PNNL-20677

U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
under Contract DE-AC05-76RL01830

Large-Scale PV Integration Study

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July 2011

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ACKNOWLEDGEMENTS

This research effort evaluates the impact of large-scale photovoltaic (PV) and distributed generation (DG) output on NV Energy's electric grid system in southern Nevada. It analyses the ability of NV Energy's generation to accommodate increasing amounts of utility-scale PV and DG, and the resulting cost of integrating variable renewable resources.

The study was jointly funded by the United States Department of Energy and NV Energy, and conducted by a project team comprised of industry experts and research scientists from Navigant Consulting Inc., Sandia National Laboratories, Pacific Northwest National Laboratory and NV Energy.

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PACIFIC NORTHWEST NATIONAL LABORATORY

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1 Executive Summary

1.1 Background

The amount of solar photovoltaic (PV) generation added to electric utility grids in the Southwest has been growing and is expected to be robust. Until recently, renewable generation has not significantly altered the operation of, or required major expansion to, the electric grid. However, there is increasing concern that the variable power produced by large-scale PV generation will strain the ability of the current grid to deliver the power reliably.

The territory served by NV Energy's southern Nevada system is well suited for large-scale PV systems. Due to the large number of pending interconnection requests, the Company in early 2010 submitted an application to the Public Utilities Commission of Nevada (PUCN) requesting approval for funding to evaluate the impacts of PV. The PUCN issued a Compliance Order approving a study of large-scale PV, and subsequently approved a second study to determine how much distributed PV generation (DG) could be installed on NV Energy's existing distribution system (December 2010 DG Study). The PUCN accepted the DG study's finding that NV Energy's distribution system alone is not a limiting factor for new DG capacity, and agreed with the Company's recommendation that DG should be evaluated as part of the large-scale PV Study.

Study Objectives

This study quantifies the impact of variable PV generation output on NV Energy's system operations, including balancing reserve requirements, and the ability of the existing generation fleet to accommodate increasing amounts of large-scale PV and DG. Because the level of detail in this study exceeds that in earlier industry studies, new and innovative methods were developed to estimate PV output and to perform the technical and economic evaluation.

The study includes four interrelated tasks:

Task 1: Estimate large-scale PV output and DG output for southern Nevada on a one-minute time scale for an entire year.

Task 2: Develop composite PV output profiles via statistical methods for ten sites and five case study scenarios in southern Nevada.

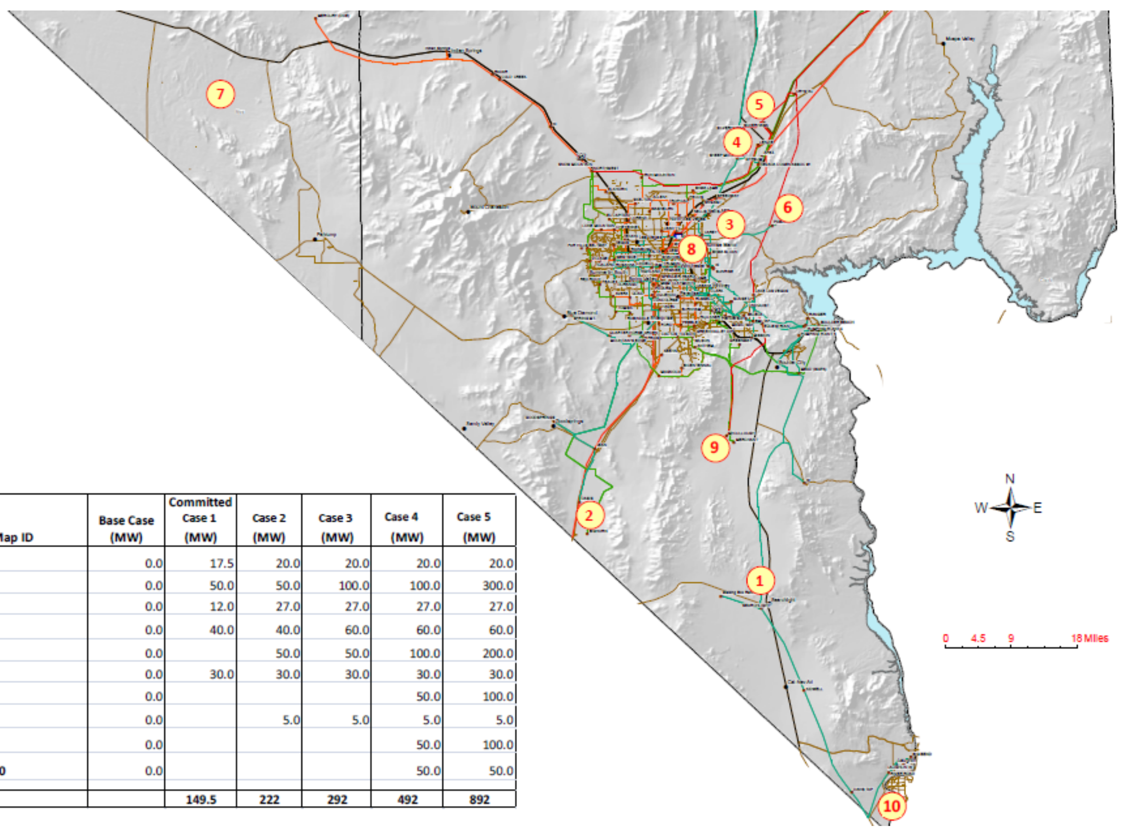
Task 3: Analyze the impact of variable PV & DG on system balancing reserve requirements within NV Energy's southern Nevada system, and evaluate the generation fleet's capability to meet the requirements.

Task 4: Identify the impacts on generation dispatch and costs of integrating PV & DG, and identify options to increase the amount of solar resources that can be installed on NV Energy's system.

Renewable Generation Scenarios

The study considers up to 1042 MW of combined large-scale PV and DG in southern Nevada. Individual PV plants range in size from 5 MW to over 300 MW at ten locations. Figure 1 illustrates the locations, sizes, and combinations of PV plants in each of five large-scale scenarios. In addition to the PV plants shown in Figure 1, DG was added in varying amounts to each of the five scenarios to create ten cases for evaluation.

Figure 1. Proposed Large PV Installations



Solar PV Project Map ID	Base Case (MW)	Committed Case 1 (MW)	Case 2 (MW)	Case 3 (MW)	Case 4 (MW)	Case 5 (MW)
Solar PV Project 1	0.0	17.5	20.0	20.0	20.0	20.0
Solar PV Project 2	0.0	50.0	50.0	100.0	100.0	300.0
Solar PV Project 3	0.0	12.0	27.0	27.0	27.0	27.0
Solar PV Project 4	0.0	40.0	40.0	60.0	60.0	60.0
Solar PV Project 5	0.0		50.0	50.0	100.0	200.0
Solar PV Project 6	0.0	30.0	30.0	30.0	30.0	30.0
Solar PV Project 7	0.0				50.0	100.0
Solar PV Project 8	0.0		5.0	5.0	5.0	5.0
Solar PV Project 9	0.0				50.0	100.0
Solar PV Project 10	0.0				50.0	50.0
Total:		**149.5**	**222**	**292**	**492**	**892**

Case Descriptions

The report includes five large PV scenarios and ten case studies with increasing amounts of large PV or DG, up to a maximum of 1042 MW combined:

- The five scenarios include large PV projects with signed Power Purchase Agreements (PPAs) and proposed projects based on data provided by developers;
- Case 1 is a stand-alone committed PV case with no DG added, and three additional cases with DG added in at increasing levels;
- Cases 2 though 10 include DG added to the five PV scenarios in amounts corresponding to those evaluated in the December 2010 DG Study (1%, 9% or 15% of NPC load); and
- All cases other than Committed PV include DG, which is assumed to be equally distributed in relation to load throughout the Las Vegas Valley.

Table 1 summarizes each of the PV cases evaluated in the study. The total number of cases studied is ten, as some amount of DG is assumed to be added to each large-scale PV case other than the committed 149 MW stand-alone PV scenario. The nomenclature adopted for the study include case descriptions numbered 1 through 5 for the five large PV scenarios; and A, B, and C for DG capacity at 1%, 9%, and 15%, respectively.

Comparisons among the combinations selected for study allow assessments to be made of the:

1. Effects of increasing large-scale PV, while holding DG constant;
2. Effects of increasing DG while holding large-scale PV constant; and
3. Effects of varying large-scale PV and DG together, while holding total generation capacity constant.

Table 1. Case Descriptions

PV/DG Cases	1% (50 MW)	9% (450 MW)	15% (750 MW)
Committed PV-149 MW	-	-	-
Case 1 – 149 MW	1A (199 MW)	1B (599 MW)	1C (899 MW)
Case 2 – 222 MW	2A (272 MW)	-	-
Case 3 – 292 MW	3A (342 MW)	-	3C (1042 MW)
Case 4 – 492 MW	4A (492 MW)	4B (942 MW)	-
Case 5 – 892 MW	5A (942 MW)	-	-

Methodology

A project team comprised of Navigant, Sandia National Laboratories (SNL), Pacific Northwest National Laboratory (PNNL), and NV Energy conducted the study.[1]

The team developed research methods to assess the impacts of DG and large-scale renewable projects in NV Energy's southern Nevada balancing area and bulk transmission grid.[2]

The primary role of each organization supporting NV Energy's efforts and the methodology employed by each organization follows:

- Sandia National Laboratories developed minute-by-minute large-scale PV and DG output profiles for southern Nevada using existing and new analytical tools, and verified results using comparable data from other PV systems in the U.S.
- Pacific Northwest National Laboratory conducted the balancing area studies, using existing and new methods to evaluate the impact of variable renewable output on balancing reserve requirements, the ability of NV Energy's generation fleet to meet increased system variability and the cycling and movements of the fleet to balance generation and load.
- Navigant performed production simulation analyses to quantify integration costs of each PV and DG case study. Navigant is also responsible for the preparation of this report, and the findings and conclusions contained herein.
- NV Energy provided the project team with load, generation and other system data necessary to conduct the study. It also produced day-ahead unit schedules for selected days and case studies using internal software to support the balancing area studies. NV Energy also performed the steady state and dynamic transmission studies using internal models and an approach consistent with those used for System Impact Studies for interconnection requests.

Specific steps the project team performed to evaluate PV and DG system impacts and to identify renewable penetration limits and costs include:

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[1] This project was jointly funded by the DOE and NV Energy.

[2] The project team researched and developed new methods to evaluate short-term impacts of variable PV, as prior industry studies and research efforts have not examined PV impacts at the short time scales considered in this research effort. The short-term impacts include evaluating the ability of balancing area generation to meet large shifts in PV output on a one-minute time scale.

1. Develop time-synchronized PV minute-by-minute output profiles and day-ahead forecasts of PV and DG hourly output. Analyze the results to quantify the impact on grid operations of increasing amounts of large-scale PV generation and DG.

2. Conduct a detailed evaluation of balancing area operations for minute-by-minute changes in net load (load – solar output) based on the large-scale PV and DG output profiles and NV Energy's generating unit operating data. Identify the additional regulation and load following requirements, including capacity and ramp rate, associated with each case study. Determine whether existing generation fleet can meet these requirements without and with generation redispatch. Quantify the impact of PV variability on generation fleet cycling and movements in regulation and load following, to establish a basis for the assessment of generator wear and tear.

3. Integrate the results of the balancing area studies and the PV and DG output profiles to quantify the impact of increasing levels of large-scale PV and DG on NV Energy's generation mix and production costs using hourly production simulation models. Identify the increased fuel and operations and maintenance (O & M) costs for existing generating units caused by higher operating reserves, increased cycling, higher heat rates, and changes in dispatch schedules.

4. Evaluate the impact of incremental DG on NV Energy's bulk power transmission system, including steady state and dynamic performance within NV Energy's southern Nevada balancing area operations.

5. Identify mitigation strategies or upgrades required to accommodate variable generation, including those needed to satisfy NERC balancing area performance requirements.

Assumptions

The evaluation of large PV and DG is performed assuming existing conditions, including a system grid configuration and generating resource mix for 2011.

Study assumptions include:

- The study assesses the ability of the system as it exists today, except that load and weather data from 2007 are used. Solar data needed to predict intermittency is not readily available for 2008 and beyond. 2007 is also the year when NV Energy experienced its all-time peak load and where predicted levels of PV output would be higher due to hot weather[3].

- Generation resources reflect a 2011 mix and operating costs, including an in-service date of January 2011 for the Harry Allen Combined Cycle plant.

- For the production simulation studies, external sales are set to zero; this is a central assumption as high PV & DG penetration could result in additional committed generation to avoid dump energy caused by units operating at minimum load.

- Evaluation criterion for integration includes an objective of no net degradation in system performance and reliability *after* three percent of time intervals experiencing the highest net change in minute-by-minute load for each hour are excluded from the analysis.

- System upgrades or mitigation is required when generating operating limits are exceeded or when NERC performance standards cannot be met.

- NERC performance standards include current requirements under CPS-1 and CPS-2.

1.2 Study Results

The primary objective of the study is to identify PV & DG impacts on system operations and the incremental cost incurred by NV Energy to integrate the capacity. The integration costs exclude transmission interconnection facilities, large-scale PV and DG installation costs, and non-utility impacts.

