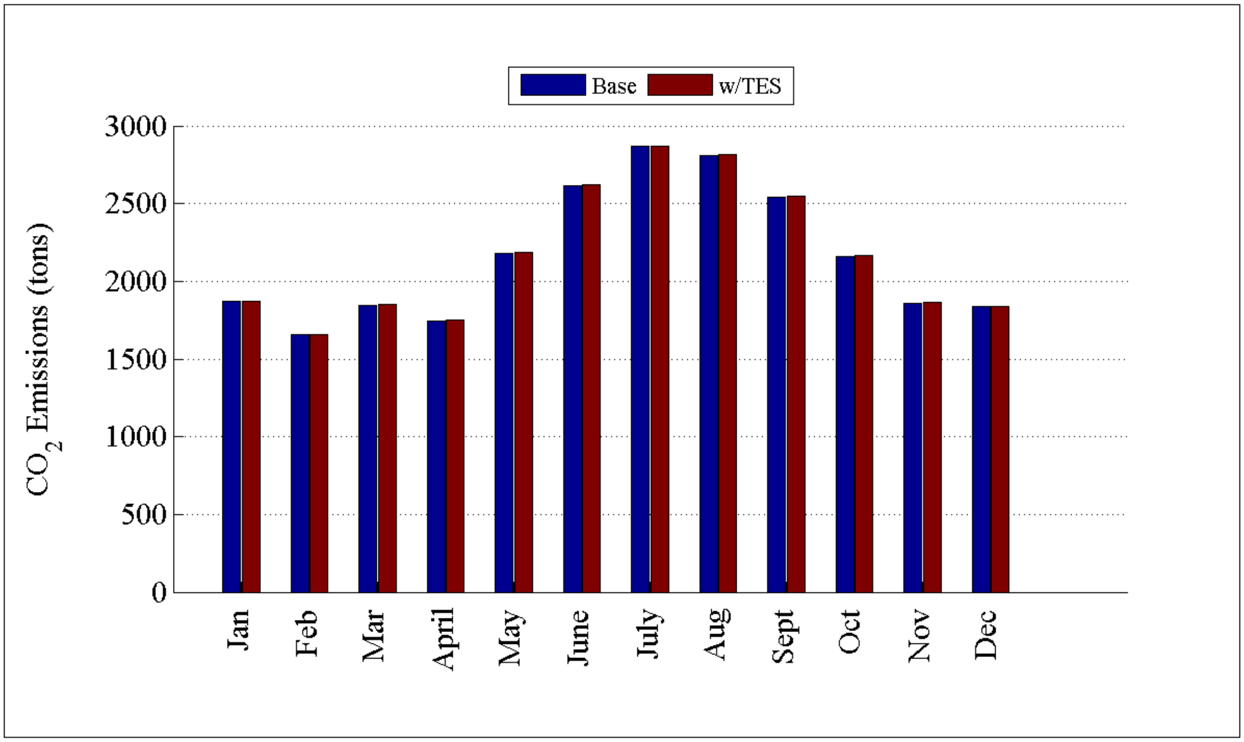

Figure D.116: CO_2 emissions by month for R3-12.47-3

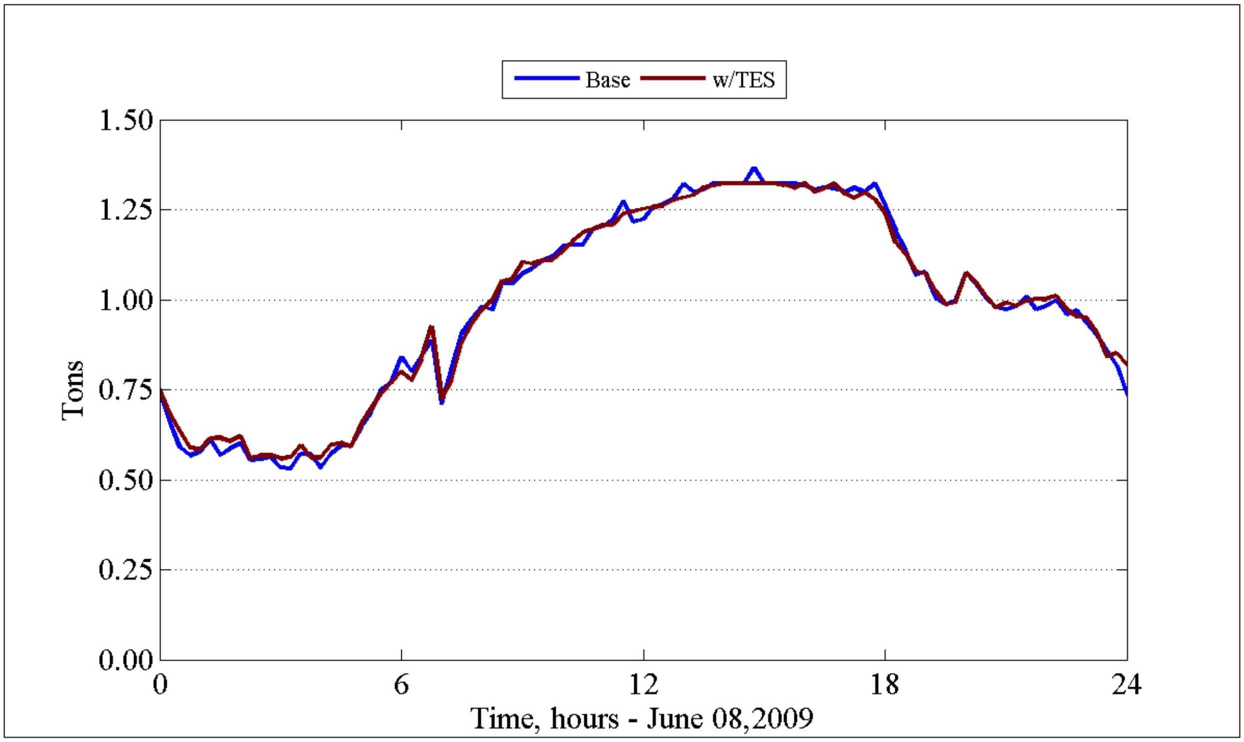

Figure D.117: Carbon dioxide emissions for peak day of R3-12.47-3

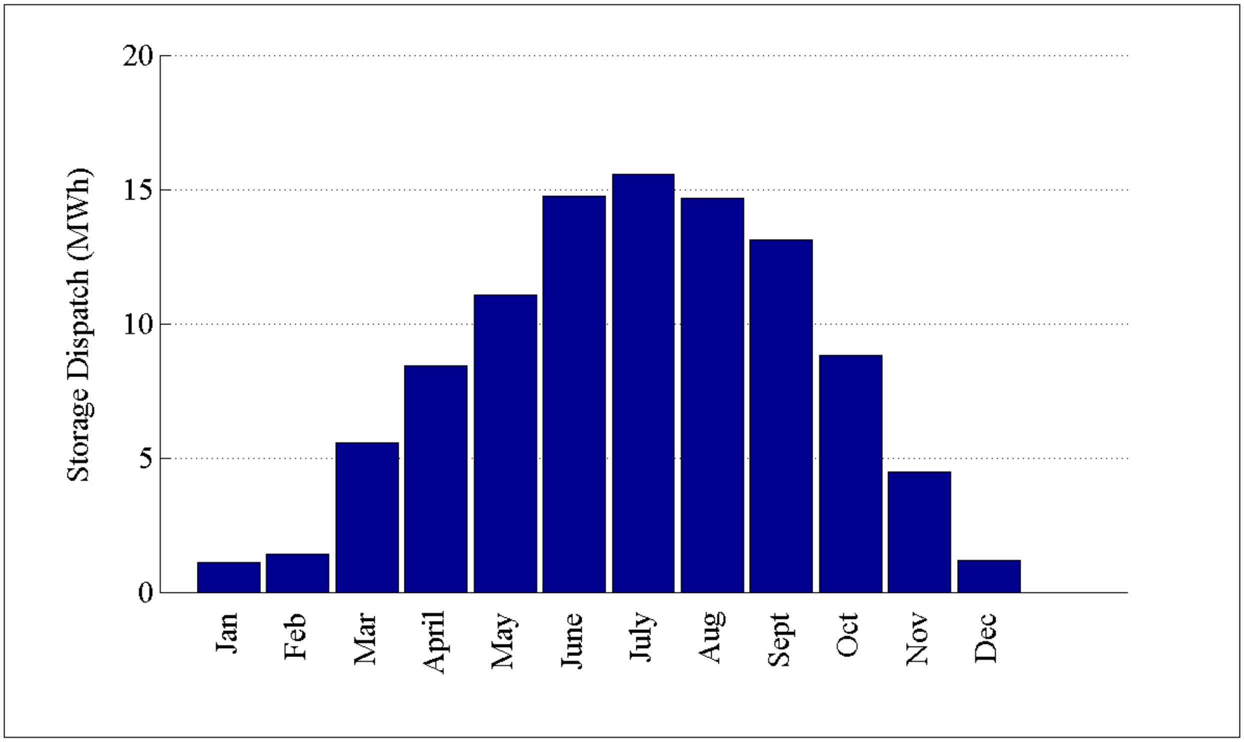

Figure D.118: Monthly storage dispatch energy for R3-12.47-3

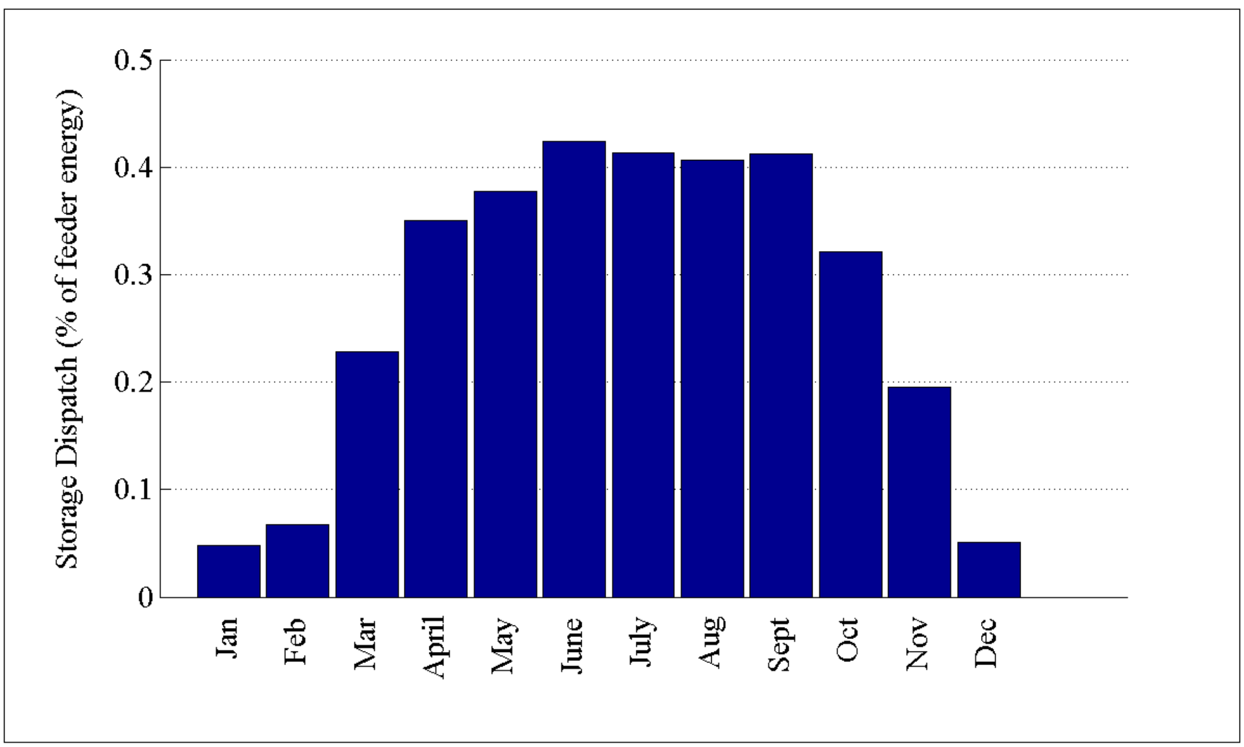

Figure D.119: Monthly storage dispatch energy percentage for R3-12.47-3

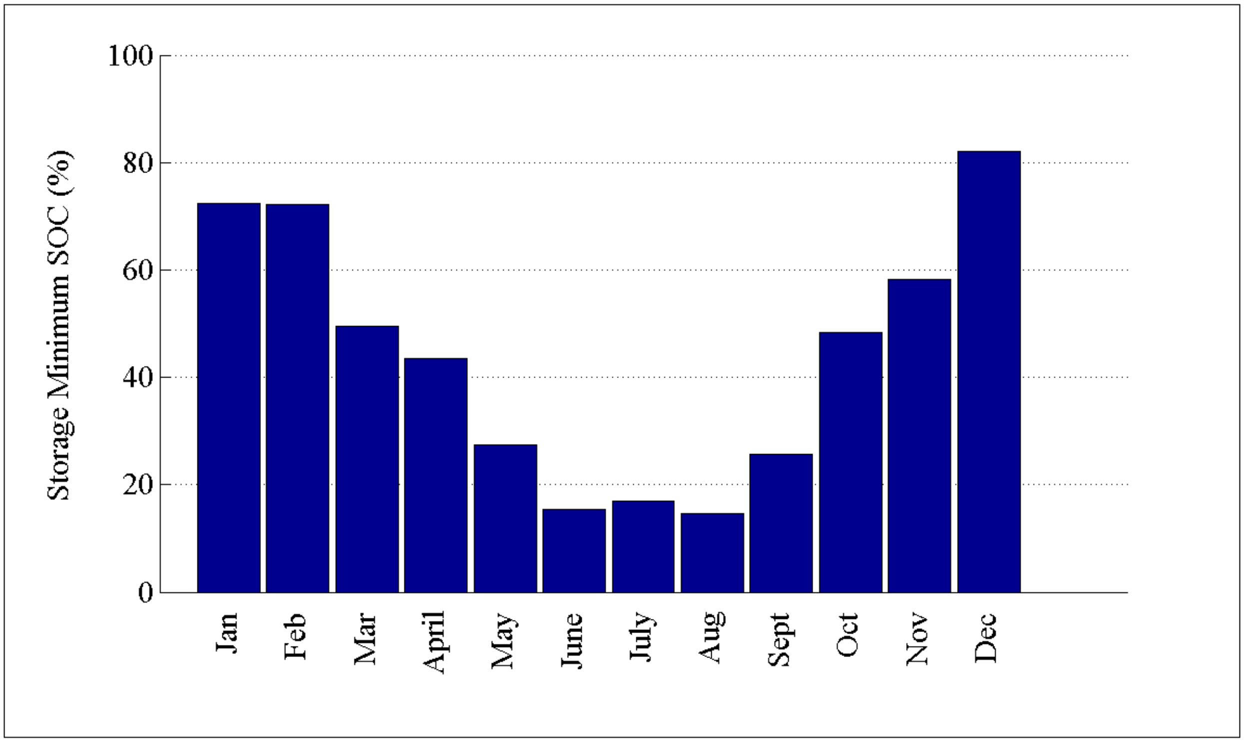

Figure D.120: Minimum state of charge for thermal energy storage on R3-12.47-3

D.17 Detailed Thermal Energy Storage Plots for GC-12.47-1_R4

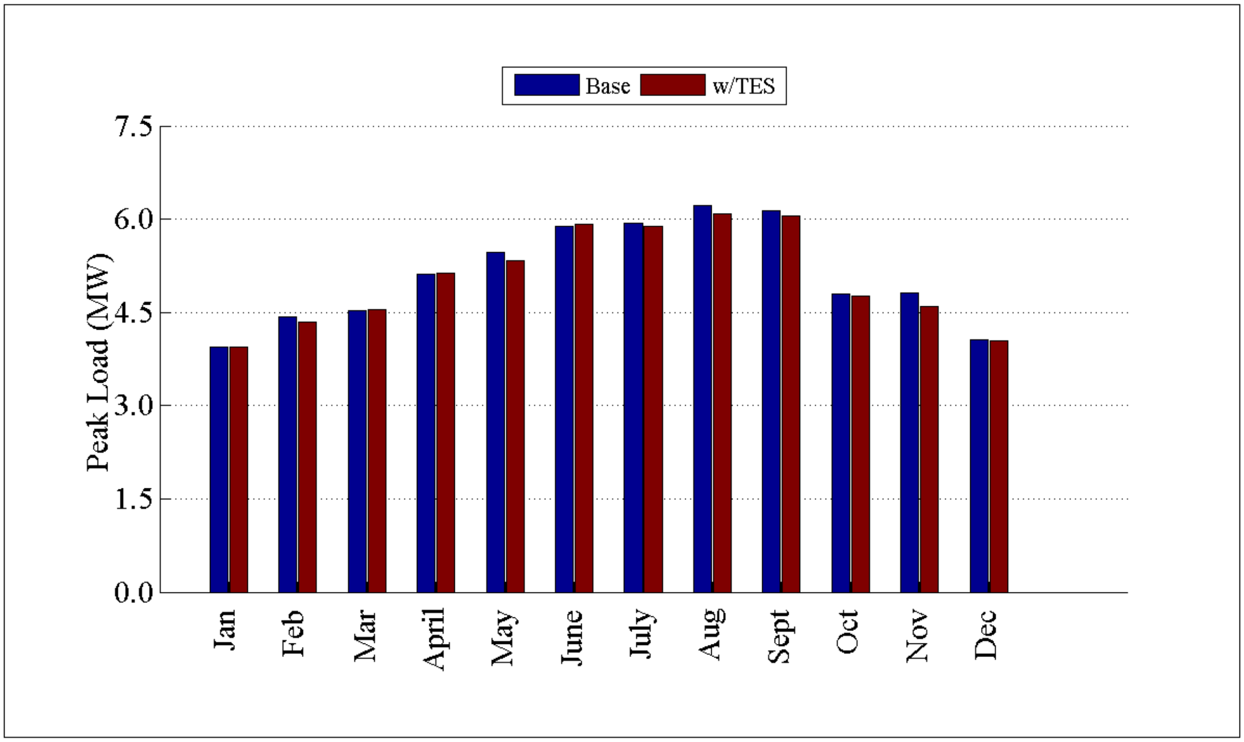

Figure D.121: Peak load by month of GC-12.47-1-r4 feeder

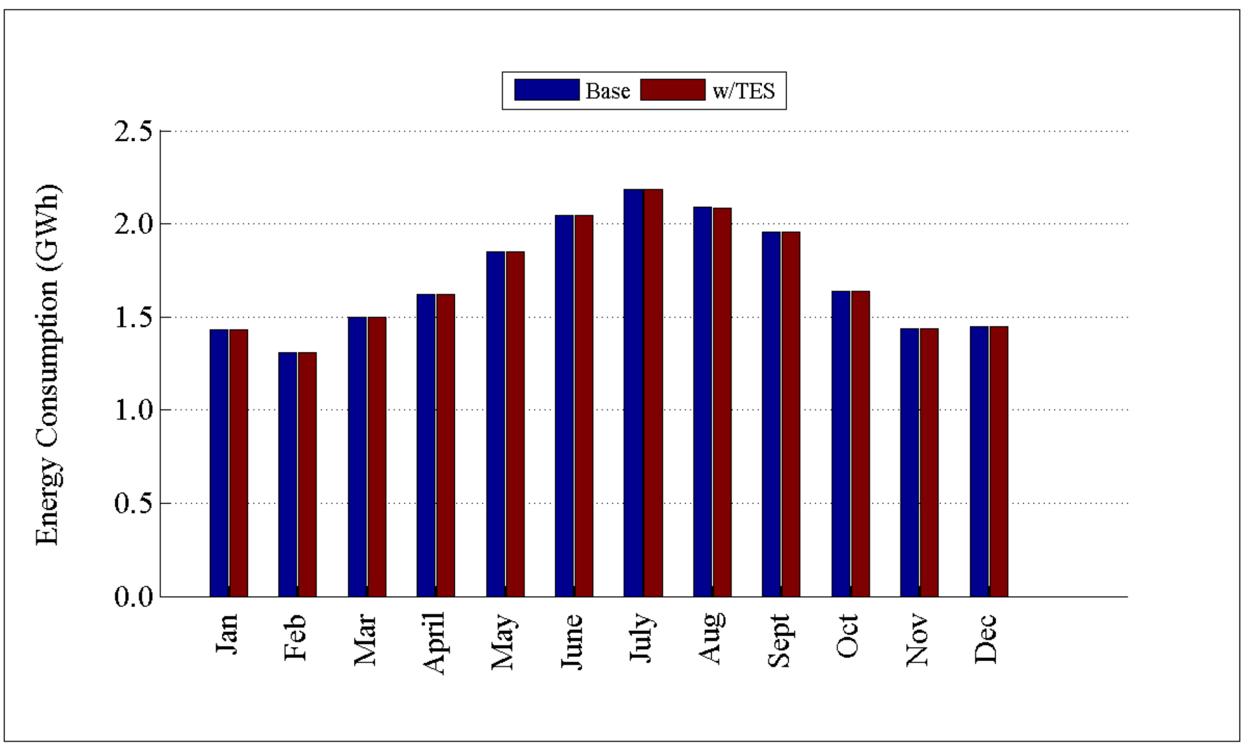

Figure D.122: Monthly energy consumption for GC-12.47-1-r4 feeder

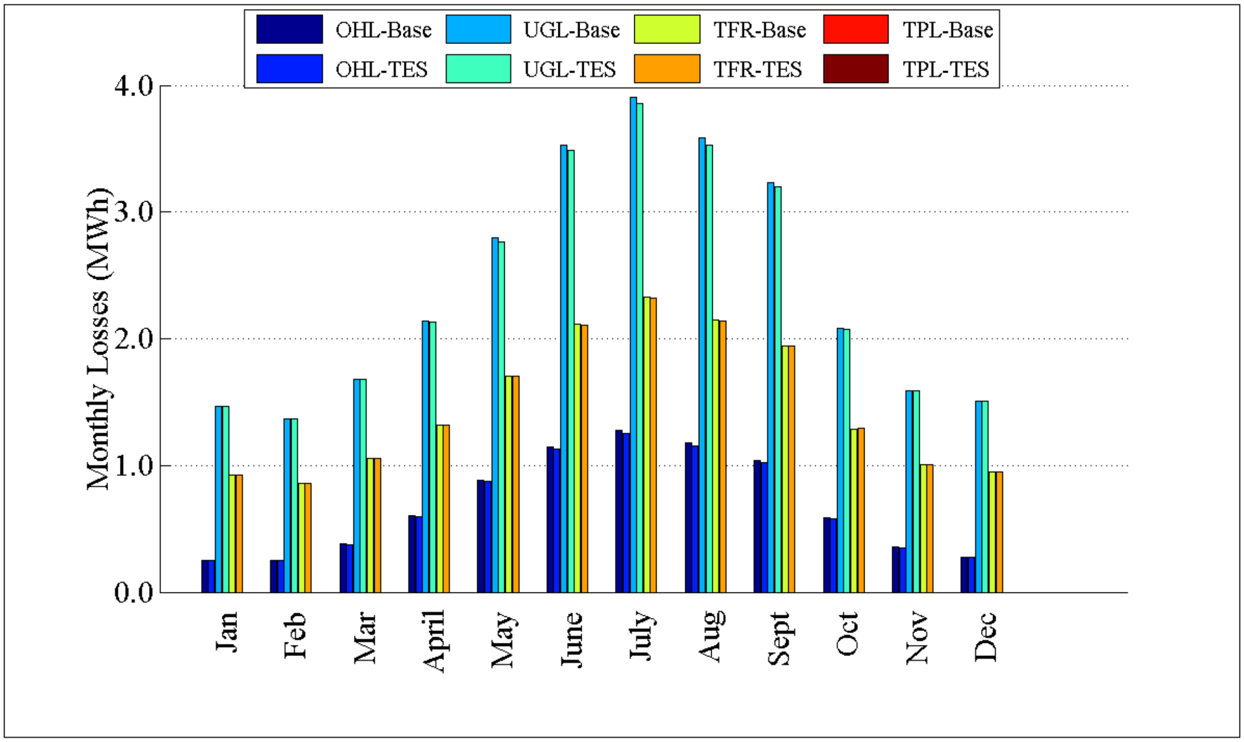

Figure D.123: Distribution system losses by month for GC-12.47-1-r4

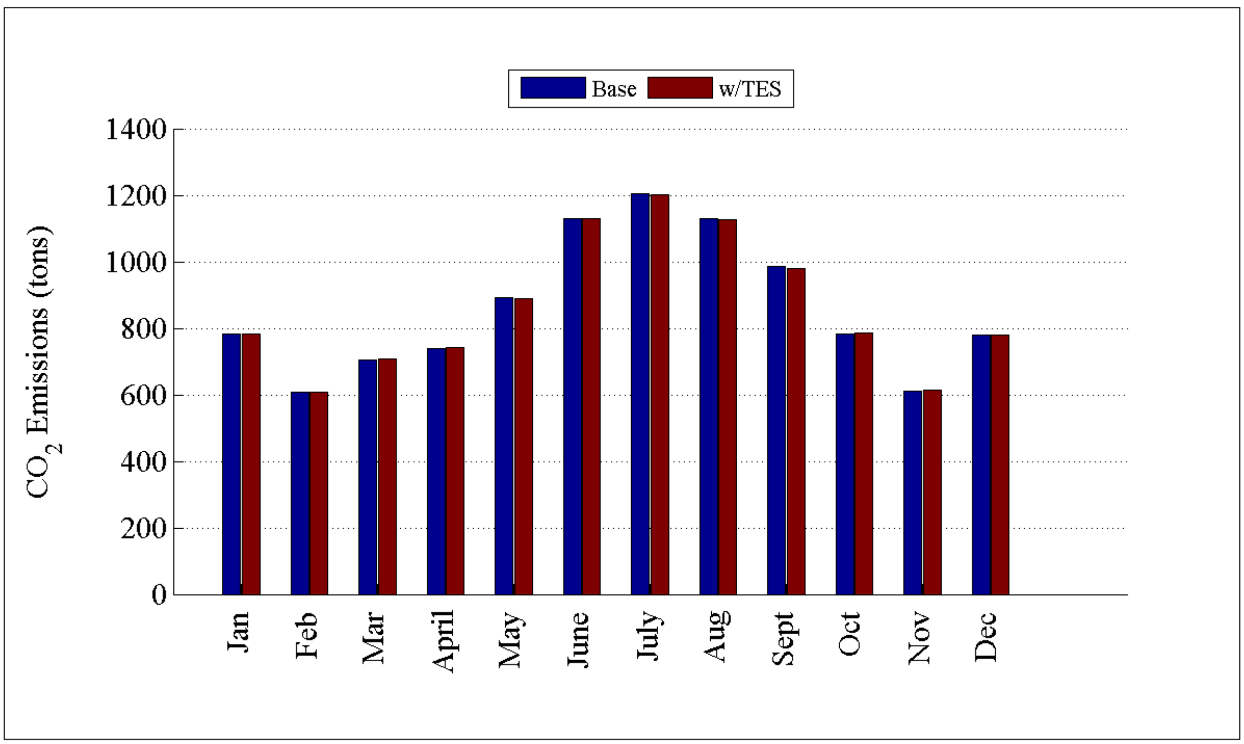

Figure D.124: CO_2 emissions by month for GC-12.47-1-r4

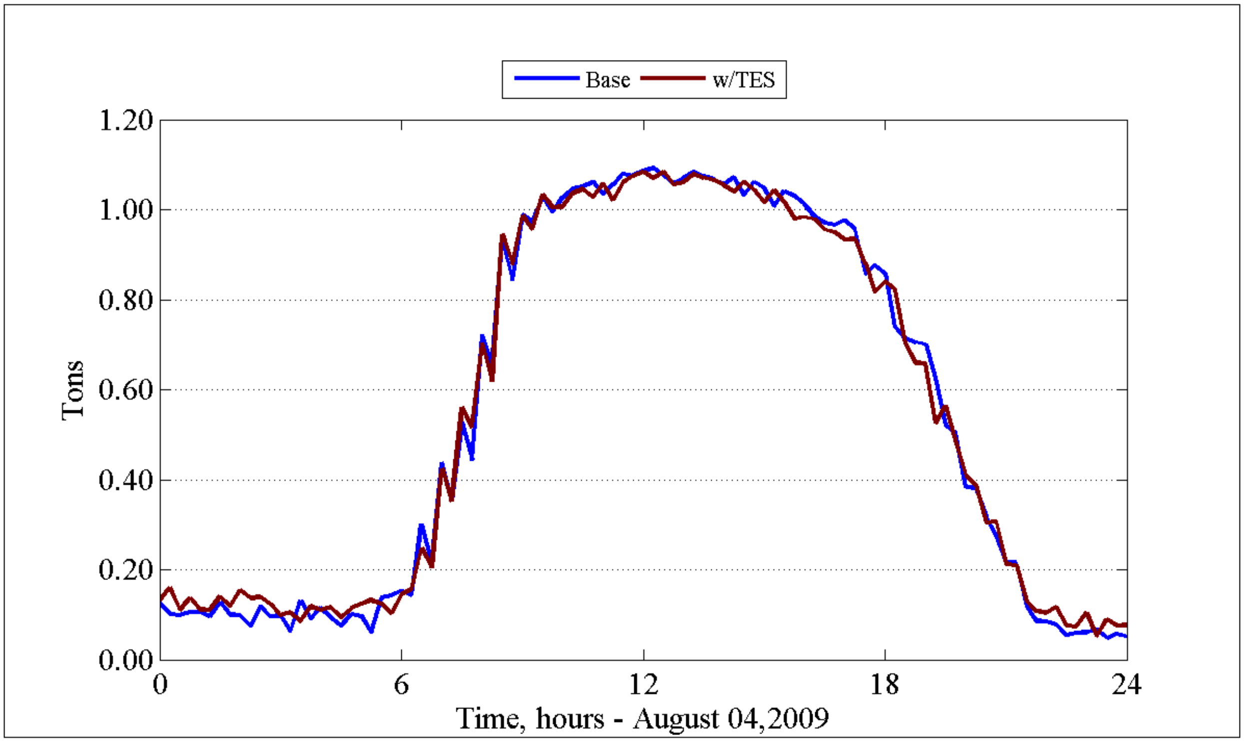

Figure D.125: Carbon dioxide emissions for peak day of GC-12.47-1-r4

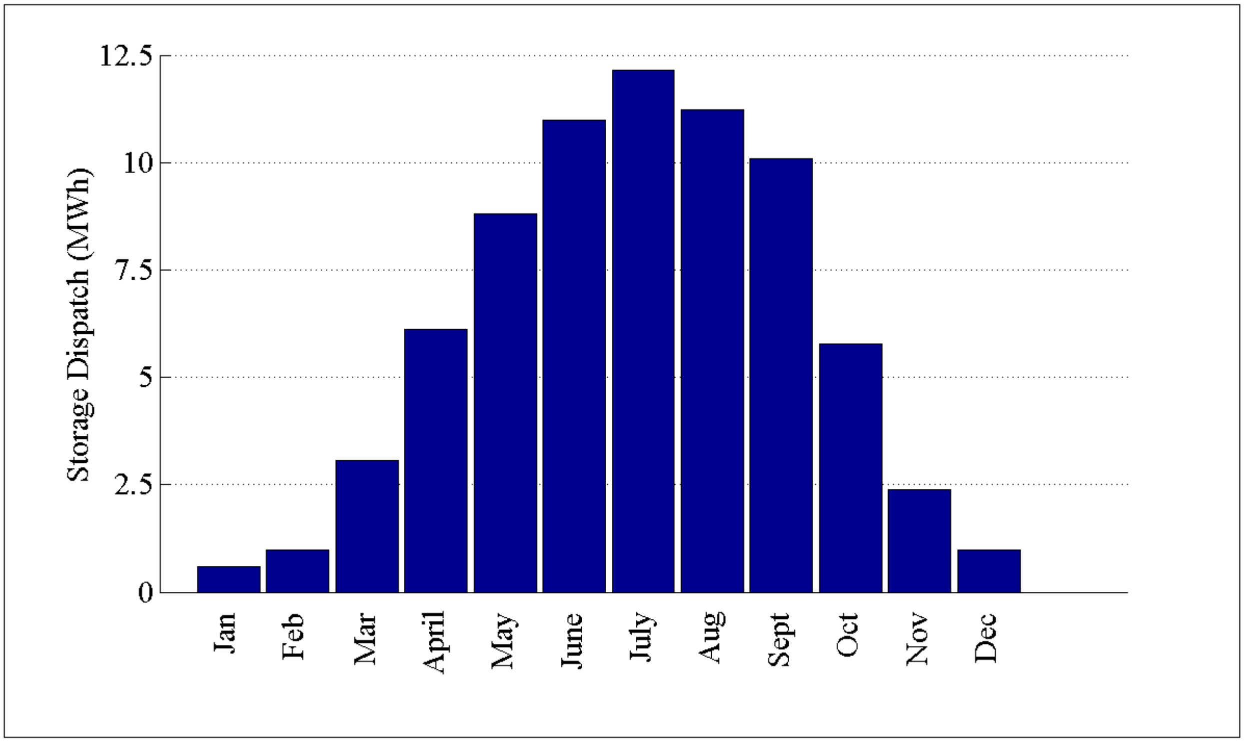

Figure D.126: Monthly storage dispatch energy for GC-12.47-1-r4

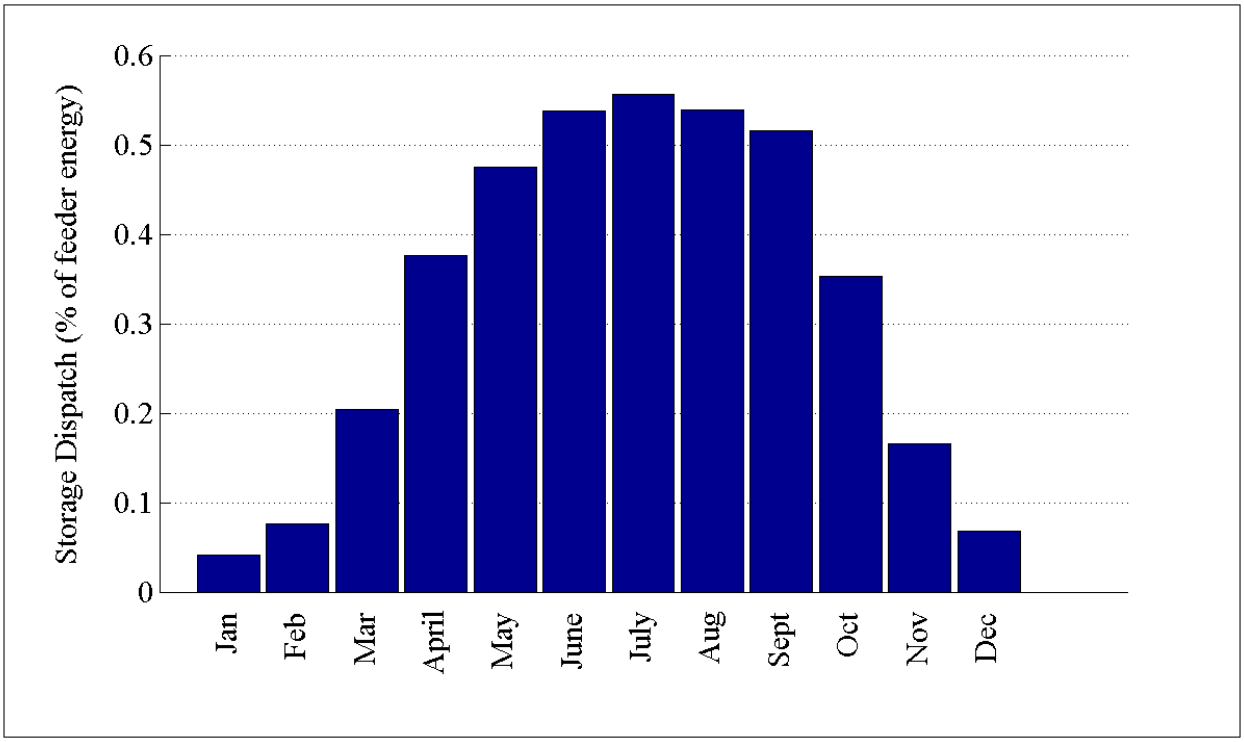

Figure D.127: Monthly storage dispatch energy percentage for GC-12.47-1-r4

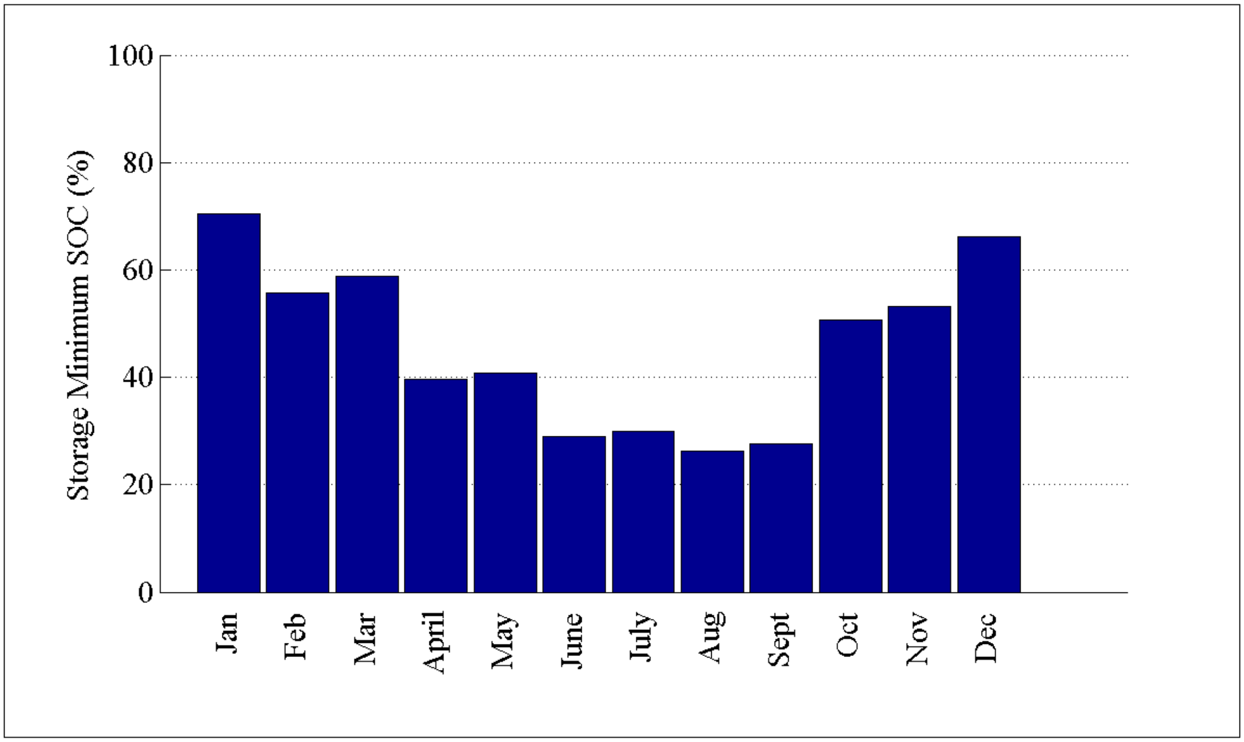

Figure D.128: Minimum state of charge for thermal energy storage on GC-12.47-1-r4

D.18 Detailed Thermal Energy Storage Plots for R4-12.47-1

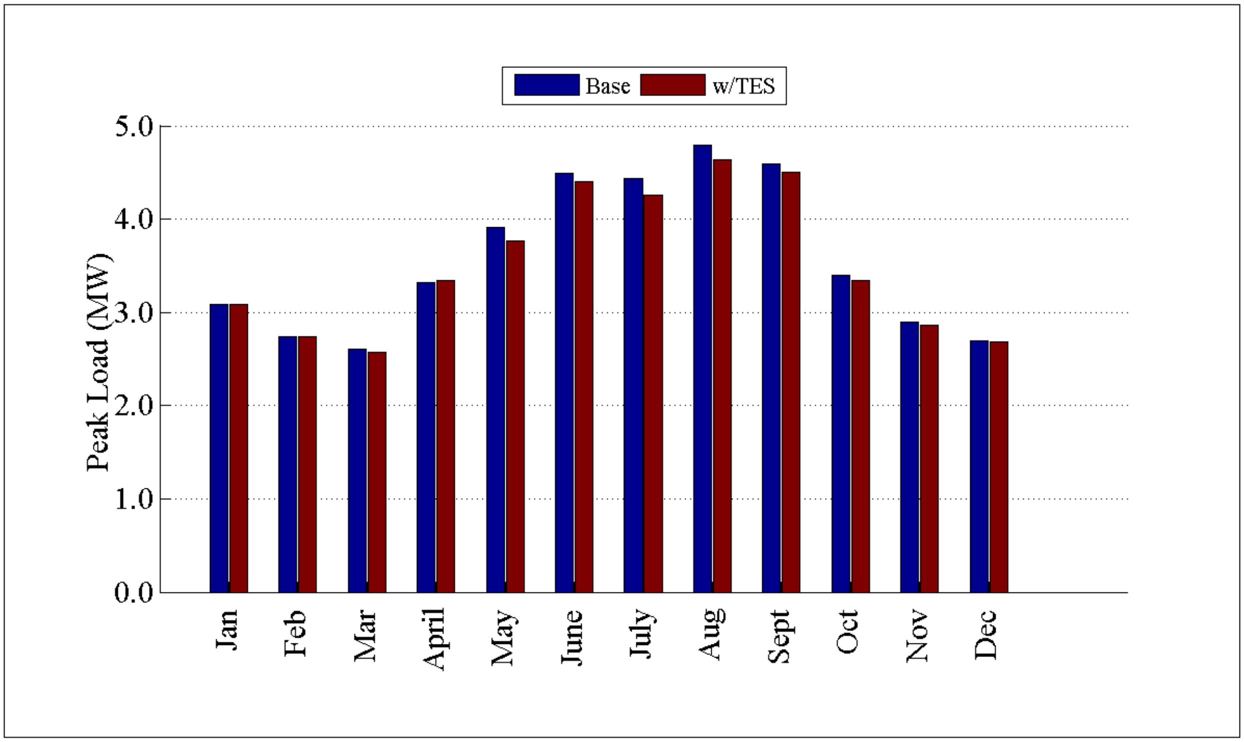

Figure D.129: Peak load by month of R4-12.47-1 feeder

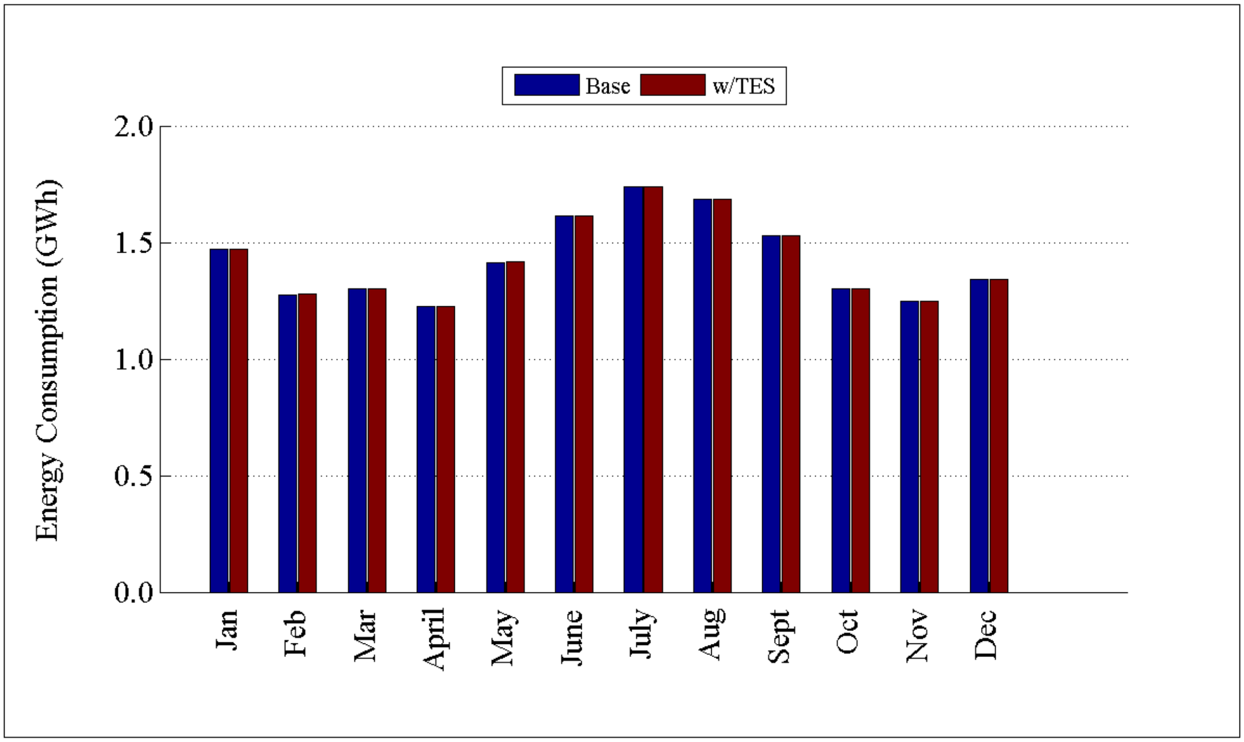

Figure D.130: Monthly energy consumption for R4-12.47-1 feeder

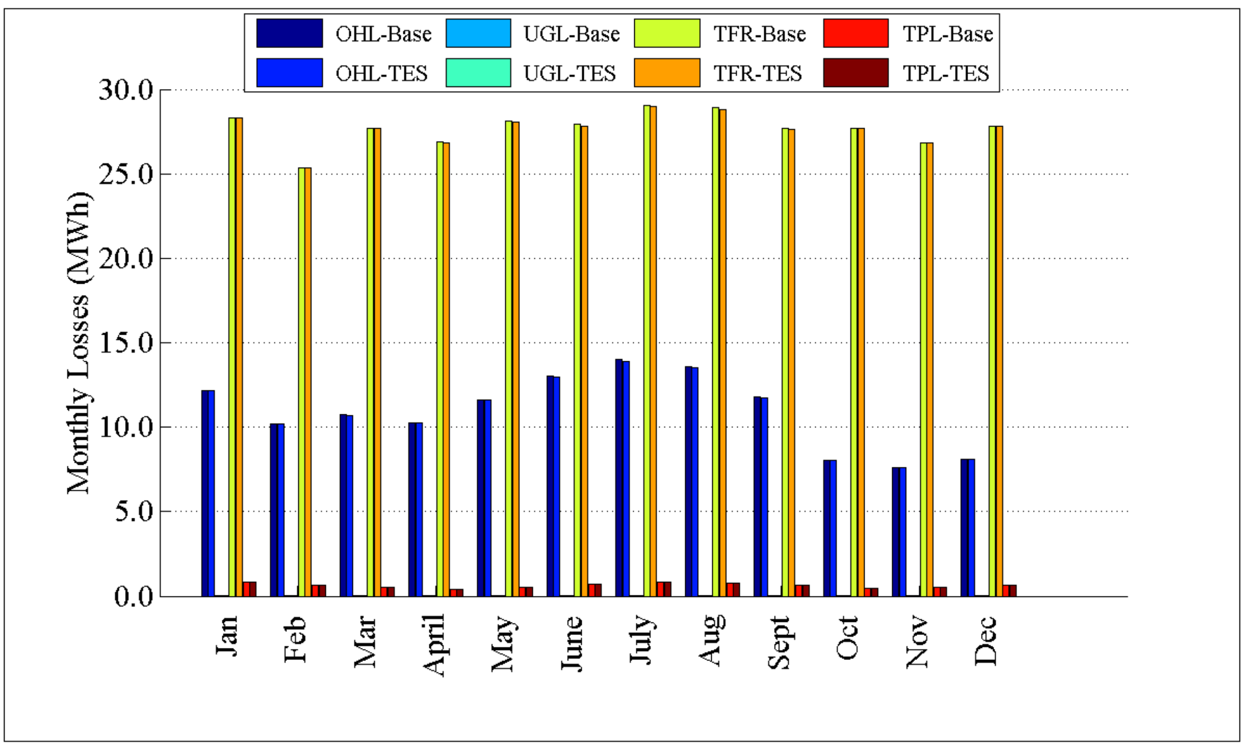

Figure D.131: Distribution system losses by month for R4-12.47-1

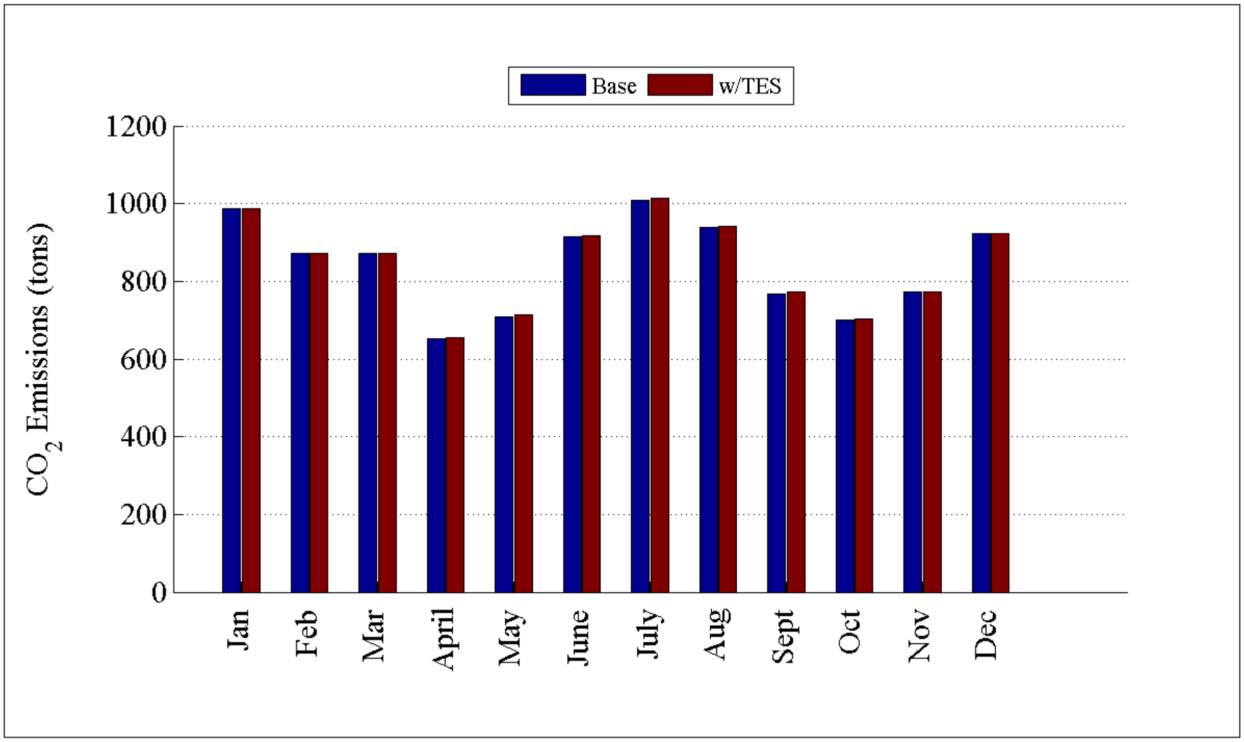

Figure D.132: CO_2 emissions by month for R4-12.47-1

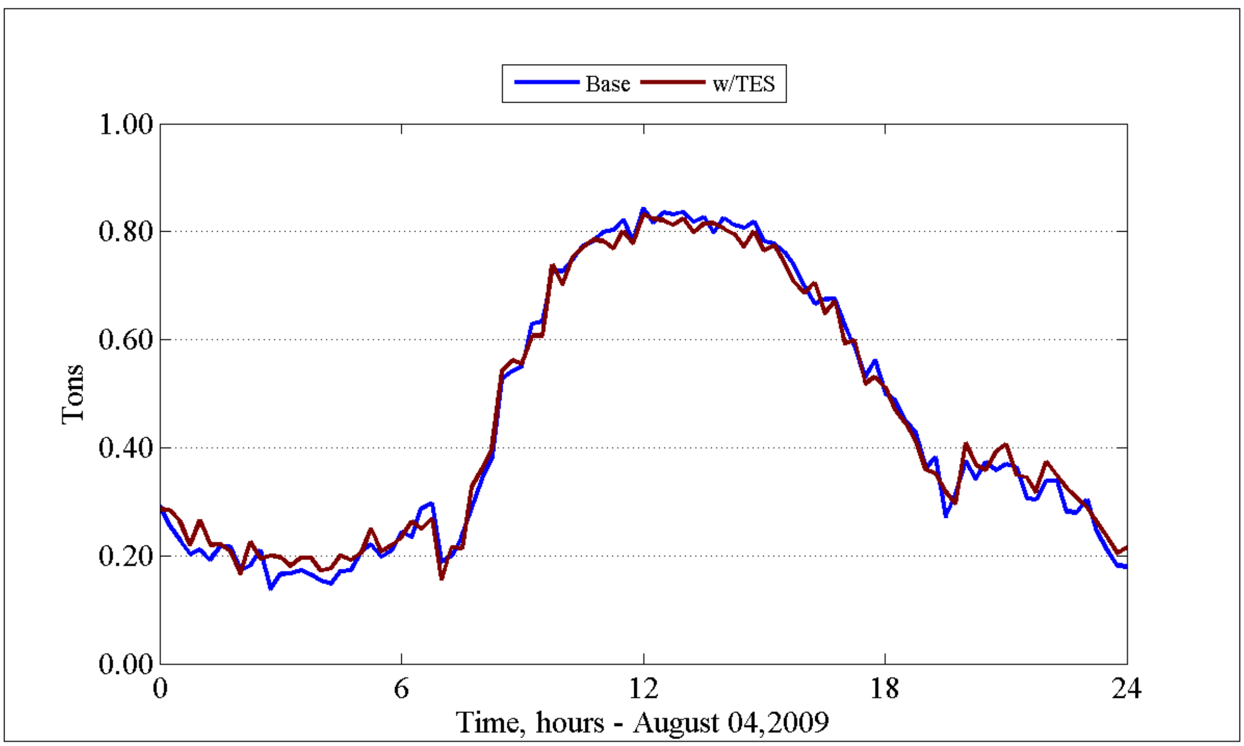

Figure D.133: Carbon dioxide emissions for peak day of R4-12.47-1

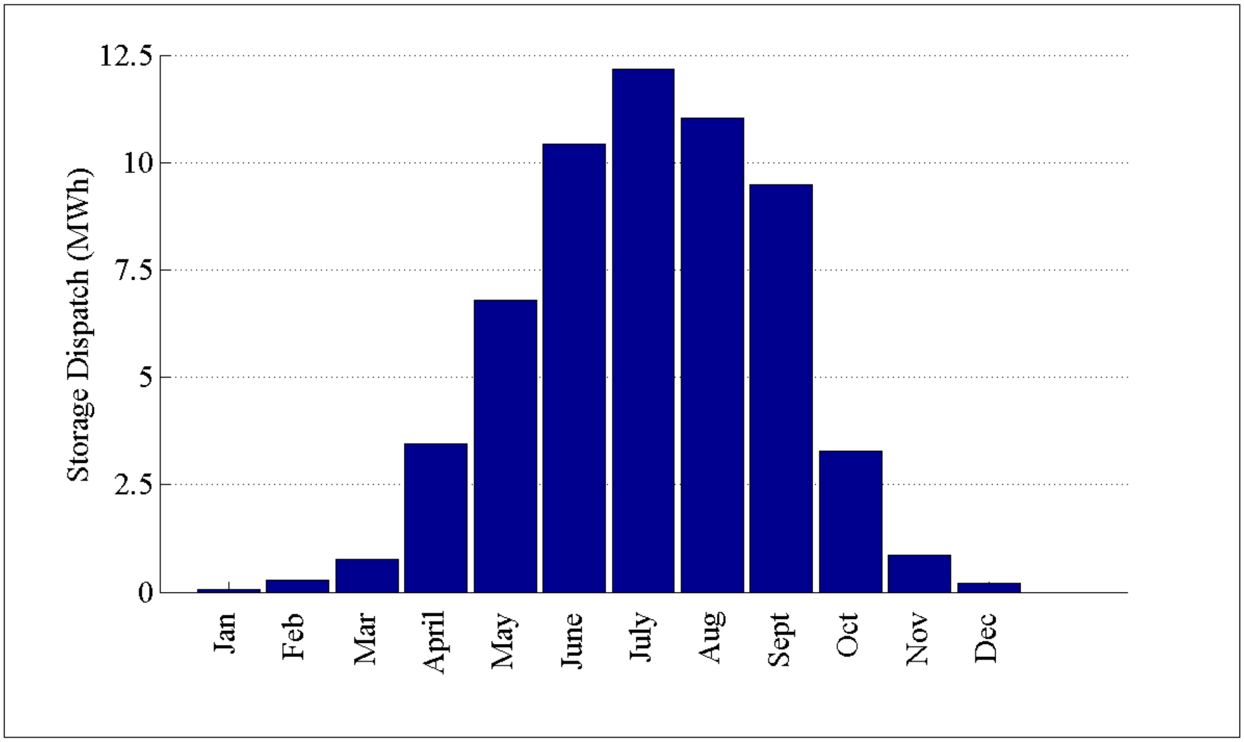

Figure D.134: Monthly storage dispatch energy for R4-12.47-1

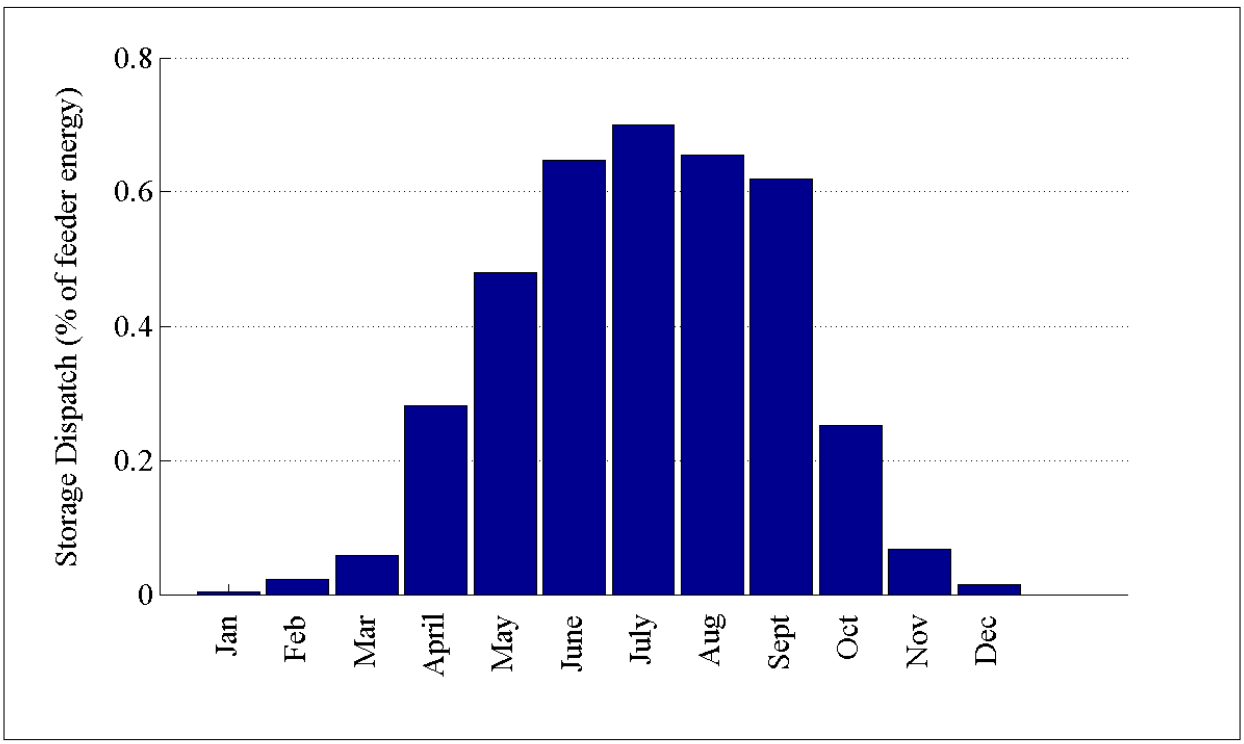

Figure D.135: Monthly storage dispatch energy percentage for R4-12.47-1

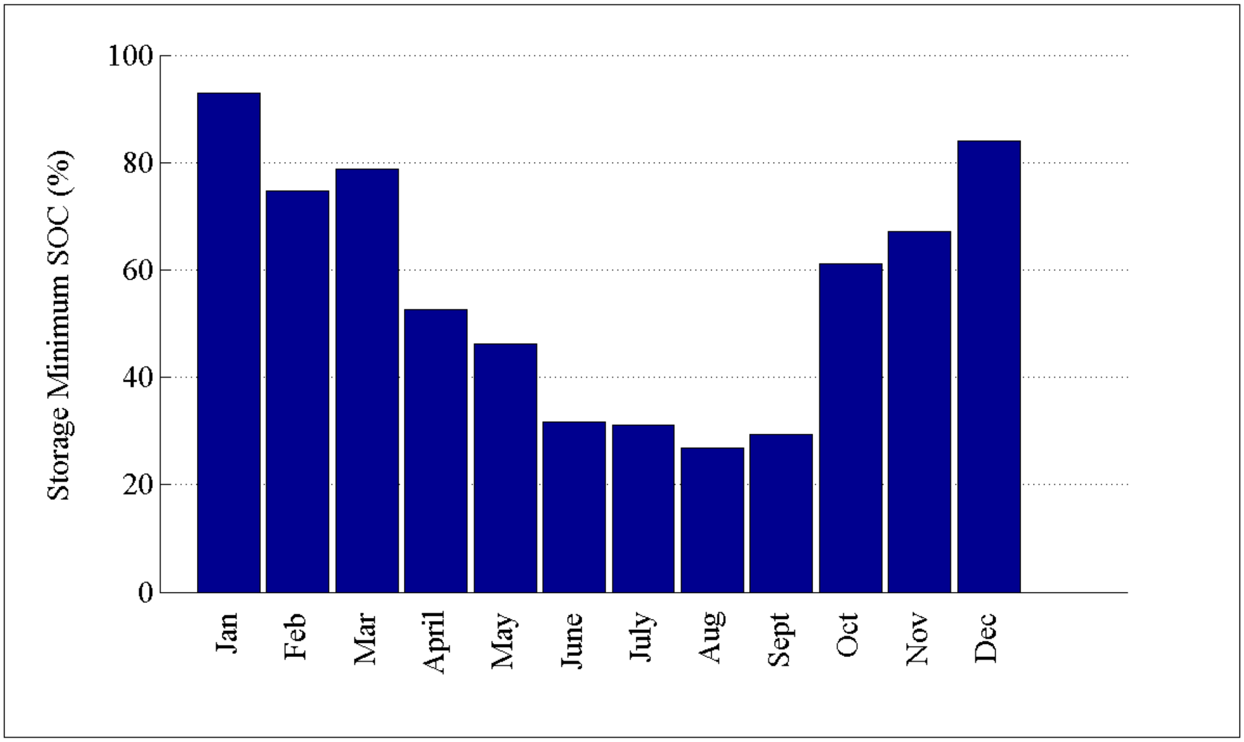

Figure D.136: Minimum state of charge for thermal energy storage on R4-12.47-1

D.19 Detailed Thermal Energy Storage Plots for R4-12.47-2

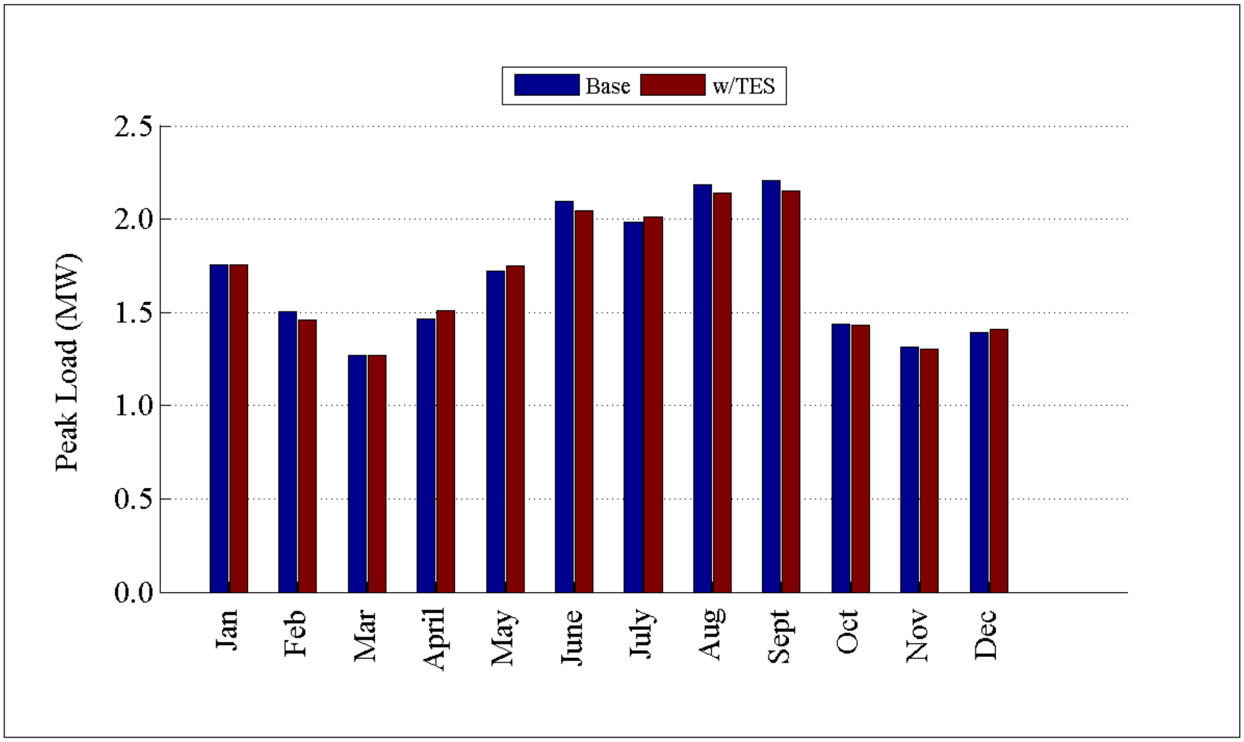

Figure D.137: Peak load by month of R4-12.47-2 feeder

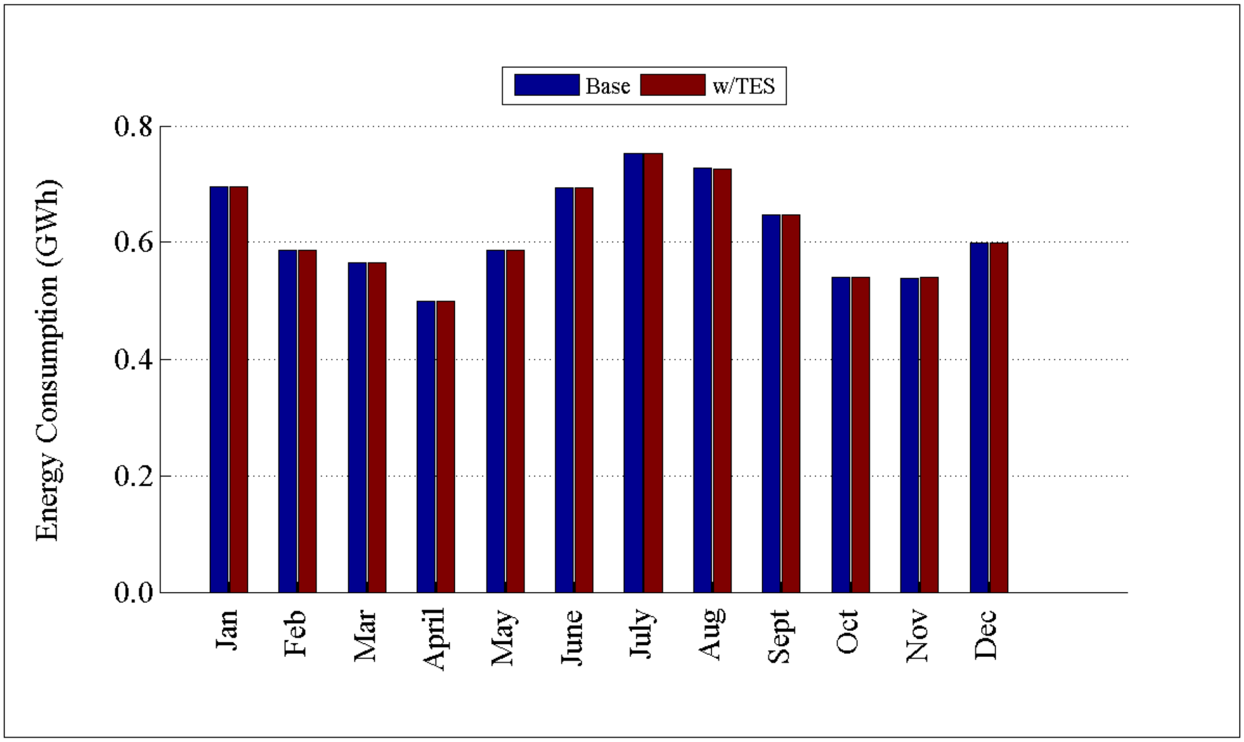

Figure D.138: Monthly energy consumption for R4-12.47-2 feeder

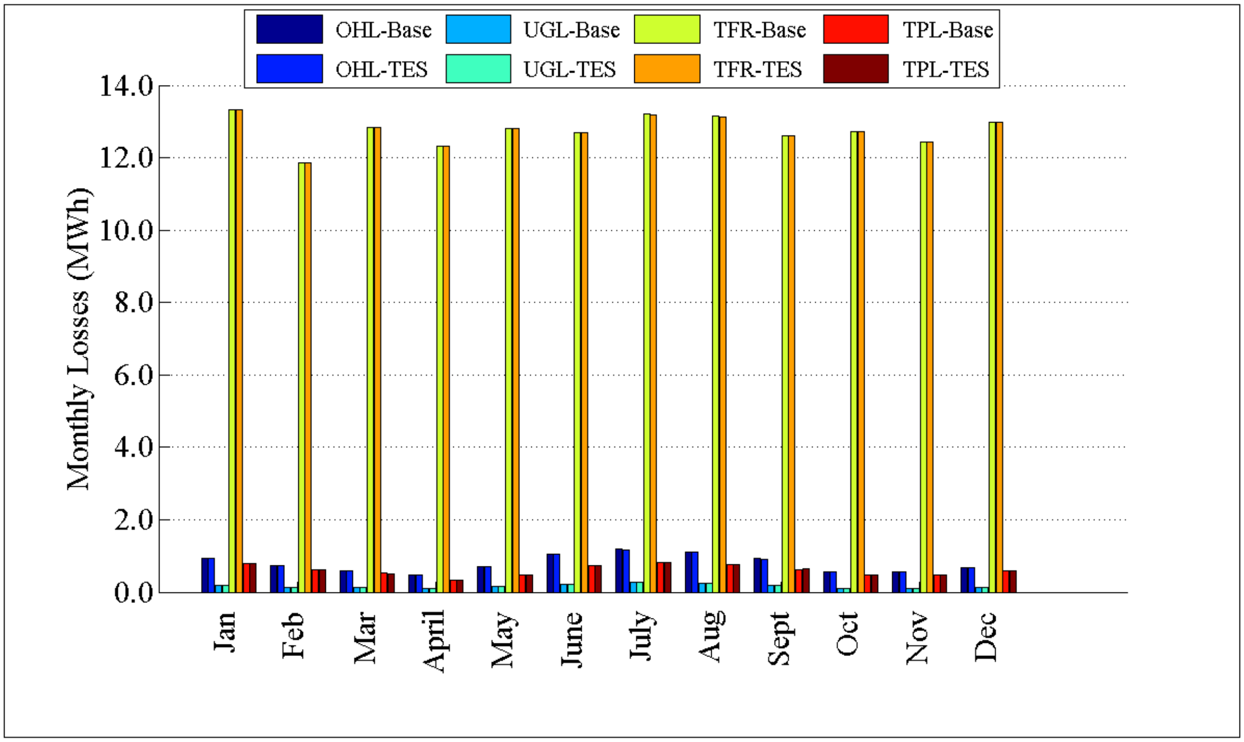

Figure D.139: Distribution system losses by month for R4-12.47-2

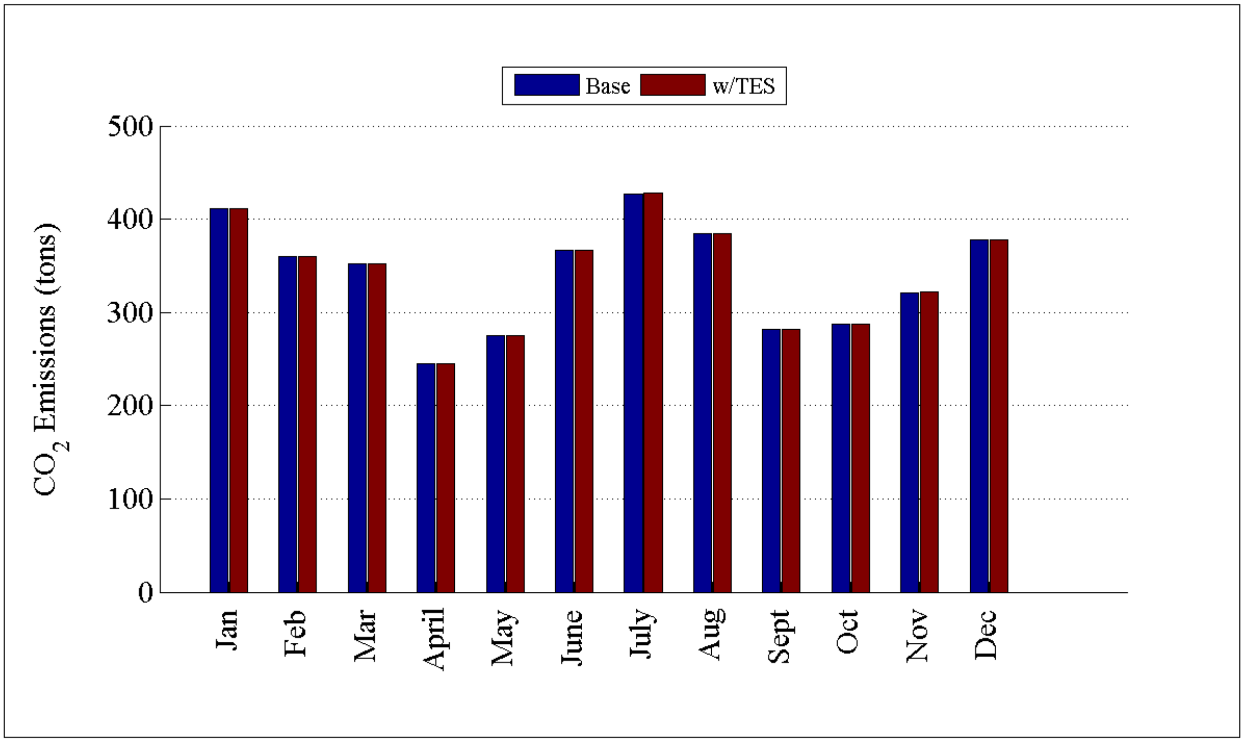

Figure D.140: CO_2 emissions by month for R4-12.47-2

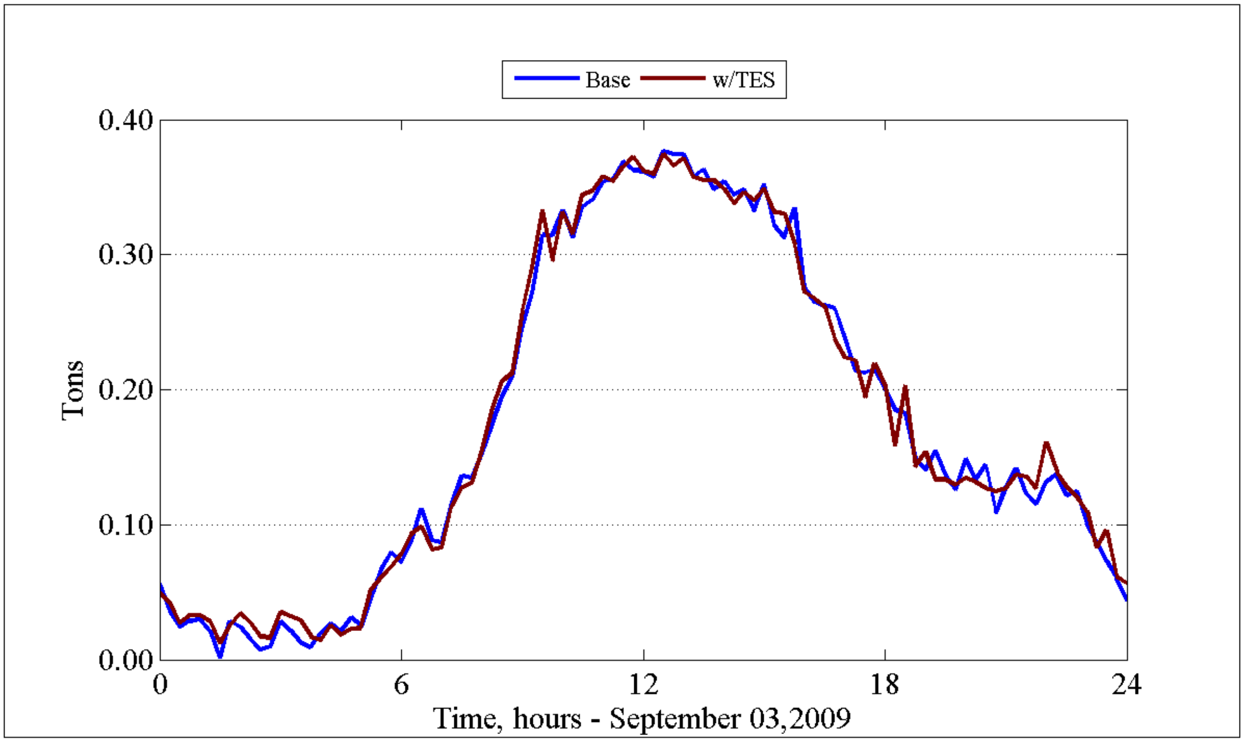

Figure D.141: Carbon dioxide emissions for peak day of R4-12.47-2

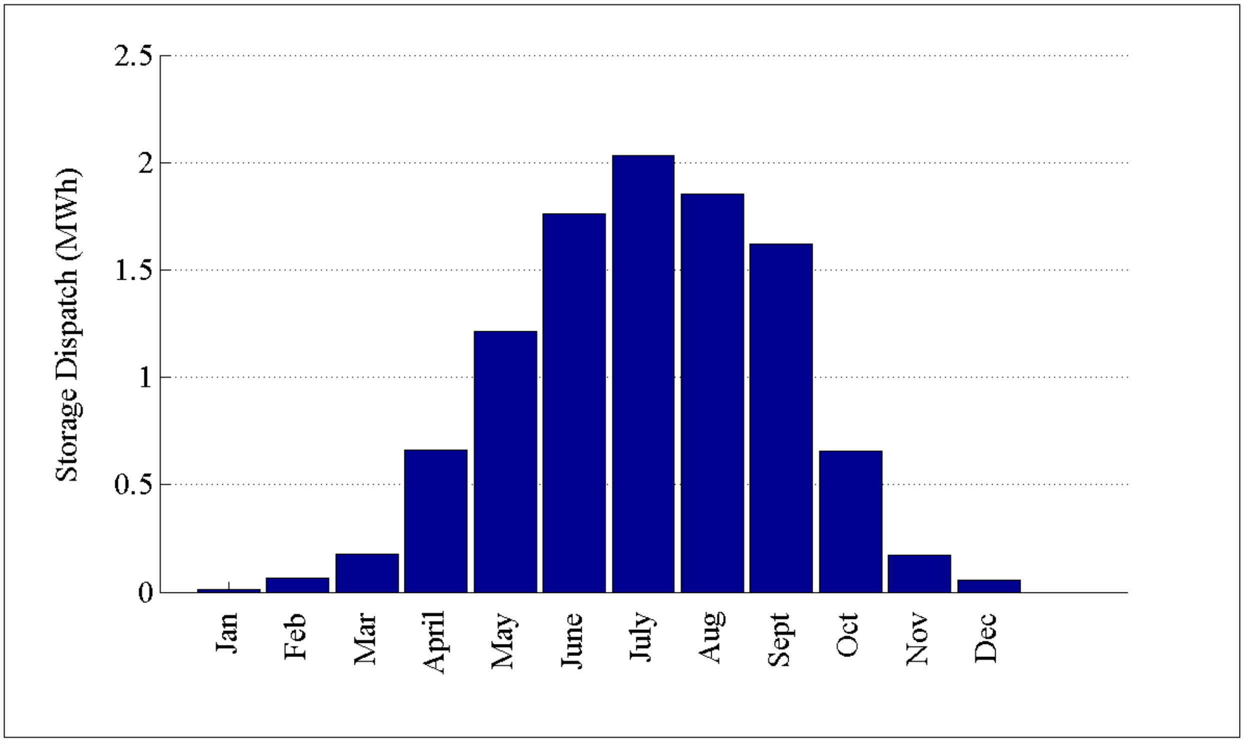

Figure D.142: Monthly storage dispatch energy for R4-12.47-2

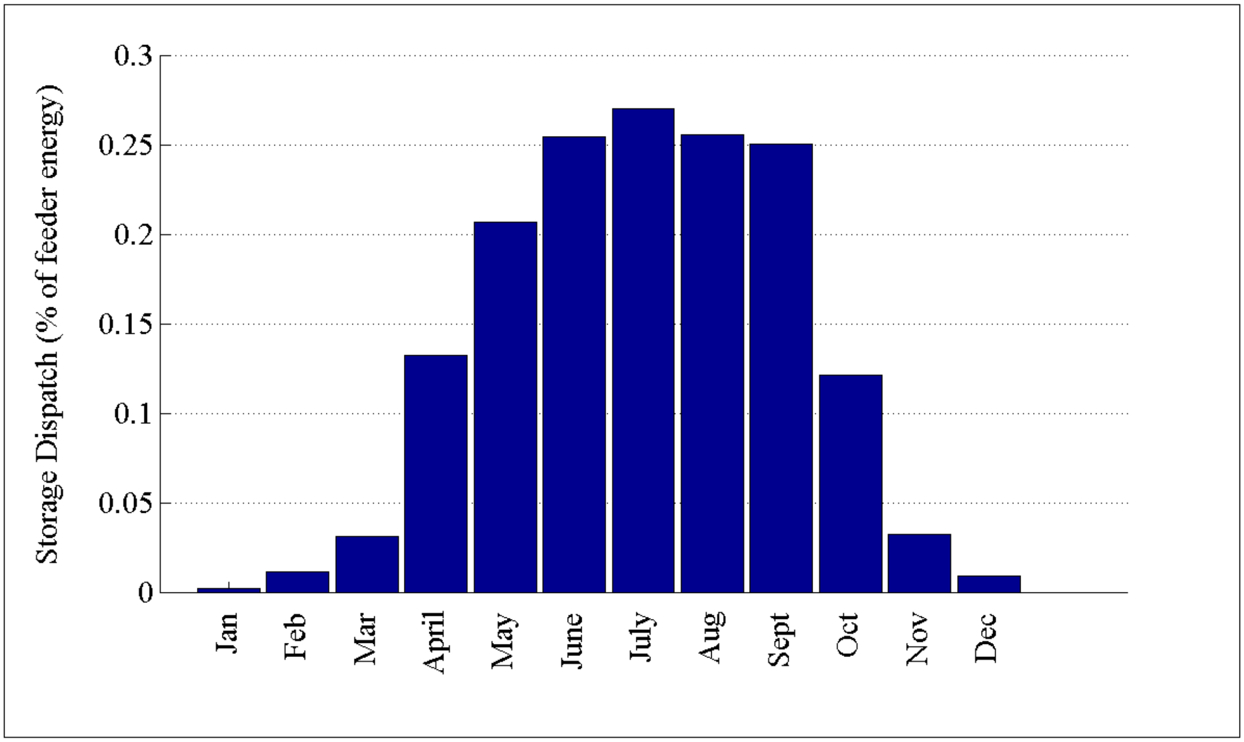

Figure D.143: Monthly storage dispatch energy percentage for R4-12.47-2

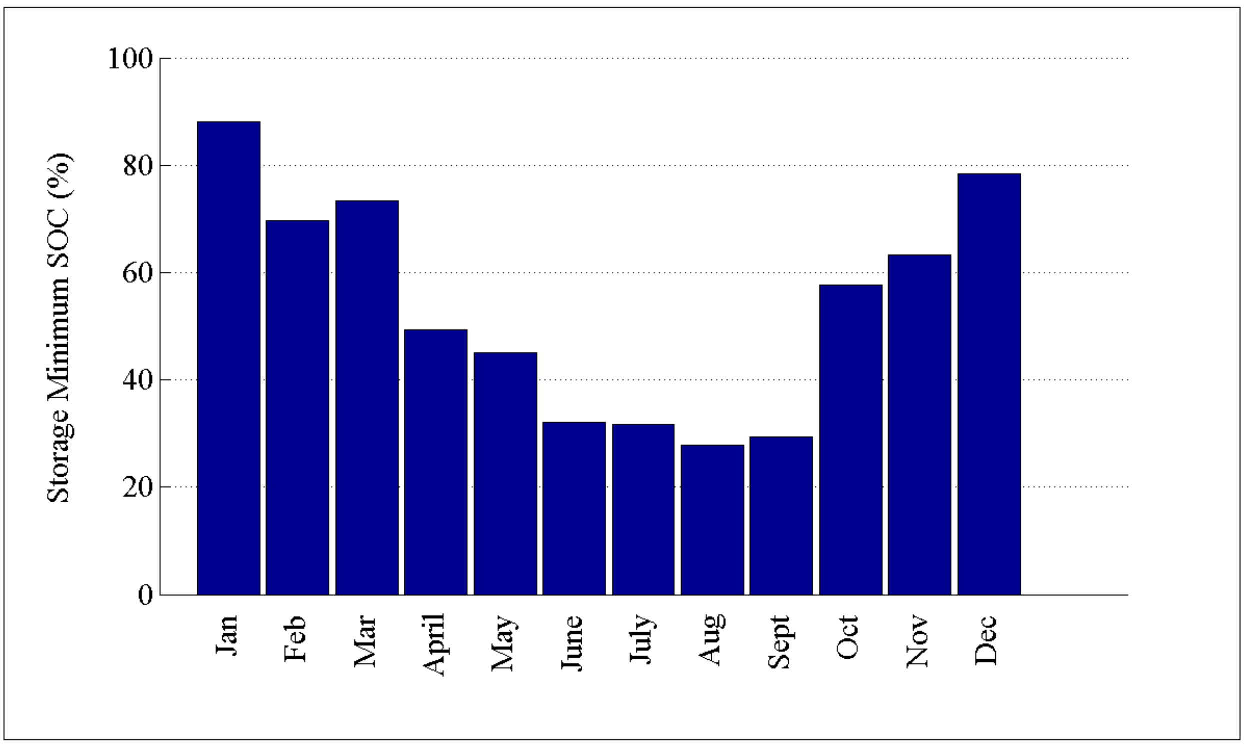

Figure D.144: Minimum state of charge for thermal energy storage on R4-12.47-2