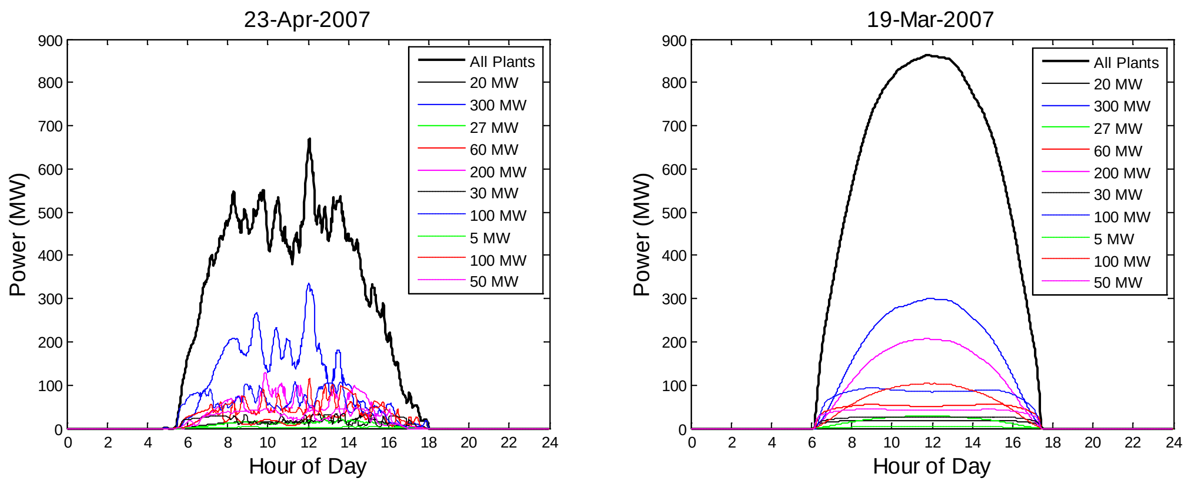
PV Output Profiles

One year of AC power output, at one-minute intervals, were produced for each PV plant listed in Table 1 for 2007. PV output profiles for a typical "clear" solar day and for an intermittently cloudy day for each of the ten proposed PV plants under a high PV penetration case (i.e., Case 5) are illustrated in Figure 2. Cases with less PV have similar output profiles and features. Results indicate that output profiles vary significantly for clear versus cloudy days; however, the level of variability as a percentage of total installed capacity becomes smaller when PV

[3] NV Energy does not expect the system peak to reach the 2007 peak until 2020.

plants are installed over a large area. The methods used to predict PV output levels are shown to produce reasonable results, with characteristics that compare favorably with characteristics of irradiance and PV data obtained from plants located elsewhere in the U.S. This finding was critical, as the level of confidence in the results of the intermittency studies derives from confidence in predictions of PV output data.

Figure 2. Large-scale PV Output for Clear and Cloudy Days. Case 5

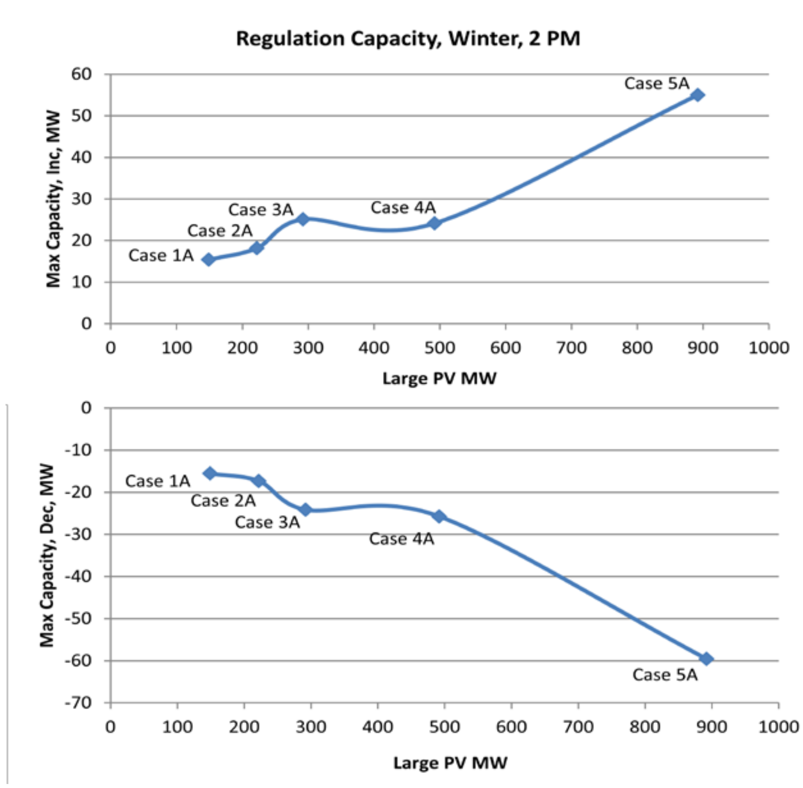


An important factor associated with large-scale PV plants is the impact of moving cloud cover on net PV plant output. The ability of generators to adjust to rapid changes in PV output due to moving clouds is one of the factors that determine how much PV capacity can be integrated into the existing system (i.e., NV Energy's southern Nevada balancing area). If generation cannot ramp up or down quickly enough to respond to variable PV, system upgrades or changes in operations would be required. Even if upgrades are unnecessary, the additional generation required to be on line to meet NERC reliability requirements will generally result in higher costs.

Solar Generation Impacts

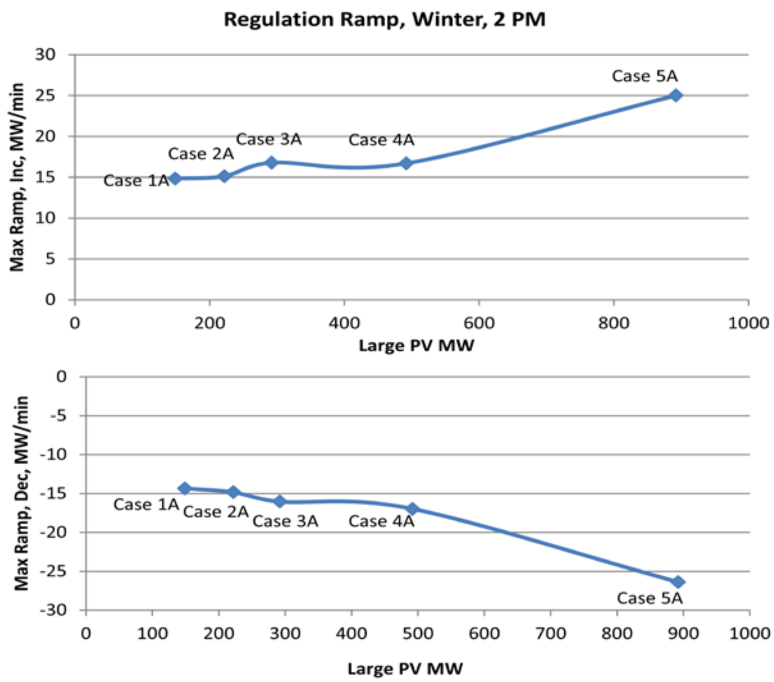
Detailed analyses of PV output profiles and loads confirm the premise that variable renewable generation would increase regulation and load following requirements in the southern Nevada system. The greatest impact is the additional operating reserves required for regulation, with very modest increases in requirements for load following. These impacts increase the amount of NV Energy thermal generation capacity that must be committed, resulting in higher operating reserves and fuel costs. Under the assumption that (1) the PV capacity expansion includes adding new sites (increase of diversity) and (2) real-time dispatch is determined from perfect load and solar generation forecasts, results indicate, on average, 1 MW of additional thermal generating capacity must be reserved for regulation for each 25 MW of PV capacity installed in NV Energy's southern Nevada system. In addition to the additional capacity, study results also indicate that regulation ramping requirements (measured in MW/minute) increase significantly with higher amounts of PV. On average, 1 MW/min of additional ramping capability must be reserved for regulation for each 75 MW of PV in NV Energy's southern system. Figure 3 and Figure 4 present the regulation capacity and ramp requirements for one of the most challenging hours in winter months. More regulation reserve would be needed under non-perfect forecasts and when PV diversity is less. Therefore, the impact results in this report should be deemed as the minimum[4].

Figure 3. Regulation Capacity Requirements Versus Large PV Capacity



[4] The actual numbers of reserve requirements for each solar case are determined by the solar generation patterns in the southern Nevada system as well as the variability of system load and may not be applicable to other systems.

Figure 4. Regulation Ramp Requirements Versus Large PV Capacity



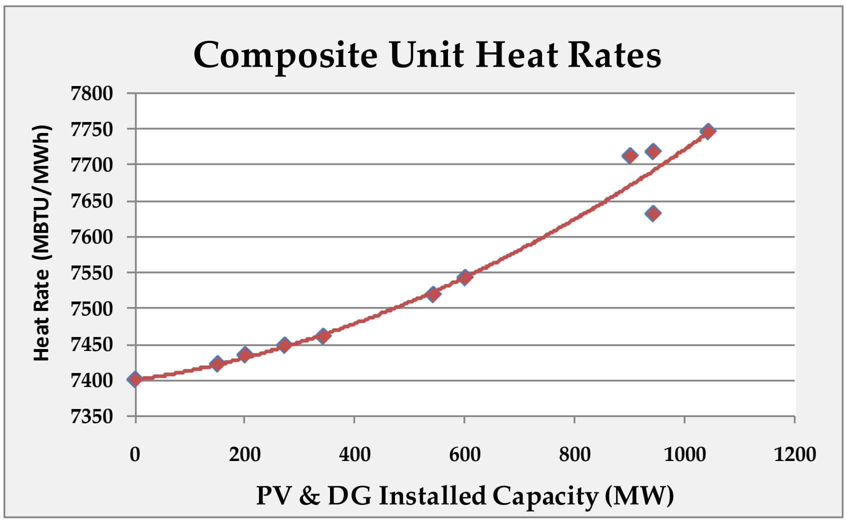
Evaluated based on the above reserve requirements, NV Energy's current generation fleet will be able to accommodate the amount of PV and DG in the studied cases, but with more operator interventions and adjustments to existing unit commitment and dispatch to ensure the regulation and load following requirements are met. Further, generating units will experience more up and down cycles and movements to balance the system as well as operate less efficiently, resulting in greater wear and tear and higher fuel cost per MWh.

Figure 5 indicates that higher operating reserves causes the operating efficiency of NV Energy's regulating capacity to decline, as measured by heat rate, relative to the amount of PV and DG capacity installed.[5] Virtually all of the regulating capacity is provided by combined cycle units and to a lesser degree, combustion turbines. The increase in the composite heat rate of regulating units is due to combined cycle generation operating at reduced capacity factor and the increasingly greater use of combustion turbine generation as PV and DG capacity increases; combustion turbines operate at a much higher heat rate than combined cycle generation. Both

[5] Generation heat rate is a measure of how much fuel is consumed to produce a unit of energy, typically in kWh or MWh. A higher heat rate means that more fuel, measured in British Thermal Units or BTUs, is needed to produce the same amount of energy as compared to a generating unit with a lower heat rate.

combined cycle generation and combustion turbines use natural gas as a fuel source, so the cost of regulating generation increases as a function of heat rate. Capacity factor for coal-fired generation is nearly constant among cases and does not measurably impact the composite system heat rate. At the highest PV and DG penetration levels (1042 MW), the system heat rate degrades by about five percent compared to the base case where PV & DG capacity is zero.

Figure 5. Composite Heat Rate (Regulating Units)



The results and findings contained within this report indicate that measures must be taken to mitigate balancing area ramp deficiencies to integrate PV and DG. These measures include increasing thermal generation operating reserve margins and committing less efficient combustion turbine generators to meet the increased flexibility in thermal generation output caused by the integration of PV and DG output.[6] The level of mitigation should include sufficient margin to account for other potential impacts and at a reasonable level of risk. Prospectively, the level of mitigation may be adjusted, upward or downward, as renewable generation is added to the system and actual performance data is collected. In the future, other mitigation measures including the installation of fast-response energy storage systems, such as hydroelectric storage and batteries may offer suitable solutions, but were beyond the scope of this study. The Company will evaluate storage options and other mitigation options based on the results and findings of this study.

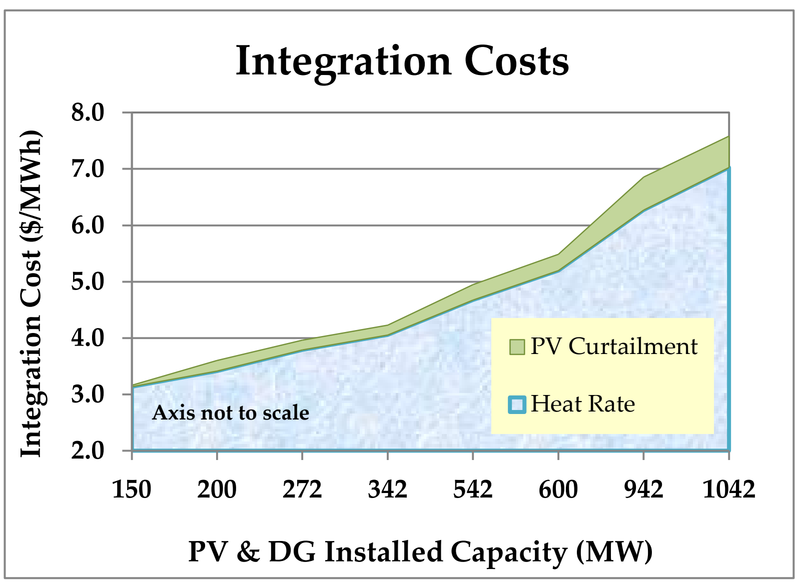
[6] DG capacity may be further limited due to clustering or other local distribution constraints as outlined in the December 2010 DG Study.

Renewable Integration Costs

Balancing area studies identified the additional operating reserves needed for new renewable capacity. The increase in reserves provides information needed to estimate increases in production cost for each case. Production cost analysis indicates the heat rate of regulating units used for operating reserves increases by up to five percent above the base case. The higher heat rates cause unit operating cost to increase at a rate commensurate with the increase in unit heat rates.

Figure 6 presents the incremental production costs – i.e. integration costs – for each case evaluated in this study. Integration costs caused by increasing operating reserves and modest curtailment of PV output range from a low of $3/MWh for low renewable penetration to a high of just under $8/MWh for the higher penetration cases. The curtailment of PV output is required during hours when on-line generation is operating at minimum output thresholds and system load net of PV is below the collective output of NV Energy's on-line generation. During these hours, the Company would be required to curtail PV output unless the power could be sold to entities outside the southern Nevada balancing area.

Figure 6. Integration Costs



In addition, the cost of operating combustion turbines to meet increased regulation ramping requirements and accelerate maintenance caused by operating units for more hours adds up to $5/MWh. These values include about $5 million to commit and must-run a 50 MW peaking unit during daytime hours (4100 hours per year) and $800,000 for accelerated maintenance associated with the increased hours of operation. However, the level of detail in both the data and methods applied – a minute-by-minute simulation of the system for the entire year is needed to more accurately predict ramp deficiency impacts and operating costs. Accordingly, the additional costs for regulation ramping are preliminary and will be updated following the completion of this report, when more sophisticated tools that were not available at the time of study become available.[7]

1.3 Conclusions

The study team determined that integration of DG and large-scale PV on NV Energy's system in southern Nevada increases regulation and load following requirements that must be supplied by NV Energy's generating resources, mostly from combined cycle and combustion turbine units. These higher requirements increase the amount of generation committed in day-ahead schedules, degrade unit efficiency, and accelerate operations and maintenance, all of which increase energy costs. Balancing area limits for traditional unit dispatch and operation are exceeded at all renewable generation levels, and system upgrades or other mitigation is necessary to accommodate variable renewable output. For capacity levels exceeding those evaluated in this study (1042 MW), NV Energy generation alone may not be capable of meeting regulation and load following requirements associated with variable resources.