D.20 Detailed Thermal Energy Storage Plots for R4-25.00-1

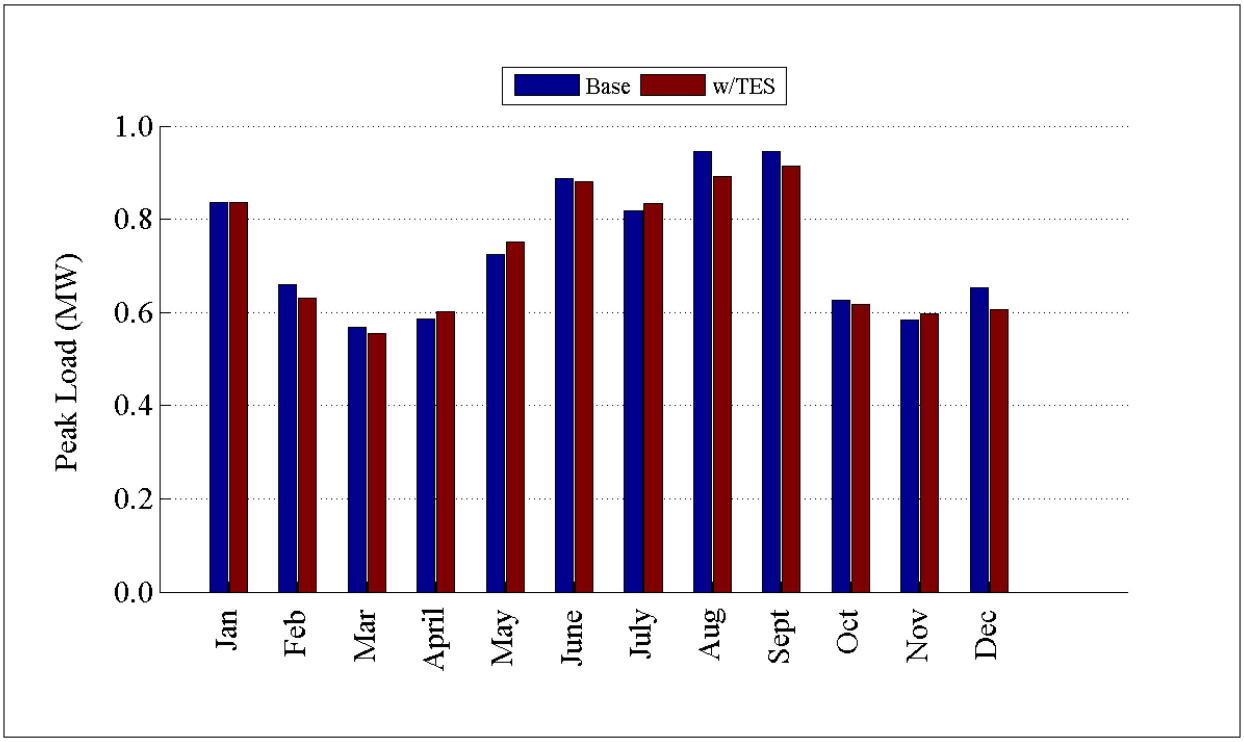

Figure D.145: Peak load by month of R4-25.00-1 feeder

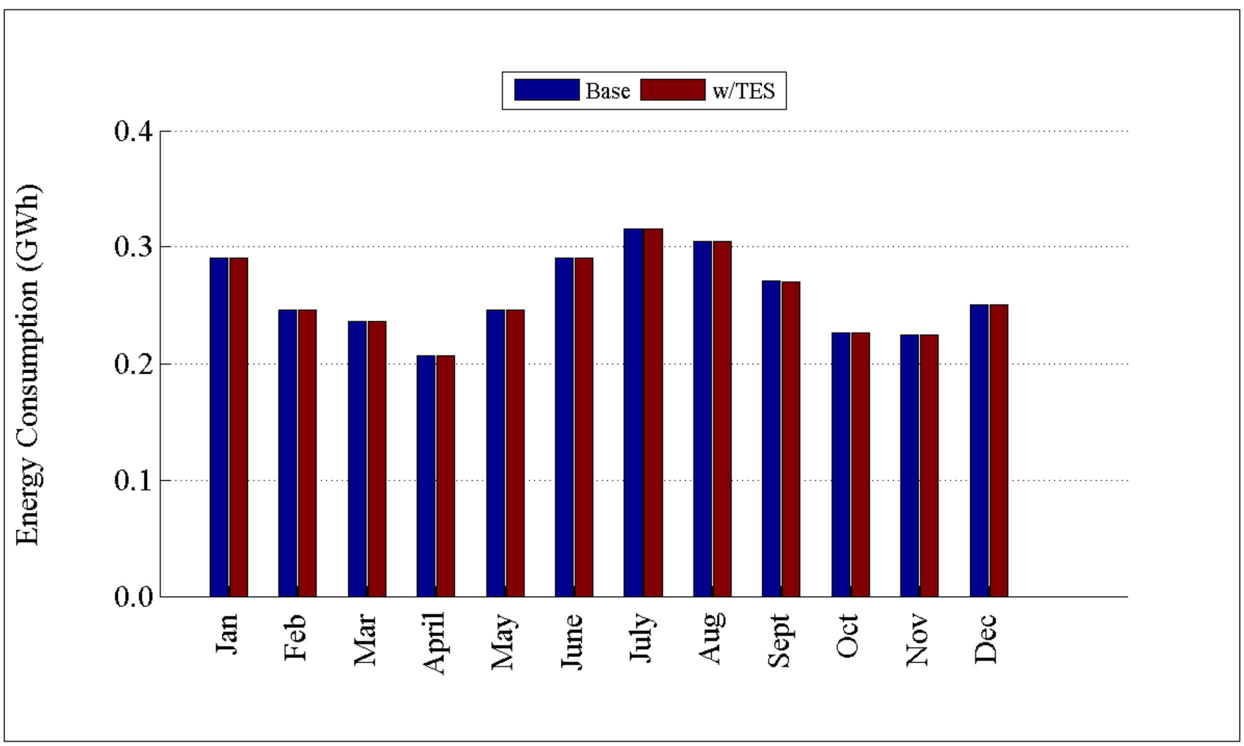

Figure D.146: Monthly energy consumption for R4-25.00-1 feeder

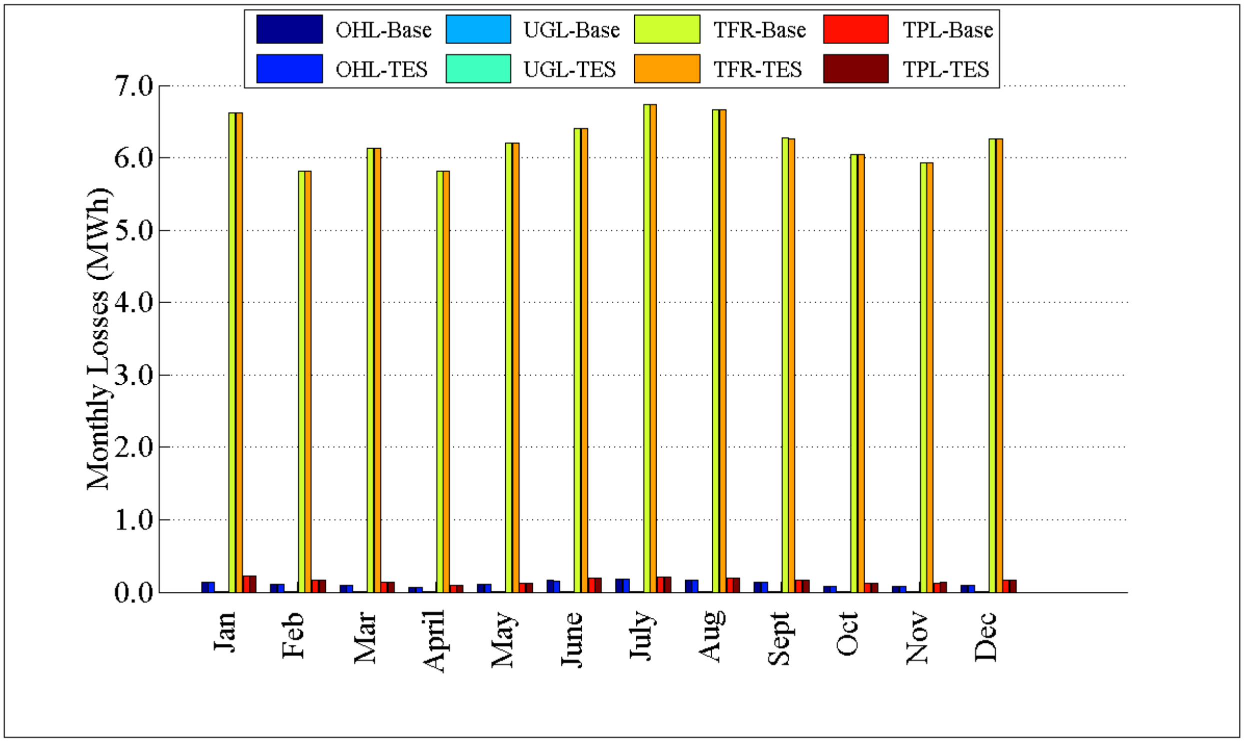

Figure D.147: Distribution system losses by month for R4-25.00-1

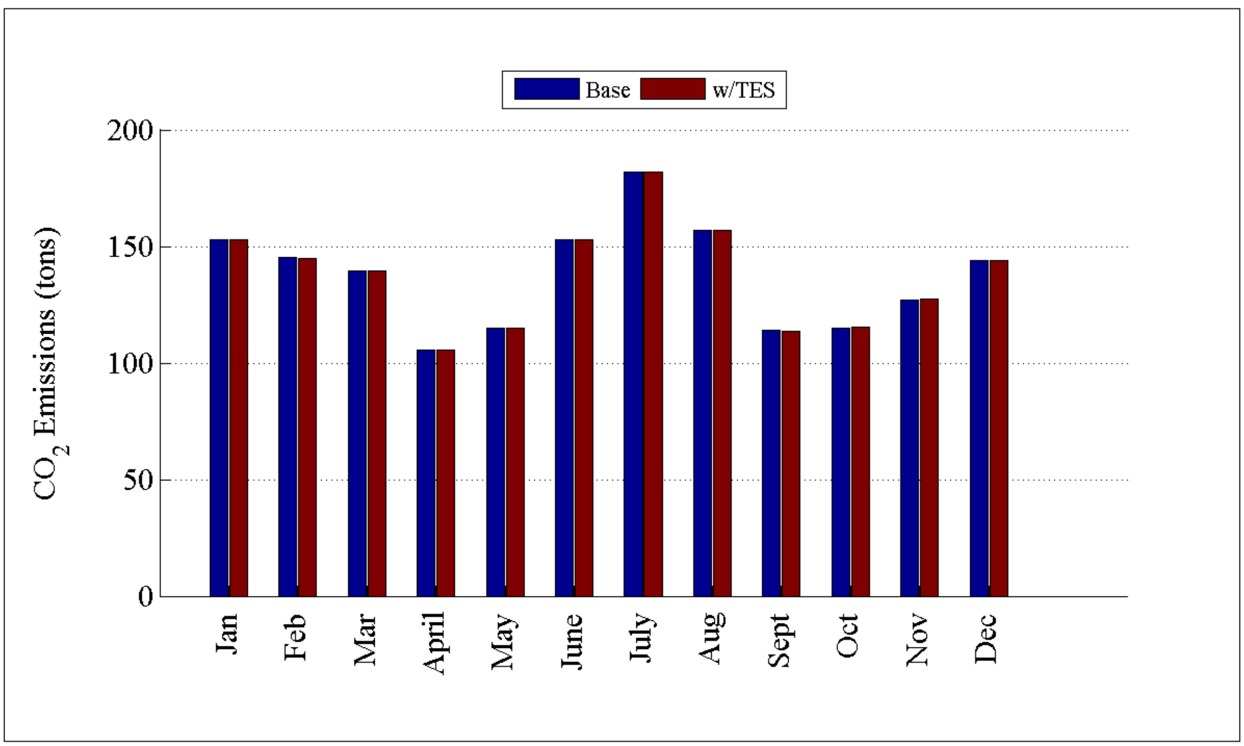

Figure D.148: CO_2 emissions by month for R4-25.00-1

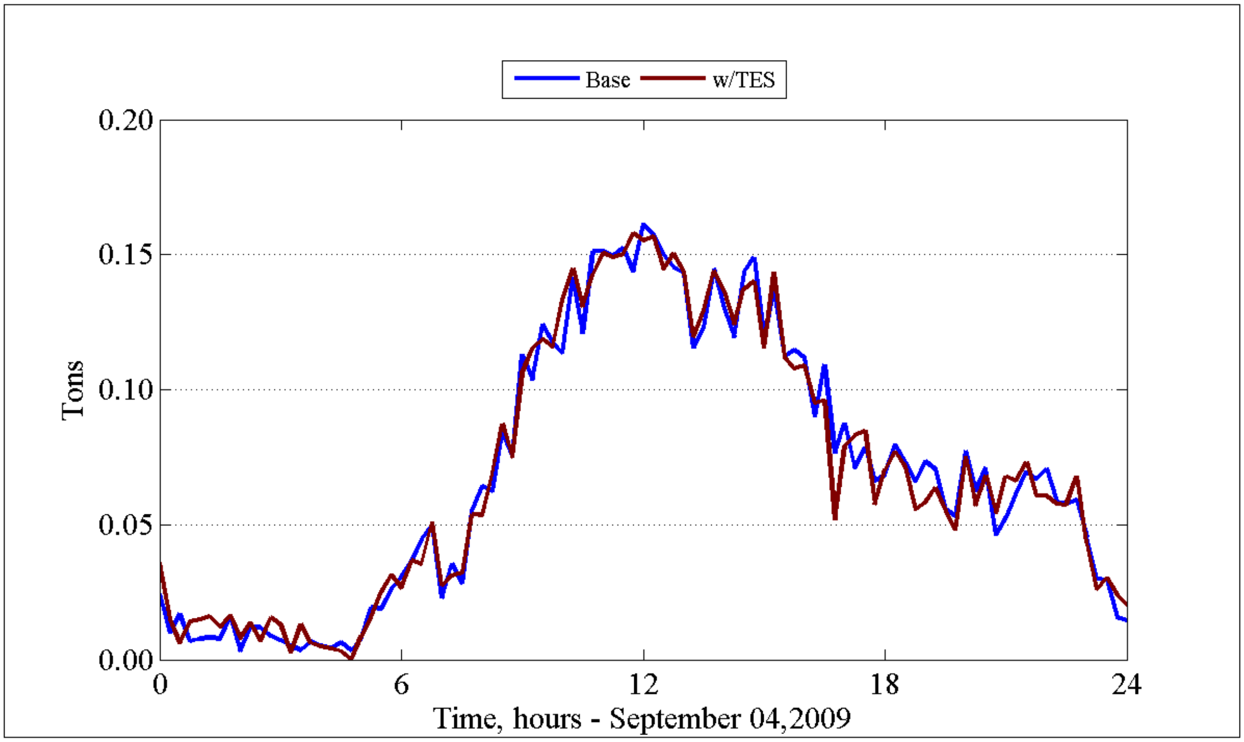

Figure D.149: Carbon dioxide emissions for peak day of R4-25.00-1

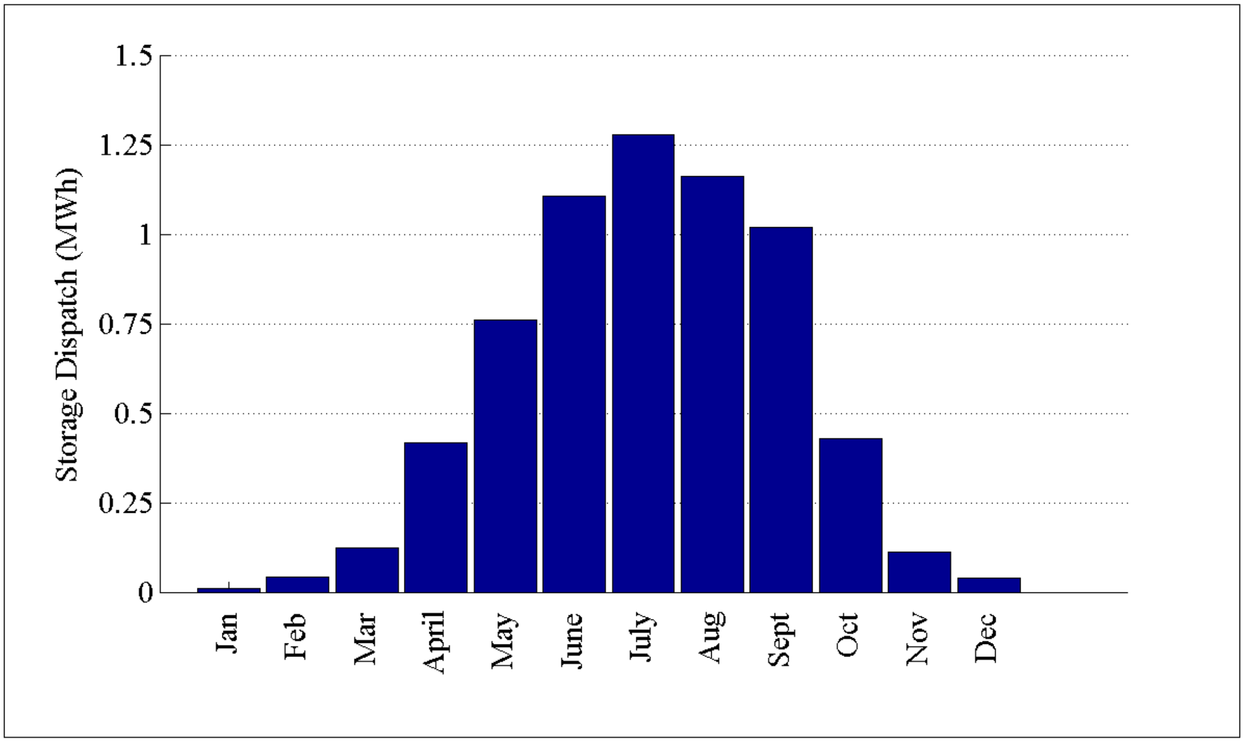

Figure D.150: Monthly storage dispatch energy for R4-25.00-1

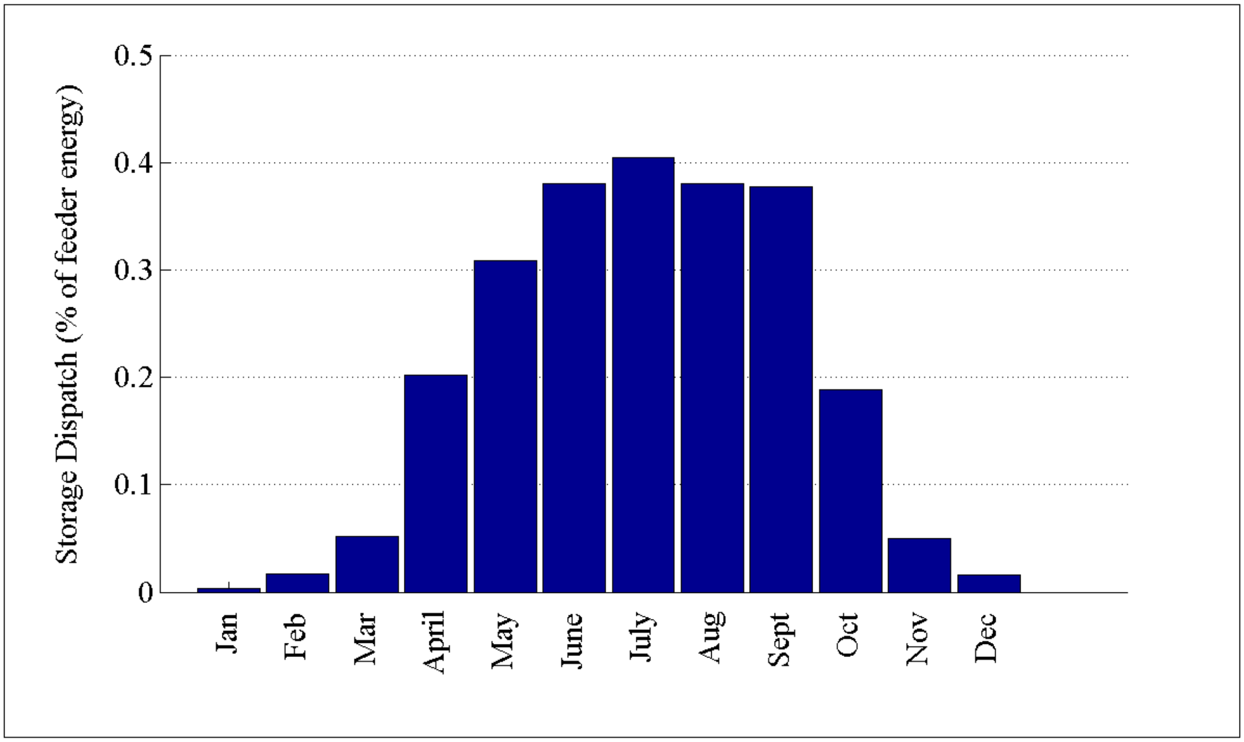

Figure D.151: Monthly storage dispatch energy percentage for R4-25.00-1

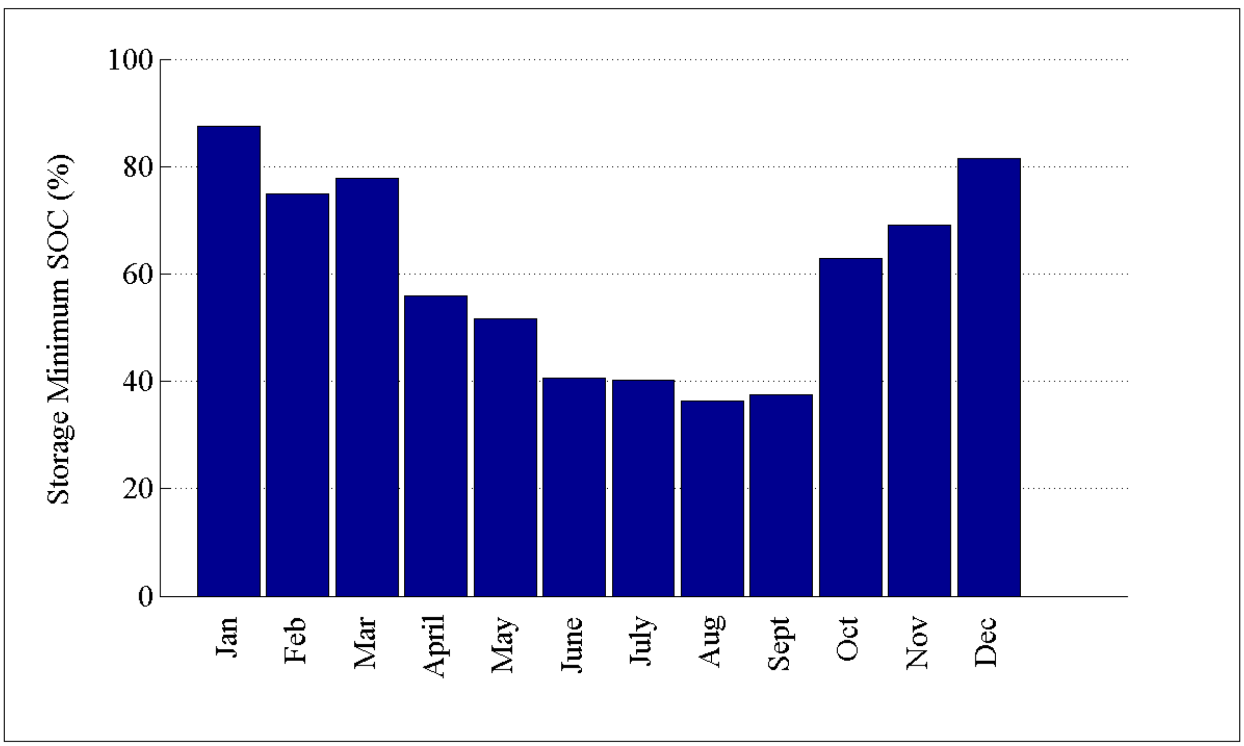

Figure D.152: Minimum state of charge for thermal energy storage on R4-25.00-1

D.21 Detailed Thermal Energy Storage Plots for GC-12.47-1_R5

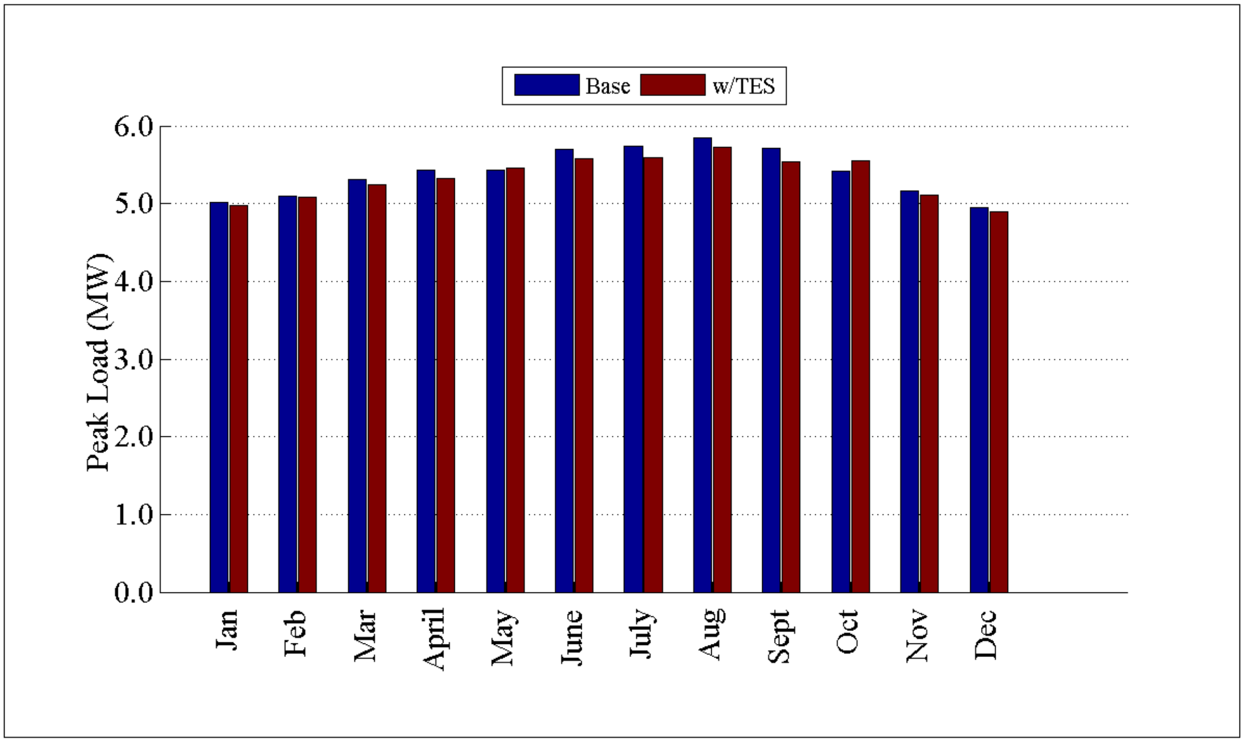

Figure D.153: Peak load by month of GC-12.47-1-r5 feeder

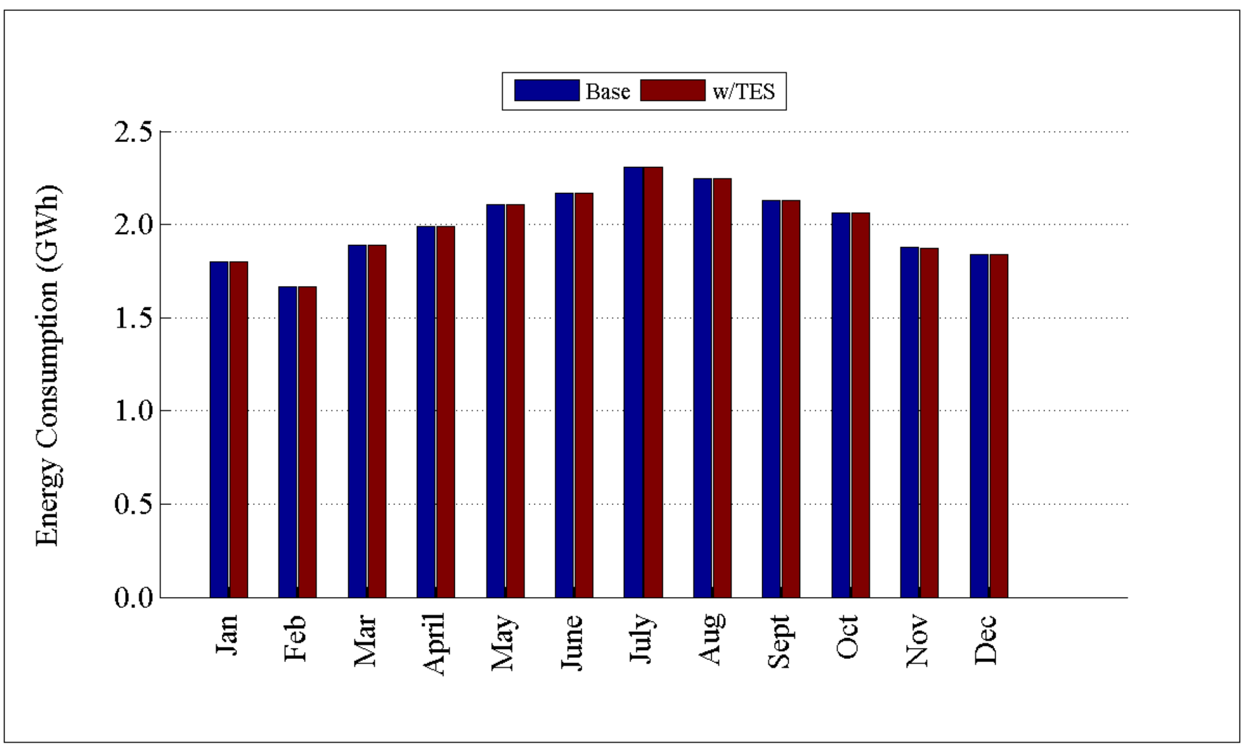

Figure D.154: Monthly energy consumption for GC-12.47-1-r5 feeder

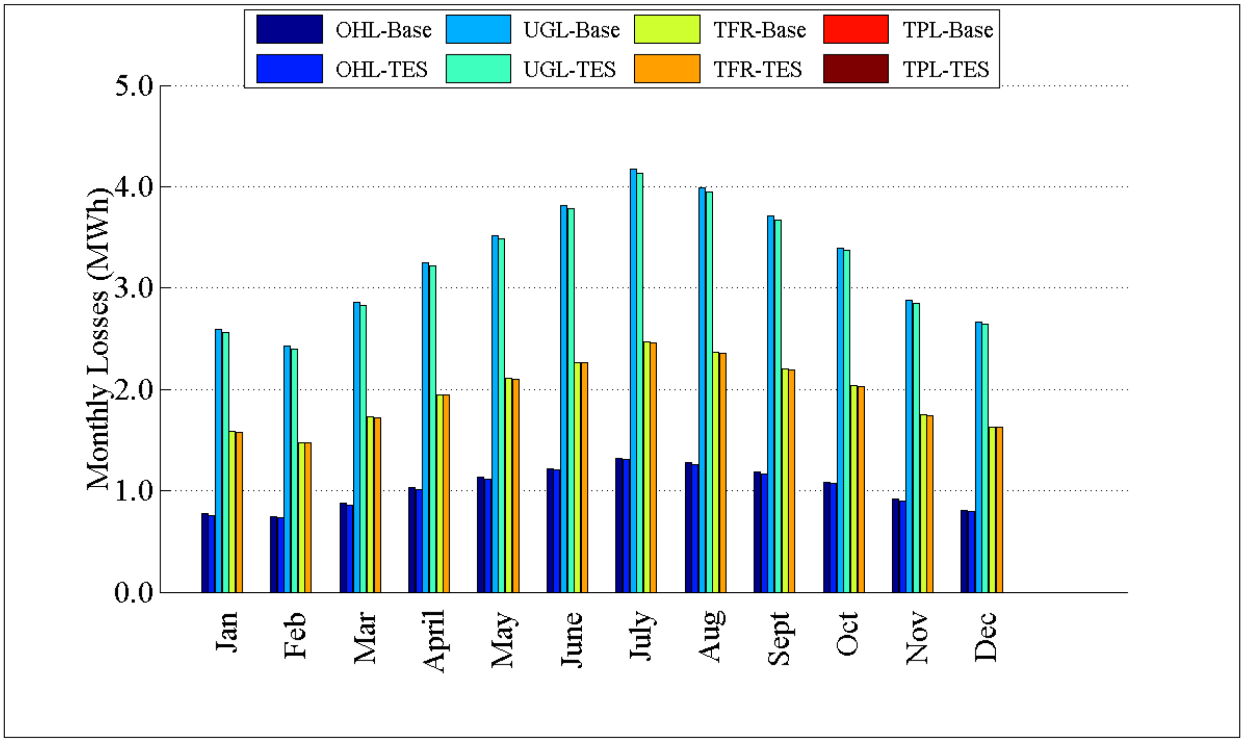

Figure D.155: Distribution system losses by month for GC-12.47-1-r5

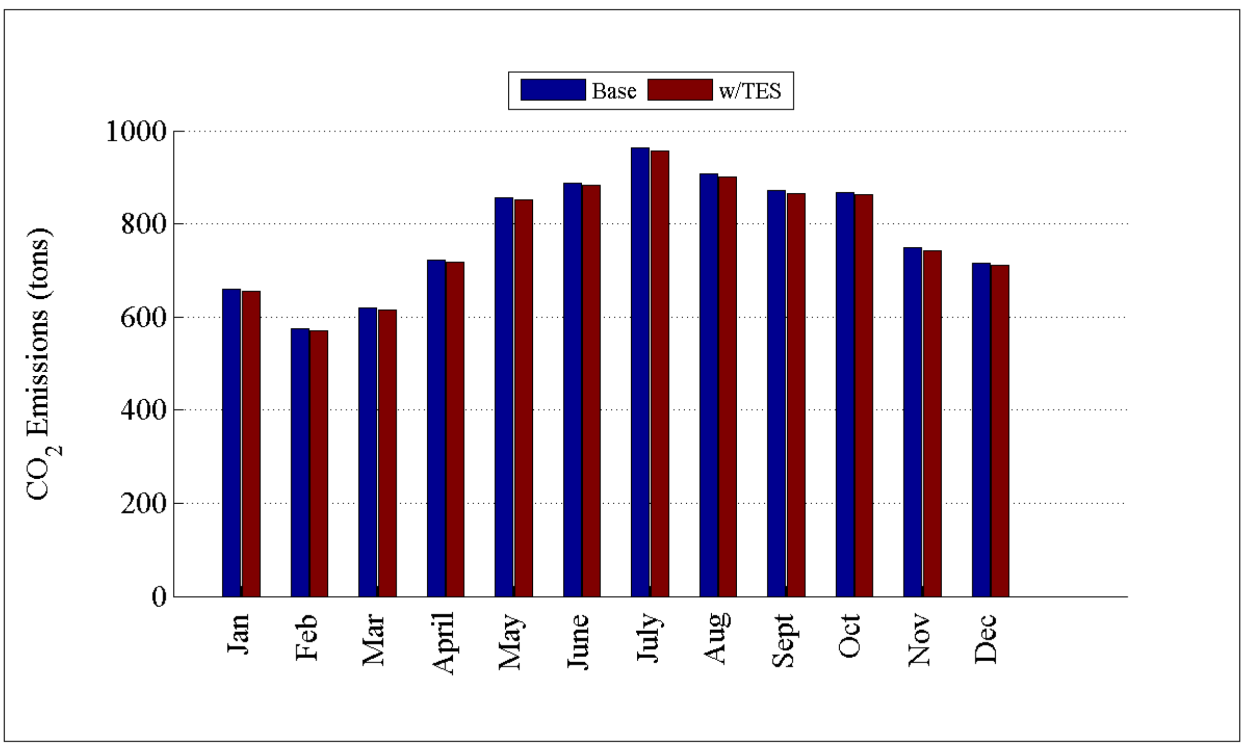

Figure D.156: CO_2 emissions by month for GC-12.47-1-r5

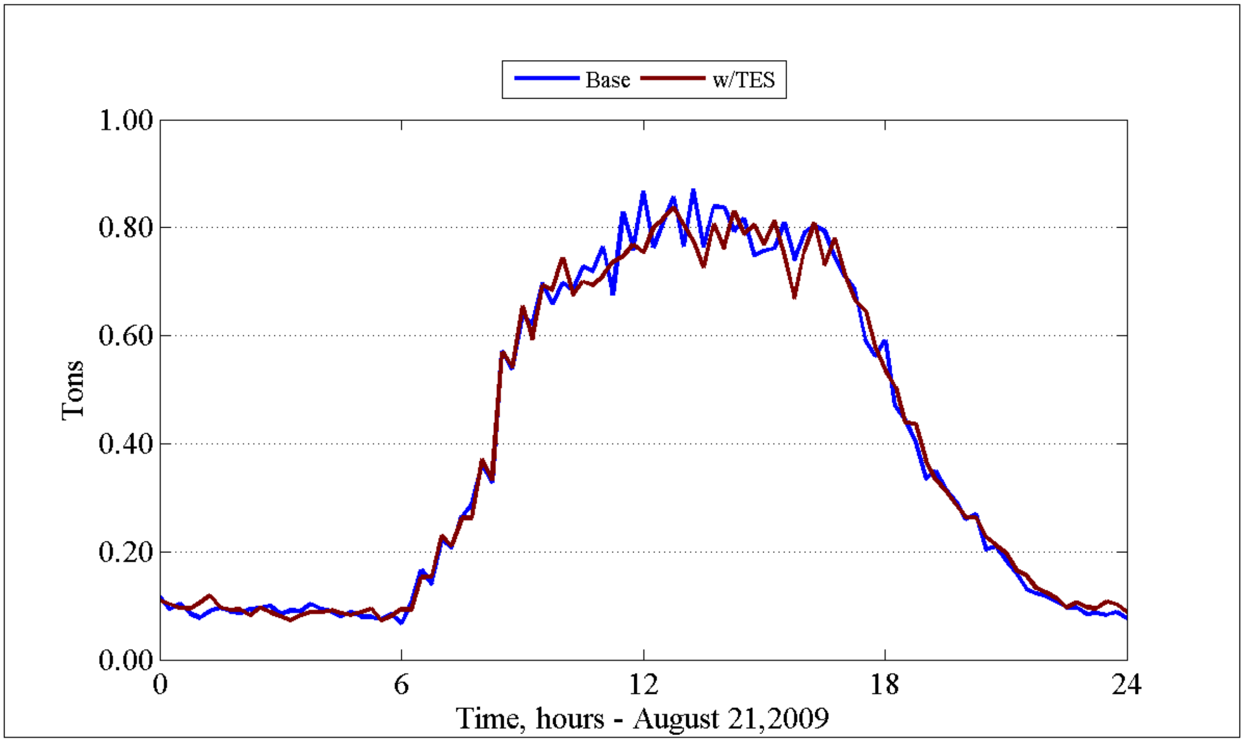

Figure D.157: Carbon dioxide emissions for peak day of GC-12.47-1-r5

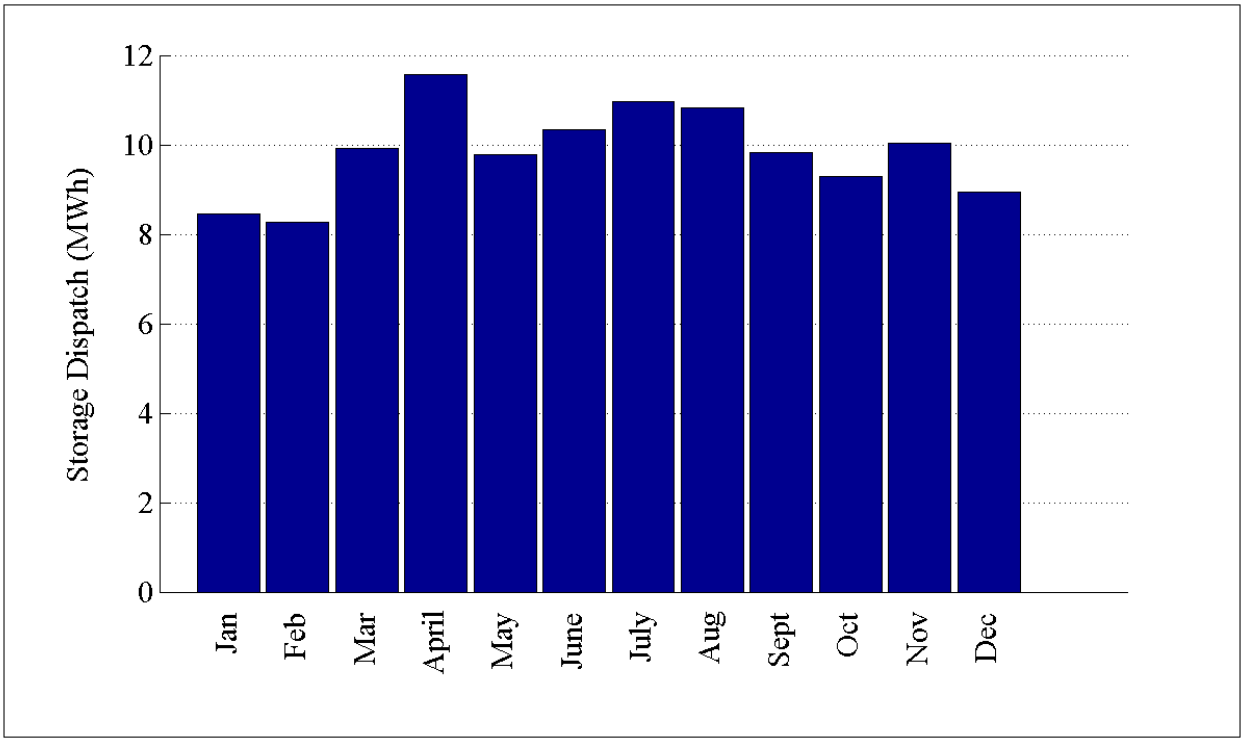

Figure D.158: Monthly storage dispatch energy for GC-12.47-1-r5

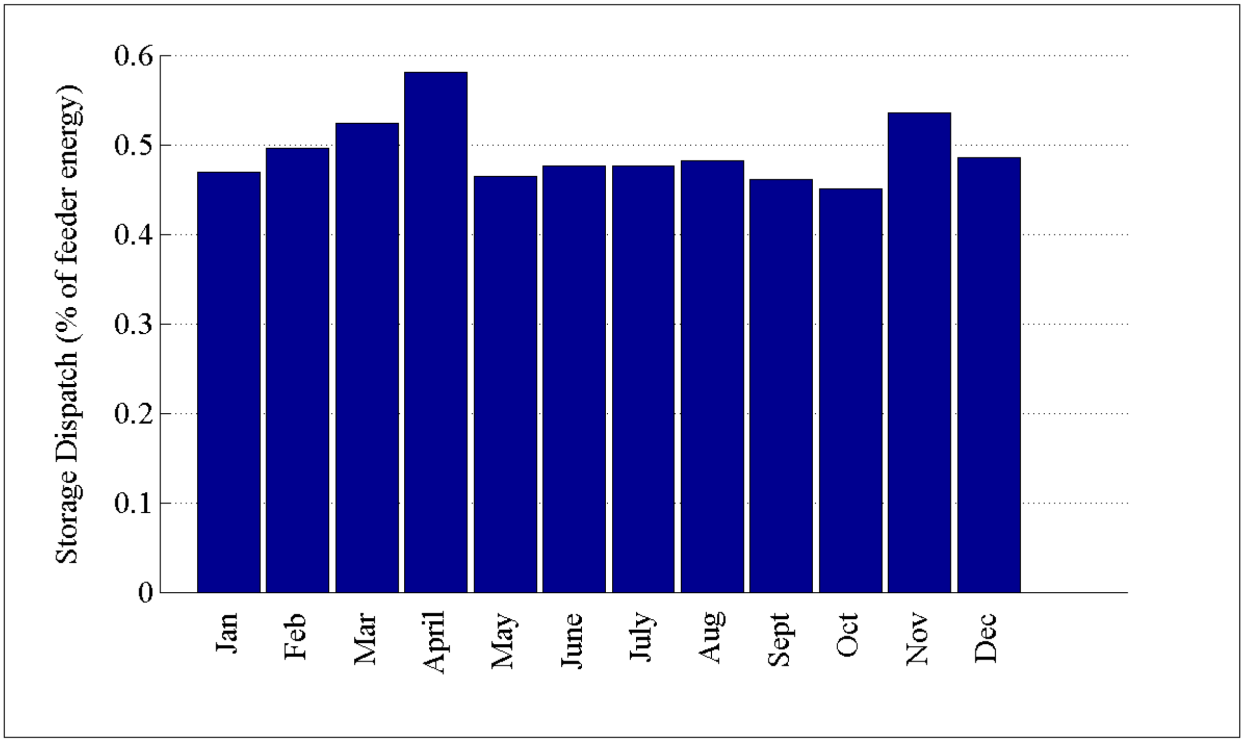

Figure D.159: Monthly storage dispatch energy percentage for GC-12.47-1-r5

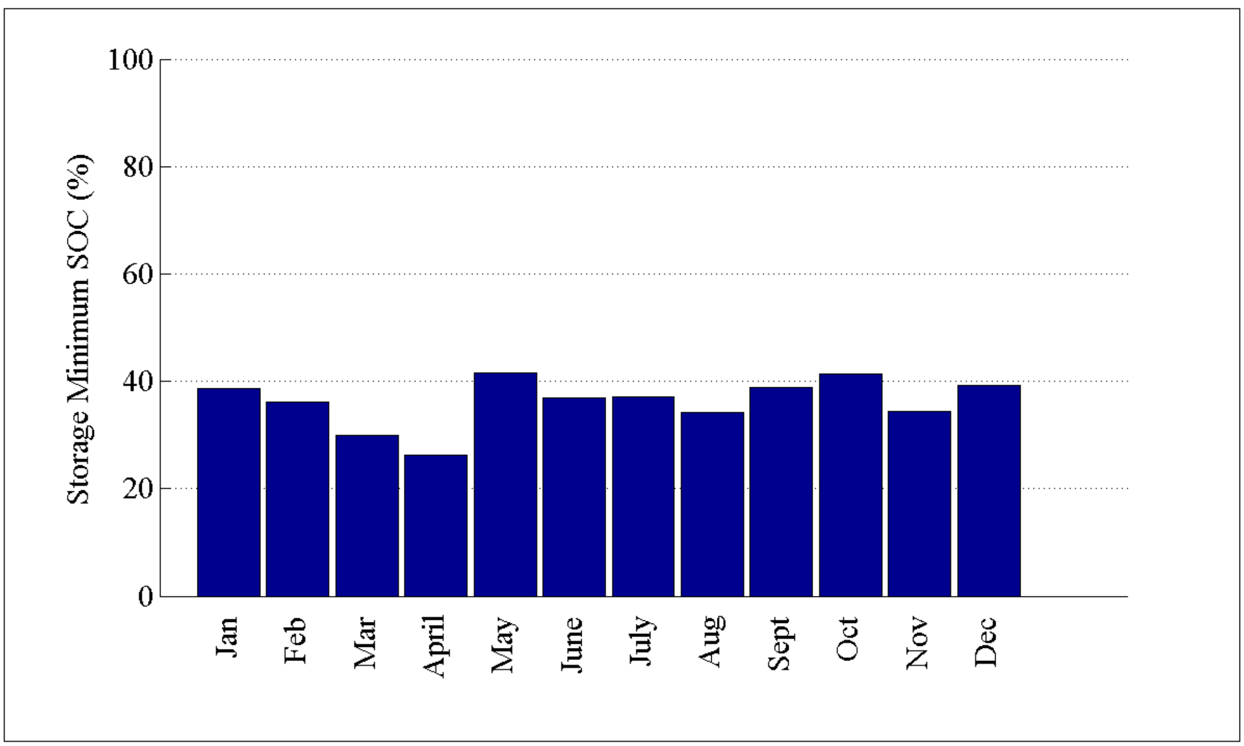

Figure D.160: Minimum state of charge for thermal energy storage on GC-12.47-1-r5