Specific study findings include:

- Analytical methods using ground-based and satellite data were developed and successfully applied to estimate minute-by-minute large PV output profiles at ten sites in southern Nevada, and for smaller PV distributed over the greater Las Vegas valley.
- The level of intermittency for large PV arrays is mitigated for some – but not all – instances when installations are distributed over a large geographic area; the highest offsets occur for similarly sized plants and when distances between plants increase.
- Rigorous analytical methods and models were successfully applied to predict system incremental balancing requirements including capacity and ramp rate, using minute-by-minute time scale (and longer) data for the integration of renewable resources.
- These models predict that large PV and DG installations will cause balancing area requirements to increase for all PV and DG penetration level *after* three percent of the

[7] Building upon the results of this study, the study team will apply PNNL's Resource Integration Model (RIM), currently under development, to perform the minute-by-minute simulation analyses.

highest changes in minute-by-minute net load (native load minus PV output) in each hour are excluded from the analysis.

- The performance impacts associated with variable PV and DG output occur regardless of the type of renewable generation installed – all PV and no DG, or vice-versa.
- Production cost simulation models confirm that integration of PV and DG will cause NV Energy's generation to operate less efficiently; further, units' cycling range and the number of unit starts also increase, resulting in higher operation and maintenance costs.
- The annual cost of operating reserves needed to integrate 150 MW to 1000 MW of large PV and DG capacity ranges from approximately $2 to $20 million, or $3 to $8 per MWh of PV and DG capacity. Forecast error and must running combustion turbines when ramping deficiencies occur increase these costs.
- Additional costs may apply to DG, where local distribution constraints caused by clustering or where DG is installed on feeders susceptible to degraded performance, as outlined in the December 2010 DG Study.
- The addition of large amounts of DG does not appear to cause violation of steady state voltage, transient voltage stability, or thermal loadings.

The results presented herein were developed using sophisticated tools and analytical methods. Inherent in advanced studies of this nature is a degree of variability that accompanies the prediction of system performance impact and cost. Due to the lack of historical solar output data, the analysis was based on a simulated solar output for a single year. Also, an accurate forecast of system load and solar output was assumed. The results presented herein, therefore, should be deemed the minimum requirements. Accordingly, the study team recommends that NV Energy apply a reasonable level of margin to minimize risk as large PV and DG is installed on its system. For example, integration costs cited above exclude any additional reserve requirements for days where PV output is not accurately forecasted; for example, due to unexpected cloudy days during winter and shoulder months. As the Company and system operators gain more experience in the impact of variable renewable output, which could lead to new approaches for forecasting day-ahead PV output on cloudy days and improved generation scheduling tools, we anticipate the methods used to predict renewable integration impacts and costs will be refined. These refinements are expected to reduce integration costs and increase the amount of variable renewable capacity that can be installed in NV Energy's southern Nevada service territory.

2 INTRODUCTION

2.1 Background

In response to regulatory, environmental, and market incentives, the amount of photovoltaic (PV) generation added to electric utility grids has grown and is expected to be robust. Until recently, electric utility planners have accommodated most of this generation without significant impact on or expansion of the electric grid. However, there is increasing uncertainty and concern regarding the variability of large-scale renewable generation output and whether it will strain the ability of the grid to deliver the power reliably.

NV Energy has a service territory well suited for large-scale PV systems. State energy, PUCN and utility officials each recognize the need to ensure the electric delivery system is capable and prepared to integrate output produced by variable resources. Due to the large number of pending applications requesting interconnection, NV Energy submitted an application proposal to the Public Utilities Commission of Nevada (PUCN) in its 2010 Integrated Resource Plan filing (Docket No. 10-02009) requesting approval to perform a study to evaluate large-scale PV integration. On July 30, 2010, the PUCN issued an Order that authorized NV Energy to evaluate large PV generation and its potential impact on NV Energy's system in southern Nevada; the region served by Nevada Power Company.

Subsequent to its Order approving the large-scale PV study, the PUCN issued a separate Compliance Order to determine how Distributed Generation (DG) can impact NV Energy's energy delivery system performance, reliability and distribution operations, and electricity rates.[8] The order to conduct a DG study responded to issues raised by various entities in Nevada seeking to install or promote the installation of DG in Nevada. In response, NV Energy engaged Navigant Consulting, Inc. (Navigant) to conduct a study to address the PUCN's primary objective in the Order, summarized in the following question:

'What is the "maximum amount of DG from renewable energy that can be integrated on the distribution systems of the Companies within the existing operating limits?"[9]

---

[8] Docket No. 10-04008, *Investigation regarding the impacts of renewable energy on Nevada's electricity rates, environment and economic development*.

[9] PUCN Order, Section III – *Procedural History*, page 2.

Navigant issued a report dated December 30, 2010 and NV Energy filed it with the PUCN on the same date. Among its findings, Navigant determined that NV Energy's distribution is not the primary limiting factor regarding the amount of DG[10] that can be installed on its system. Preliminary studies confirmed that DG can impact the bulk power system and the report included a recommendation to evaluate DG impacts as part of the large-scale PV study. The PUCN accepted the DG study.[11]

2.2 Project Scope

NV Energy balances load and generation for most of Nevada and seeks to determine how different levels of PV generation will affect generation performance within NV Energy's southern system.[12] The *Large-Scale PV Integration Study* evaluates integration requirements for large-scale PV and small DG. A team comprised of Navigant, the Department of Energy (DOE), Sandia National Laboratories (SNL), Pacific Northwest National Laboratories (PNNL), and NV Energy conducted the study, focusing on the impact of large-scale PV and DG on bulk system generation and balancing performance and operations.[13]

The study evaluates up to 1042 MW of renewable PV and DG located in southern Nevada. The capacity of individual large-scale PV plants ranges from 5 MW to over 300 MW. The project team developed five large-scale PV scenarios for evaluation. Figure 7 illustrates the location, size, and combination of the projects that comprise each of the scenarios. In addition to the PV additions outlined in Figure 7, DG was added in varying amounts to each scenario for a total of nine cases selected for detailed evaluation. The amount of DG included in each of the cases is presented in Section 2.4.

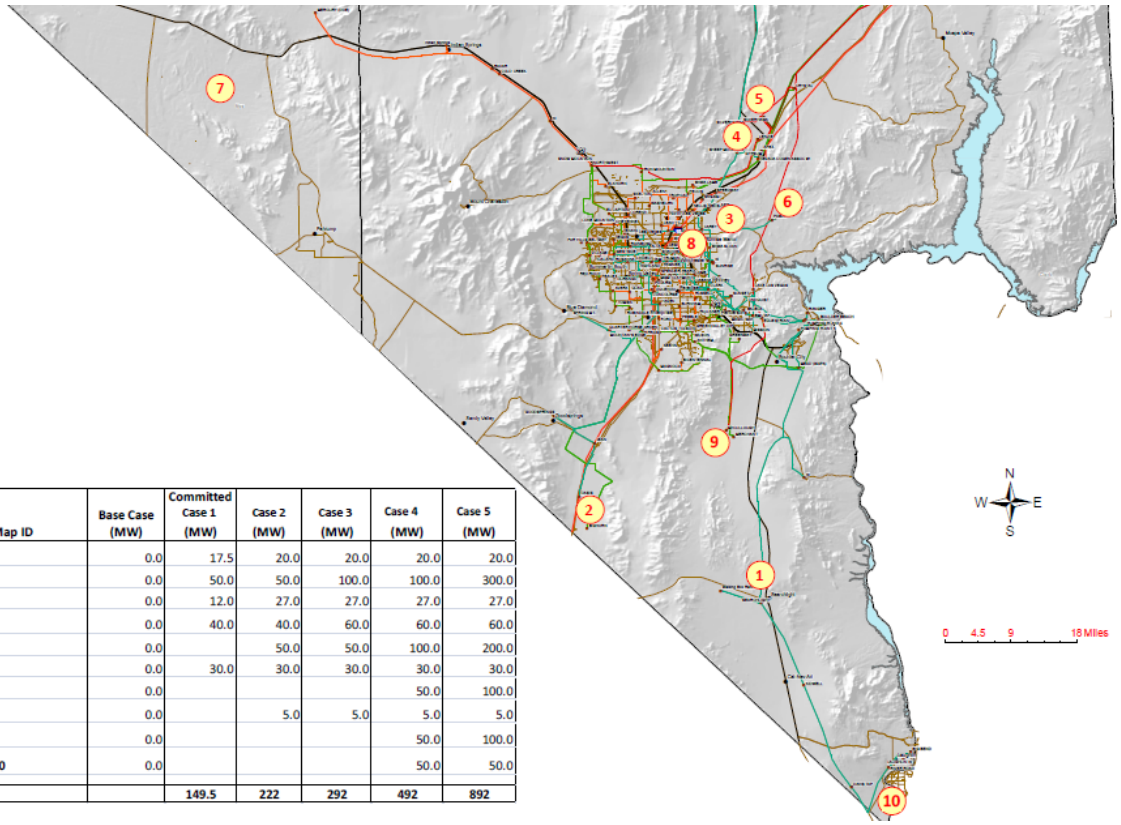
[10] DG was defined as wind and PV rated 5 MW or less, connected to distribution lines rated 25kV or below. For the present study, DG is considered only as PV.

[11] Docket No. 10-04008, PUCN Final Order, May 3, 2011.

[12] NV Energy is responsible for balancing area operations for both NPC and Sierra Pacific Power Company (SPPC). Currently, NPC and SPPC operate as separate balancing areas. This study focuses solely on NPC balancing area impacts. Further, impacts are evaluated with respect to the NPC system.

[13] This project is jointly funded by the DOE and NV Energy.

Figure 7. Proposed PV Plant Locations



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Solar PV Project 4	0.0	40.0	40.0	60.0	60.0	60.0
Solar PV Project 5	0.0		50.0	50.0	100.0	200.0
Solar PV Project 6	0.0	30.0	30.0	30.0	30.0	30.0
Solar PV Project 7	0.0				50.0	100.0
Solar PV Project 8	0.0		5.0	5.0	5.0	5.0
Solar PV Project 9	0.0				50.0	100.0
Solar PV Project 10	0.0				50.0	50.0
Total:		149.5	222	292	492	892

This study includes sub-minute analyses of variable output from large-scale PV and DG on NV Energy balancing area performance in southern Nevada. The analysis includes the development and application of predictive methods to quantify regulation and load following requirements to integrate variable generation, and to evaluate the capability of NV Energy's existing generation fleet to accommodate increasing levels of large-scale PV and DG.

An important factor associated with large-scale PV plants is the impact of moving cloud cover on net plant output. The ability of generators to adjust to rapid changes in PV output due to moving clouds is one of the factors that determine how much PV can be integrated into NV Energy's southern balancing area. If generation cannot ramp up or down quickly enough to respond to variable PV, then system upgrades or changes in operations may be required. Even if upgrades are unnecessary, the additional generation required to be on line (i.e., operating reserves to continuously balance resources with demand) may result in higher costs. The cost of the additional on-line generation required to balance net load with demand is commonly used to derive renewable integration costs.

The study includes four primary tasks, described below.

Task 1: Prepare high-resolution PV output data for southern Nevada (on a one-minute time scale for an entire year).

Task 2: Develop composite PV output profiles via statistical methods for ten sites and five case study scenarios in southern Nevada.

Task 3: Analyze the impact of large-scale PV and DG on system balancing reserve requirements within NV Energy's southern Nevada system, and evaluate the generation fleet's capability to meet the requirements.

Task 4: Identify the impacts on generation dispatch and costs of integrating PV & DG, and identify options to increase the amount of solar resources that can be installed on NV Energy's system.

Section 3 of this report presents the methodology and results for Tasks 1 and 2 above; Section 4 presents the results of Task 3; and Section 5 presents the results of Task 4.

Appendix A presents NV Energy's utility-scale renewable project portfolio. Appendix B presents the results of steady state and dynamic transmission analyses. Appendix C shows the large-scale PV generation profiles in Case 5. Appendix D shows the regulation ramp rate deficiencies identified for each solar case. Appendix E shows the regulation ramp rate deficiencies after generation redispatch.

2.3 Methodology

The project team developed research methods to assess the impacts of DG and large-scale renewable projects on NV Energy's southern Nevada balancing area and networked transmission system.[14] The large-scale renewable projects include those that have signed purchase power agreements (PPAs), but not yet in commercial operation, as well as several projects that exhibit potential to be secured under future PPAs. The study includes an evaluation of the system impacts of integrating PV and DG in southern Nevada, with total

[14] The project team researched and developed new methods to evaluate short-term impacts of variable PV output and the capability of the generation fleet to meet large variations in PV output and cycling and movements of the fleet, as prior industry studies and research efforts have not examined PV impacts with the same degree of rigor as presented in this research effort.

amounts ranging from a low of 150 MW to a high of approximately 1,050 MW. At the higher penetration levels, PV and DG could supply up to 20 percent of NV Energy's load at peak and up to 50 percent or more during off-peak hours. At this level of output, the cost of compensating for the operation of PV and DG generation may be significant, both in terms of the fuel cost and the additional operating and maintenance expenses incurred by rapidly changing thermal generation output that is needed to follow variable renewable output.

The primary role of the team in supporting NV Energy's efforts and the methodology employed by each organization follows:

- Sandia National Laboratories developed minute-by-minute large-scale PV and DG output profiles for southern Nevada using existing and new analytical tools, and verified results using comparable data from other PV systems in the U.S.
- Pacific Northwest National Laboratory conducted the balancing operations (including load following and regulation) studies, using existing and new methods to evaluate the impact of variable renewable output on balancing reserve requirements, the ability of NV Energy's generation fleet to meet increased system variability and the cycling and movements of the fleet to balance generation and load.
- Navigant performed production simulation analyses to quantify integration costs of each PV and DG case. Navigant is also responsible for the preparation of this report, and the findings and conclusions contained herein.
- NV Energy provided the team with load, generation and other system data necessary to conduct the study. It also produced day-ahead unit schedules for selected days and case studies using internal software to support the balancing area studies. The Company also performed transmission steady state and dynamic studies using internal models and an approach consistent with those used for System Impact Studies for interconnection requests.

Specific steps performed by the project team to evaluate PV and DG system impacts and identify the renewable penetration limits and cost include:

1. Develop time-synchronized PV minute-by-minute output profiles and day-ahead forecasts of average PV and DG hourly output. Analyze the results to quantify the impact of increasing amounts of large-scale PV generation and small distributed PV in southern Nevada.

2. Conduct a detailed evaluation of balancing area operations for minute-by-minute changes in net load (load – solar output) using the PV and DG output profiles and NV Energy generating unit operating data. Identify the additional regulation and load following requirements, including capacity and ramp rate, associated with each case study. Determine whether existing generation fleet can meet these requirements without and with generation redispatch. Quantify the impact of PV variability on generation fleet cycling and movements in regulation and load following, to establish a basis for the assessment of generator wear and tear.

3. Integrate the results of the balancing area studies and the PV and DG output profiles to quantify the impact of increasing levels of PV and DG on NV Energy's generation mix and production costs using production cost simulation models. Identify the increased fuel and O & M costs for existing generating units caused by higher operating reserves, increased cycling, higher heat rates, and changes in dispatch schedules.

4. Evaluate the impact of incremental DG on NV Energy's bulk power transmission system, including steady state and dynamic performance within the southern Nevada balancing area operations.

5. Identify mitigation strategies or upgrades required to accommodate variable resource additions, including those needed to satisfy NERC balancing area performance requirements.

Analytical Tools

Navigant, SNL, and PNNL employed rigorous analytical methods and tools to evaluate the impact of increasing levels of DG on NV Energy's energy delivery system. Each is summarized below. Additional details are provided in subsequent sections of this report.

(1) Sandia National Laboratories

Sandia Labs used several existing and developed new tools to model PV output given specific irradiance levels, PV array attributes and locational data. To create minute-by-minute output profiles, SNL developed new models designed specifically for this project. The tools included the use of publicly available databases and external models that predicted PV output at each of the 10 proposed PV sites in southern Nevada. Among other resources, SNL used satellite imagery data available from the National Oceanic and Atmospheric Administration (NOAA), and ground-based one-minute solar insolation data from the Las Vegas Valley Water District

(LVVWD). Specific citations are included in this report where analytical methods developed by prior SNL or non-SNL studies were employed or where data from external sources were used.

(2) Pacific Northwest National Laboratory

PNNL employed several analytical methods and models used previously to evaluate renewable energy integration, including large-scale wind and PV. In addition, new analytical methods were developed to simulate large-scale PV impacts on NV Energy's balancing area operations. These included models designed to predict whether NV Energy's generating mix is sufficient to meet potentially higher regulation and load following requirements for increasing amounts of PV and DG. NV Energy Systems Operations provided detailed load and generation data needed by PNNL to determine whether existing resources could serve increasing amounts of variable renewable output without violating generating units operating limits or NERC performance standards. NV Energy resource schedulers provided day-ahead unit commitment schedules for selected days deemed to be most challenging for generation to reliably meet regulatory and load following requirements. Using this information and data, PNNL developed a set of analytical models designed to evaluate balancing area performance for a range of PV output profiles and generating commitment schedules. PNNL also developed new methods to quantify the impact of PV variability on generation fleet cycling and movements in regulation and load following, to establish a basis for the assessment of generator wear and tear.

(3) Navigant Consulting, Inc

Navigant applied sophisticated, industry-accepted simulation models to predict the impact of DG on power delivery system performance and costs. The *Ventyx*[15] *PROMOD Production Costing Simulation Model* was used to estimate fuel and variable operation and maintenance savings and to predict emissions reductions. Navigant utilized PROMOD and NV Energy's databases to conduct production simulations studies for 2011 using 2007 hourly load data. The cases Navigant prepared are a modification of the resources mix and loads used in recent studies, updated to reflect assumptions used by this study for PV and DG output profiles, which include greater detail for modeling load following units, mostly for combined cycle generation. A number of other updates to the model database were made to isolate the impact of incremental PV and DG on NV Energy's southern Nevada resource mix and resulting energy costs. NV Energy provided the database and assumptions needed to conduct PROMOD studies for a 2011 resource mix.

[15] Ventyx is an ABB Company

For the transmission system analyses, performed by NV Energy System Operations and Transmission Departments under Navigant's direction, several commercial models were used to assess impacts. The primary tool used to assess transmission level steady state impacts was the *General Electric Positive Sequence Load Flow (PSLF) Model* and the PSSE 32 PTI Siemens programs for steady state and transient analysis. The PSLF model contains a detailed database of both the Western Electricity Coordination Council (WECC) and NV Energy's transmission grid, thereby ensuring DG technologies are accurately modelled and their impacts fully detected within and outside of NV Energy's balancing area. The PSLF model evaluates how increasing levels of DG installed on NV Energy's distribution affects steady state feeder thermal loadings and performance for key contingency events. These contingencies included a loss of key transmission lines and concurrent loss of DG due to the event. An adjunct model was employed to assess dynamic impacts of a concurrent loss of lines and DG within NV Energy's balancing area. Both the methods employed and models used to evaluate transmission impacts are comparable to those used to perform System Impact Studies for large-scale PV (and other generation) interconnection requests.

2.4 Study Assumptions

Navigant expanded the technology, operating, and cost assumptions that were approved by Stakeholders in the DG Study to include additional data and assumptions needed for this study.

Navigant expanded its analysis and study assumptions upon its finding that NV Energy's distribution system alone was not the limiting factor to integrating new DG capacity and therefore needed to include transmission and bulk grid impacts. This finding required Navigant to jointly assess the impacts of DG on NV Energy's distribution, generation and transmission systems. Accordingly, the ongoing *Large-Scale PV Integration Study* incorporates this recommendation.[16]

1. The study focuses on the ability of the system as it exists today to accommodate large-scale PV and DG, with some exceptions:

[16] Future studies of renewable projects should include DG when evaluating impacts on the transmission system and balancing area operations.

- 2007 load and solar data is applied, as the solar and weather data needed to predict solar output is not readily available for 2008 and later years.[17] It also represents a year when predicted PV output and NV Energy loads experienced all-time peaks[18]

- Generation resources reflect 2011 mix and operating costs (Harry Allen Combined Cycle unit is assumed to be in service beginning January 2011)

- External sales are set to zero; this is an important assumption as high PV & DG penetration results in dump energy due to the requirement that generation must operate within capacity limits

2. The study is conducted for one year and excludes load growth, system expansion and resource additions

   - All future PV projects with PPAs are removed from the base case model (2012 – 2013) but included as one of the case studies (Case 1 – Committed Renewables)

   - Only NV Energy's southern balancing area is evaluated

   - Actual, non-normalized 2007 hourly loads are used in balancing area and production cost studies (5,800 MW peak).

3. The location of PV projects is based on pending PPA contracts; DG penetration levels conform to the December 2010 DG Study, and the output profiles were developed using 2007 solar and weather data.

4. Evaluation criterion for integration includes an objective of no net degradation in system performance and reliability after the upper three percent of intervals experiencing the highest change in net load are excluded[19]

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[17] The cost to acquire the more recent data and time needed to process the data precluded its use in this study.

[18] NV Energy does not expect the system peak to reach the 2007 peak until 2020.

[19] The NERC performance thresholds under CPS-2 allow up to 10 percent violation and still remain in compliance. A violation is deemed to occur when NV Energy's Area Control Error (ACE) exceeds 44 MW in a 10-minute interval. In consideration of the 10 percent allowance, the project team agreed that a 3 percent exclusion of intervals with the highest variances (load and PV or DG) should be excluded from the analysis. However, the 3 percent exclusion should not be interpreted as 3 percent of the total 10 percent FERC allowance, as measurement of the violations falling under the NERC L 10 rule is calculated using different metrics. Additional details are provided in Section 5.

5. Evaluation includes utility system impacts and excludes customer, third party, and societal impacts.

6. All studies include the cost of increased operating reserves and other mitigation required to integrate PV and DG within existing generating operating limits and avoid violation of NERC reliability performance requirements. NERC performance standards include current requirements under BAL-001, including the performance metrics of CPS-1 and CPS-2.

Case Descriptions

The report includes five large PV scenarios and ten case studies with increasing amounts of large PV or DG, up to a maximum of 1042 MW combined:

- The five scenarios include large PV projects with signed Power Purchase Agreements (PPAs) and proposed projects based on data provided by developers;
- Case 1 includes a stand-alone committed PV case with no DG added, and three additional cases with DG added in at increasing levels;
- Cases 2 though 10 include DG added to the five PV scenarios in amounts corresponding to those evaluated in the December 2010 DG Study (1%, 9% or 15% of NPC load); and
- All cases other than Committed PV include DG, which is assumed to be equally distributed in relation to load throughout the Las Vegas Valley.

Table 2 summarizes each of the PV cases evaluated in the study. The total number of cases studied is ten, as some amount of DG is assumed to be added to each large-scale PV case other than the committed 149 MW stand-alone PV scenario. The nomenclature adopted for the study include case descriptions numbered 1 through 5 for the five large PV scenarios; and A, B, and C for DG capacity at 1%, 9%, and 15%, respectively.

Comparisons among the combinations selected for study allow assessments to be made of the:

4. Effects of increasing large-scale PV, while holding DG constant;
5. Effects of increasing DG while holding large-scale constant; and
6. Effects of varying large-scale PV and DG together, while holding total generation capacity constant.

Table 2. Case Descriptions

PV/DG Cases	1% (50 MW)	9% (450 MW)	15% (750 MW)
Committed PV-149 MW	-	-	-
Case 1 – 149 MW	1A (199 MW)	1B (599 MW)	1C (899 MW)
Case 2 – 222 MW	2A (272 MW)	-	-
Case 3 – 292 MW	3A (342 MW)	-	3C (1042 MW)
Case 4 – 492 MW	4A (492 MW)	4B (942 MW)	-
Case 5 – 892 MW	5A (942 MW)	-	-

2.5 Integration Requirements

The outcome of studies used to support findings in this report also are used to identify integration requirements for developers or other parties seeking to interconnect large PV to NV Energy's southern transmission grid. NV Energy currently performs System Impact Studies for interconnection requests at the transmission level using methods consistent with FERC open access transmission rules. Typically, these studies identify the additional transmission or system redispatch, if any, required to interconnect new or upgraded generation. The methods employed to assess bulk system impacts in this study are consistent with those used for System Impact Studies. The outcome of this study incorporates the cost of redispatch or other mitigation that may be needed generators seeking interconnection once a threshold has been reached. This threshold is dependent on the amount of variable renewable output that can be added to the system before NV Energy incurs additional costs. Accordingly, this study estimates the incremental costs for integrating renewable generation for each of the scenarios presented in Table 2.[20]

[20] The System Impact Studies the Company and other utilities perform in response to interconnection requests typically do not address the impact of high levels of variable output from renewable resources. Accordingly, the integration costs presented in this report may be deemed to be above and beyond those authorized by FERC. Some entities have imposed integration costs to renewable projects producing output intermittently, including the Bonneville Power Administration.

3 PV OUTPUT PROFILES

3.1 Overview

The DOE retained SNL to develop a modeling approach to simulate time-synchronized, one-minute power output from large-scale PV plants and from distributed PV generation in southern Nevada. All of the proposed plants are within NV Energy's service territory surrounding greater Las Vegas. Because site-specific ground measurements of solar irradiance are unavailable at these sites, SNL developed an approach that combined irradiance estimated from satellite imagery at each proposed plant location, with one-minute measurements from comparable sites in southern Nevada.

Calendar year 2007 was selected for the analysis as the necessary irradiance data is readily available and when NV Energy experienced its all-time peak load. The PV output datasets generated for 2007 in southern Nevada are critical inputs to balancing area analyses used to estimate integration costs for increasing amounts of large-scale PV generation. Large-scale plant designs used to develop one-minute net PV output profiles ranged in size from 5 to 300 MW_{AC} and included both fixed-tilt thin-film and single axis- tracked polycrystalline Si systems. Distributed PV systems range from 4 kW_{AC} to $3MW_{AC}$ and comprise both roof-mounted and ground-mounted systems.

3.2 PV Model Objectives

SNL's analysis provided four inputs to the *Large-Scale PV Integration Study*:

- Time-synchronized PV plant power output profiles for up to ten proposed sites in southern Nevada and three levels of DG at one-minute time scales, and reduced to one-hour averages;
- Day-ahead forecasts of hourly average PV and DG output;
- A description of the analysis methods;
- An analysis that validates the simulation results and increases confidence in PV data sets.

The one-minute output profiles for large-scale PV plants were created for ten sites in the greater Las Vegas Valley using 2007 satellite irradiance data and ground-based irradiance measurements provided by the Las Vegas Valley Water District (LVVWD). The DG output profiles were generated by a simpler method that relied only on the ground-based irradiance measurements. The validation process includes confirming that calculated irradiance and PV output patterns are comparable to patterns based on real data collected at other sites in the United States. SNL's methodology and its results are described in the remainder of this section; a separate Sandia publication provides more details.[21]

3.3 Summary of Methodology

Background

The instantaneous power output from a PV system is determined by a number of factors, including module and inverter characteristics, irradiance over the plant area, PV cell temperature, angle of incidence and spectral quality of the light, and soiling, wiring, and conversion losses. After years of outdoor module and array testing, SNL developed the Sandia PV Array Performance Model.[22] One challenge in applying this and other PV models to large-scale systems is that they generally use a single value of irradiance as an input. However, as PV systems become larger, as is the case with the large-scale plants considered in this study, irradiance will vary spatially over the plant as cloud shadows traverse the plant's footprint.

The model described in the following sections tackles this problem using a multi-step approach. It first simulates one-minute point irradiance at locations without ground-based measurements, then estimates the spatial average irradiance over each of the ten PV arrays, and translates the spatial average irradiance to plane-of-array (POA) irradiance. The spatial average POA irradiance is used as a single input value to the performance model to estimate power. Analysis of power output from a large PV array in Hawaii has demonstrated that spatial average irradiance is closely correlated with overall plant output. Conversely, point measurements of irradiance taken near the plant were not highly correlated with output.[23]

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[21] *Simulation of One-Minute Power Ouput from Utility-Scale Photovoltaic Generation Systems*, C. Hansen, J. Stein, A. Ellis, Sandia National Laboratories, August 2011

[22] *Photovoltaic Array Performance* Model, Albuquerque, NM, King, D. L., E. E. Boyson, et al., Sandia National Laboratories. SAND2004-3535, 2004

[23] S. Kuszmaul et al., "*Lanai High-Density Irradiance Sensor Network for Characterizing Solar Resource Variability of MW-Scale PV System*". *35th IEEE PVSC*, 2010, pp. 283-288

Analytical Methods for Large-Scale Plants

The following outlines the four-step approach SNL used to derive detailed PV output profiles for large-scale plants:

Step 1: Estimate One-Minute Irradiance from Satellite Data for 2007

1. At PV plant locations, obtain estimates of hourly average irradiance (i.e., averaged over time) for each day of 2007 from satellite data.
2. Create a library of "irradiance days" from irradiance measured at one-minute intervals at LVVWD sites; calculate one-hour averages from the one-minute data.
3. For each day at the PV plant locations, select an irradiance day from the library that best matches the day's hourly average irradiance estimated from the satellite data.
4. Where necessary, adjust the selected irradiance days to prevent selection of duplicate days at different PV plant locations.