D.22 Detailed Thermal Energy Storage Plots for R5-12.47-1

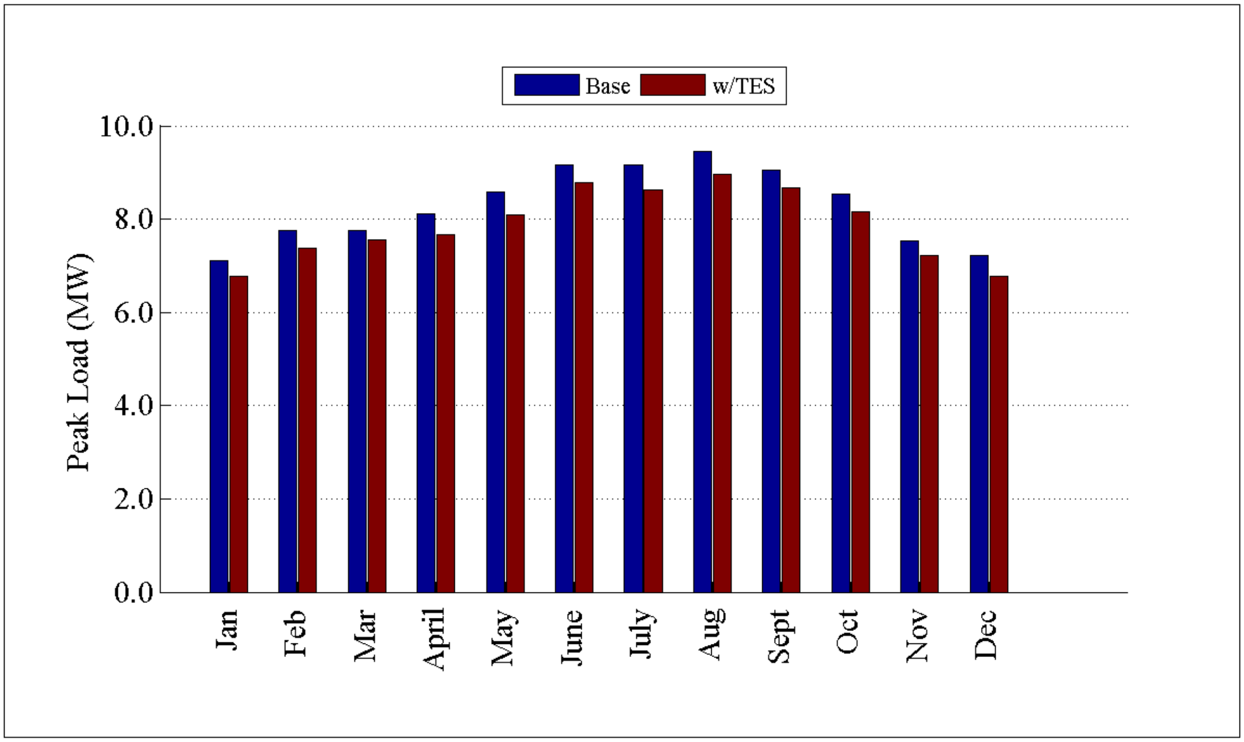

Figure D.161: Peak load by month of R5-12.47-1 feeder

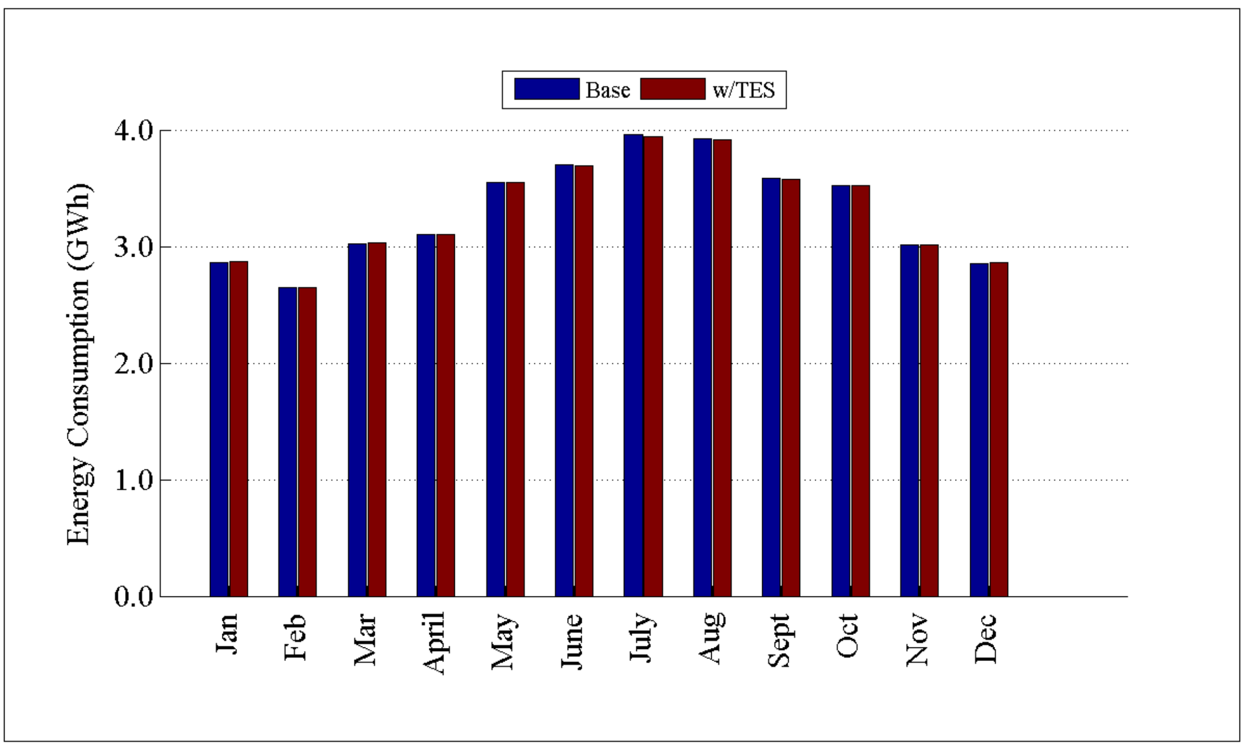

Figure D.162: Monthly energy consumption for R5-12.47-1 feeder

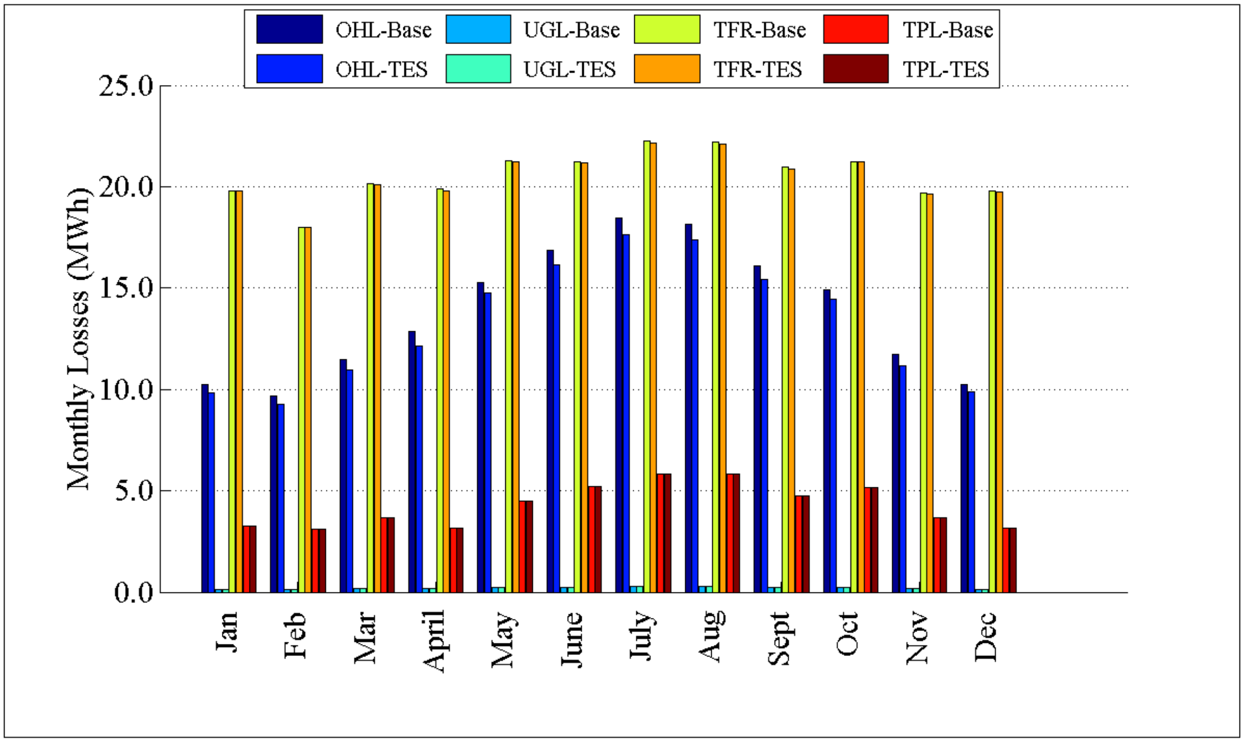

Figure D.163: Distribution system losses by month for R5-12.47-1

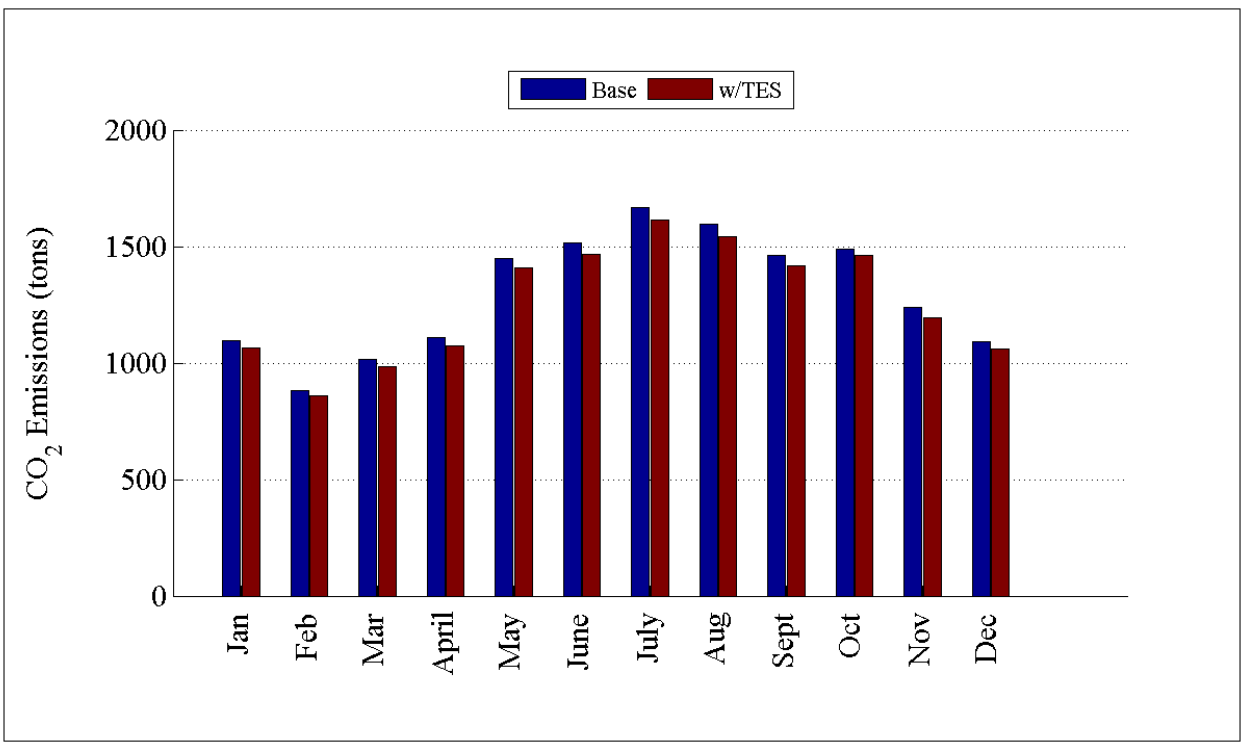

Figure D.164: CO_2 emissions by month for R5-12.47-1

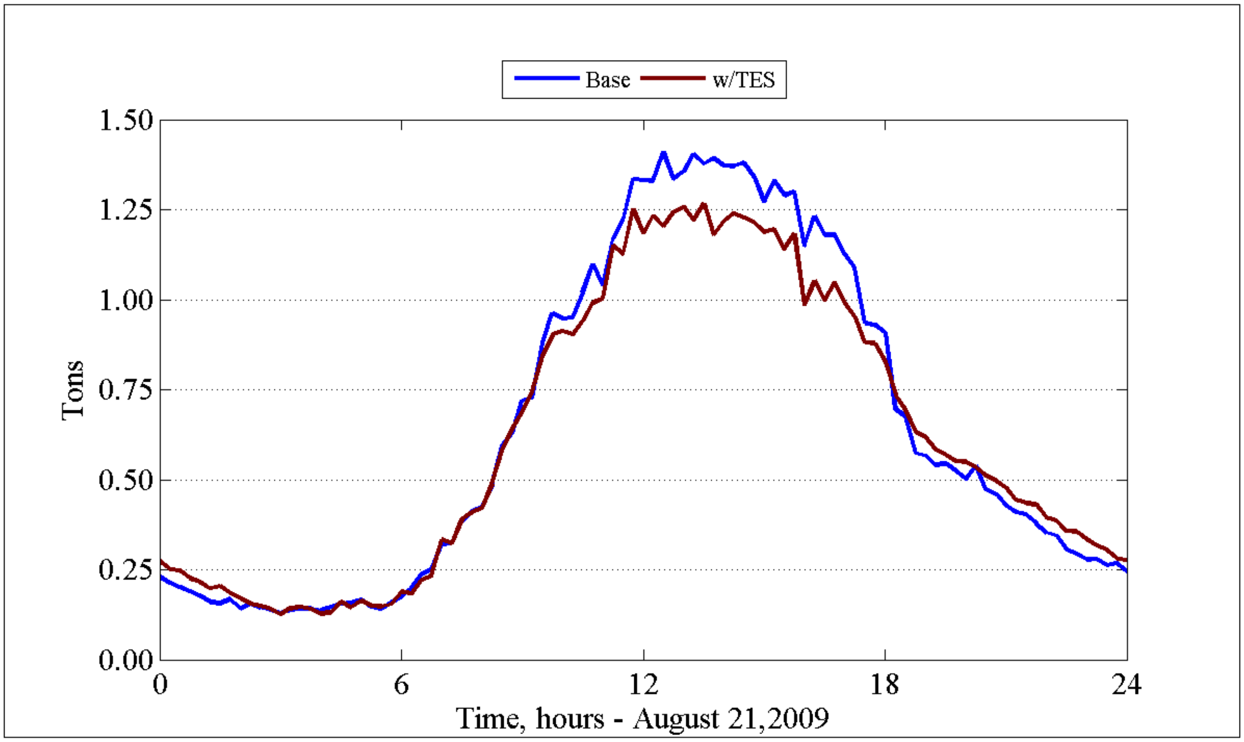

Figure D.165: Carbon dioxide emissions for peak day of R5-12.47-1

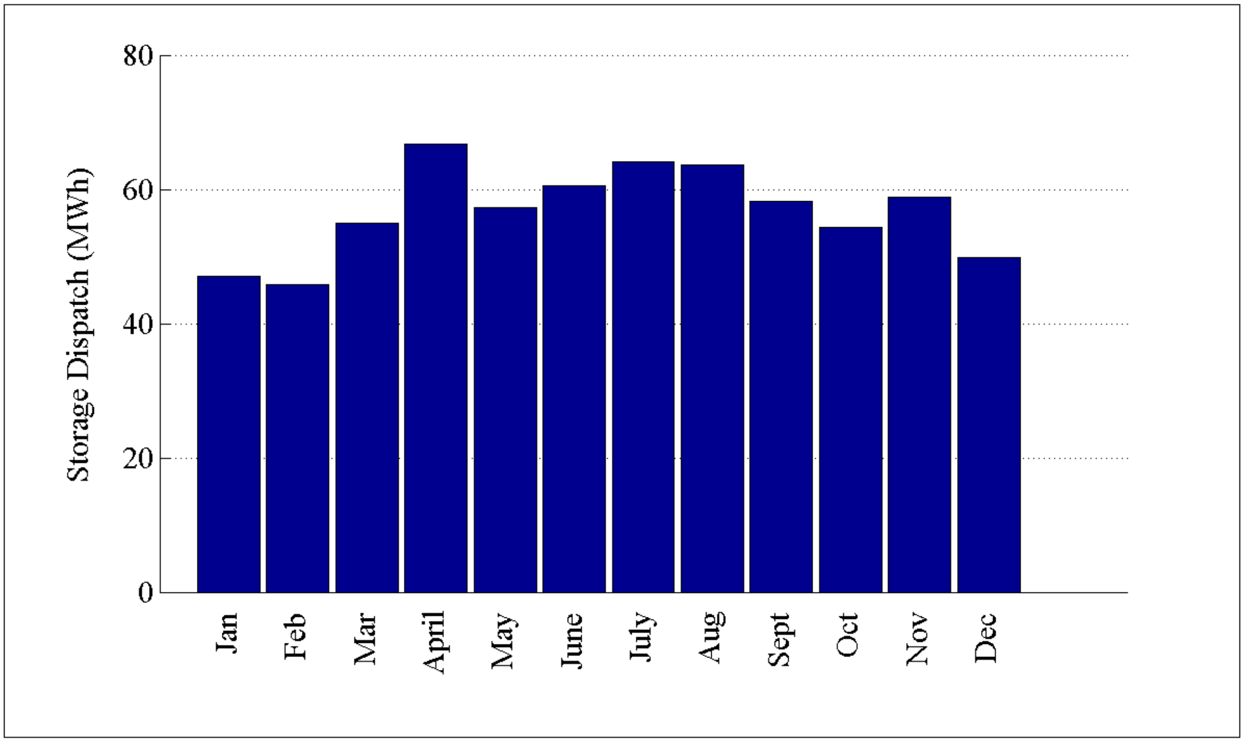

Figure D.166: Monthly storage dispatch energy for R5-12.47-1

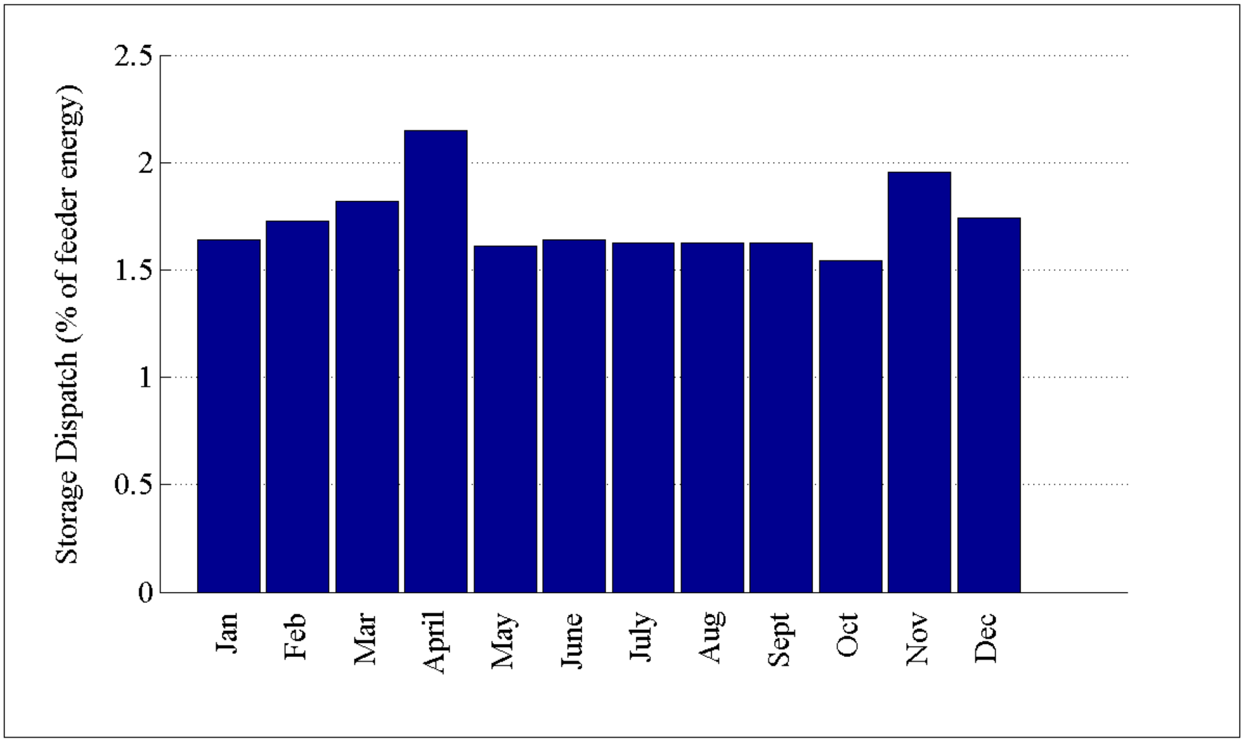

Figure D.167: Monthly storage dispatch energy percentage for R5-12.47-1

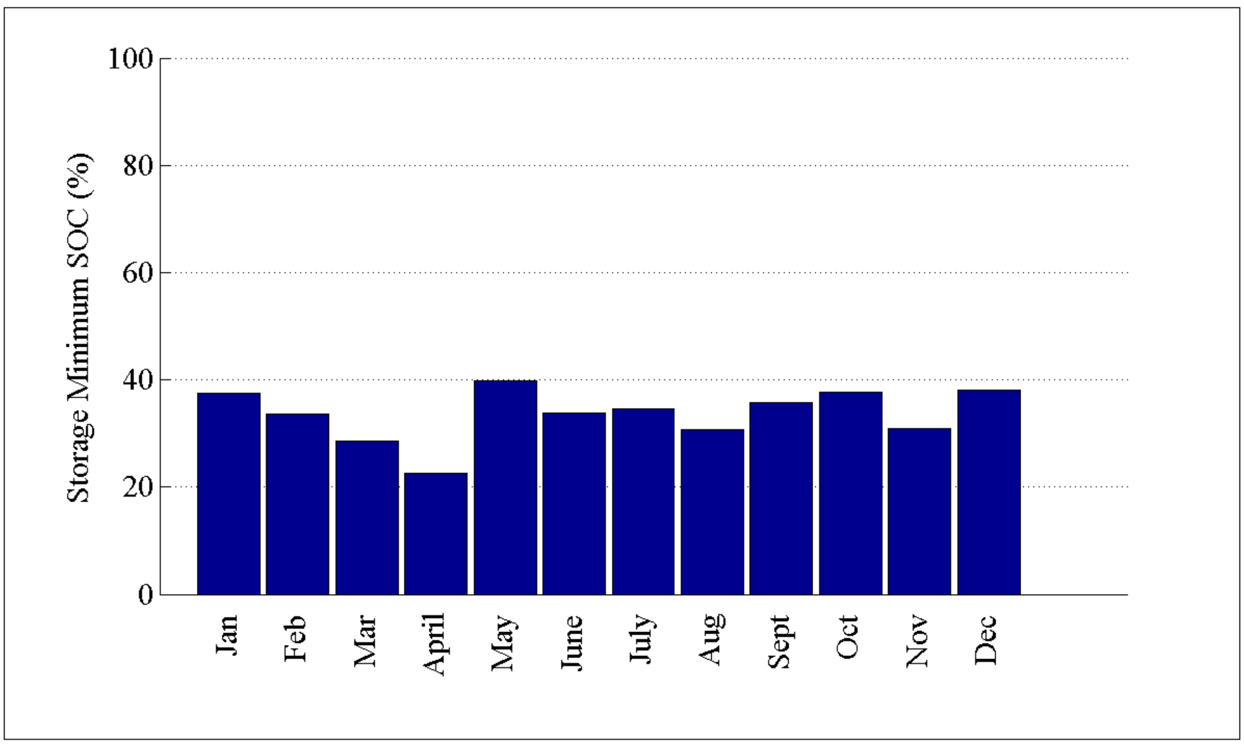

Figure D.168: Minimum state of charge for thermal energy storage on R5-12.47-1

D.23 Detailed Thermal Energy Storage Plots for R5-12.47-2

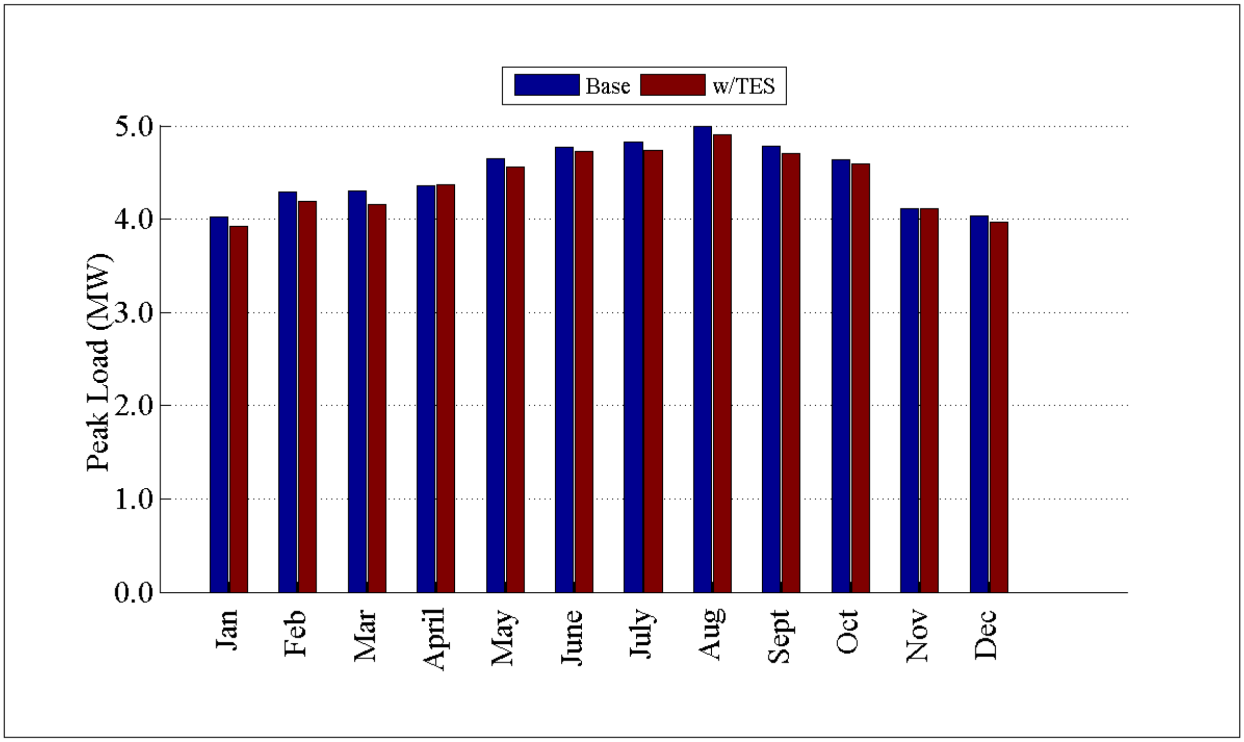

Figure D.169: Peak load by month of R5-12.47-2 feeder

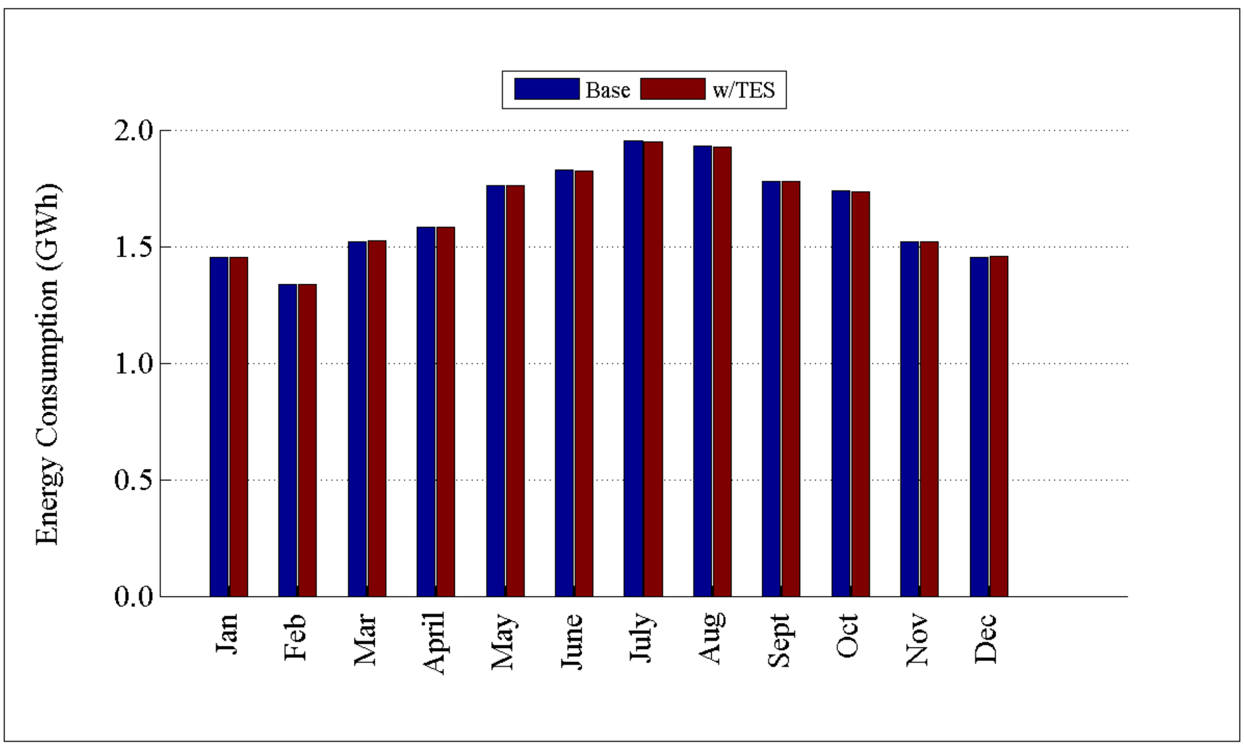

Figure D.170: Monthly energy consumption for R5-12.47-2 feeder

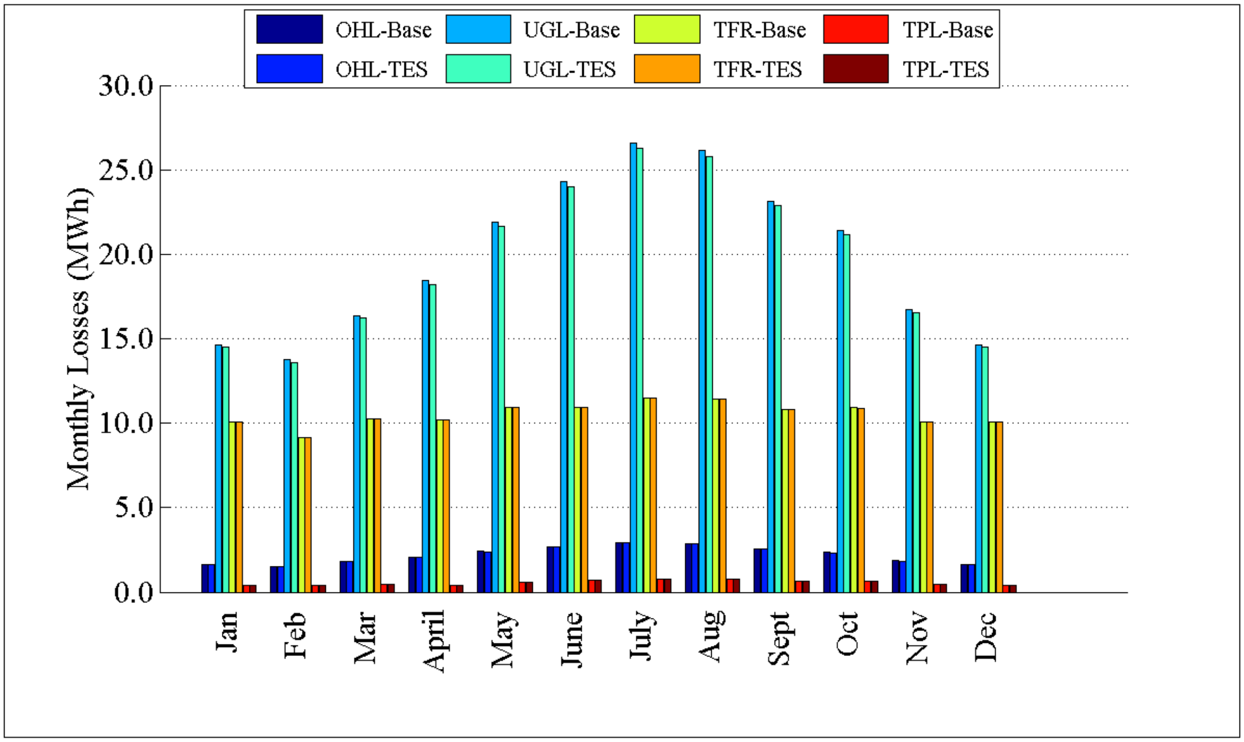

Figure D.171: Distribution system losses by month for R5-12.47-2

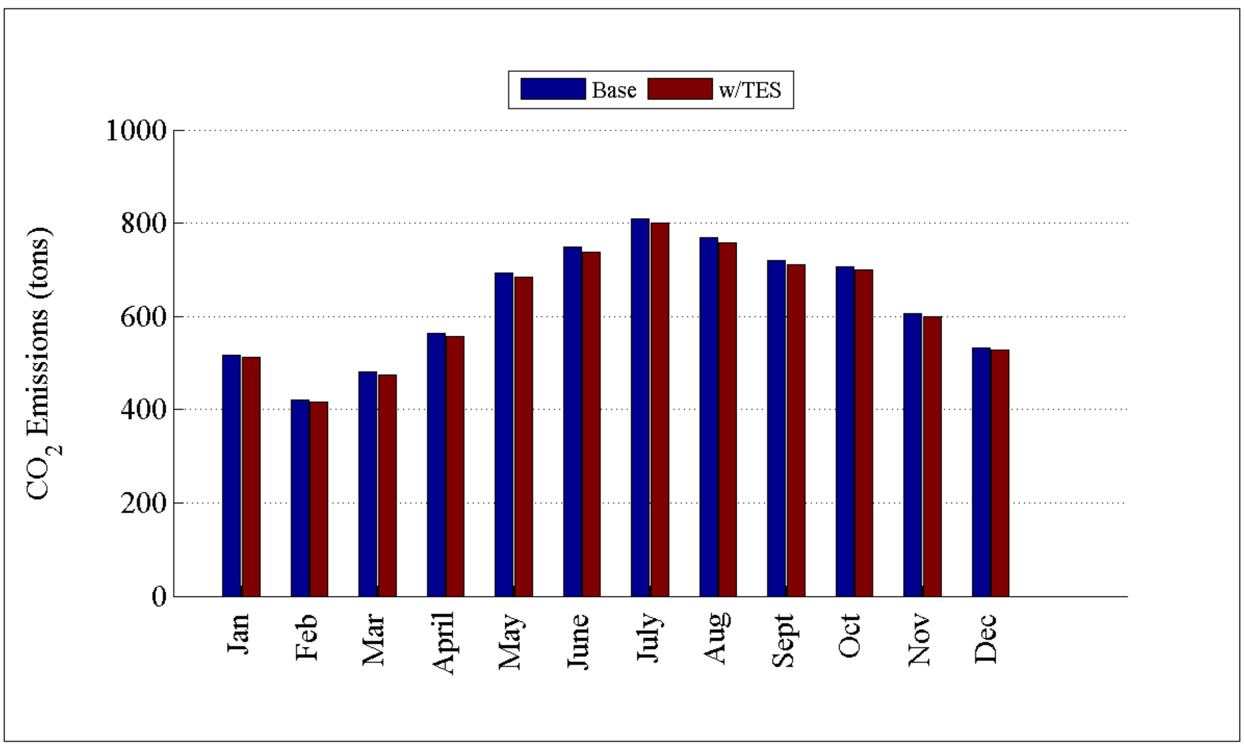

Figure D.172: CO_2 emissions by month for R5-12.47-2

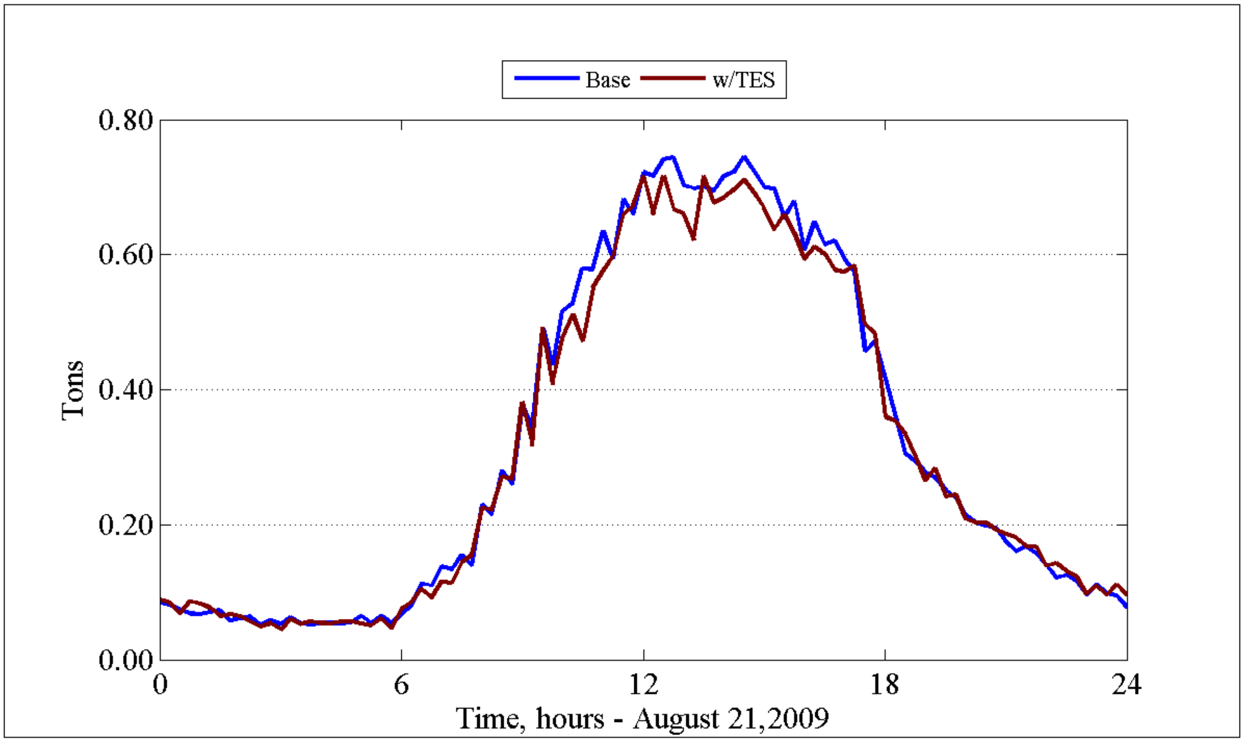

Figure D.173: Carbon dioxide emissions for peak day of R5-12.47-2

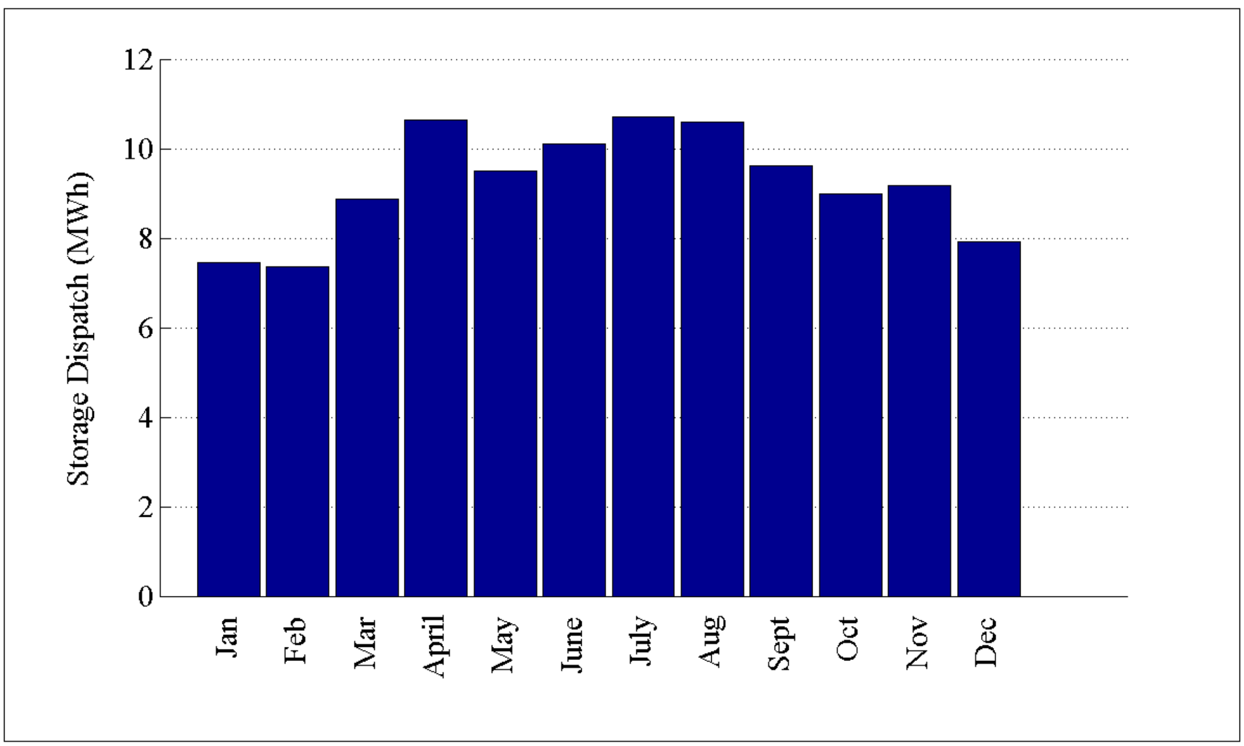

Figure D.174: Monthly storage dispatch energy for R5-12.47-2

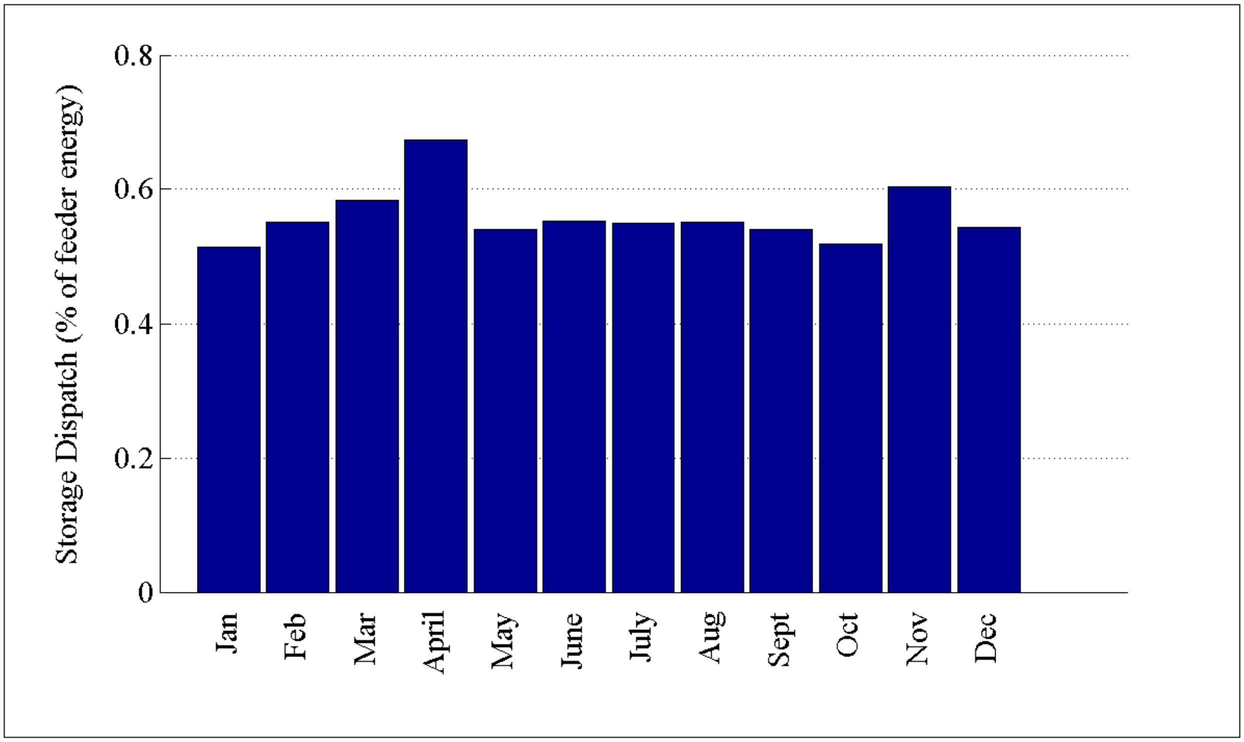

Figure D.175: Monthly storage dispatch energy percentage for R5-12.47-2

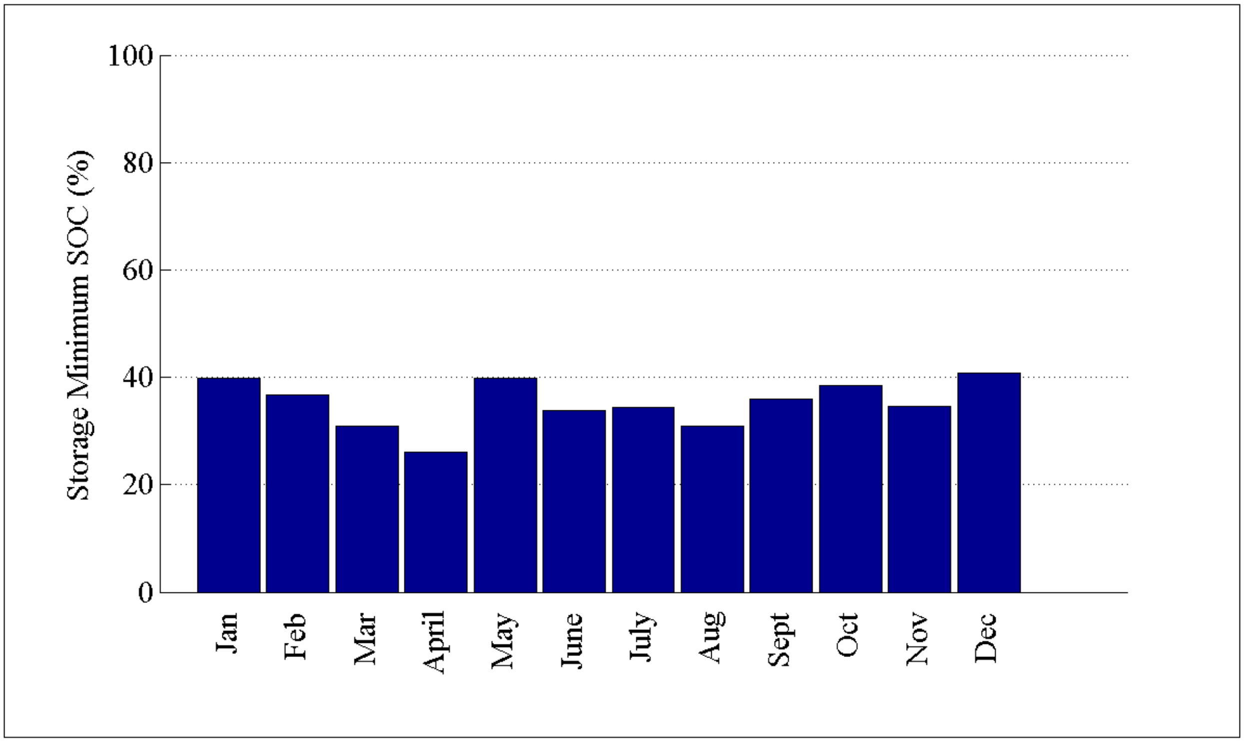

Figure D.176: Minimum state of charge for thermal energy storage on R5-12.47-2

D.24 Detailed Thermal Energy Storage Plots for R5-12.47-3

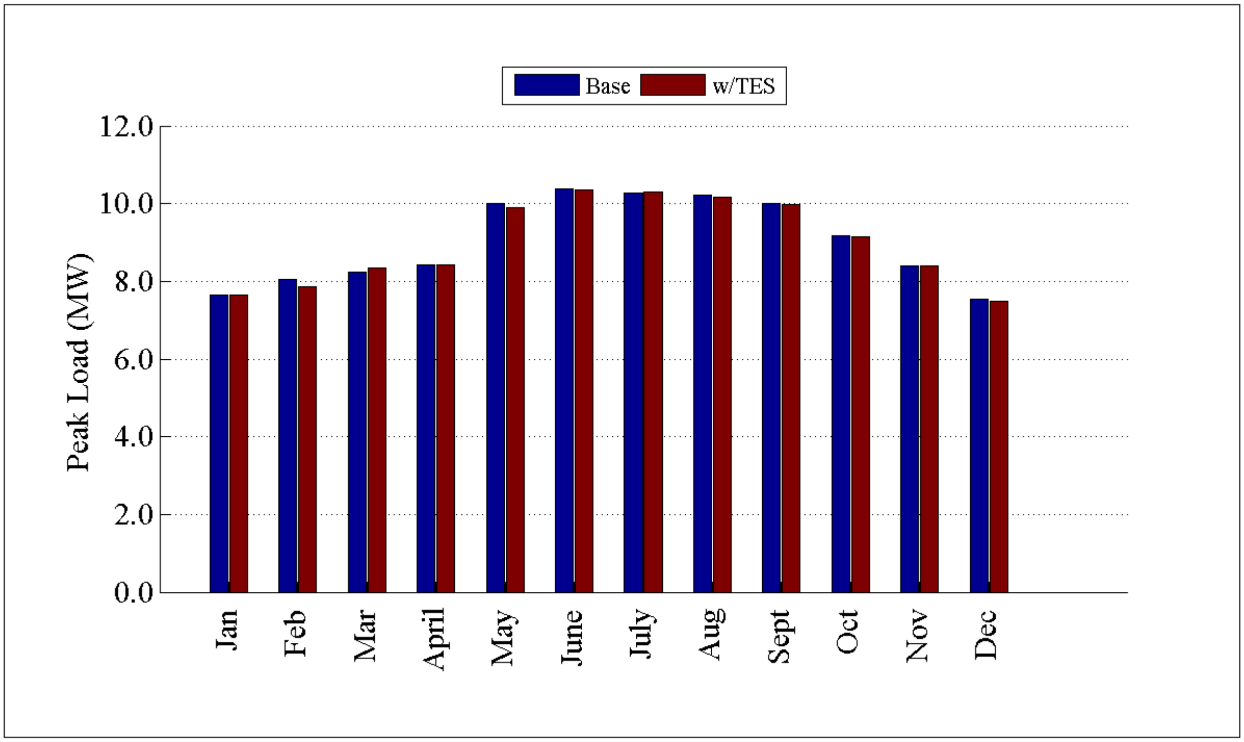

Figure D.177: Peak load by month of R5-12.47-3 feeder

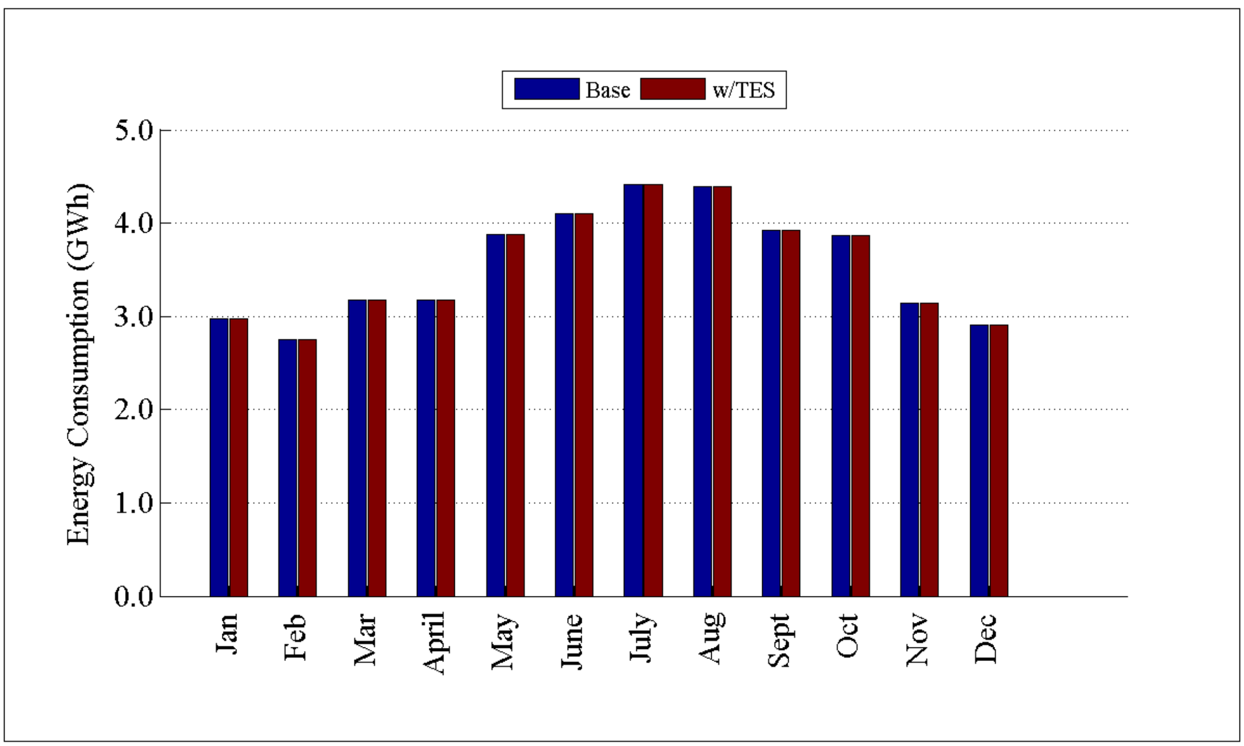

Figure D.178: Monthly energy consumption for R5-12.47-3 feeder

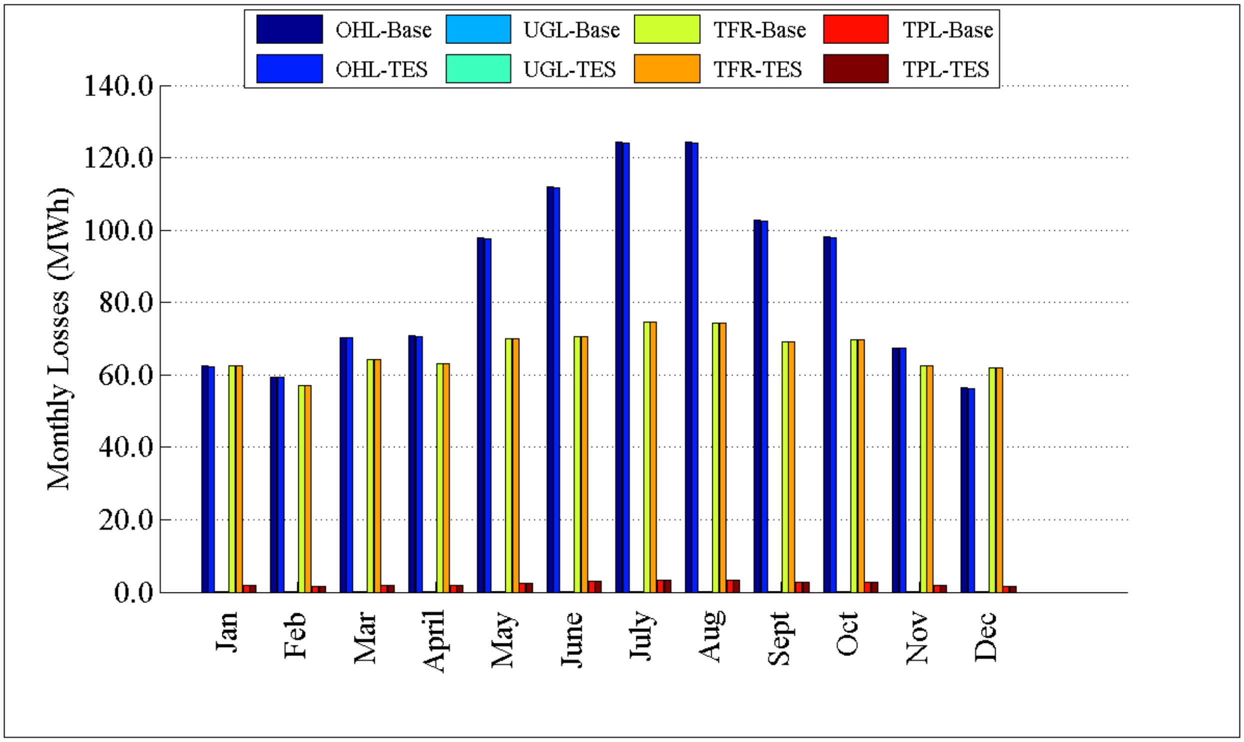

Figure D.179: Distribution system losses by month for R5-12.47-3

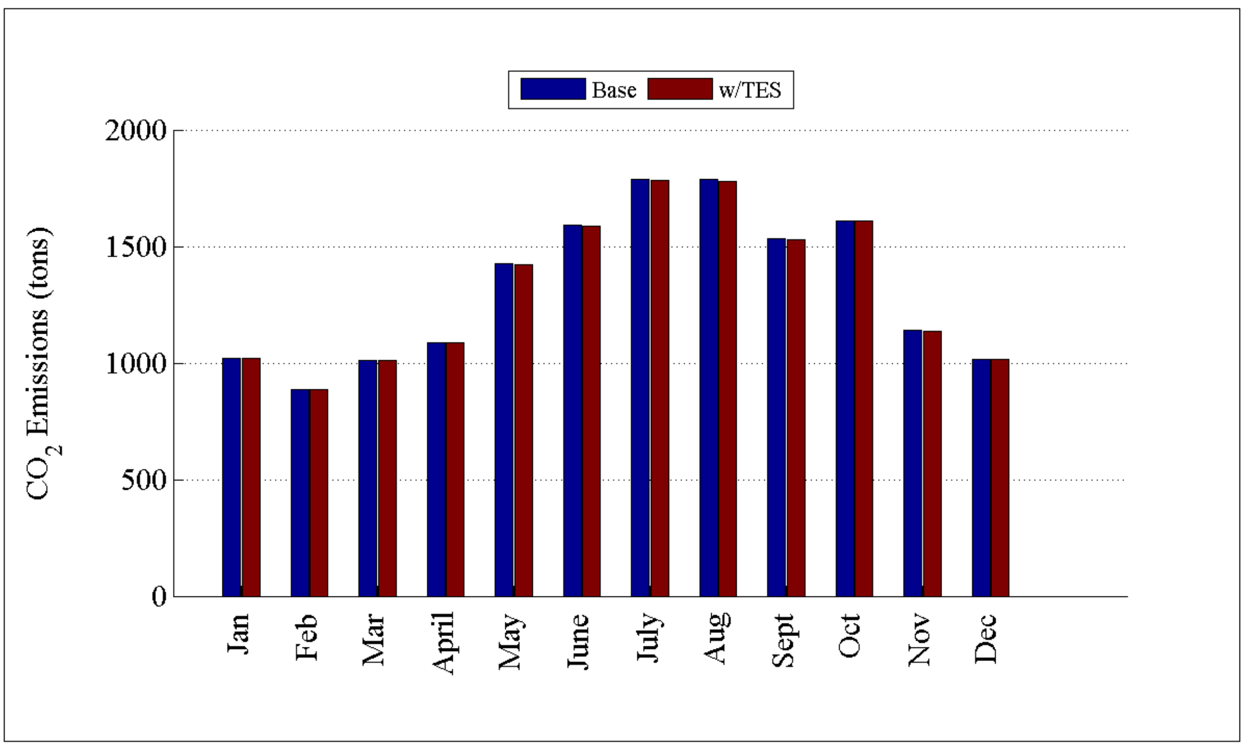

Figure D.180: CO_2 emissions by month for R5-12.47-3

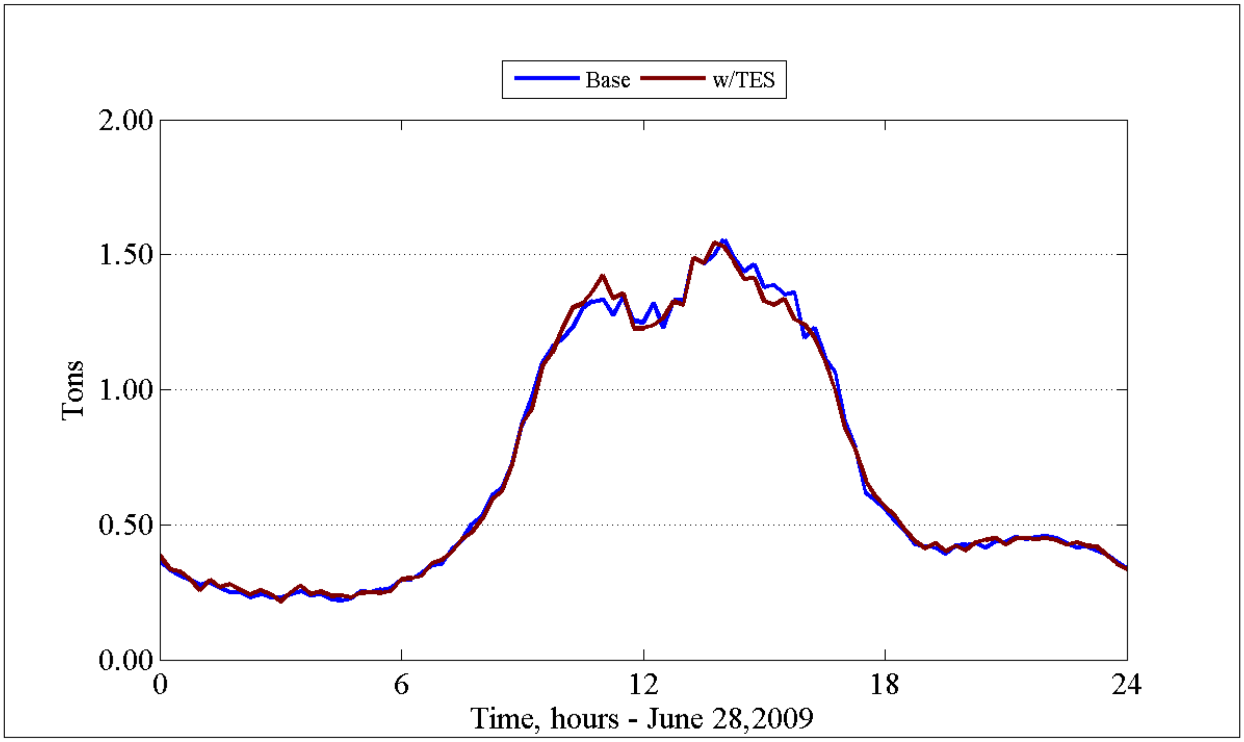

Figure D.181: Carbon dioxide emissions for peak day of R5-12.47-3

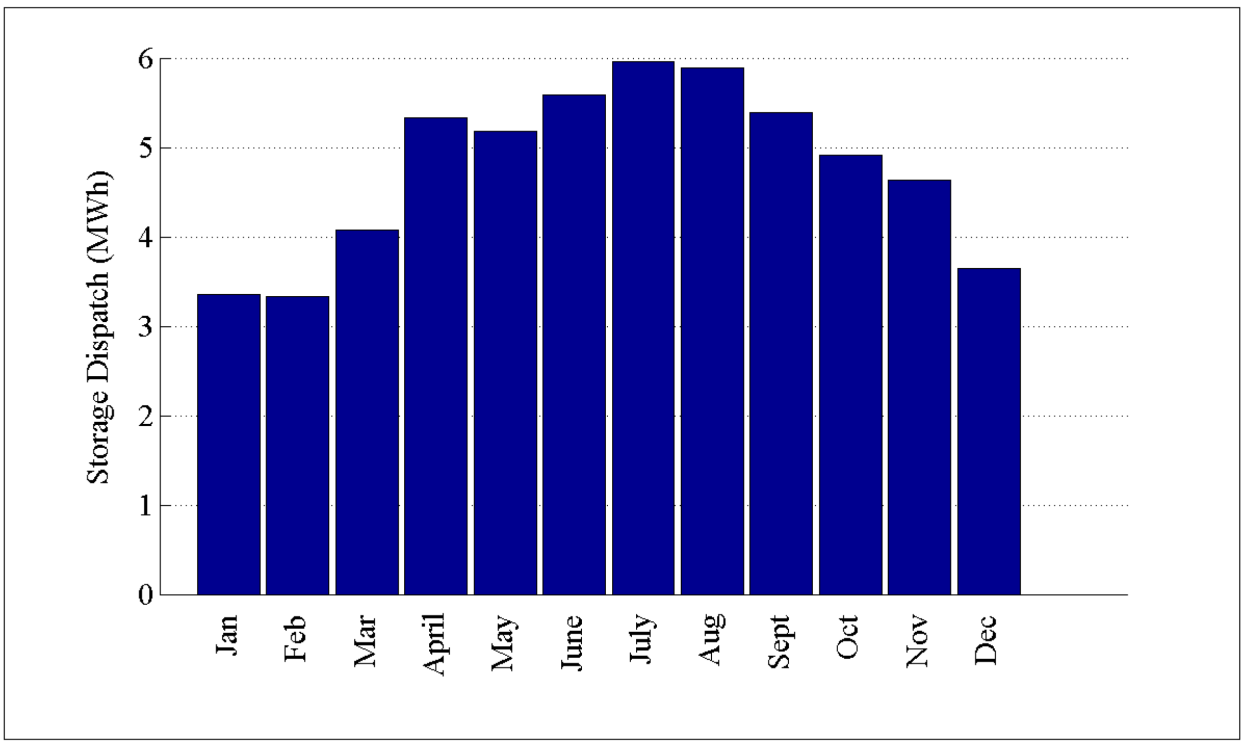

Figure D.182: Monthly storage dispatch energy for R5-12.47-3

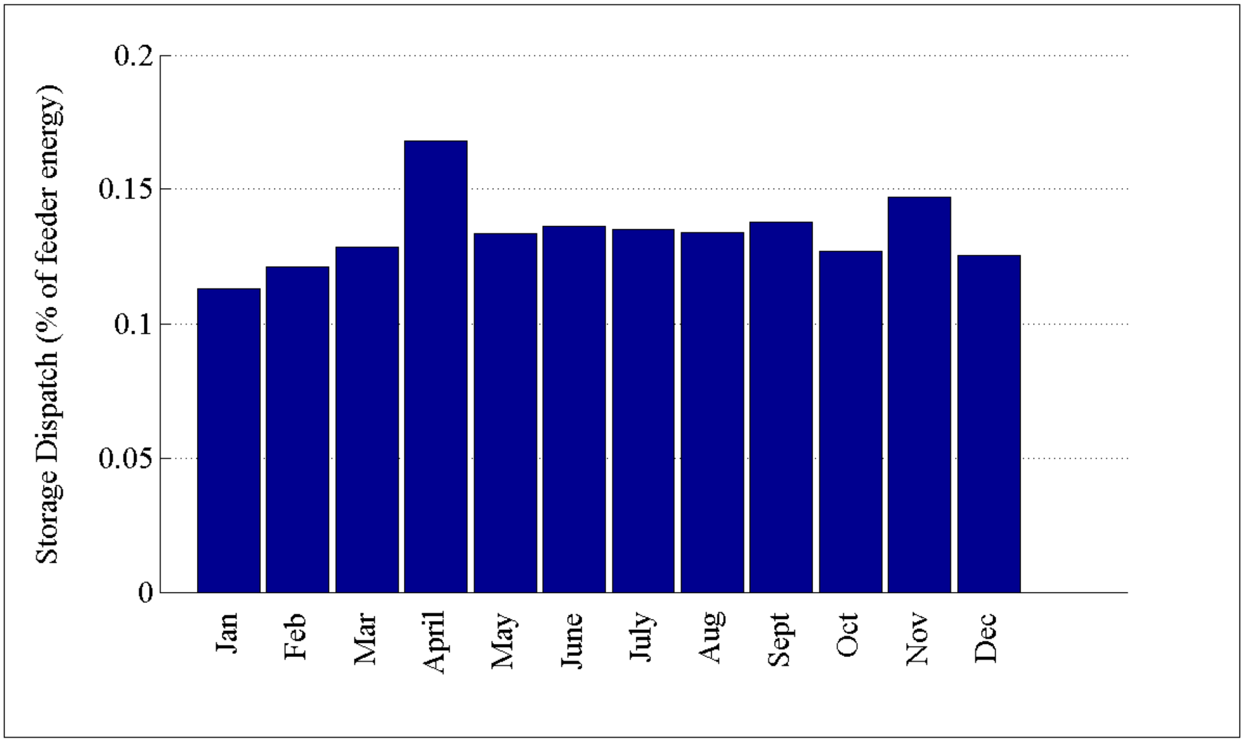

Figure D.183: Monthly storage dispatch energy percentage for R5-12.47-3

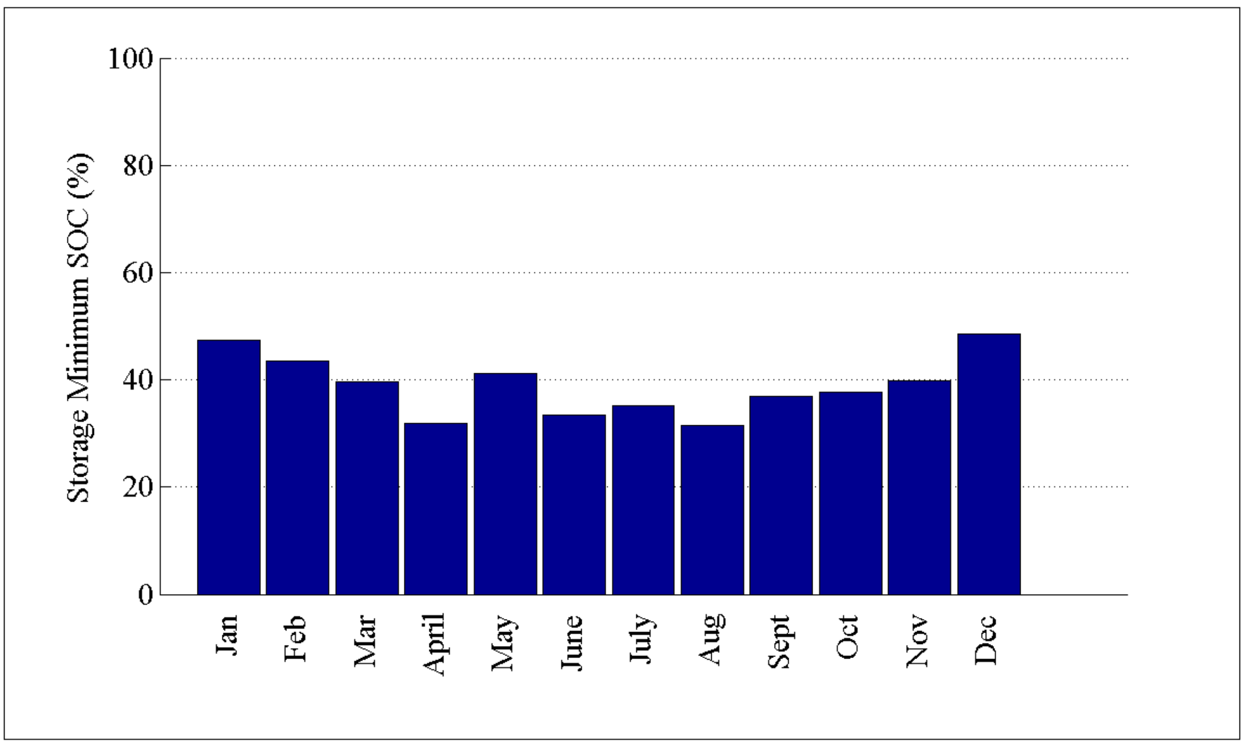

Figure D.184: Minimum state of charge for thermal energy storage on R5-12.47-3

D.25 Detailed Thermal Energy Storage Plots for R5-12.47-4

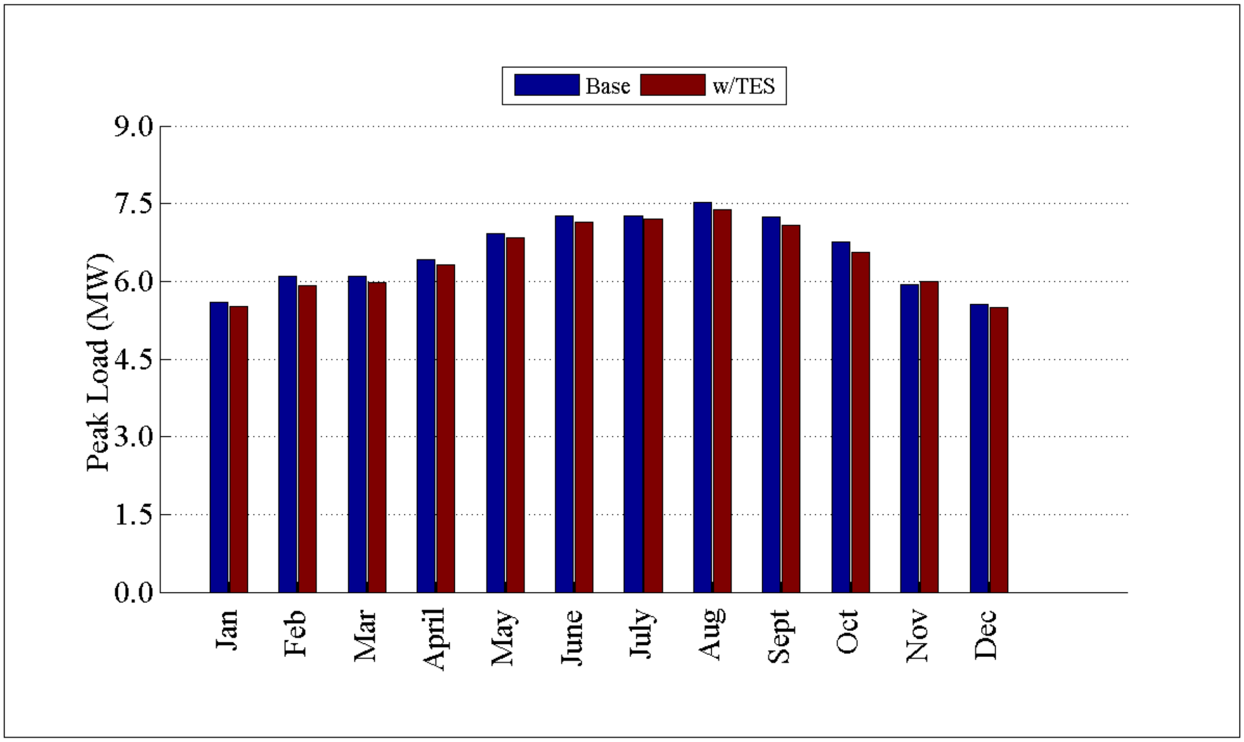

Figure D.185: Peak load by month of R5-12.47-4 feeder

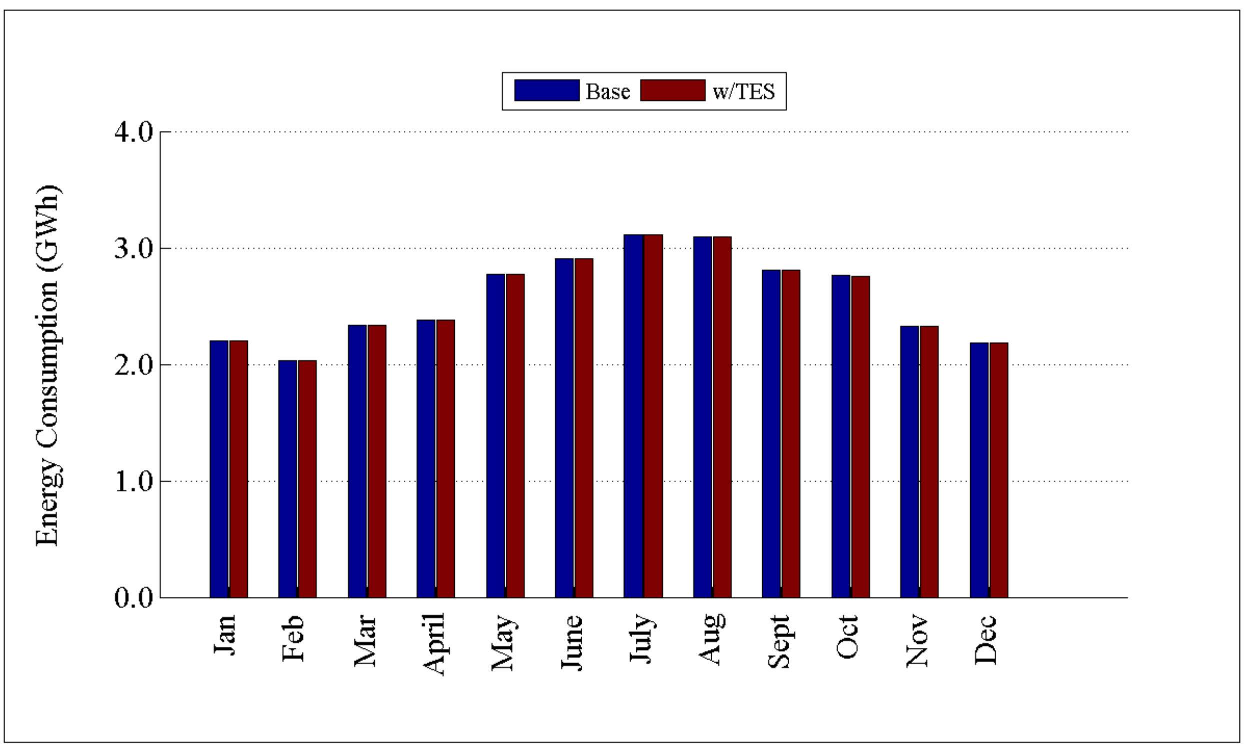

Figure D.186: Monthly energy consumption for R5-12.47-4 feeder

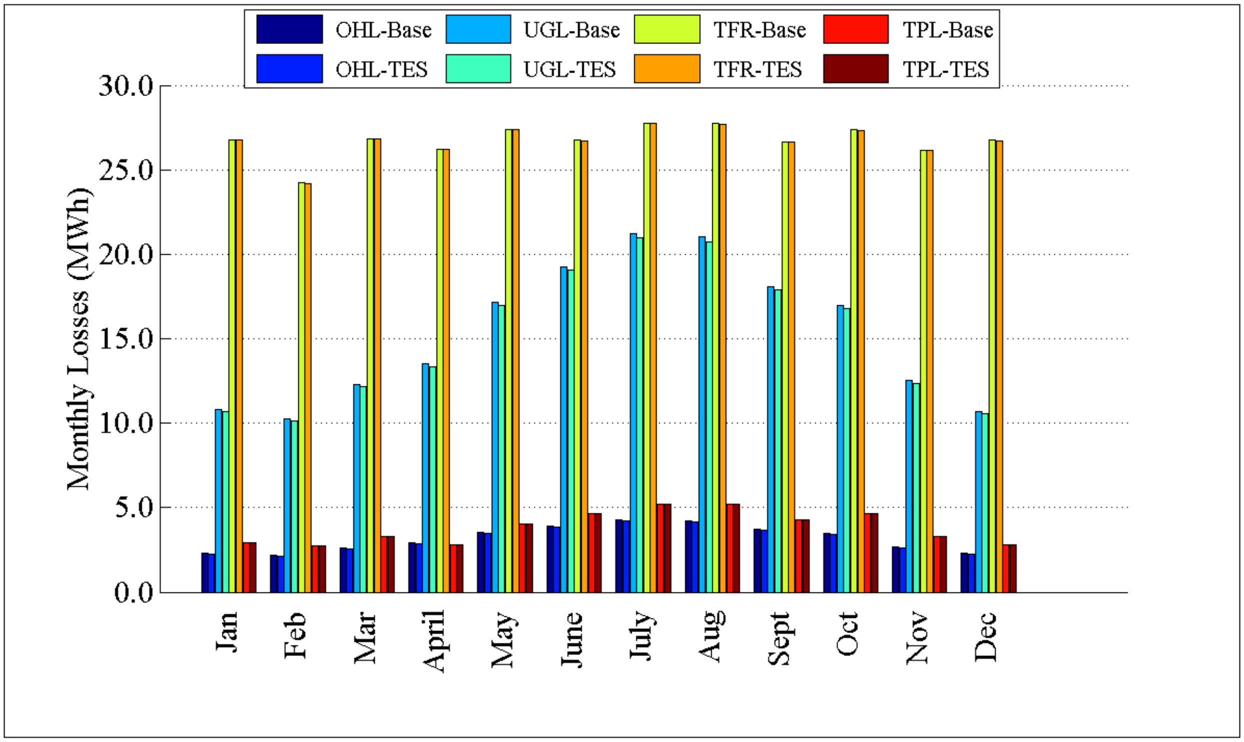

Figure D.187: Distribution system losses by month for R5-12.47-4

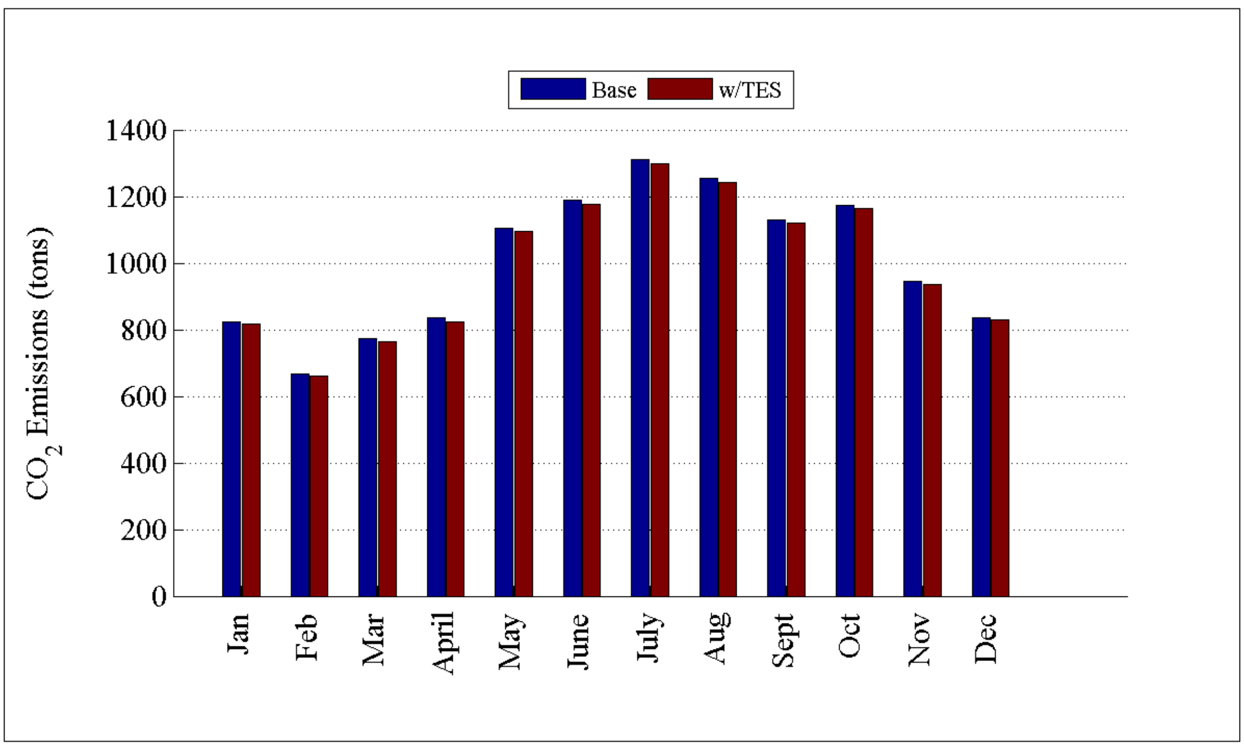

Figure D.188: CO_2 emissions by month for R5-12.47-4

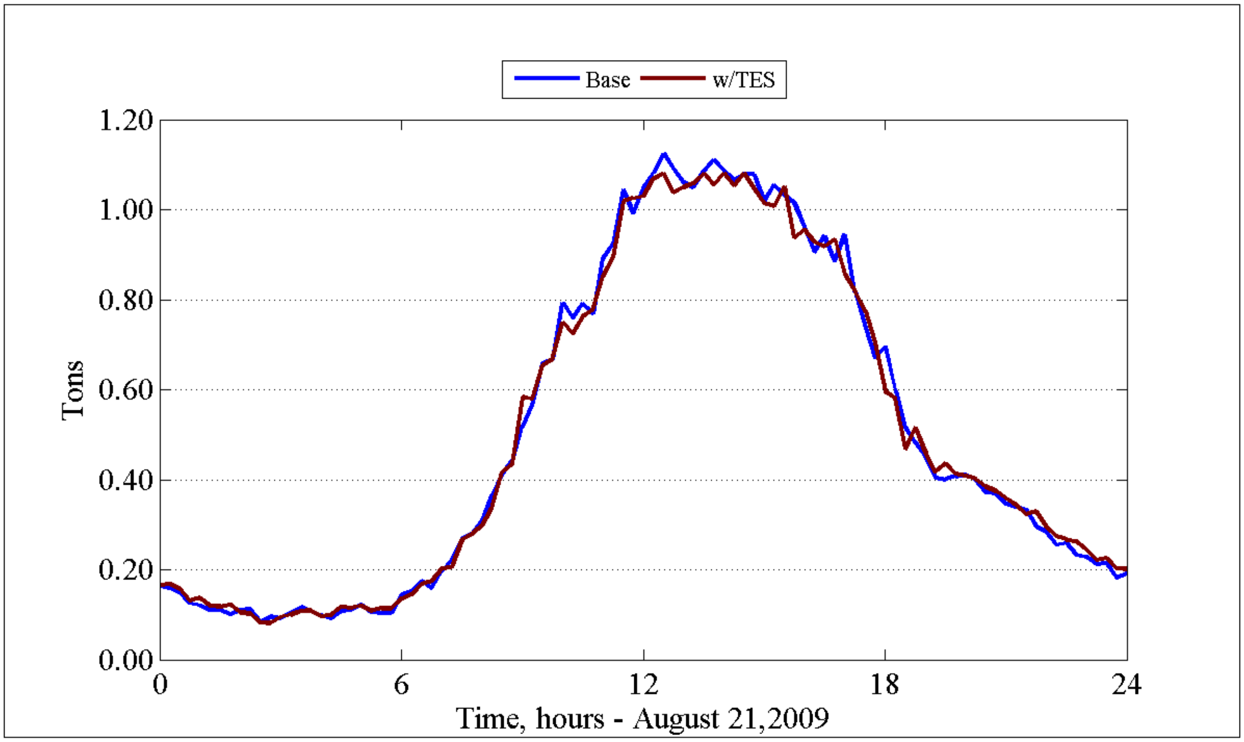

Figure D.189: Carbon dioxide emissions for peak day of R5-12.47-4

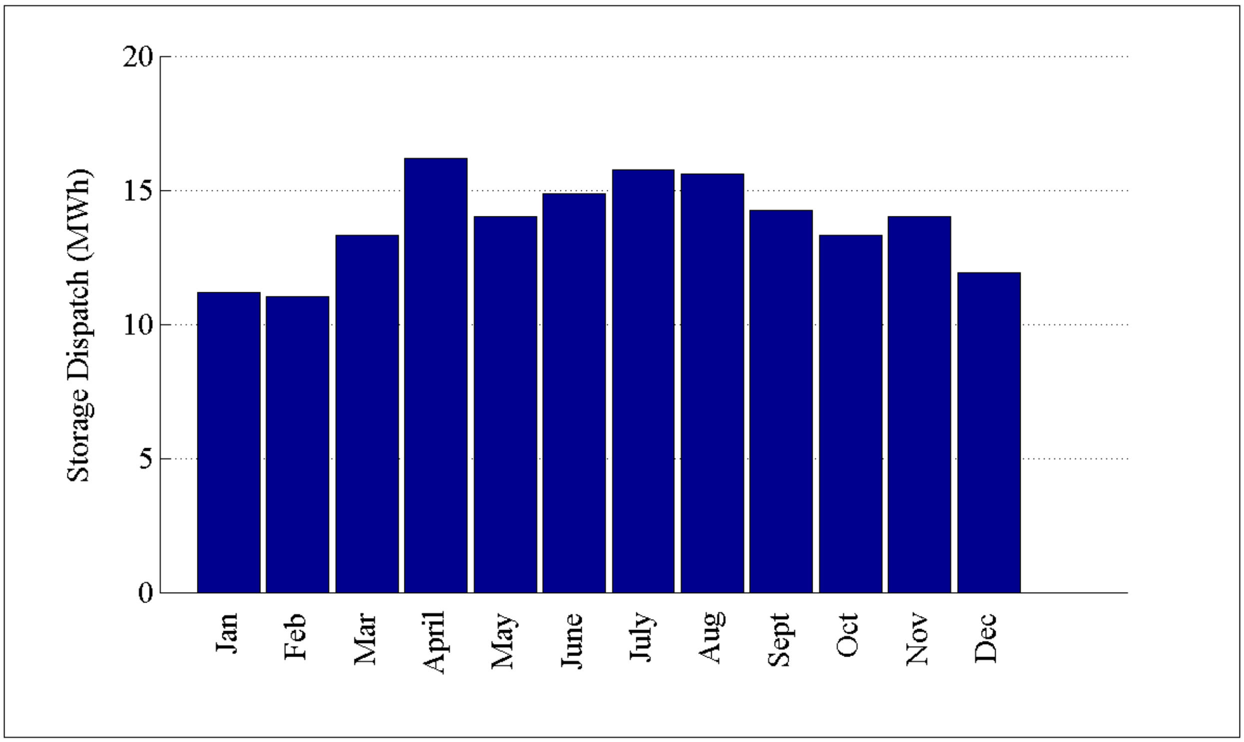

Figure D.190: Monthly storage dispatch energy for R5-12.47-4

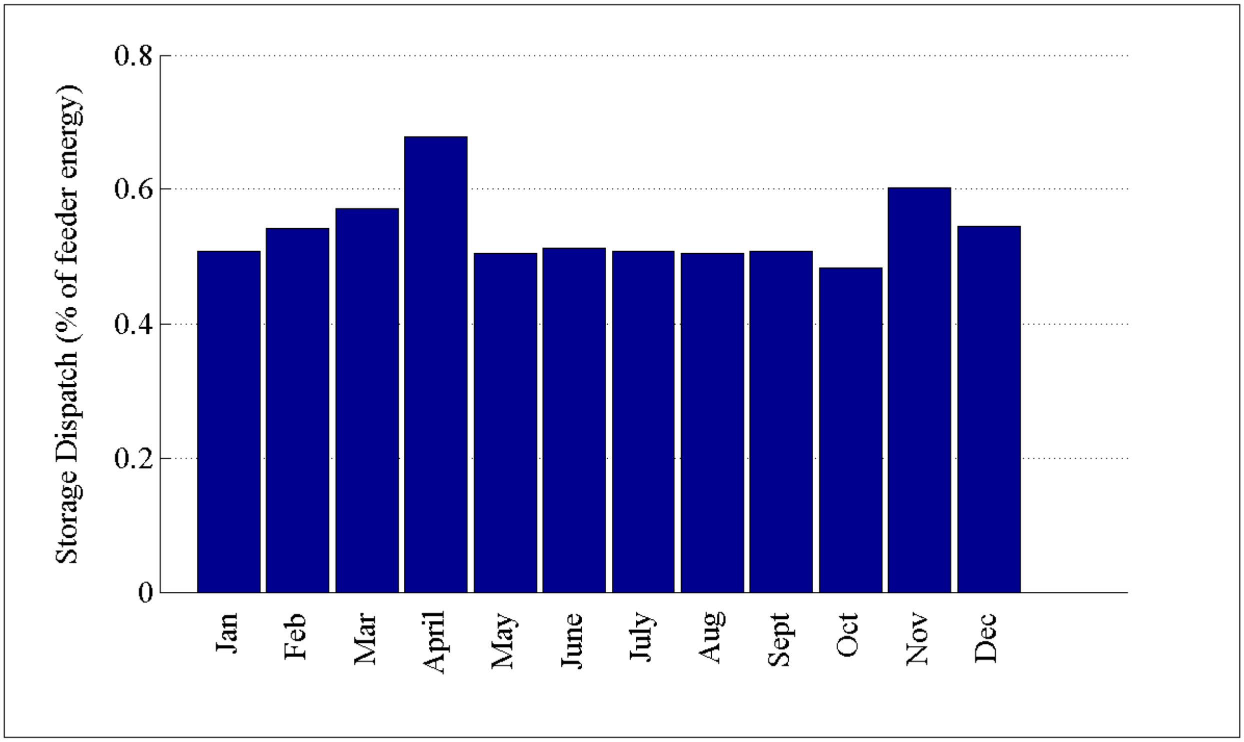

Figure D.191: Monthly storage dispatch energy percentage for R5-12.47-4

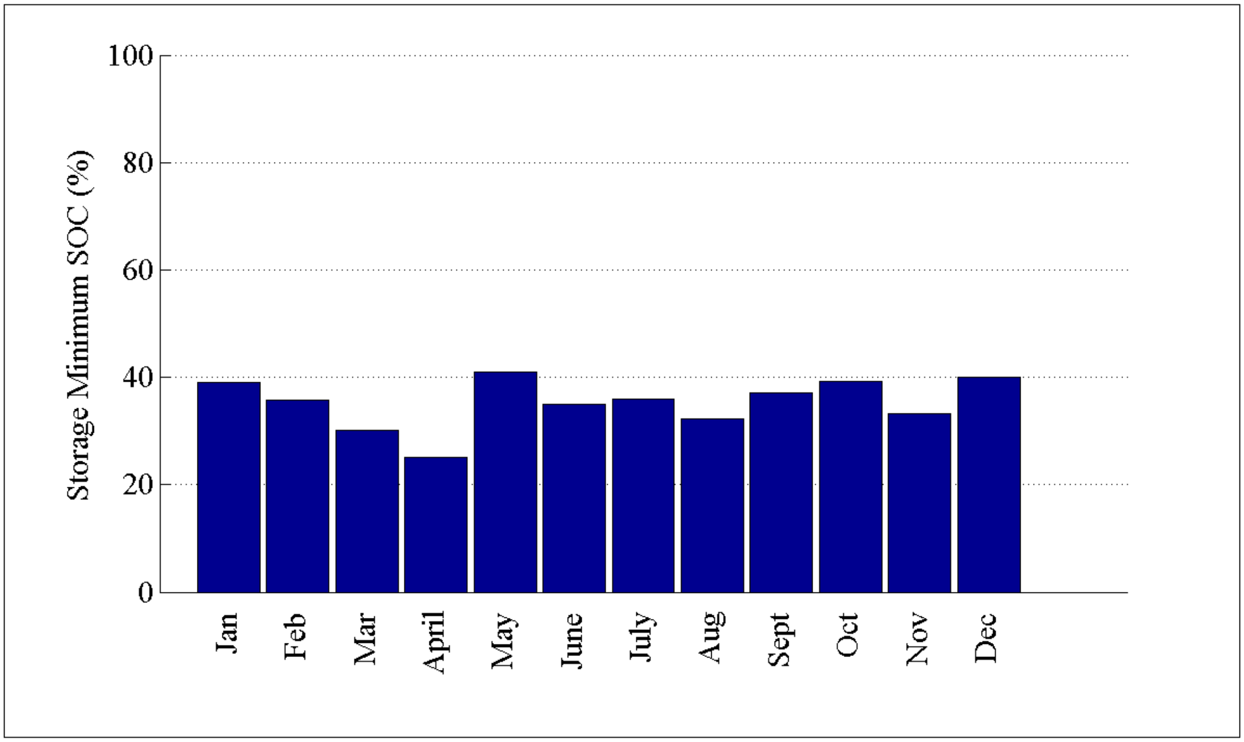

Figure D.192: Minimum state of charge for thermal energy storage on R5-12.47-4

D.26 Detailed Thermal Energy Storage Plots for R5-12.47-5

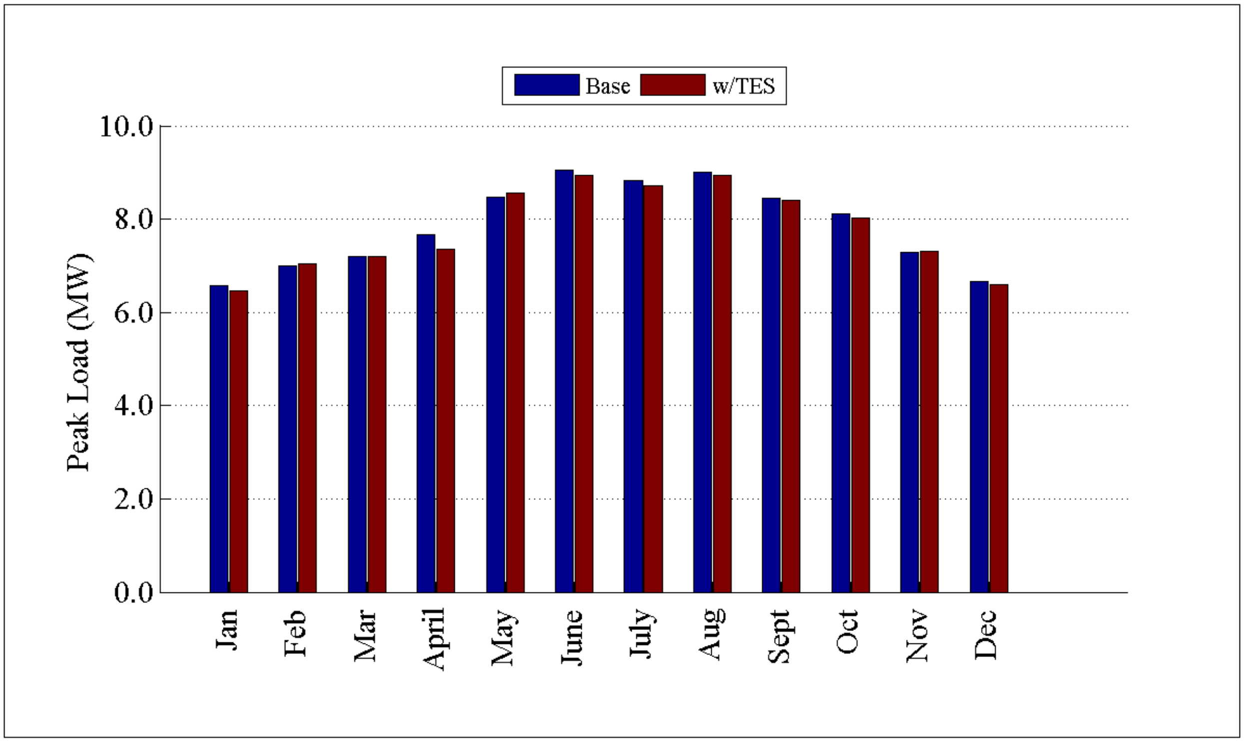

Figure D.193: Peak load by month of R5-12.47-5 feeder

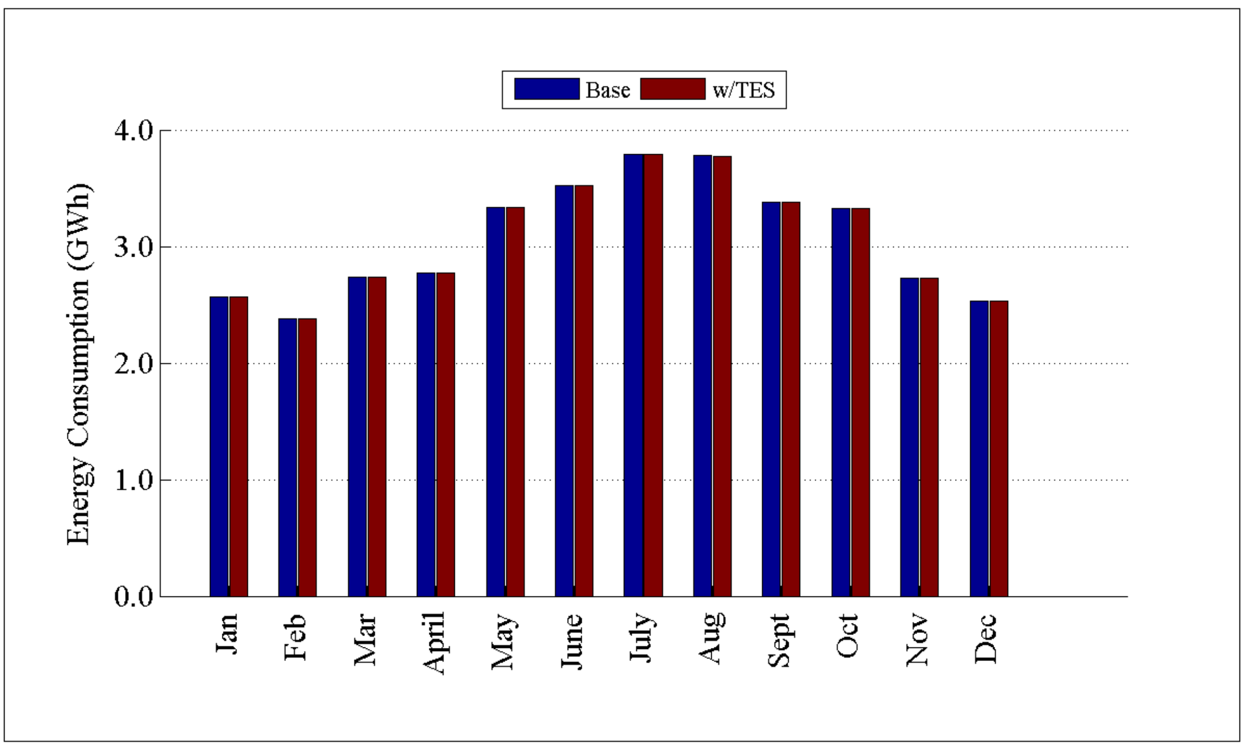

Figure D.194: Monthly energy consumption for R5-12.47-5 feeder

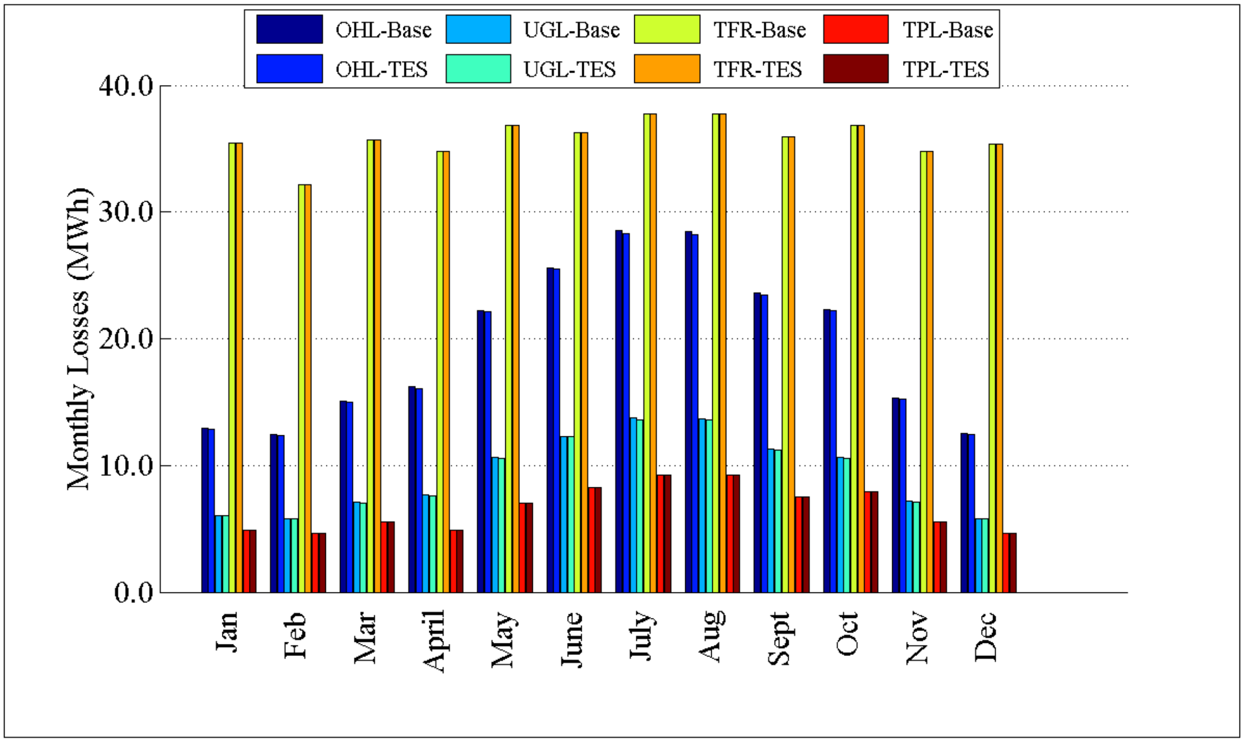

Figure D.195: Distribution system losses by month for R5-12.47-5

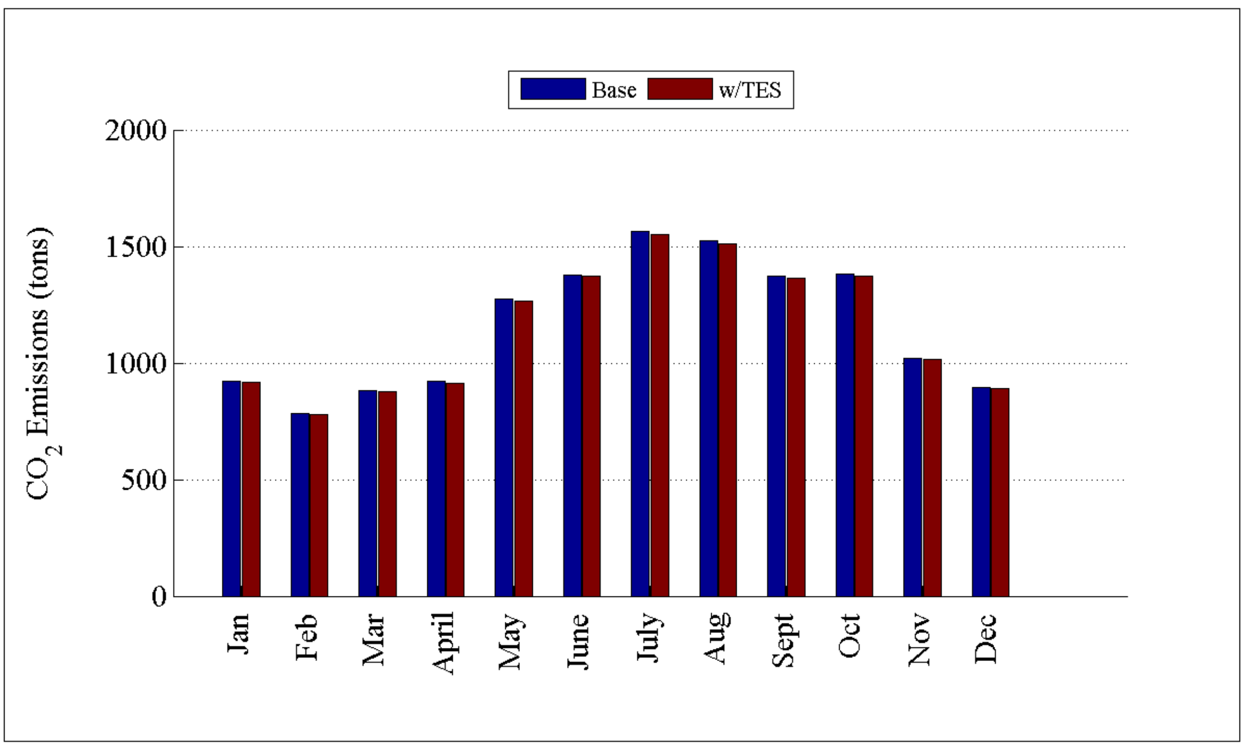

Figure D.196: CO_2 emissions by month for R5-12.47-5

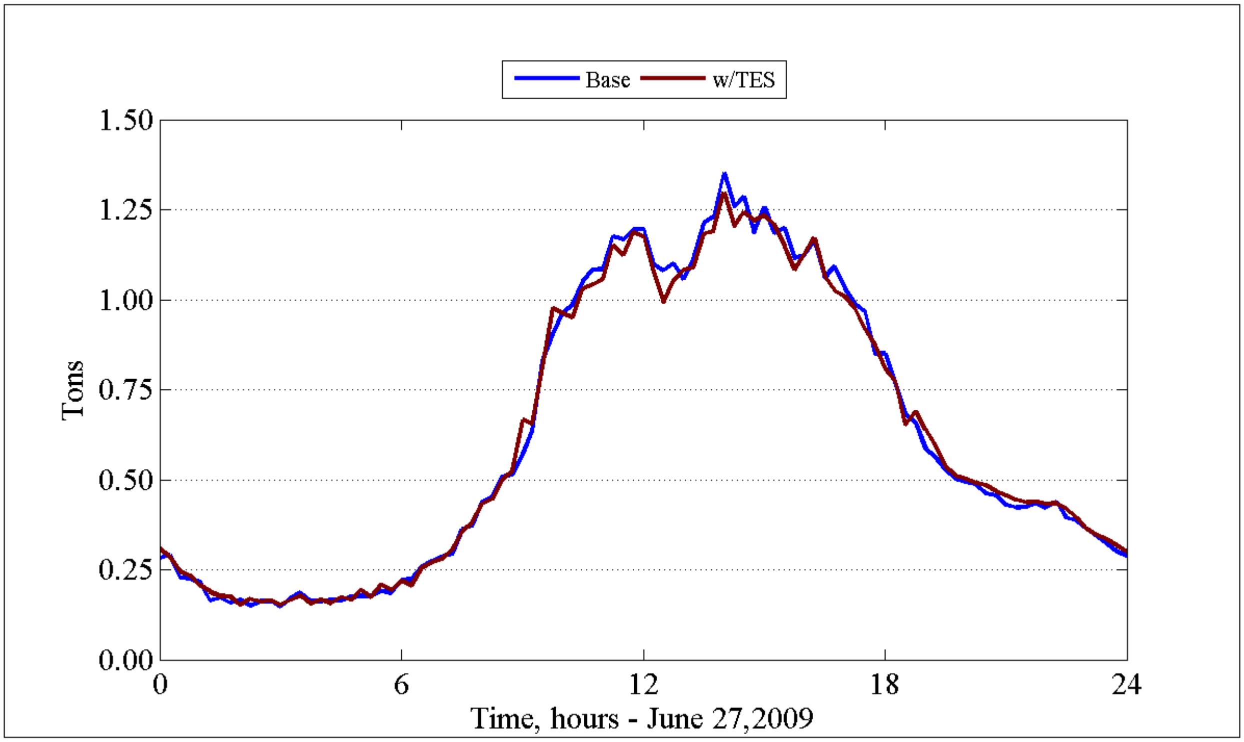

Figure D.197: Carbon dioxide emissions for peak day of R5-12.47-5

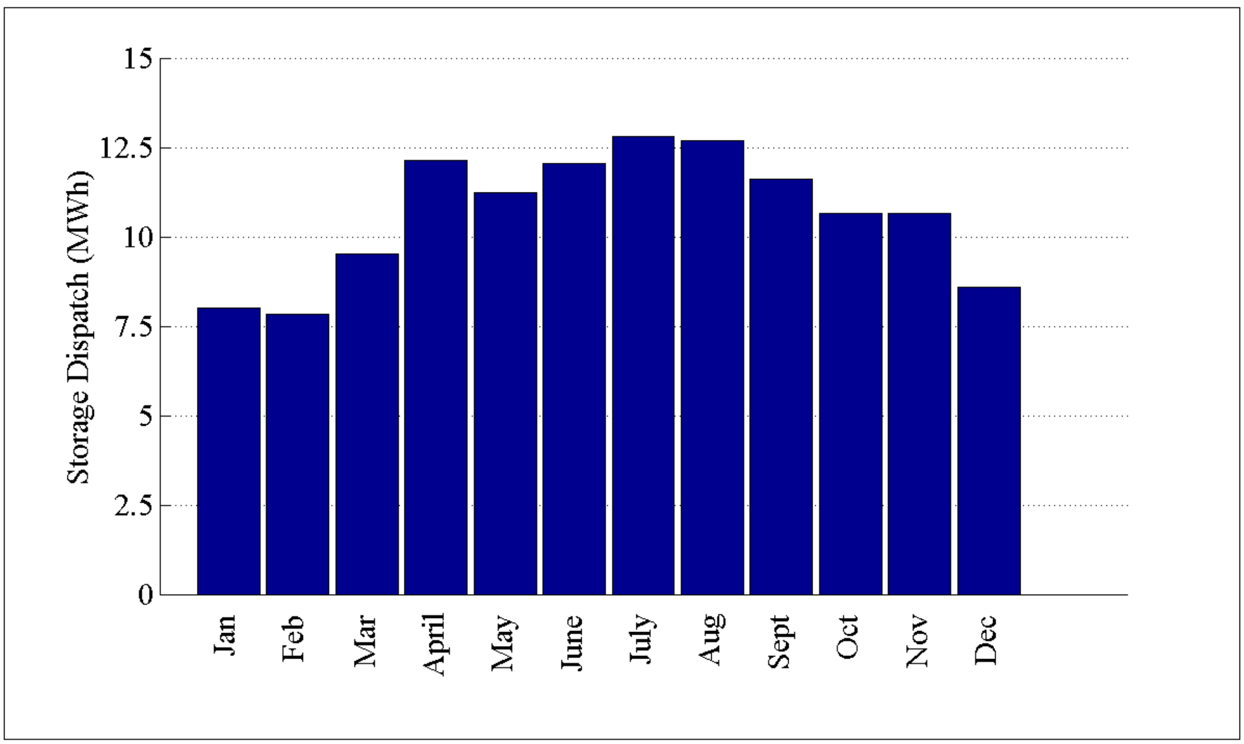

Figure D.198: Monthly storage dispatch energy for R5-12.47-5

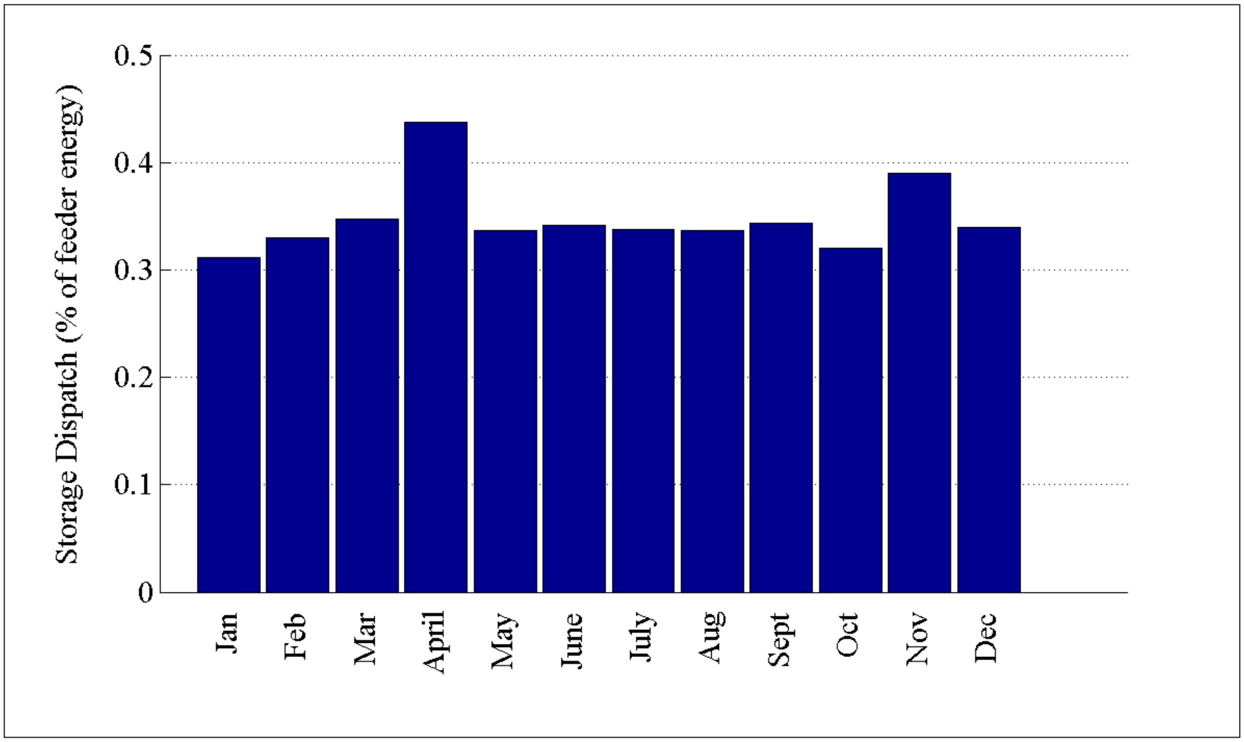