Step 2: Calculate Spatial Average Irradiance for Each PV Plant

1. Calculate dimensions of PV plant assuming a square configuration.
2. Estimate spatial average irradiance as a moving average with a time window equal to the time it takes for a cloud to pass over the plant. Obtain cloud speeds for 2007 from the NOAA weather balloon at Desert Rock, NV.

Step 3: Calculate POA (Plane of Array) Irradiance

1. Apply SERI/NREL DISC model[24] to calculate direct normal irradiance (DNI) fraction.
2. Calculate diffuse horizontal irradiance (DHI).
3. Calculate angle of incidence (AOI) for fixed and single-axis tracking configurations.
4. Apply tilted plane model to calculate POA diffuse irradiance[25]
5. Derive POA beam irradiance as a function of DNI

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[24] *A Quasi-Physical Model for Converting Hourly Global Horizontal to Direct Normal Insolation*, Maxwell, E. L., Golden, CO, Solar Energy Research Institute, 1987.

[25] *Modeling Daylight Availability and Irradiance Components from Direct and Global Irradiance*, Perez, Richard; Ineichen, Pierre; and Seals, Robert, Solar Energy 44 (5): 271-289, 1990.

Step 4: Model PV Output

1. Define plant design assumptions:
   - Module layout and type;
   - Inverter type and characteristics;
   - DC deration factor.
2. Apply Sandia PV Array Performance Model to calculate DC power using 2007 air temperature and ground surface wind speed from Las Vegas, adjusted for elevation differences between each site and Las Vegas.
3. Apply Sandia Inverter Model to calculate AC power.

Additional details, citations, and specific assumptions used in the four-step approach for large-scale plants are presented in Section 3.5.

Analytical Methods for Distributed PV Systems

The following outlines the four-step approach SNL used to derive detailed PV output profiles for distributed PV systems:

Step 1: Estimate Spatial Average Irradiance for the Las Vegas valley for 2007

1. Average irradiance measurements from the LVVWD sites.
2. Estimate spatial average irradiance as a moving average with a time window approximately equal to the time it takes for a cloud to pass over the valley, i.e., using a fixed 10 minute window.

Step 2: Calculate POA (Plane of Array) Irradiance

1. Apply SERI/NREL DISC model[26] to calculate direct normal irradiance (DNI) fraction.
2. Calculate diffuse horizontal irradiance (DHI).
3. Calculate angle of incidence (AOI) for fixed and single-axis tracking configurations.
4. Apply tilted plane model to calculate POA diffuse irradiance[27]

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[26] *A Quasi-Physical Model for Converting Hourly Global Horizontal to Direct Normal Insolation*, Maxwell, E. L., Golden, CO, Solar Energy Research Institute, 1987.

[27] *Modeling Daylight Availability and Irradiance Components from Direct and Global Irradiance*, Perez, Richard; Ineichen, Pierre; and Seals, Robert, Solar Energy 44 (5): 271-289, 1990.

5. Derive POA beam irradiance as a function of DNI

Step 4: Model PV Output

1. Define distributed PV system characteristics:
   - Module layout and type;
   - Inverter type and characteristics;
   - DC deration factor.
2. Apply Sandia PV Array Performance Model to calculate DC power using 2007 air temperature and ground surface wind speed from Las Vegas.
3. Apply Sandia Inverter Model to calculate AC power.

Additional details, citations, and specific assumptions used in the four-step approach for large-scale plants are presented in Section 3.5.

3.4 Assumptions

Key study assumptions to derive PV output profiles are summarized below. Specific data and calculations employed are presented in sections that follow.

- A single year (2007) is used to derive PV output profiles.
- All proposed PV sites are located in southern Nevada.
- PV plants and performance assumptions are based on currently available technology.
- No inverter clipping or power curtailment occurs.
- Changes in PV performance over time are not considered (one-year snapshot only).
- The following PV module technologies are used in the analysis (Table 3):

Table 3. PV Technologies

Module Technology	Mounting Configuration	Land Requirements (acres/MW_{AC})
Polycrystalline Si	Single-axis tracking	10
Thin-Film	Fixed latitude tilt	12.5

Table 4 presents the five scenarios for large-scale plants outlined in Section 2, with the size of each plant listed by location. The table is color-coded according to whether a plant is designated as fixed or tilt axis.

Table 4. PV Plant Scenarios

Solar PV Project Map ID	Case I (MW)	Case II (MW)	Case III (MW)	Case IV (MW)	Case V (MW)
Solar PV Project 1	17.5	20	20	20	20
Solar PV Project 2	***50***	***50***	***100***	***100***	***300***
Solar PV Project 3	***12***	***27***	***27***	***27***	***27***
Solar PV Project 4	40	40	60	60	60
Solar PV Project 5		***50***	***50***	***100***	***200***
Solar PV Project 6	30	30	30	30	30
Solar PV Project 7				50	100
Solar PV Project 8		***5***	***5***	***5***	***5***
Solar PV Project 9				***50***	***100***
Solar PV Project 10				50	50
Total	**149.5**	**222**	**292**	**492**	**892**

1. **Blue, italics = Thin film (fixed tilt)**
2. Black = Polycrystalline Si (single axis tracking)

Table 5 presents the three scenarios for distributed PV systems outlined in Section 2. Distributed PV comprises a mixture of residential rooftop, commercial rooftop and commercial ground-mounted systems.

Table 5. Distributed PV System Scenarios

DG Penetration	Residential	Commercial Rooftop	Commercial Ground Mount
	4 kWAC fixed tilt	300 kWAC flat roof mount	3 MWAC single-axis tracker
1%	42 MW	7 MW	7 MW
9%	378 MW	63 MW	63 MW
15%	630 MW	105 MW	105 MW

3.5 PV Data Derivation

The methods used to generate large-scale plant output are presented first, followed by the methods used to generate DG output.

Derivation of One-Minute Large-scale PV Site Irradiance Data

Currently, ground-based irradiance data is not available at any of the ten proposed PV plant sites. However, one-minute averages of global horizontal irradiance are available at six Las Vegas Valley Water District (LVVWD) PV installations within the Las Vegas Valley, presented in Table 6. A methodology based on readily available LVVWD data was developed by SNL to simulate one-minute irradiance at each of the proposed PV sites.

Table 6. Irradiance Measurements - LVVWD Ground Station Locations

Station Name	Start Date for Data	End Date for Data
Fort Apache	08/23/2006	4/29/2009
Grand Canyon	09/30/2006	4/29/2009
Las Vegas State Park	07/26/2007	4/29/2009
Spring Mountain	11/30/2006	4/29/2009
LUCE	05/02/2007	4/29/2009
Ronzone	04/27/2006	4/29/2009

For any 10 x 10 km area in the U.S., estimates of hourly irradiance are available through the SolarAnywhere service from Clean Power Research.[28] This data is currently provided free of charge for any time period older than 3 years. Irradiance is estimated from GOES satellite imagery using algorithms developed by Perez and others.[29] These algorithms have been validated by several researchers.[30] Irradiance estimates for 2007 at hourly intervals for the 10 study sites were obtained. These estimates represent instantaneous irradiance over a single satellite pixel (~1 km^2), which is located within the 10 × 10 km area.

Several options were considered and evaluated to estimate one-minute irradiance at each PV site, including several existing time-series simulation models. The review indicated these models would likely overstate the frequency of PV output ramps. A new method was developed that would produce one-minute irradiance time series that closely match hourly averages, reproduce observed ramp frequencies, and reflect the seasonal patterns among the sites indicated in the irradiance data. The method uses the following steps:

1. Assemble a library of more than 5,000 one-day sequences of irradiance at one-minute intervals using all available LVVWD ground station data (Table 6). Calculate the hourly average irradiance for each day in the library.
2. Calculate the sum of the squared differences (SSD) between the hourly average target irradiance (from the satellite data) and the hourly average irradiance for each of the

[28] https://www.solaranywhere.com

[29] *A New Operational Satellite to-Irradiance Model*, Perez, R., Ineichen, P., Moore, K., Kmiecik, M., Chain, C., George, R., and Vignola, F, Solar Energy 73, 5, pp.307-317, 2002.

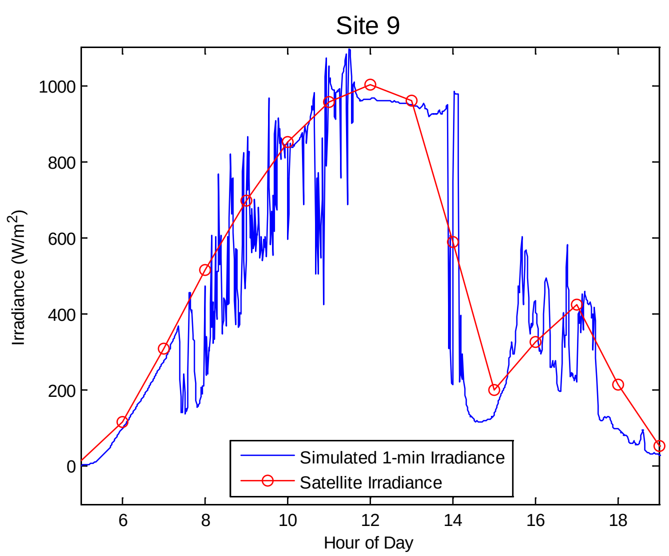
[30] For example, *Validation of PV Performance Models using Satellite-Based Irradiance Measurements*, Stein, J., R. Perez, A. Parkins, Proc. of ASES Annual Conference, 2010. .

library days for each day at the ten PV sites. Sort the library days by lowest SSD (best fit) for each day of 2007 for each PV site.

3. Assign a library irradiance day to each PV site for each day of the year. To prevent the same library day being assigned to more than one site for any given day, generate a random permutation of 1 to 10 for each day of the year. These samples represent the order in which sites are assigned library days.[31]. Once a library day is assigned to a site, that library day is not assigned to another site on the same day. The process ensures that the selection algorithm does not produce perfectly-correlated one-minute irradiance at different PV sites on the same day.

Figure 8 shows an example of the satellite irradiance for a day and the corresponding one-minute irradiance day selected from the library using the process outlined above. A partly cloudy day was selected to highlight the distinction between hourly averages derived from satellite data versus the one-minute variations in irradiance obtained from the LVVWD sites.

Figure 8. Comparison of Satellite and the Best Fit One-Minute Irradiance Data



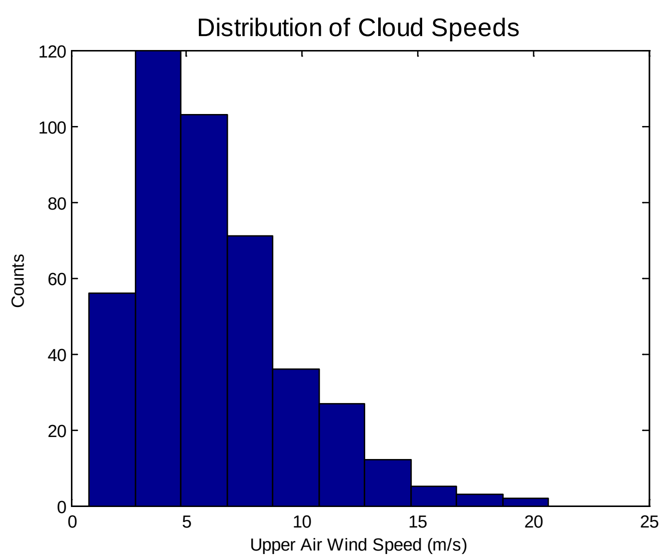
Large-scale PV Plant Spatial Average Irradiance

[31] To illustrate, if the first four integers are 4, 1, 9, 2 for a particular day, the library day for Site 4 is selected first, followed by selection of a library day for Site 1, and so forth.

The ground-based LVVWD irradiance data used to assign irradiance days to each plant site are point measurements rather than spatial averages over an area such as a PV array. Thus, the next required step in the process was to estimate the spatial average irradiance over each PV plant footprint.

The spatial average irradiance over each plant was derived using a methodology developed by Longhetto and others.[32] This method assumes that the spatial average of irradiance over an area can be estimated as a time average of point measurements of irradiance with an averaging window equal to the time required for a cloud to pass over the PV plant. Two key inputs for this method include plant size and cloud speed. The characteristic length of the plant was estimated as the square root of the plant area (i.e., plants are assumed to be square). The cloud velocity was estimated using upper air wind speed measurements obtained from NOAA weather balloons launched from the Desert Rock station in Mercury, NV.[33] These balloons are launched every 12 hours throughout the year. Wind speed at cloud level was calculated as the average of the wind speeds measured between 1,000 to 8,000 meters above sea level. Figure 9 presents the distribution of upper air wind speeds for 2007 (mean = 6.2 meters/second).

Figure 9. Distribution of Calculated Upper Air Wind Speed-Desert Rock Station (2007)



[32] *Effect of correlations in time and spatial extent on performance of very large solar conversion systems*, Longhetto, A., G. Elisei, et al., Solar Energy **43**(2): 77-84, 1989.

[33] Data obtained from University of Wyoming College of Engineering web service: http://weather.uwyo.edu/upperair/sounding.html. Desert Rock station number 72387.

The results presented in subsequent sections demonstrate a reduction in power output variability as plants become larger. This is due to the greater time required for clouds to traverse over the area of the plant.

Plane-of-Array (POA) Irradiance at Large-scale PV Sites

The Sandia PV Array Performance Model requires direct and diffuse components of POA irradiance. The DISC (Direct Insolation Simulation Code) model[34] was used to estimate direct normal irradiance (DNI) from the global horizontal irradiance (GHI) and calculated the diffuse (horizontal) as the difference.[35] The DISC model is based on empirical data collected across the U.S. relating the diffuse fraction to GHI. Beam irradiance at the POA is derived based on the angle of incidence between the sun and the module surface.[36] Diffuse irradiance on the POA was calculated using the translation model developed by Perez and others.[37] Ground reflectance was assumed to be constant (0.2) with no shading of the array.

Large-scale PV Plant Power

DC power output from each array was derived using the Sandia PV Array Performance Model[38], which calculated the maximum power point for each minute of the year. DC power was translated to AC power using the Sandia PV Inverter Model.[39]

Key assumptions used to derive one-minute AC power output using the Sandia PV Performance model include:

- Polycrystalline Si plants use Yingli Solar YL230-29b modules and thin film plants use First Solar FS-275 modules;

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[34] *A Quasi-Physical Model for Converting Hourly Global Horizontal to Direct Normal Insolation*, Maxwell, E. L., Golden, CO, Solar Energy Research Institute, 1987.

[35] i.e., Diffuse = GHI - DNI × cos(Z), where Z is the zenith angle.

[36] i.e., Beam irradiance = DNI × cos(AOI), where AOI is the angle of incidence between the sun and the module surface.

[37] *Modeling Daylight Availability and Irradiance Components from Direct and Global Irradiance*, Perez, Richard; Ineichen, Pierre; and Seals, Robert, Solar Energy **44** (5): 271-289, 1990.

[38] *Photovoltaic Array Performance* Model, Albuquerque, NM, King, D. L., E. E. Boyson, et al., Sandia National Laboratories. SAND2004-3535, 2004

[39] *Performance Model for Grid-Connected Photovoltaic Inverters*, King, D. l., S. Gonzalez, et al., Albuquerque, NM, Sandia National Laboratories. SAND2007-5036, 2007.

- All PV plant types are divided into 500 kWAC blocks using SatCon PVS-500 (480VAC) inverters;
- No inverter clipping or curtailment occurs;
- A sufficient number of series strings was used to ensure the product of the assumed DC derate factor of 0.85 and the DC rating of the modules was equal to the AC rating of the system (in MW);
- Cell temperatures are estimated using a model[40] which includes the effects of POA irradiance, air temperature and wind speed; and
- Weather data, including measured wind speed at McCarran International airport and measured air temperature data, lapse-adjusted for elevation differences between each site, are for greater Las Vegas in 2007.

Spatially Averaged Irradiance for Distributed PV Generation

Distributed PV systems are assumed to be randomly distributed throughout the Las Vegas valley, which is approximately 1,500 km^2. Aggregate power from the ensemble of these PV systems is estimated using the spatial average of irradiance over the Las Vegas valley, as the relatively large number of systems and their geographic dispersal will reduce temporal variation in output. The spatial average of GHI over the Las Vegas valley was estimated by averaging GHI measured at the six LVVWD stations (Table 6), and then smoothing the resulting time series of average GHI with a ten-minute moving average. Because the variability in the simple average of the LVVWD data (without any temporal averaging) is representative of the aggregate power from a few discrete systems, rather than hundreds of systems, it is appropriate to further smooth the average by using a temporal average with a time window commensurate with the time for a cloud shadow to transit the length of the Las Vegas valley.

Plane-of-Array (POA) Irradiance for Distributed PV Systems

POA irradiance for distributed PV systems was calculated using the same methods applied to large-scale PV plants.

Distributed PV System Power

[40] *Photovoltaic Array Performance* Model, Albuquerque, NM, King, D. L., E. E. Boyson, et al., Sandia National Laboratories. SAND2004-3535, 2004

DC power output from distributed PV systems was calculated using the Sandia PV Array Performance Model[41], which calculated the maximum power point for each minute of the year. DC power was translated to AC power using the Sandia PV Inverter Model.[42] AC power for all distributed PV systems was aggregated into a single time series of power.

Key assumptions used to derive one-minute AC power output using the Sandia PV Performance model include:

- Residential rooftop PV systems use polycrystalline Si modules (specifically, Yingli Solar YL230-29b modules, the same modules assumed for flat-plate large-scale PV plants). Residential systems are assumed to use a single SMA 4kW$_{AC}$ inverter, are oriented to the south, and are equally distributed among five different roof pitches: 4/12, 5/12, 6/12, 7/12 and 8/12.
- Commercial rooftop PV systems are assumed to use the same polycrystalline Si modules as residential rooftops systems, but are in a horizontal configuration. Systems are assumed to use three SatCon 100 kW$_{AC}$ inverters.
- Commercial ground-mount PV systems use the same polycrystalline Si modules as residential and commercial rooftop systems and are mounted on single-axis trackers oriented to the south. Six SatCon PVS-500 500kW$_{AC}$ inverters are assumed.
- No inverter clipping or curtailment occurs;

3.6 Large-scale PV Output Profiles

Using the above methodology, one year of AC power output at one-minute intervals was produced for each large-scale PV plant listed in Table 2 for 2007. PV output patterns for a "clear" solar day and an intermittently cloudy day are illustrated in Figure 10. Figure 10 shows output profiles from each of the ten proposed PV plants for a high PV penetration case (Case 5: 892 MW$_{AC}$). Plants with single axis tracking systems (e.g. 100 MW plant on 19-Mar-2007) display a flatter profile than do plants with fixed tilt angles (e.g. 300 MW plant). Additional examples of PV output patterns for Case 5 (892 MW) are presented in Appendix C.

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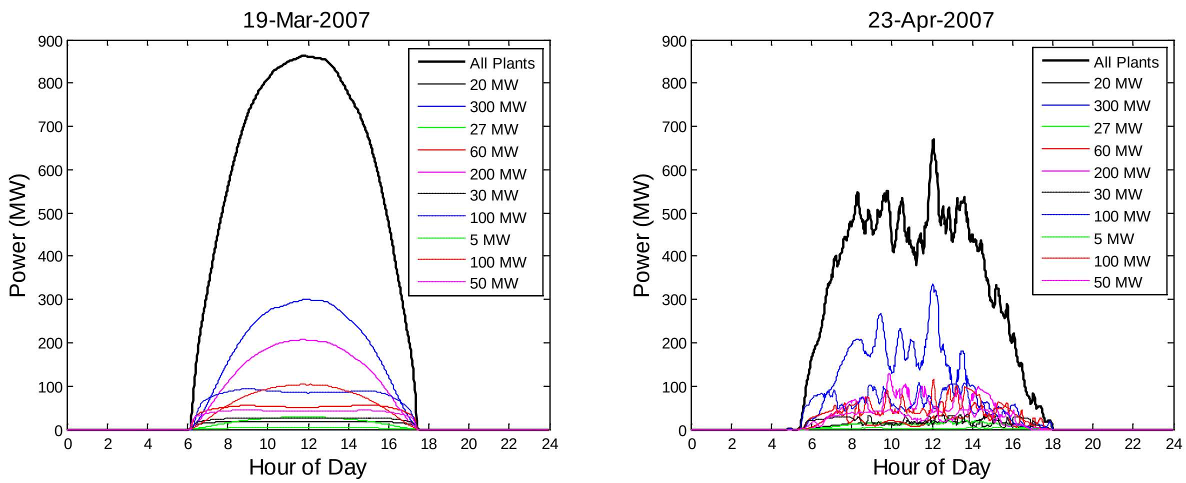
41 *Photovoltaic Array Performance* Model, Albuquerque, NM, King, D. L., E. E. Boyson, et al., Sandia National Laboratories. SAND2004-3535, 2004

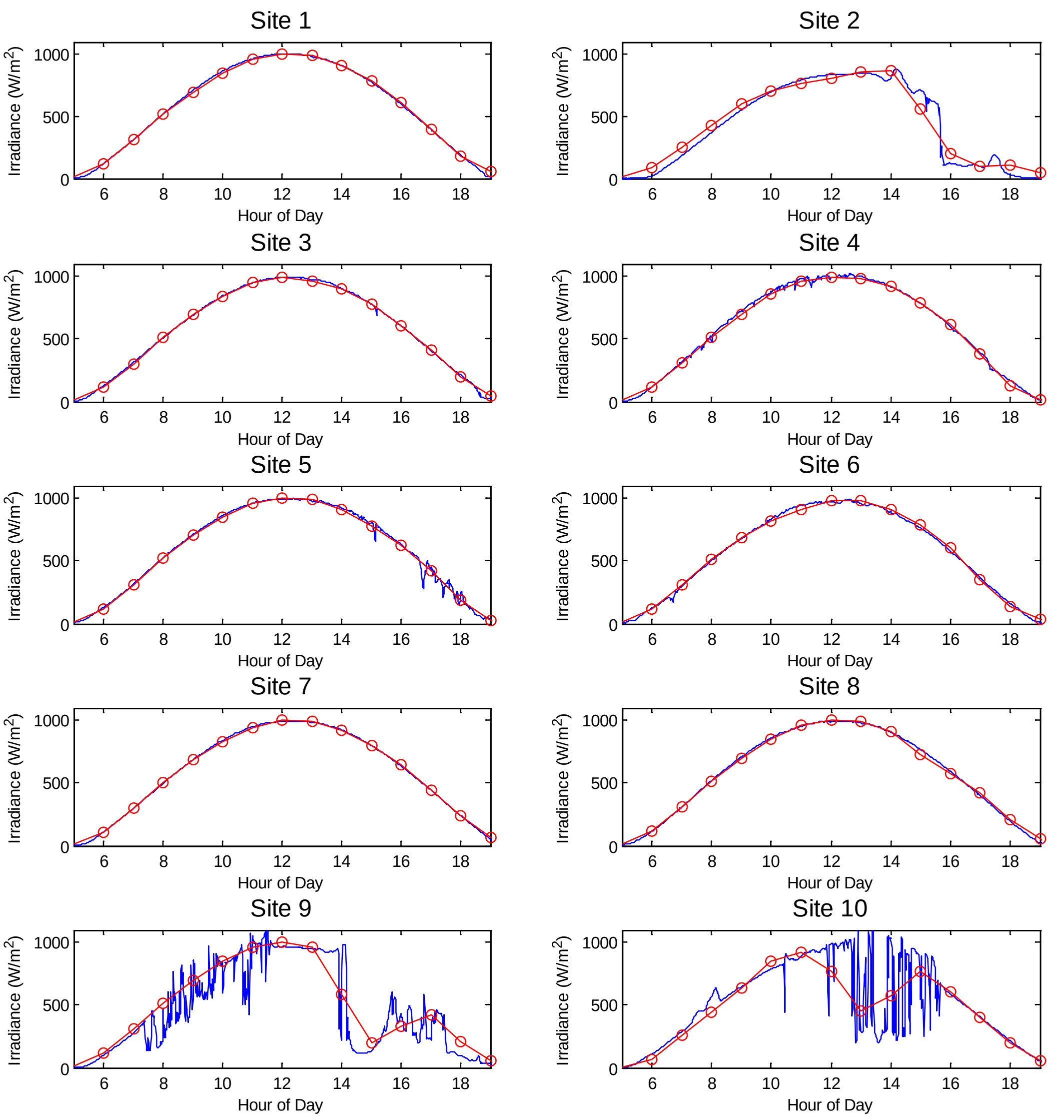
42 *Performance Model for Grid-Connected Photovoltaic Inverters*, King, D. l., S. Gonzalez, et al., Albuquerque, NM, Sandia National Laboratories. SAND2007-5036, 2007.

Figure 10. Case 5 Results – Clear versus Cloudy Day PV Profiles



Intermittency in irradiance (and consequent power output) can vary significantly among individual sites; that is, cloud cover impacts some, but not all PV sites simultaneously. Figure 11 illustrates this phenomena, as two sites (Sites 9 and 10, and to a lesser extent, Site 3) show variable irradiance throughout the day, whereas the profiles at other sites generally reflect clear conditions.

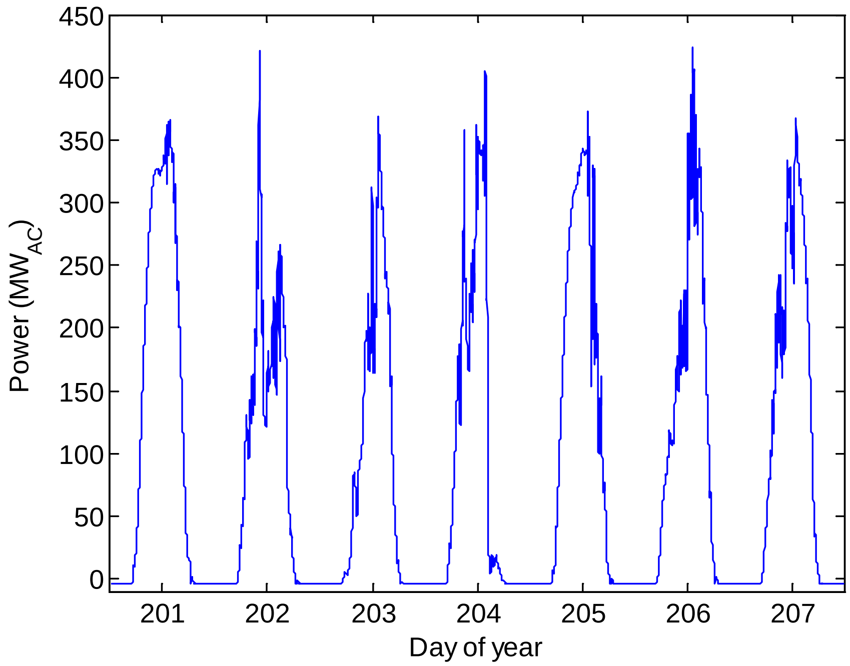
Figure 11. Example Irradiance Results (July 21, 2007)



3.7 Distributed PV System Output Profiles

One year of AC power output from the aggregate of all distributed PV systems (Table 5) was generated at one-minute time resolution. Figure 12 illustrates one week (i.e., July 20, 2007 to July 26, 2007) of aggregate power for the 9% (450MW) DG case. Power closely follows the estimated ten-minute temporal average of irradiance over the Las Vegas valley, which is approximated by the average over the six LVVWD irradiance measurements. At night, power is estimated to be slightly negative reflecting the implicit load presented by the DG systems' inverters, which remain connected to the grid and consume a slight amount of power.

Figure 12. Example Aggregate Power from Distributed PV Systems



3.8 Model and Data Validation for Large-scale Plants

PV output profiles are considered valid if they are based on reasonable data, methods, and assumptions and if the results exhibit patterns similar to those observed for actual data collected at other locations. Comparison of the power output profiles to output from PV systems in the same geographic region is challenging because performance data for the existing systems is proprietary. Moreover, several PV plants in this study are significantly larger than any plant built worldwide. Therefore, validation of the PV output profiles largely focuses on comparing statistics of and patterns in simulated irradiance with observed statistics and patterns of irradiance measured at different locations in southern Nevada.