Figure D.199: Monthly storage dispatch energy percentage for R5-12.47-5

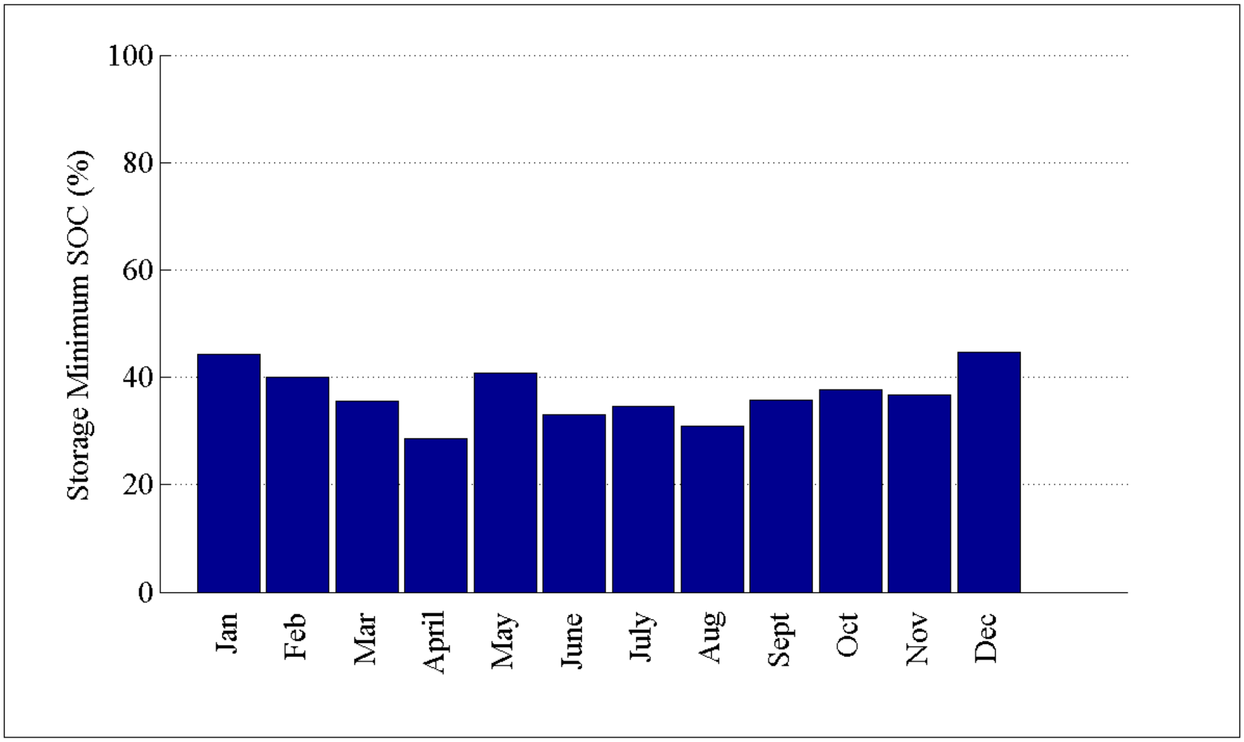

Figure D.200: Minimum state of charge for thermal energy storage on R5-12.47-5

D.27 Detailed Thermal Energy Storage Plots for R5-25.00-1

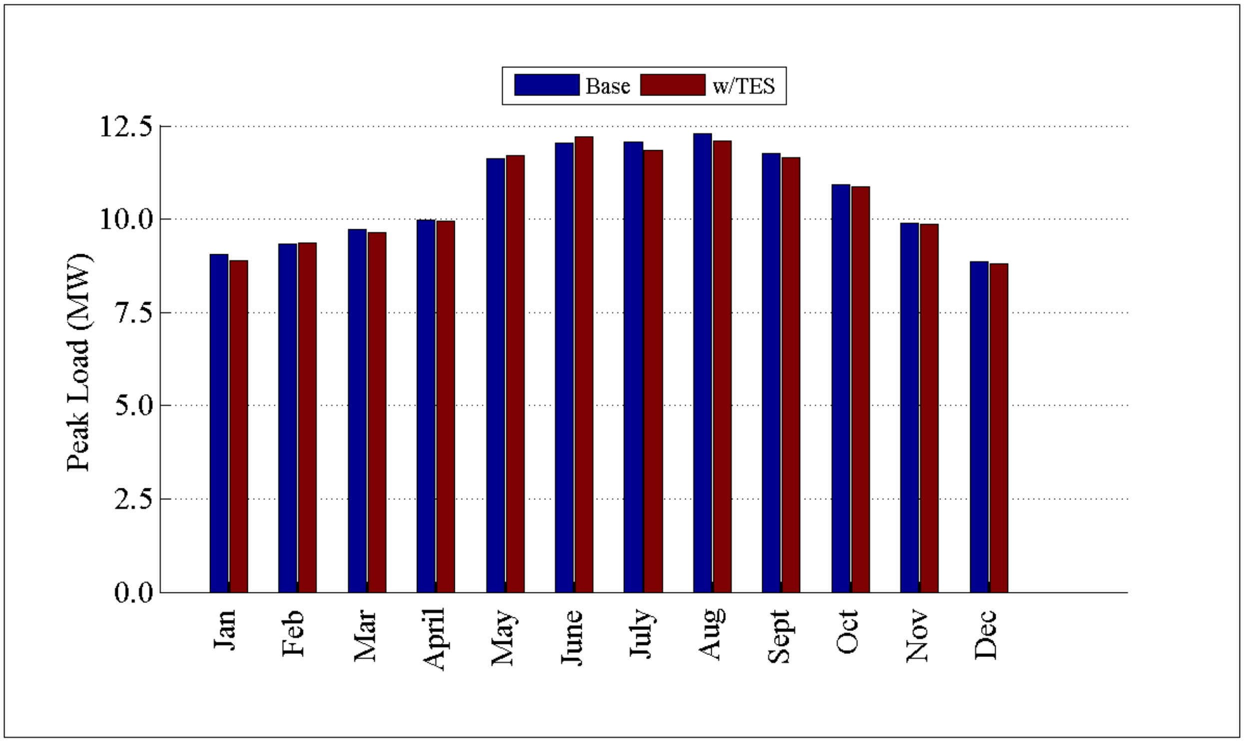

Figure D.201: Peak load by month of R5-25.00-1 feeder

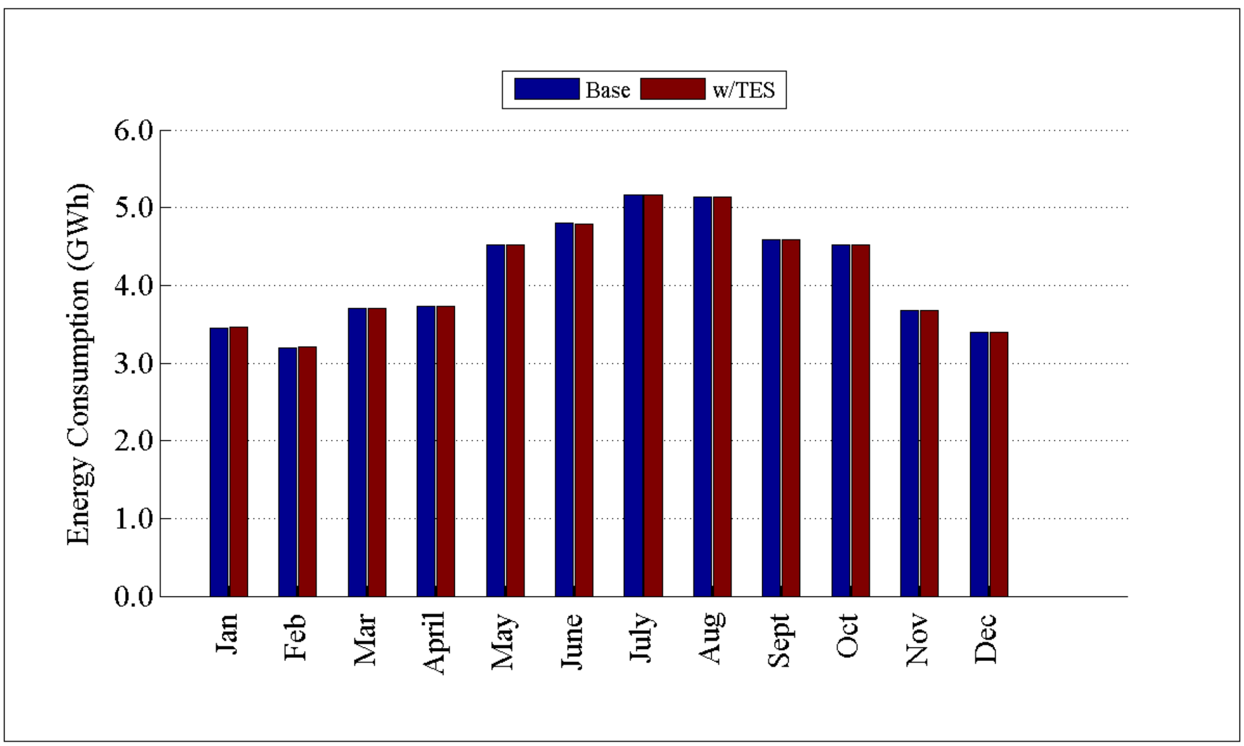

Figure D.202: Monthly energy consumption for R5-25.00-1 feeder

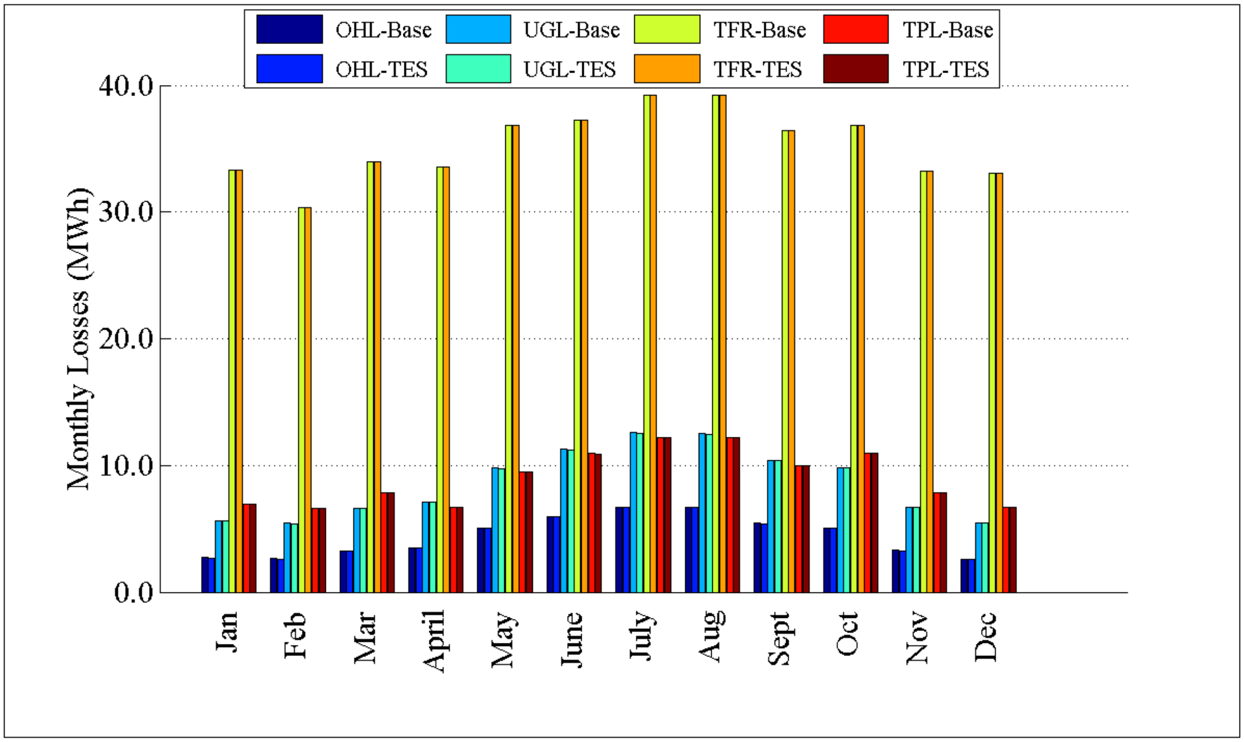

Figure D.203: Distribution system losses by month for R5-25.00-1

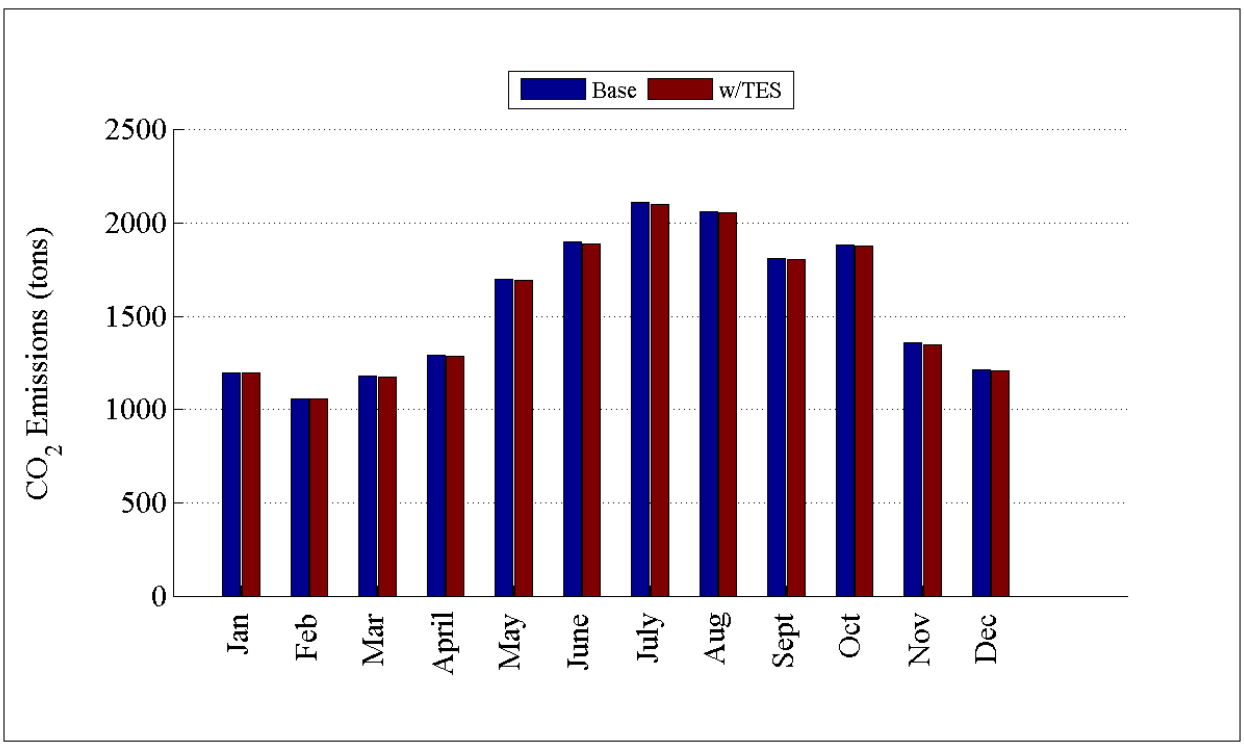

Figure D.204: CO_2 emissions by month for R5-25.00-1

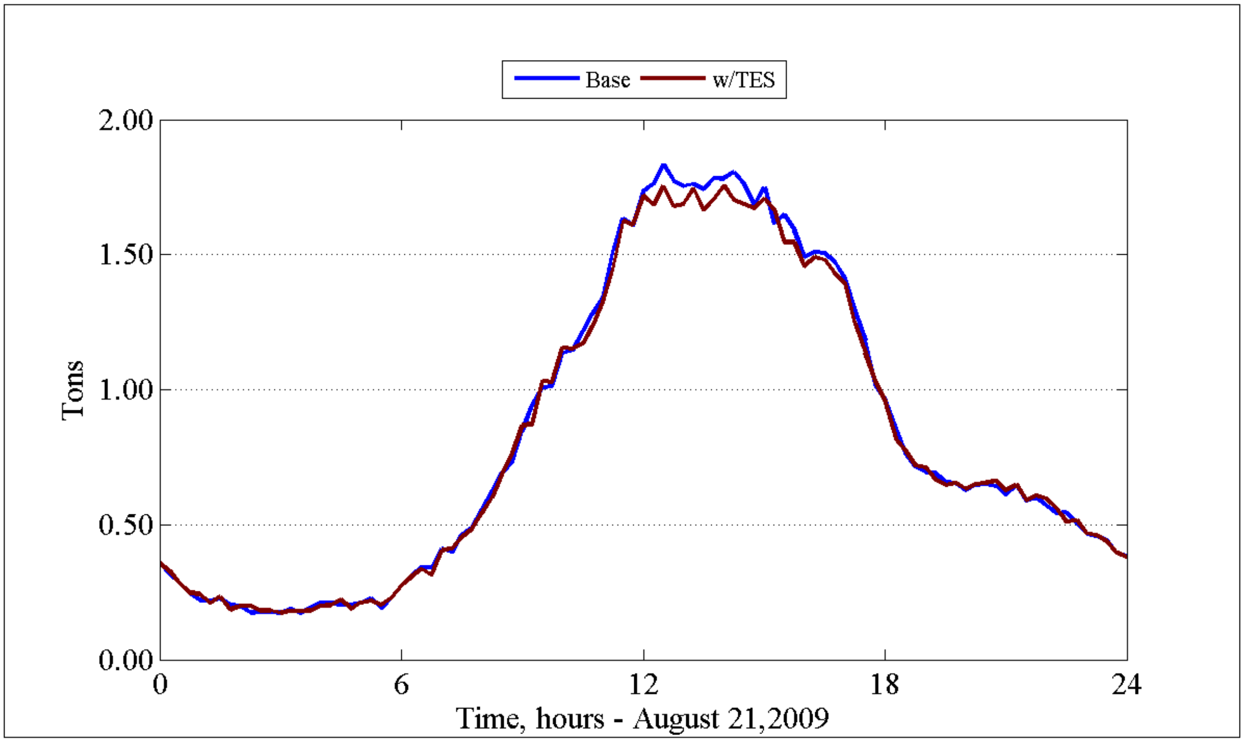

Figure D.205: Carbon dioxide emissions for peak day of R5-25.00-1

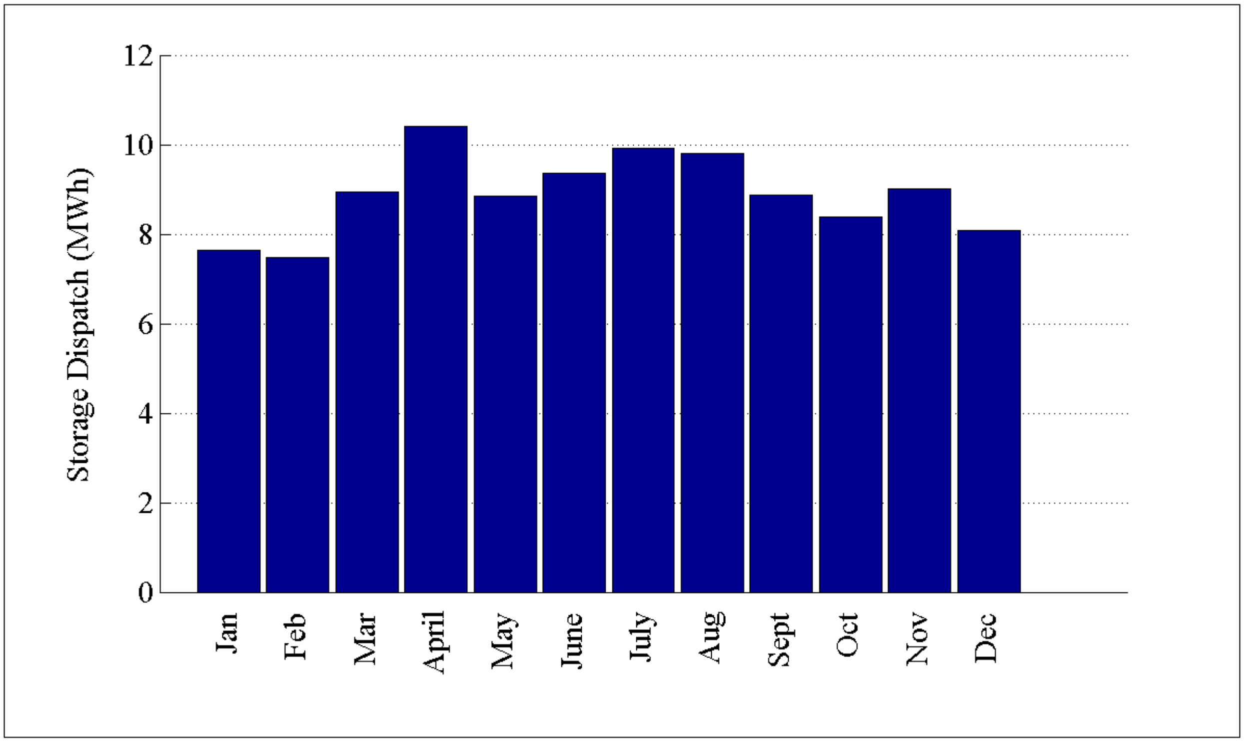

Figure D.206: Monthly storage dispatch energy for R5-25.00-1

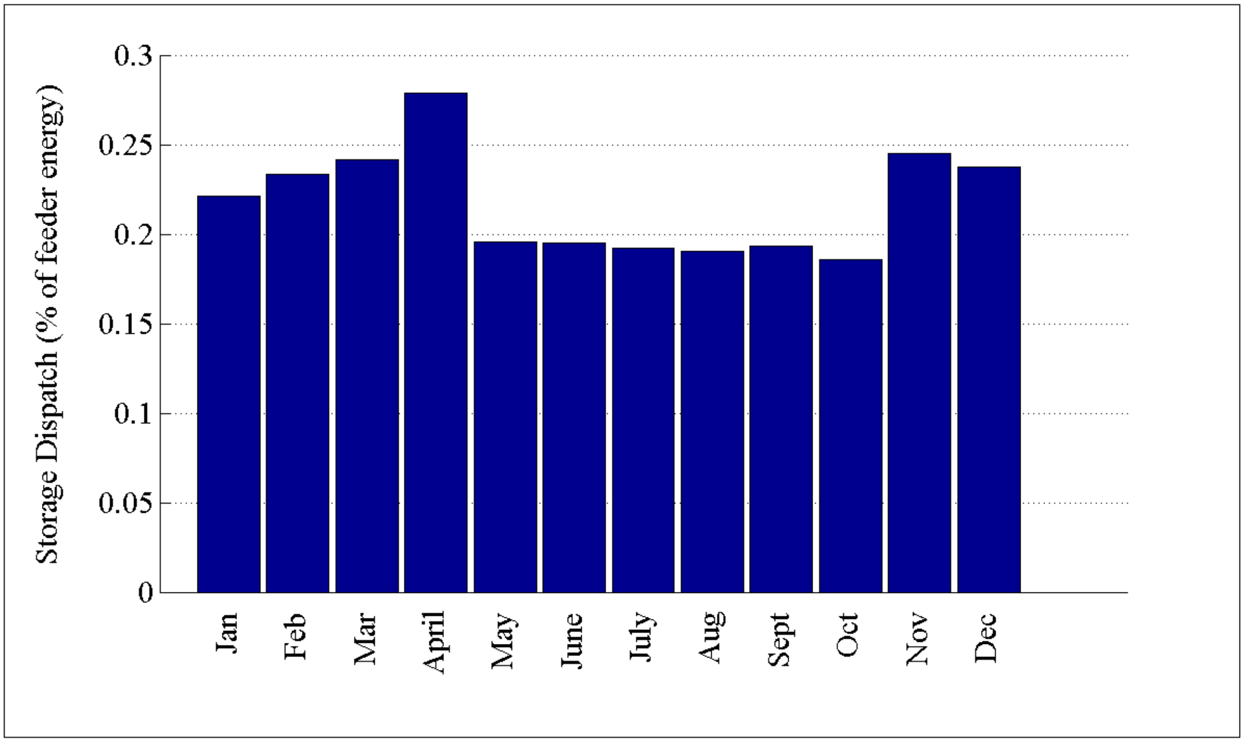

Figure D.207: Monthly storage dispatch energy percentage for R5-25.00-1

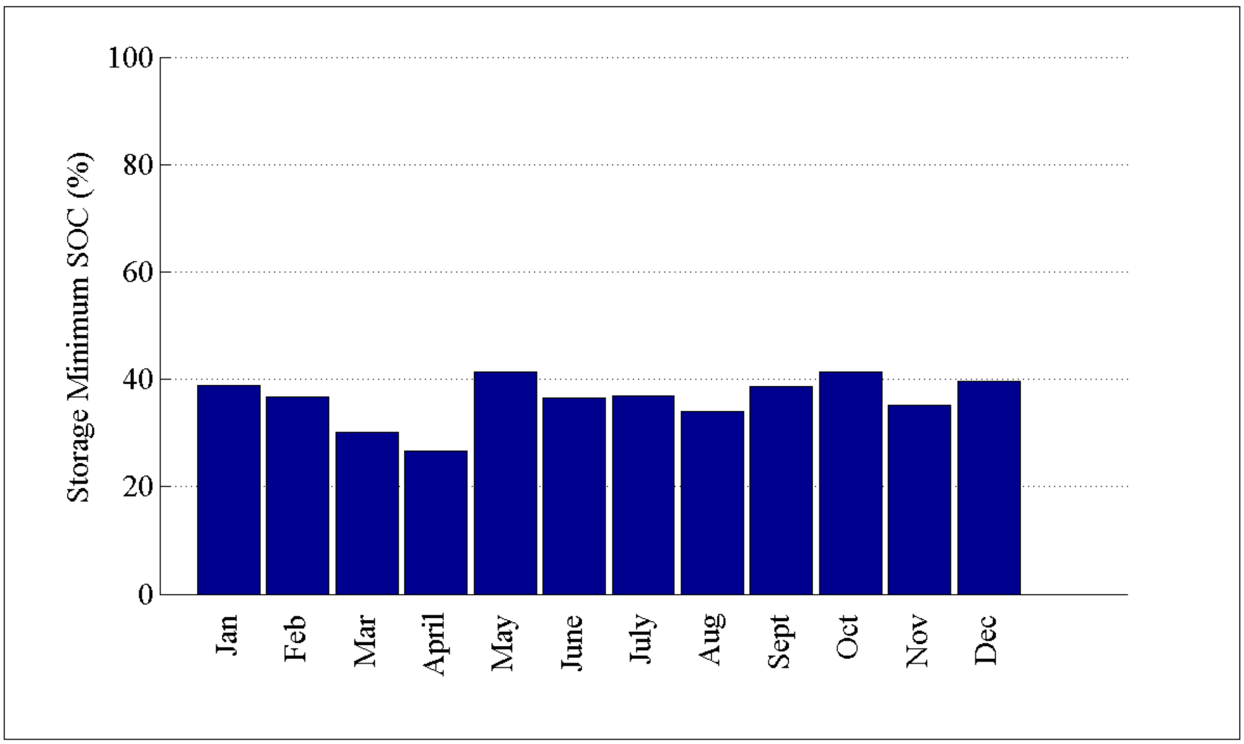

Figure D.208: Minimum state of charge for thermal energy storage on R5-25.00-1

D.28 Detailed Thermal Energy Storage Plots for R5-35.00-1

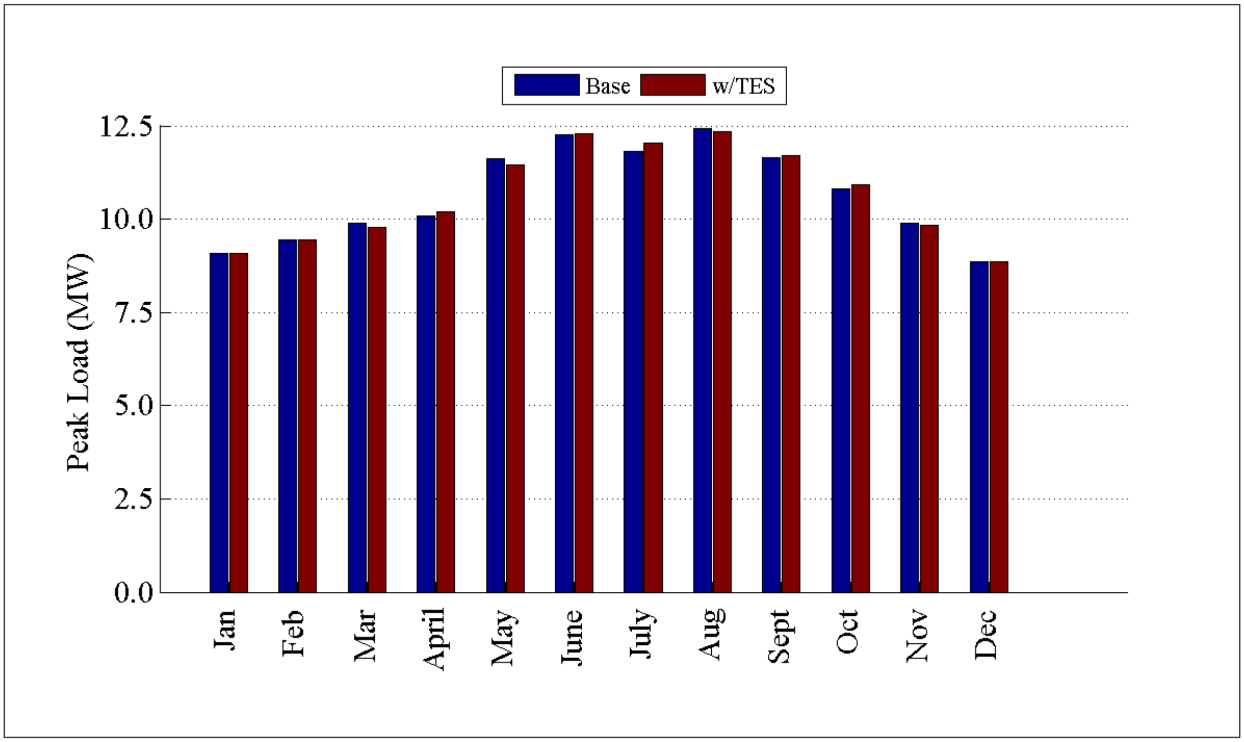

Figure D.209: Peak load by month of R5-35.00-1 feeder

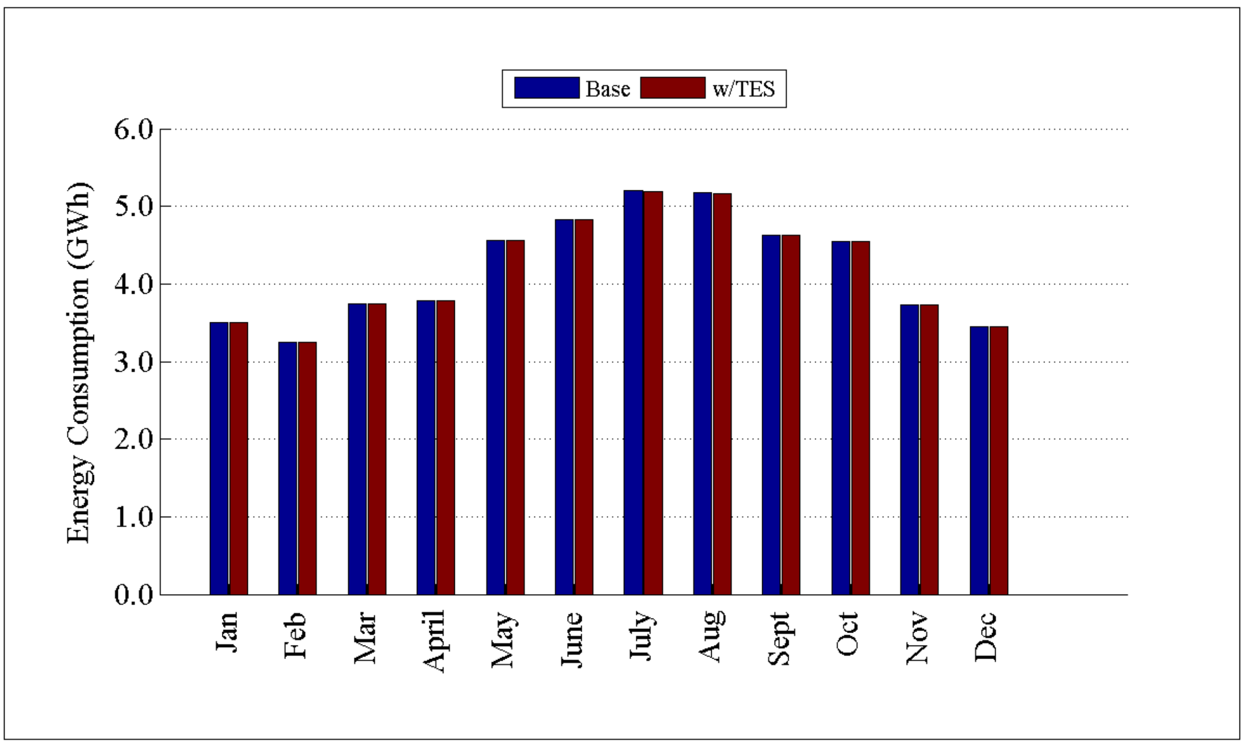

Figure D.210: Monthly energy consumption for R5-35.00-1 feeder

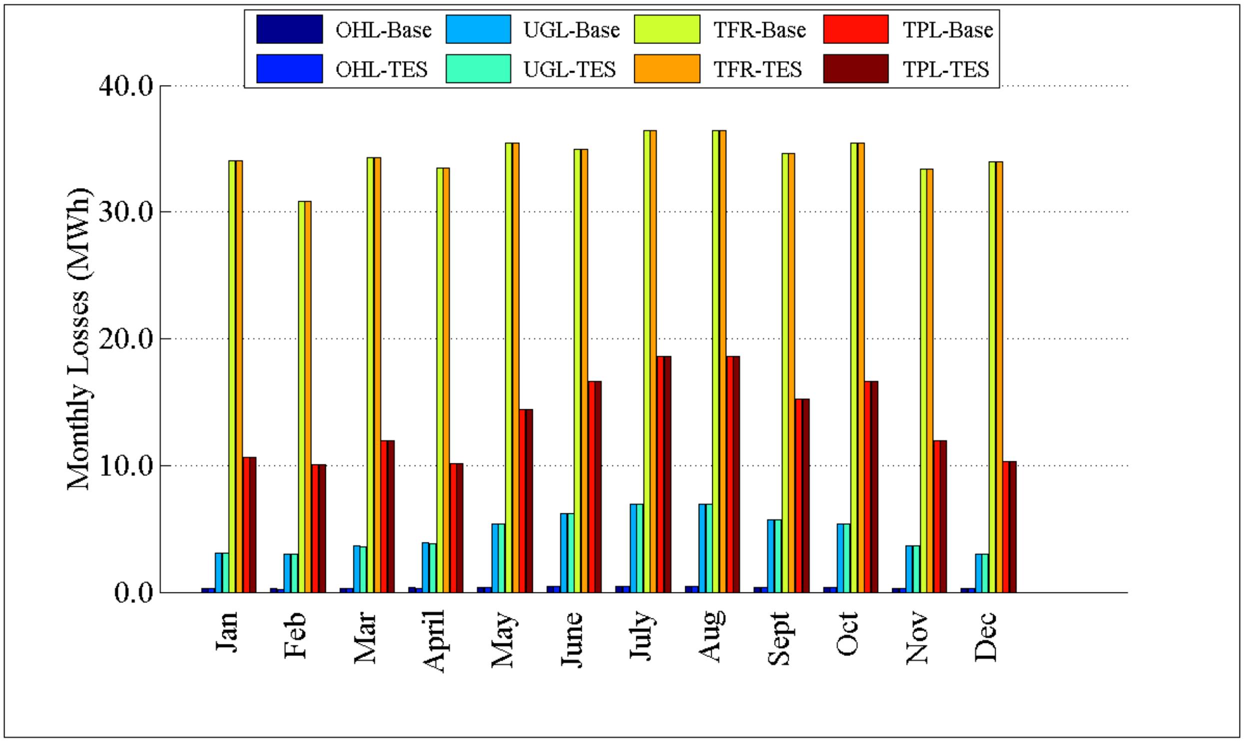

Figure D.211: Distribution system losses by month for R5-35.00-1

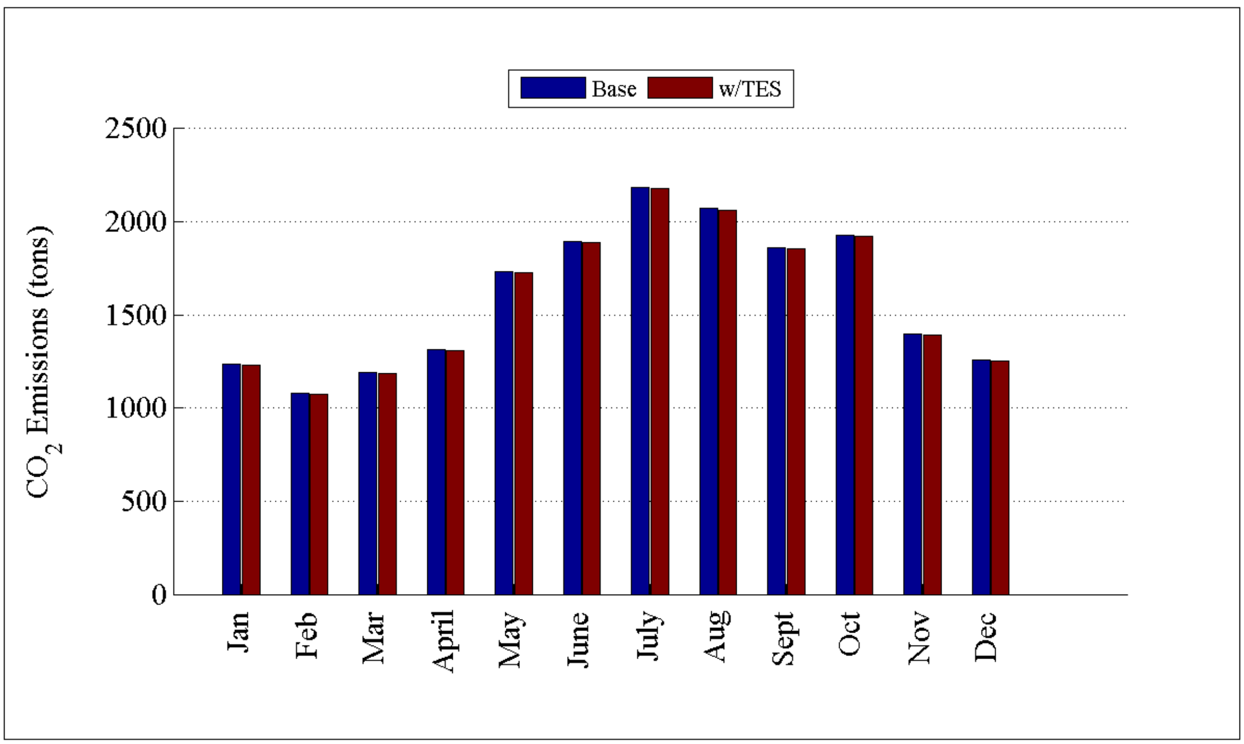

Figure D.212: CO_2 emissions by month for R5-35.00-1

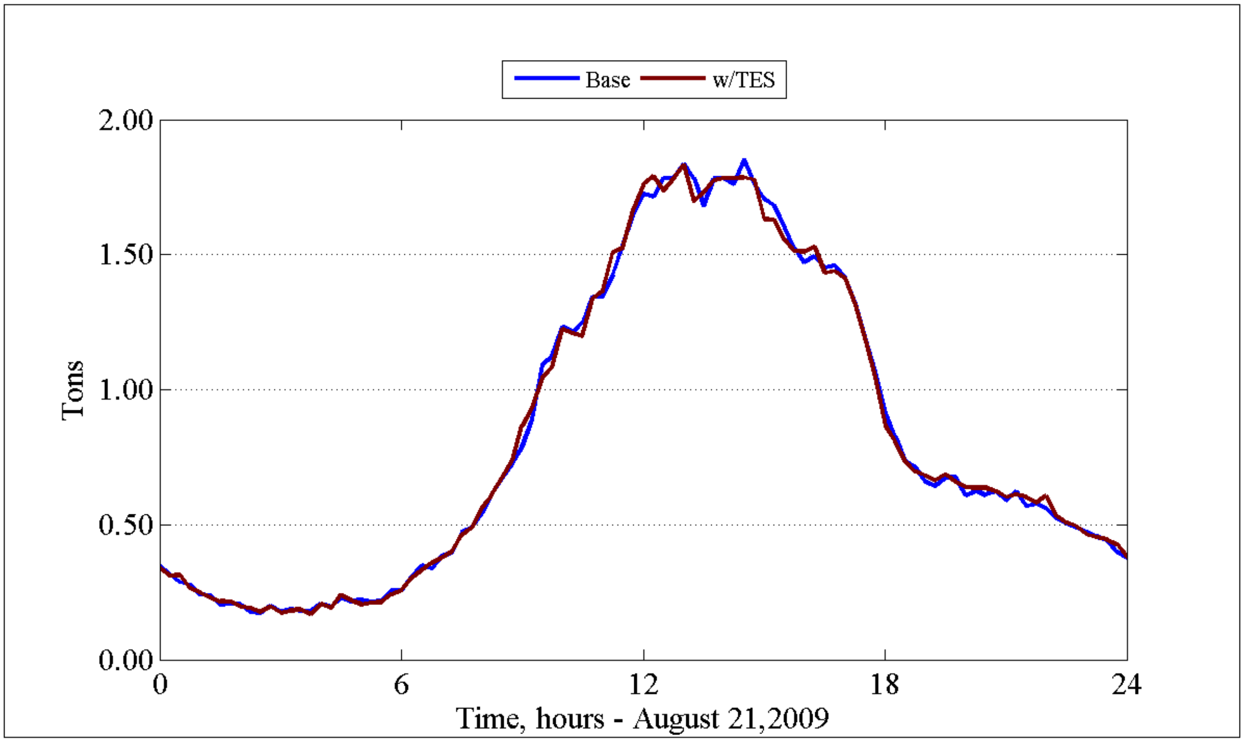

Figure D.213: Carbon dioxide emissions for peak day of R5-35.00-1

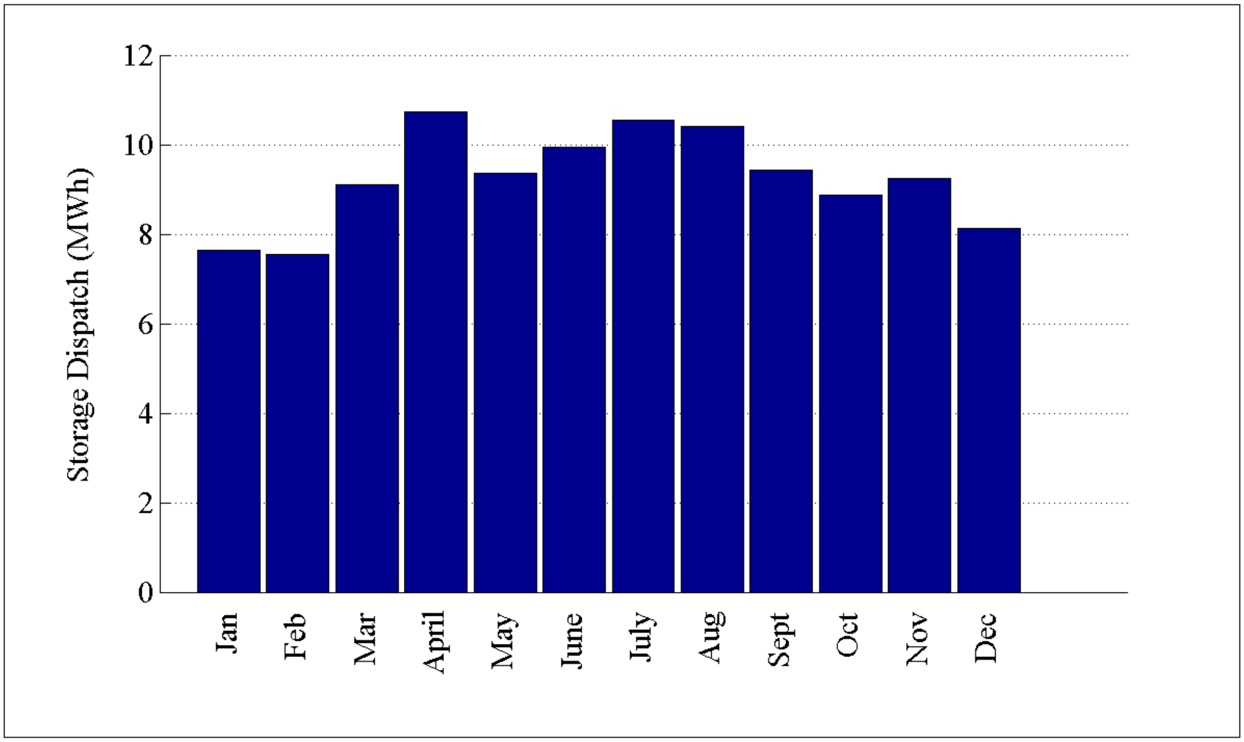

Figure D.214: Monthly storage dispatch energy for R5-35.00-1

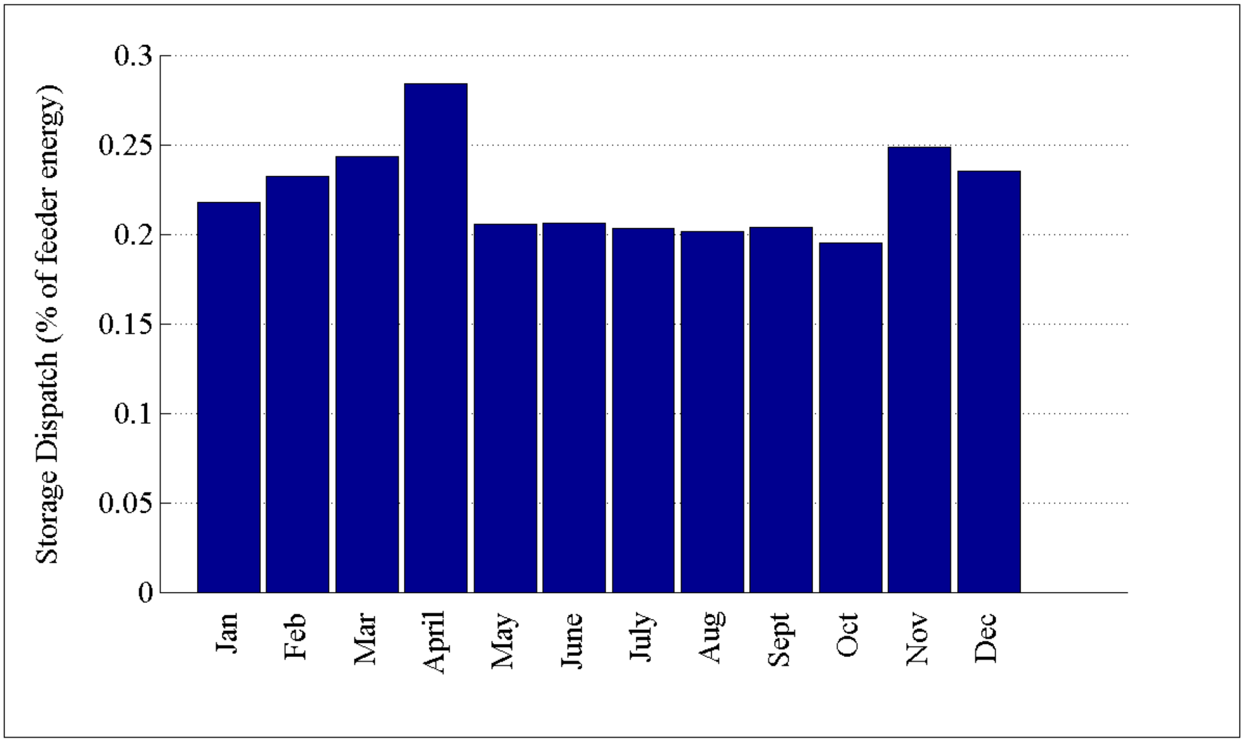

Figure D.215: Monthly storage dispatch energy percentage for R5-35.00-1

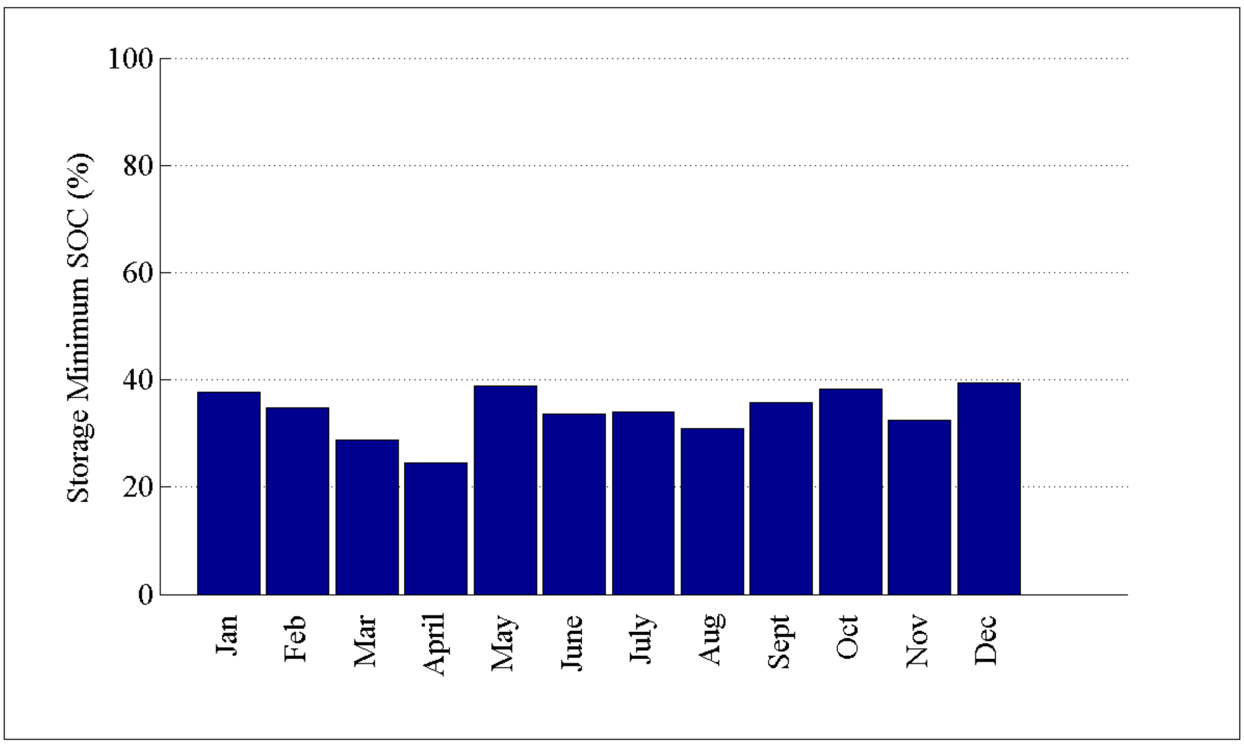

Figure D.216: Minimum state of charge for thermal energy storage on R5-35.00-1

Appendix E: Individual Feeder Impact Metrics

This appendix contains the raw performance metric values for each of the prototypical distribution feeders. The impact matrices in Section 4.1 are calculated from the raw values in this appendix.

E.1 Individual Performance Metrics for Base Case

These values represent the base-simulation results before any technology was applied to the feeders.

Table E.1: Base case performance metrics for region 1

Index	Metric	Units	GC-12.47-1 R1	R1-12.47-1	R1-12.47-2	R1-12.47-3	R1-12.47-4	R1-25.00-1
1	Hourly Customer Electricity Usage	kWh	2,083	2,692	992	435	1,948	875
2	Monthly Customer Electricity Usage	MWh	1,521	1,965	724	317	1,422	639
3	Peak Generation	kW	5,313	7,329	2,675	1,261	5,050	2,317
	Nuclear	%	10.68	10.68	10.68	10.68	10.09	10.68
	Solar	%	0.25	0.25	0.25	0.25	0.21	0.25
	Bio	%	0.67	0.67	0.67	0.67	0.72	0.67
	Wind	%	4.07	4.07	4.07	4.07	3.55	4.07
	Coal	%	2.88	2.88	2.88	2.88	4.38	2.88
	Hydroelectric	%	36.88	36.88	36.88	36.88	26.32	36.88
	Natural Gas	%	41.38	41.38	41.38	41.38	51.24	41.38
	Geothermal	%	2.84	2.84	2.84	2.84	3.11	2.84
	Petroleum	%	0.35	0.35	0.35	0.35	0.38	0.35
4	Peak Load	MW	5,288	7,085	2,590	1,247	4,924	2,261
7	Annual Electricity Production	MWh	18,290	24,196	8,964	3,829	17,276	7,776
12	CO2 Emissions	Tons	1,783	2,273	818	392	1,774	752
13	SOx Emissions	Tons	0.03	0.03	0.01	0.01	0.04	0.01
	NOx Emissions	Tons	0.24	0.28	0.10	0.05	0.22	0.10
	PM-10 Emissions	Tons	0.25	0.32	0.12	0.06	0.25	0.11
17	Annual Storage Dispatch	kWh	0	0	0	0	0	0
18	Average Energy Storage Efficiency	%	0	0	0	0	0	0
21	Feeder Real Load	MW	2,088	2,762	1,023	437	1,972	888
	Feeder Reactive Load	MVAR	68	-284	-200	11	62	-70
29	Distribution Losses	%	0.23	2.54	3.05	0.56	1.21	1.44
39	CO2 Emissions	Tons	1,787	2,332	844	394	1,796	763
40	SOx	Tons	0.03	0.03	0.01	0.01	0.04	0.01
	NOx	Tons	0.24	0.29	0.11	0.05	0.22	0.10
	PM-10	Tons	0.25	0.33	0.12	0.06	0.26	0.11

Table E.2: Base case performance metrics for region 2

Index	Metric	Units	GC-12.47-1 R2	R2-12.47-1	R2-12.47-2	R2-12.47-3	R2-25.00-1	R2-35.00-1
1	Hourly Customer Electricity Usage	kWh	2,169	2,268	1,970	2,975	6,342	4,576
2	Monthly Customer Electricity Usage	MWh	1,584	1,656	1,438	2,171	4,630	3,340
3	Peak Generation	kW	5,749	6,287	5,777	8,555	16,840	12,676
	Nuclear	%	26.33	26.33	26.33	27.95	26.33	26.33
	Solar	%	0.01	0.01	0.01	0.01	0.01	0.01
	Bio	%	0.82	0.82	0.82	0.84	0.82	0.82
	Wind	%	1.41	1.41	1.41	1.70	1.41	1.41