Several validation comparisons suggest the simulation methods and resulting PV output profiles are reasonable. The comparisons include:

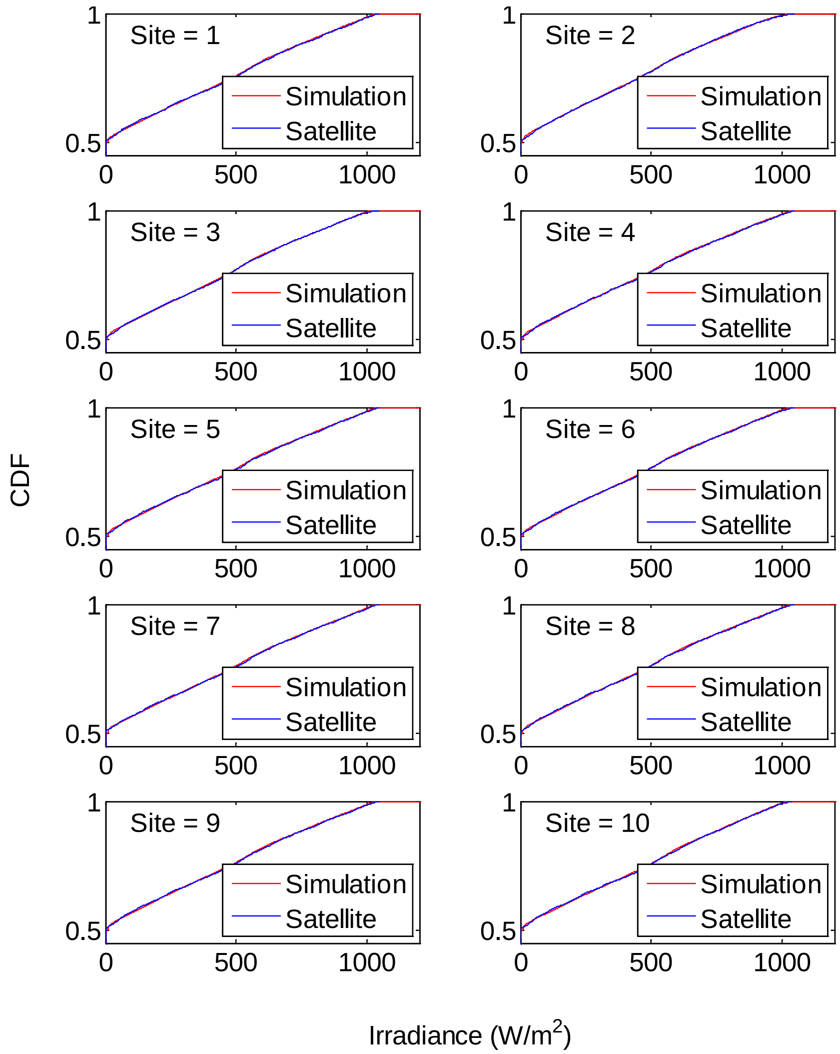
1. Annual distributions of simulated one-minute irradiance with hourly irradiance estimated by satellite;
2. Distributions of simulated irradiance changes with measured irradiance changes from the LVVWD sites;
3. Correlation coefficients for changes in the clearness index as a function of time and distance;
4. Power changes for a 20 MW plant over one- and 10-minute intervals.

Annual Distributions of Irradiance

Figure 13 compares the cumulative distribution function (CDF) of hourly irradiance estimated from satellite data with simulated irradiance for each of the 10 large-scale PV sites. The annual distributions of one-minute irradiance are nearly identical to the distributions of hourly irradiance, confirming that the model accurately predicts the annual energy of the PV systems, as the irradiance estimated from satellite data has low annual bias errors[43].

[43] Perez R., P. Ineichen, K. Moore, M. Kmiecik, C. Chain, R. George and F. Vignola, (2002): A New Operational Satellite-to-Irradiance Model. Solar Energy 73, 5, pp. 307-317

Figure 13. Distributions of Simulated One-Minute and Hourly Satellite Irradiance

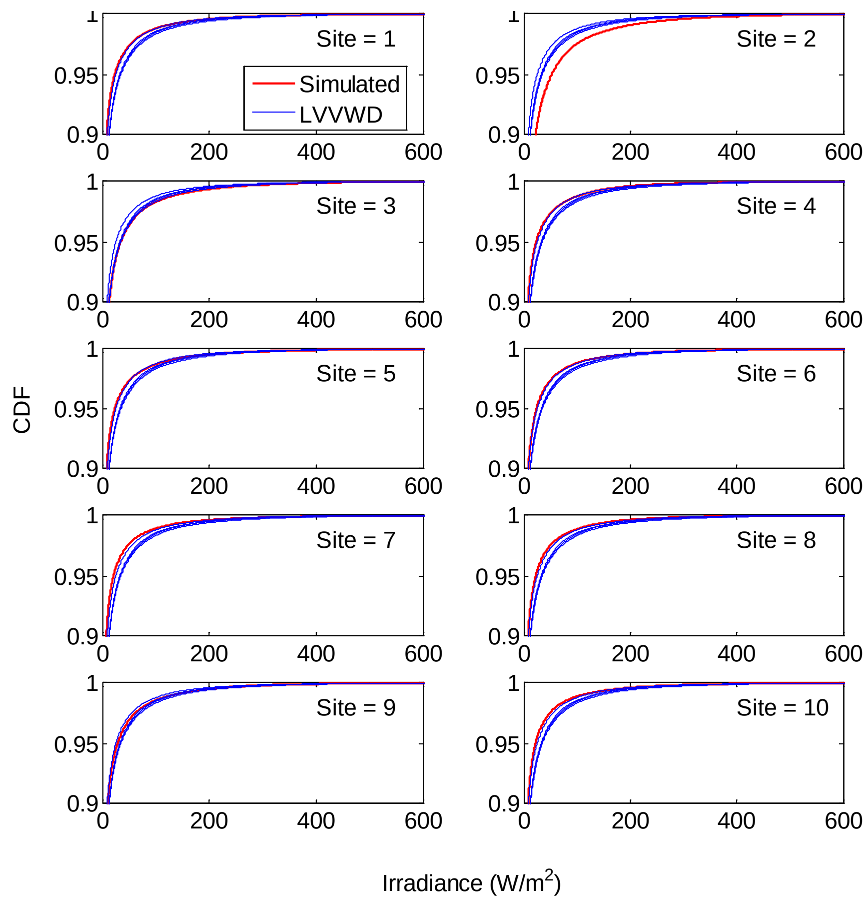


Ramp Rate Distributions

Figure 14 compares CDFs of one-minute changes in irradiance measured at the LVVWD stations to the CDFs of one-minute changes in simulated irradiance at each study site. With the exception of Site 2, the annual distributions of large (i.e. 90th percentile and above) one-minute irradiance ramp rates in the simulated irradiance (red curves) are very similar to the distributions of ramp rates observed at the four LVVWD sites with complete 2007 data (blue curves). The close match between these distributions demonstrates that the simulated irradiance sequences reproduce the frequency of one-minute changes observed in the greater

Las Vegas area. In general, Site 2 has about five percent less annual irradiance than other sites, indicating that cloudy conditions are more frequent at this location (as determined from satellite-based estimates of irradiance). Consequently, it is reasonable to expect large changes in irradiance to occur more frequently at Site 2 than at other locations.

Figure 14. Cumulative Distribution of Changes in Simulated 1-Minute Irradiance versus Changes in Measured Irradiance from Four LVVWD Ground Stations



Spatial Correlation Patterns

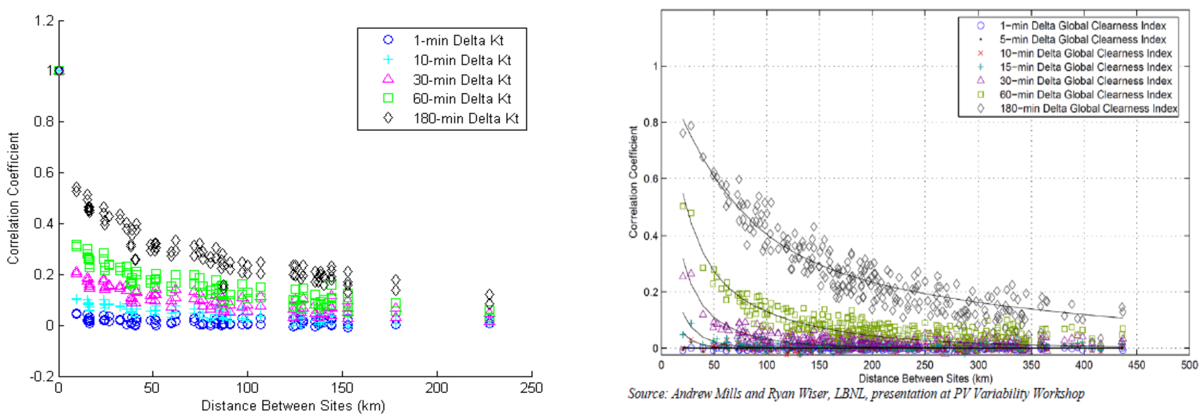
Earlier studies[44] confirm that the correlation between step changes in the clearness index[45] at two locations varies as a function of their distance and the time lag used to compute the step

[44] *Understanding Variability and Uncertainty of Photovoltaics for Integration with the Electric Power System*, Mills, A., M. Ahlstrom, et al., Berkeley National Laboratory. LBNL-2855E, 2009.

[45] Clearness index is defined as irradiance divided by the irradiance that would be observed in clear-sky conditions,

changes. Figure 15 compares the correlations for the simulated irradiance generated for this study with correlations determined for irradiance data collected in the Great Plains. The similarity between these plots confirms that correlations of changes in clearness index in the simulated data are consistent with those observed for measured irradiance data. In both simulated and observed data, correlations between sites decrease with distance and increase with time lag.[46]

Figure 15. Comparison of Correlations of Irradiance Changes between Simulated Irradiance (left) and Irradiance Measured in the Great Plains (right).



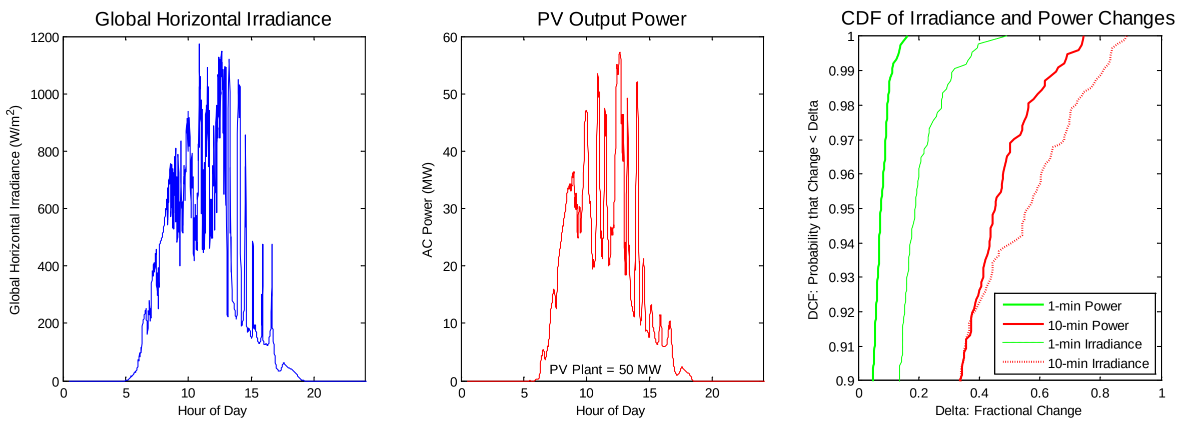
Source: Andrew Mills and Ryan Wiser, LBNL, presentation at PV Variability Workshop

Power Ramps

Several analysts have demonstrated that fractional ramps (i.e., change in a value as a fraction of its maximum) are lower for power than for point values of irradiance, and are greater for longer time intervals (e.g., one minute versus 10 minutes). These characteristics result because a PV plant effectively integrates irradiance over the plant area to produce power; hence changes in power are smoother than are changes in irradiance. Data generated by SNL for this study also exhibit these characteristics. Figure 16 illustrates simulated point irradiance for a single day (DOY 113), the corresponding power output, and the CDFs for ramps in irradiance and power for a 50 MW plant, for two time intervals (one and ten minutes). The pattern exhibited (less frequent ramps for power than irradiance, and larger ramps for longer time intervals) is similar to that observed for similarly-sized large-scale PV systems at other locations.

[46] Correlations are somewhat lower for the simulated data, which might reflect a systematic feature of the model approach, or may be a real difference between weather patterns at the two locations (Great Plains vs. Nevada).

Figure 16. CDF of 1-Min and 10-Min Power Changes from a Simulated 50MW PV Plant.



3.9 Day-Ahead Forecasts

SNL also developed a method to emulate day-ahead forecasts of hourly average power, for use in estimation of regulation and load following requirements.

Day-Ahead Forecast of Hourly Average Power Output

SNL reviewed literature describing forecasting methods and analyses of forecast performance and defined a method to emulate next-day forecasts of hourly average power at each plant with forecast errors consistent with current forecasting capabilities. Notably, Lorenz et al. (2009)[47] and Perez et al. (2010)[48] examine current forecasting methods and report estimates of day-ahead irradiance forecast performance. However, because PV power output is nearly linear with irradiance, relative errors for irradiance forecasts are similar to those for power forecasts. Thus, reported performance for irradiance forecasts was used to emulate power forecasts. The following method was used to produce day-ahead forecasts of hourly average power to accompany the simulated hourly average power for each site:

1. Assume that forecast models can reliably predict clear or partly cloudy conditions for the next day.

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[47] E. Lorenz et al, *Irradiance Forecasting for the Power Prediction of Grid-Connected Photovoltaic Systems*, IEEE Jour. Of Sel. Topics in Appl. Earth Obs. And Remote Sensing, Vol 2 pp. 2-10, Mar. 2009.

[48] R. Perez et al, *Validation of Short and Medium Term Operational Solar Radiation Forecasts in the US*, Solar Energy 84, pp. 2161-2172, 2010.

2. If clear conditions are predicted at the site, the relative forecast error (the ratio between the forecast value and the simulated power) is modeled as normally distributed with a mean of one (e.g. the forecast value equals the simulated power). The standard deviation for the error distribution is set equal to the standard deviation of the ratio between hourly average irradiance measured at the LVVWD locations for clear days, and the hourly average irradiance projected by a clear sky model. One value for the relative forecast error is independently sampled for each clear day and each site and is multiplied by the simulated power to obtain the forecast for the site.
3. If cloudy conditions are predicted, the relative forecast error is randomly sampled for each hour from a normal distribution with a mean of zero, with an imposed correlation between values for successive hours. The standard deviation for the distribution of each hour depends on the hour's clearness index, with values taken from Lorenz et al. (2009). Extreme values for the error (clearness index values below 1% or above 110%) are replaced by resampling.
4. Forecast errors are determined independently for each PV plant.
5. The relative forecast error is multiplied by the simulated power to produce the day-ahead power forecast for each plant.