	Coal	%	47.18	47.18	47.18	45.54	47.18	47.18
	Hydroelectric	%	7.42	7.42	7.42	9.05	7.42	7.42
	Natural Gas	%	16.33	16.33	16.33	14.47	16.33	16.33
	Geothermal	%	0.07	0.07	0.07	0.07	0.07	0.07
	Petroleum	%	0.43	0.43	0.43	0.37	0.43	0.43
4	Peak Load	MW	5,720	6,166	5,647	8,360	16,622	12,533
7	Annual Electricity Production	MWh	19,050	20,128	17,588	26,686	56,091	40,417
12	CO2 Emissions	Tons	8,419	9,246	8,417	12,627	26,866	17,434
13	SOx Emissions	Tons	3.81	4.21	3.88	5.82	12.33	7.86
	NOx Emissions	Tons	2.43	2.67	2.46	3.69	7.81	5.02
	PM-10 Emissions	Tons	1.25	1.37	1.25	1.87	3.99	2.58
17	Annual Storage Dispatch	kWh	0	0	0	0	0	0
18	Average Energy Storage Efficiency	%	0	0	0	0	0	0
21	Feeder Real Load	MW	2,175	2,298	2,008	3,046	6,403	4,614
	Feeder Reactive Load	MVAR	92	116	146	-130	333	69
29	Distribution Losses	%	0.25	1.27	1.87	2.36	0.96	0.82
39	CO2 Emissions	Tons	8,440	9,365	8,578	12,932	27,125	17,579
40	SOx	Tons	3.82	4.26	3.95	5.96	12.45	7.93
	NOx	Tons	2.44	2.71	2.51	3.78	7.88	5.06
	PM-10	Tons	1.25	1.39	1.27	1.92	4.03	2.61

Table E.3: Base case performance metrics for region 3

Index	Metric	Units	GC-12.47-1 R3	R3-12.47-1	R3-12.47-2	R3-12.47-3
1	Hourly Customer Electricity Usage	kWh	2,635	3,661	1,642	3,705
2	Monthly Customer Electricity Usage	MWh	1,924	2,673	1,199	2,705
3	Peak Generation	kW	6,594	9,315	4,422	8,417
	Nuclear	%	8.65	9.72	9.72	9.72
	Solar	%	0.13	0.13	0.13	0.13
	Bio	%	0.23	0.25	0.25	0.25
	Wind	%	2.05	2.45	2.45	2.45
	Coal	%	40.24	41.52	41.52	41.52
	Hydroelectric	%	5.58	6.40	6.40	6.40
	Natural Gas	%	41.67	37.88	37.88	37.88
	Geothermal	%	1.25	1.40	1.40	1.40
	Petroleum	%	0.20	0.25	0.25	0.25
4	Peak Load	MW	6,554	9,122	4,364	8,157
7	Annual Electricity Production	MWh	23,160	32,687	14,483	33,603
12	CO2 Emissions	Tons	16,269	23,430	9,963	25,107
13	SOx Emissions	Tons	7.03	10.24	4.25	11.14
	NOx Emissions	Tons	4.38	6.36	2.66	6.88
	PM-10 Emissions	Tons	2.42	3.49	1.48	3.74
17	Annual Storage Dispatch	kWh	0	0	0	0
18	Average Energy Storage Efficiency	%	0	0	0	0
21	Feeder Real Load	MW	2,644	3,731	1,653	3,836
	Feeder Reactive Load	MVAR	219	484	143	547
29	Distribution Losses	%	0.33	1.87	0.69	3.40
39	CO2 Emissions	Tons	16,323	23,877	10,032	25,991
40	SOx	Tons	7.05	10.44	4.28	11.53
	NOx	Tons	4.39	6.48	2.67	7.12
	PM-10	Tons	2.43	3.56	1.49	3.87

Table E.4: Base case performance metrics for region 4

Index	Metric	Units	GC-12.47-1 R4	R4-12.47-1	R4-12.47-2	R4-25.00-1
1	Hourly Customer Electricity Usage	kWh	2,339	1,909	832	347
2	Monthly Customer Electricity Usage	MWh	1,708	1,393	607	253
3	Peak Generation	kW	6,221	4,798	2,205	945
	Nuclear	%	21.91	21.91	23.58	23.58
	Solar	%	0.00	0.00	0.00	0.00
	Bio	%	0.18	0.18	0.21	0.21
	Wind	%	0.60	0.60	0.59	0.59
	Coal	%	57.14	57.14	56.06	56.06
	Hydroelectric	%	2.20	2.20	3.09	3.09
	Natural Gas	%	17.49	17.49	16.14	16.14
	Geothermal	%	0.00	0.00	0.00	0.00
	Petroleum	%	0.48	0.48	0.33	0.33
4	Peak Load	MW	6,186	4,701	2,171	928
7	Annual Electricity Production	MWh	20,550	17,195	7,457	3,118
12	CO2 Emissions	Tons	10,321	9,844	3,994	1,608
13	SOx Emissions	Tons	4.91	4.72	1.92	0.77
	NOx Emissions	Tons	3.00	2.87	1.17	0.47
	PM-10 Emissions	Tons	1.54	1.47	0.60	0.24
17	Annual Storage Dispatch	kWh	0	0	0	0
18	Average Energy Storage Efficiency	%	0	0	0	0
21	Feeder Real Load	MW	2,346	1,963	851	356
	Feeder Reactive Load	MVAR	138	-413	98	45
29	Distribution Losses	%	0.28	2.76	2.32	2.53
39	CO2 Emissions	Tons	10,350	10,123	4,089	1,650
40	SOx	Tons	4.93	4.86	1.96	0.79
	NOx	Tons	3.00	2.95	1.19	0.48
	PM-10	Tons	1.54	1.51	0.61	0.25

Table E.5: Base case performance metrics for region 5

Index	Metric	Units	GC-12.47-1 R5	R5-12.47-1	R5-12.47-2	R5-12.47-3	R5-12.47-4	R5-12.47-5	R5-25.00-1	R5-35.00-1
1	Hourly Customer Electricity Usage	kWh	2,747	4,490	2,226	4,669	3,468	4,116	5,627	5,689
2	Monthly Customer Electricity Usage	MWh	2,005	3,278	1,625	3,408	2,532	3,005	4,108	4,153
3	Peak Generation	kW	5,841	9,451	4,992	10,384	7,531	9,041	12,282	12,428
	Nuclear	%	13.85	13.85	13.85	13.53	13.85	13.53	13.85	13.85
	Solar	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Bio	%	0.33	0.33	0.33	0.31	0.33	0.31	0.33	0.33
	Wind	%	1.48	1.48	1.48	1.74	1.48	1.74	1.48	1.48
	Coal	%	30.17	30.17	30.17	30.37	30.17	30.37	30.17	30.17
	Hydroelectric	%	0.63	0.63	0.63	0.78	0.63	0.78	0.63	0.63
	Natural Gas	%	51.68	51.68	51.68	51.29	51.68	51.29	51.68	51.68
	Geothermal	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Petroleum	%	1.86	1.86	1.86	1.98	1.86	1.98	1.86	1.86
4	Peak Load	MW	5,810	9,319	4,848	9,772	7,373	8,784	12,088	12,270
7	Annual Electricity Production	MWh	24,144	39,806	19,900	42,781	30,976	36,921	49,992	50,486
12	CO2 Emissions	Tons	9,364	15,419	7,414	15,195	11,809	13,594	18,504	18,904
13	SOx Emissions	Tons	1.55	2.23	1.11	1.64	1.70	1.66	2.19	2.34
	NOx Emissions	Tons	1.38	2.11	1.04	1.82	1.61	1.72	2.31	2.41
	PM-10 Emissions	Tons	1.37	2.26	1.09	2.23	1.73	1.99	2.71	2.77
17	Annual Storage Dispatch	kWh	0	0	0	0	0	0	0	0
18	Average Energy Storage Efficiency	%	0	0	0	0	0	0	0	0
21	Feeder Real Load	MW	2,756	4,544	2,272	4,884	3,536	4,215	5,707	5,763
	Feeder Reactive Load	MVAR	248	542	242	-357	407	594	650	641
29	Distribution Losses	%	0.33	1.19	2.02	4.41	1.92	2.34	1.39	1.28
39	CO2 Emissions	Tons	9,395	15,605	7,567	15,895	12,040	13,919	18,766	19,150
40	SOx	Tons	1.55	2.26	1.14	1.72	1.73	1.70	2.22	2.37
	NOx	Tons	1.39	2.14	1.06	1.91	1.65	1.76	2.34	2.44
	PM-10	Tons	1.38	2.29	1.11	2.33	1.77	2.04	2.75	2.81

E.2 Individual Performance Metrics for Thermal Energy Storage Case

These values represent the simulation results after thermal energy storage has been deployed on the feeders.

Table E.6: Thermal energy storage performance metrics for region 1

Index	Metric	Units	GC-12.47-1 R1	R1-12.47-1	R1-12.47-2	R1-12.47-3	R1-12.47-4	R1-25.00-1
1	Hourly Customer Electricity Usage	kWh	2,086	2,692	992	435	1,950	877
2	Monthly Customer Electricity Usage	MWh	1,523	1,965	724	317	1,424	640
3	Peak Generation	kW	5,246	7,335	2,622	1,228	5,032	2,263
	Nuclear	%	10.68	10.68	10.68	10.68	10.09	10.68
	Solar	%	0.25	0.25	0.25	0.25	0.21	0.25
	Bio	%	0.67	0.67	0.67	0.67	0.72	0.67
	Wind	%	4.07	4.07	4.07	4.07	3.55	4.07
	Coal	%	2.88	2.88	2.88	2.88	4.38	2.88
	Hydroelectric	%	36.88	36.88	36.88	36.88	26.32	36.88
	Natural Gas	%	41.38	41.38	41.38	41.38	51.24	41.38
	Geothermal	%	1.94	2.84	1.24	0.53	3.11	0.85
	Petroleum	%	0.00	0.43	0.00	0.00	0.02	0.00
4	Peak Load	MW	5,221	7,091	2,538	1,214	4,905	2,207
7	Annual Electricity Production	MWh	18,315	24,197	8,965	3,830	17,292	7,790
12	CO2 Emissions	Tons	1,758	2,273	817	390	1,762	734
13	SOx Emissions	Tons	0.02	0.03	0.01	0.01	0.03	0.01
	NOx Emissions	Tons	0.23	0.28	0.10	0.05	0.22	0.10
	PM-10 Emissions	Tons	0.25	0.32	0.12	0.06	0.25	0.10
17	Annual Storage Dispatch	MWh	50.15	1.22	2.28	3.83	37.78	34.31
18	Average Energy Storage Efficiency	%	102.91	103.65	103.76	103.55	103.04	102.79
21	Feeder Real Load	MW	2,091	2,762	1,023	437	1,974	889
	Feeder Reactive Load	MVAR	66	-284	-200	10	61	-72
29	Distribution Losses	%	0.23	2.54	3.05	0.56	1.20	1.43
39	CO2 Emissions	Tons	1,762	2,332	843	392	1,784	745
40	SOx	Tons	0.02	0.03	0.01	0.01	0.03	0.01
	NOx	Tons	0.24	0.29	0.11	0.05	0.22	0.10
	PM-10	Tons	0.25	0.33	0.12	0.06	0.25	0.11

Table E.7: Thermal energy storage performance metrics for region 2

Index	Metric	Units	GC-12.47-1 R2	R2-12.47-1	R2-12.47-2	R2-12.47-3	R2-25.00-1	R2-35.00-1
1	Hourly Customer Electricity Usage	kWh	2,172	2,271	1,971	2,975	6,345	4,581
2	Monthly Customer Electricity Usage	MWh	1,586	1,657	1,439	2,171	4,632	3,344
3	Peak Generation	kW	5,614	6,108	5,760	8,492	16,559	12,079
	Nuclear	%	26.33	26.33	26.33	26.33	26.33	26.33
	Solar	%	0.01	0.01	0.01	0.01	0.01	0.01
	Bio	%	0.82	0.82	0.82	0.82	0.82	0.82
	Wind	%	1.41	1.41	1.41	1.41	1.41	1.41
	Coal	%	47.18	47.18	47.18	47.18	47.18	47.18
	Hydroelectric	%	5.58	5.08	7.42	7.42	6.25	3.21
	Natural Gas	%	16.33	16.33	16.33	16.33	16.33	16.33
	Geothermal	%	0.00	0.00	0.07	0.02	0.00	0.00
	Petroleum	%	0.00	0.00	0.13	0.00	0.00	0.00
4	Peak Load	MW	5,585	5,988	5,630	8,298	16,341	11,936
7	Annual Electricity Production	MWh	19,077	20,145	17,593	26,686	56,120	40,463
12	CO2 Emissions	Tons	8,461	9,275	8,424	12,628	26,909	17,473
13	SOx Emissions	Tons	3.84	4.23	3.89	5.82	12.36	7.90
	NOx Emissions	Tons	2.45	2.69	2.46	3.69	7.83	5.05
	PM-10 Emissions	Tons	1.25	1.38	1.25	1.87	3.99	2.59
17	Annual Storage Dispatch	MWh	138.11	86.72	32.24	4.57	166.77	233.80
18	Average Energy Storage Efficiency	%	102.84	102.40	102.98	102.83	102.74	102.71
21	Feeder Real Load	MW	2,178	2,300	2,008	3,046	6,406	4,619
	Feeder Reactive Load	MVAR	86	113	145	-130	325	59
29	Distribution Losses	%	0.24	1.27	1.87	2.36	0.95	0.82
39	CO2 Emissions	Tons	8,482	9,394	8,584	12,933	27,169	17,617
40	SOx	Tons	3.85	4.28	3.96	5.96	12.48	7.97
	NOx	Tons	2.46	2.72	2.51	3.78	7.91	5.09
	PM-10	Tons	1.26	1.39	1.27	1.92	4.03	2.61

Table E.8: Thermal energy storage performance metrics for region 3

Index	Metric	Units	GC-12.47-1 R3	R3-12.47-1	R3-12.47-2	R3-12.47-3
1	Hourly Customer Electricity Usage	kWh	2,637	3,666	1,645	3,705
2	Monthly Customer Electricity Usage	MWh	1,925	2,676	1,201	2,705
3	Peak Generation	kW	6,480	9,033	4,229	8,276
	Nuclear	%	8.65	9.72	9.72	8.50
	Solar	%	0.13	0.13	0.13	0.14
	Bio	%	0.23	0.25	0.25	0.21
	Wind	%	2.05	2.45	2.45	2.20
	Coal	%	40.24	41.52	41.52	41.42
	Hydroelectric	%	5.30	5.02	3.70	4.59
	Natural Gas	%	41.67	37.88	37.88	41.48
	Geothermal	%	0.00	0.00	0.00	1.26
	Petroleum	%	0.00	0.00	0.00	0.69
4	Peak Load	MW	6,440	8,839	4,172	8,015
7	Annual Electricity Production	MWh	23,171	32,723	14,507	33,601
12	CO2 Emissions	Tons	16,360	23,654	10,083	25,159
13	SOx Emissions	Tons	7.10	10.42	4.34	11.18
	NOx Emissions	Tons	4.42	6.45	2.71	6.90
	PM-10 Emissions	Tons	2.44	3.52	1.50	3.75
17	Annual Storage Dispatch	MWh	118.86	279.76	145.18	100.11
18	Average Energy Storage Efficiency	%	103.42	103.12	103.42	103.64
21	Feeder Real Load	MW	2,645	3,735	1,656	3,836
	Feeder Reactive Load	MVAR	213	472	137	543
29	Distribution Losses	%	0.32	1.86	0.68	3.40
39	CO2 Emissions	Tons	16,413	24,102	10,152	26,044
40	SOx	Tons	7.12	10.61	4.37	11.58
	NOx	Tons	4.43	6.58	2.73	7.14
	PM-10	Tons	2.44	3.59	1.51	3.88

Table E.9: Thermal energy storage performance metrics for region 4

Index	Metric	Units	GC-12.47-1 R4	R4-12.47-1	R4-12.47-2	R4-25.00-1
1	Hourly Customer Electricity Usage	kWh	2,340	1,909	831	347
2	Monthly Customer Electricity Usage	MWh	1,708	1,394	607	253
3	Peak Generation	kW	6,090	4,635	2,150	914
	Nuclear	%	21.91	21.91	23.58	23.58
	Solar	%	0.00	0.00	0.00	0.00
	Bio	%	0.18	0.18	0.21	0.21
	Wind	%	0.60	0.60	0.59	0.59
	Coal	%	57.14	57.14	56.06	56.06
	Hydroelectric	%	0.57	0.00	0.92	0.19
	Natural Gas	%	17.49	16.77	16.14	16.14
	Geothermal	%	0.00	0.00	0.00	0.00
	Petroleum	%	0.00	0.00	0.00	0.00
4	Peak Load	MW	6,055	4,538	2,116	898
7	Annual Electricity Production	MWh	20,559	17,198	7,457	3,118
12	CO2 Emissions	Tons	10,320	9,864	3,995	1,609
13	SOx Emissions	Tons	4.92	4.74	1.92	0.77
	NOx Emissions	Tons	3.00	2.88	1.17	0.47
	PM-10 Emissions	Tons	1.54	1.47	0.60	0.24
17	Annual Storage Dispatch	MWh	73.18	58.79	10.29	6.50
18	Average Energy Storage Efficiency	%	103.48	103.63	103.75	103.86
21	Feeder Real Load	MW	2,347	1,963	851	356
	Feeder Reactive Load	MVAR	135	-416	97	44
29	Distribution Losses	%	0.28	2.75	2.32	2.53
39	CO2 Emissions	Tons	10,348	10,143	4,090	1,651
40	SOx	Tons	4.93	4.87	1.96	0.79
	NOx	Tons	3.01	2.96	1.19	0.48
	PM-10	Tons	1.54	1.51	0.61	0.25

Table E.10: Thermal energy storage performance metrics for region 5

Index	Metric	Units	GC-12.47-1 R5	R5-12.47-1	R5-12.47-2	R5-12.47-3	R5-12.47-4	R5-12.47-5	R5-25.00-1	R5-35.00-1
1	Hourly Customer Electricity Usage	kWh	2,748	4,492	2,225	4,669	3,468	4,117	5,627	5,690
2	Monthly Customer Electricity Usage	MWh	2,006	3,279	1,624	3,409	2,532	3,005	4,108	4,154
3	Peak Generation	kW	5,719	8,956	4,900	10,356	7,388	8,949	12,200	12,357
	Nuclear	%	13.85	13.85	13.85	13.53	13.85	13.85	13.53	13.85
	Solar	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Bio	%	0.33	0.33	0.33	0.31	0.33	0.33	0.31	0.33
	Wind	%	1.48	1.48	1.48	1.74	1.48	1.48	1.74	1.48
	Coal	%	30.17	27.42	30.17	30.37	30.17	30.17	30.37	30.17
	Hydroelectric	%	0.40	0.00	0.63	0.78	0.59	0.63	0.78	0.63
	Natural Gas	%	51.68	51.68	51.68	51.29	51.68	51.68	51.29	51.68
	Geothermal	%	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Petroleum	%	0.00	0.00	0.03	1.71	0.00	1.14	3.22	1.28
4	Peak Load	MW	5,688	8,824	4,756	9,744	7,230	8,692	12,006	12,199
7	Annual Electricity Production	MWh	24,147	39,816	19,886	42,785	30,974	36,924	49,987	50,492
12	CO2 Emissions	Tons	9,297	14,972	7,330	15,164	11,697	13,513	18,433	18,841
13	SOx Emissions	Tons	1.49	1.84	1.05	1.61	1.60	1.59	2.13	2.29
	NOx Emissions	Tons	1.35	1.90	1.00	1.81	1.56	1.68	2.28	2.38
	PM-10 Emissions	Tons	1.36	2.20	1.07	2.22	1.72	1.98	2.70	2.76
17	Annual Storage Dispatch	MWh	118.42	682.66	111.14	57.38	165.75	127.98	106.92	111.18
18	Average Energy Storage Efficiency	%	101.41	101.44	101.35	101.49	101.33	101.47	101.49	101.42
21	Feeder Real Load	MW	2,756	4,545	2,270	4,884	3,536	4,215	5,706	5,764
	Feeder Reactive Load	MVAR	243	508	236	-360	398	588	645	636
29	Distribution Losses	%	0.33	1.17	2.00	4.40	1.91	2.33	1.39	1.28
39	CO2 Emissions	Tons	9,327	15,149	7,479	15,861	11,924	13,836	18,694	19,085
40	SOx	Tons	1.49	1.86	1.07	1.69	1.63	1.63	2.16	2.31
	NOx	Tons	1.35	1.92	1.03	1.89	1.59	1.72	2.31	2.41
	PM-10	Tons	1.37	2.22	1.10	2.32	1.75	2.03	2.74	2.80

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