Results

The method requires identification of days with clear and cloudy conditions, which was performed by comparing the total daily insolation to that predicted by the clear sky model. Days with total insolation within 8% of clear sky insolation are classified as clear; the remaining days are identified as cloudy. Figure 17 demonstrates the ability of the total insolation criteria to distinguish between clear and cloudy days. Figure 18 demonstrates two weeks of simulated irradiance and the distinction between clear and cloudy days.

Figure 17. Identification of Clear and Cloudy Days

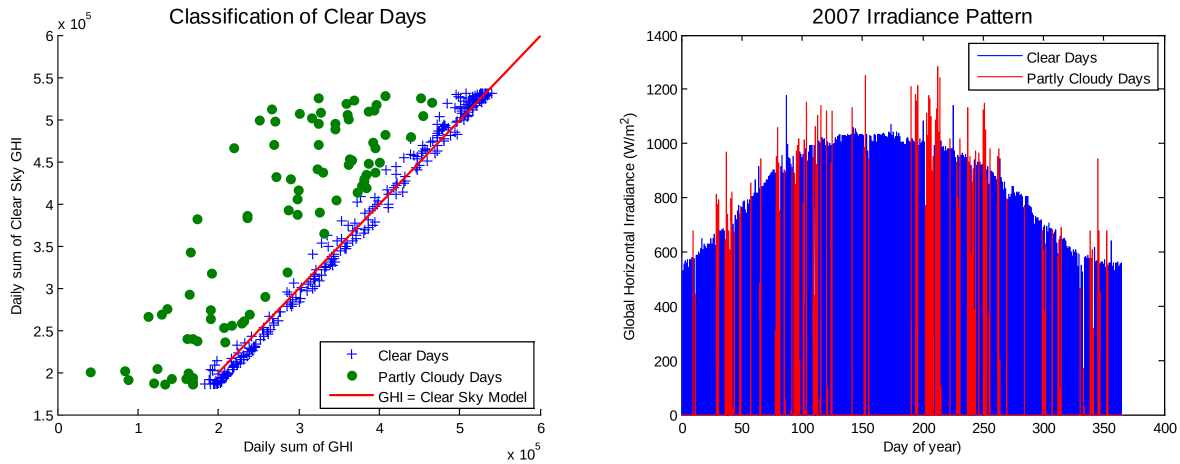


Figure 18. 2007 Irradiance Pattern

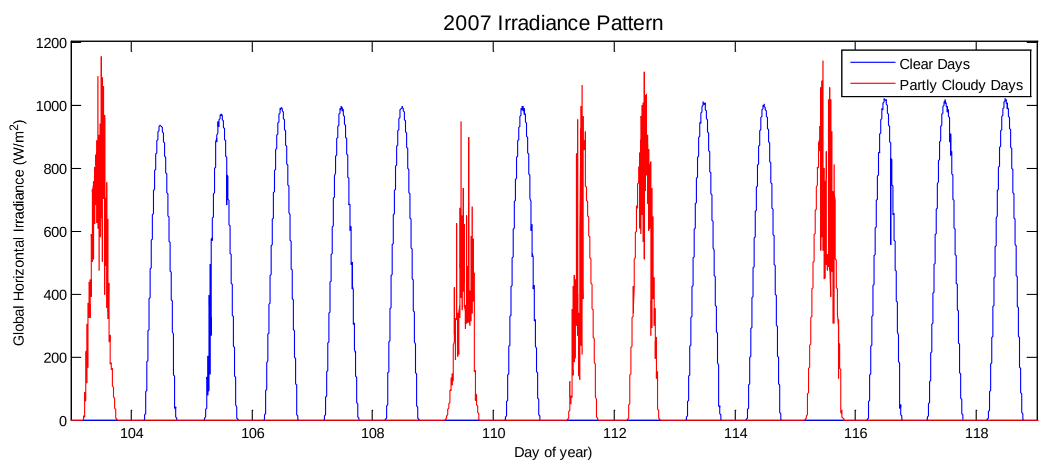


Figure 19 compares simulated GHI irradiance and the accompanying forecast for six days. Curves appear relatively smooth because the hourly values are connected by straight line segments. The greater range of errors on cloudy days is apparent (e.g. Day 201 and 206) whereas Day 204 shows that forecast errors are generally smaller for clear days.

Figure 19. Comparison of Simulated Irradiance to Day-Ahead Forecast

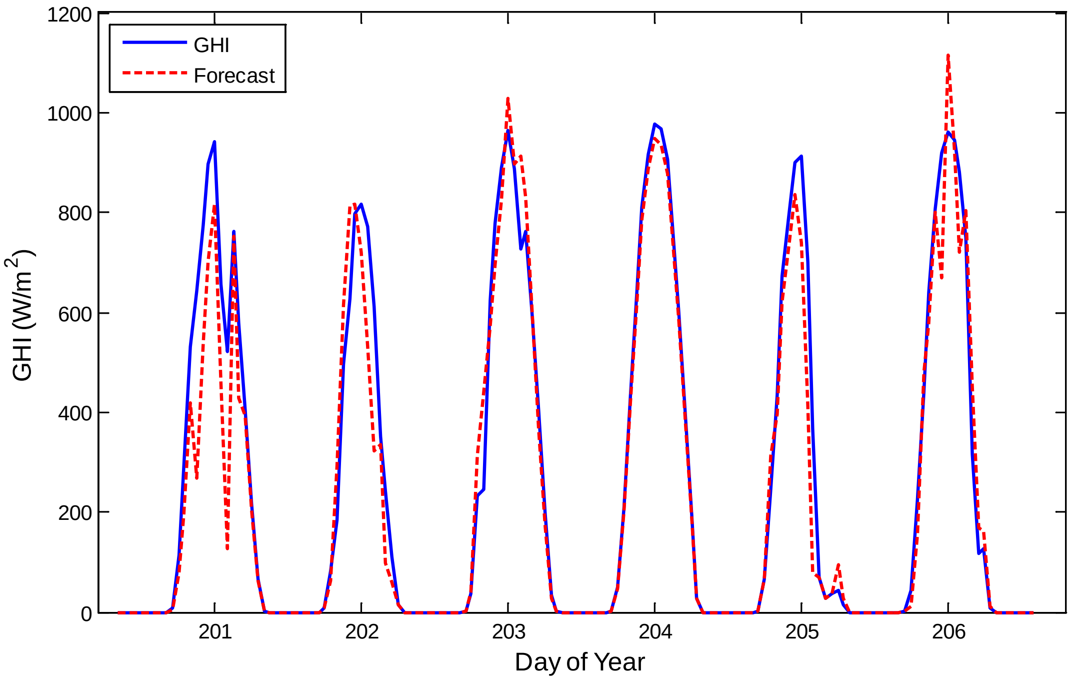
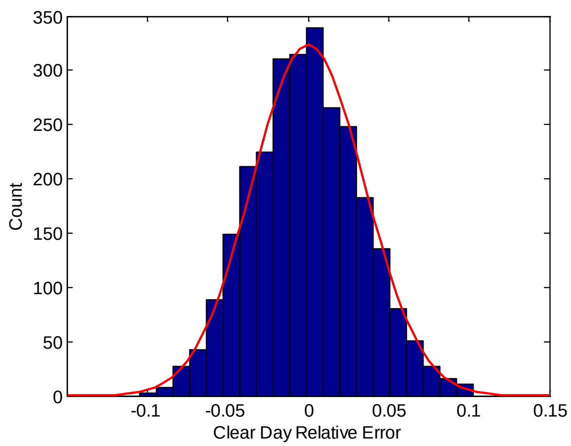


Figure 20 confirms that the forecasts reproduce the selected distributions of relative error. For clear days, the histogram of relative forecast errors over all sites compares favorably with the normal distribution from which the errors are sampled. The truncation of relative forecast errors at 110 percent eliminates the right tail from the clear day sample. For cloudy days, the relative root mean square error (RMSE) for Sites 1 through 5 compares favorably to the target values from Lorenz et al (2009)[49].

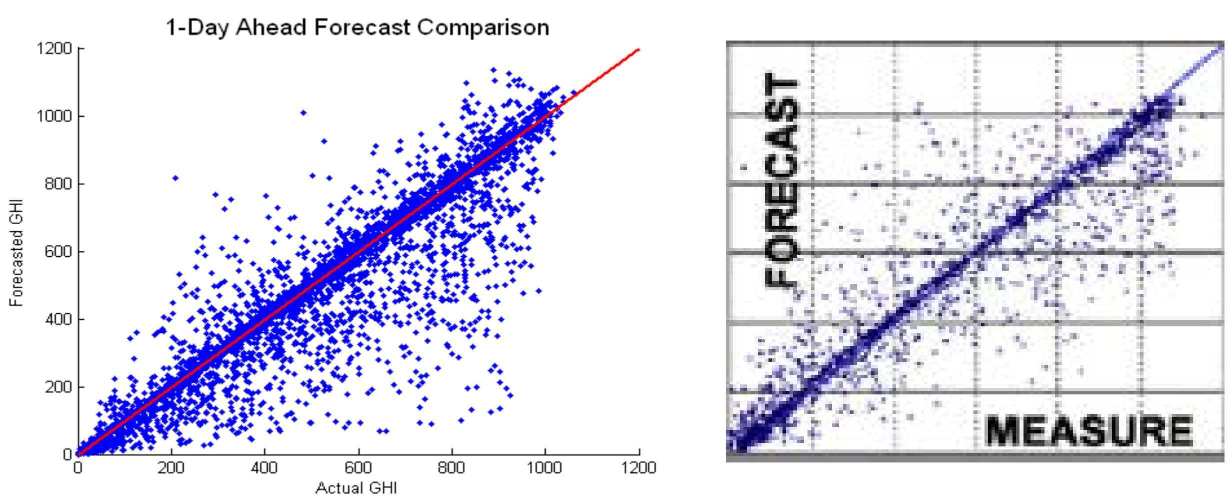
[49] E. Lorenz et al, *Irradiance Forecasting for the Power Prediction of Grid-Connected Photovoltaic Systems*, IEEE Jour. Of Sel. Topics in Appl. Earth Obs. And Remote Sensing, Vol 2 pp. 2-10, Mar. 2009.

Figure 20. Distributions of Forecast Errors for Clear and Cloudy Days



The time series of forecast error can be applied to simulated GHI (rather than to simulated power) to produce an emulated day-ahead irradiance forecast. Figure 21 demonstrates that a comparison of emulated forecast irradiance to simulated irradiance produces a scatterplot similar to a scatterplot of an actual irradiance forecast against measured irradiance at Desert Rock, NV.

Figure 21. Comparison of Actual and Forecast GHI. Emulated Forecast (left) and Numerical Weather Model-Based Forecast for Desert Rock, Nevada[50] (right)



[50] Perez, R., et al. *Validation of Short and Medium Term Operational Solar Radiation Forecasts in the US*, Solar Energy 84, pp. 2161-2172, 2010.

4 BALANCING RESERVE REQUIREMENTS AND CHALLENGING OPERATING HOURS

Two methods were developed to quantify the impact of large-scale PV and DG on NV Energy's southern Nevada system. The first method analyzes balancing reserve requirements, including load following and regulation, for different solar penetration cases. Increases in reserve capacity and ramp rate requirements to compensate for solar variability was quantified in this step. The first method is based on the methodology developed by PNNL in previous projects and applied in California ISO[51], Bonneville Power Administration[52], Department of Energy[53], ColumbiaGrid[54], and current WECC and California Energy Commission studies. The second method evaluates the ramp capability of the generation fleet and compares it to the requirements derived in the previous step. Challenging operating hours that have insufficient ramp capability can then be identified. The deficiencies in fleet ramp rate can be used as a measure to evaluate whether the amount of solar power being studied can be accommodated by the system without degrading performance (before applying any mitigation approaches). Cycling and movements of conventional generators to provide balancing services are then quantified for each solar penetration case using cycling mileage and ramp statistics. Methods and results in this section are from the work performed by the Pacific Northwest National Laboratory.

4.1 Operation Processes

An electric power grid, such as NV Energy's southern Nevada system, must continually balance system load (demand) and generation (supply). A significant imbalance may cause transmission voltage or power flow violations, frequency deviations, instability, and other

[51] Y. V. Makarov, C. Loutan, J. Ma, and P. de Mello, "Operational Impacts of Wind Generation in California", *IEEE Transactions on Power Systems*, Vol. 24, No. 2, May 2009.

[52] Yuri V. Makarov, S. Lu, B. McManus and J. Pease, "The Future Impact of Wind on BPA Power System Ancillary Services", *IEEE Transmission and Distribution Conference 2008*, Chicago, April 2008.

[53] Y.V. Makarov, S. Lu, N. Samaan, Z. Huang, K. Subbarao, P. V. Etingov, J. Ma, N. Lu, R. Diao, and R. P. Hafen, "Integration of Uncertainty Information into Power System Operations," *Proc. 2011 PES General Meeting*, 24-29 July 2011, Detroit, Michigan, USA. (Panel paper).

[54] Y.V. Makarov, C.R. Sastry, N.A. Samaan, R. Diao, S. Malhara, and R.T. Guttromson, "ColumbiaGrid Balancing Area Consolidation Feasibility Study", Final Report PNWD-4169, Prepared for ColumbiaGrid, Battelle Memorial Institute, Pacific Northwest Division, Richland, WA, April 2010.

undesirable performance impacts. Solar generation is not dispatchable (except curtailments of large PV in rare cases) and produces variable output that depends on weather conditions. As a result, when large amounts of solar capacity are installed and integrated into the electric power grid, it can become increasingly difficult to maintain this balance. This section describes the power system operation processes to meet system load, which provides the basis for the evaluation of balancing reserve requirements and challenging operating hours.

Overview

Power system operators and schedulers maintain hourly day-ahead generation schedules designed to economically serve system loads while meeting generation reserve requirements. In real time, the level of generation is adjusted to meet differences between actual loads and the hourly schedules. This real-time adjustment, or within-hour balancing, can be separated into "load following" (within-hour resource dispatching) and "regulation" (sub-minute adjustments of generation) processes according to their respective time scales. Load following typically requires adjustments every 5 to 15 minutes (10-minute intervals are used in the NV Energy study). This is accomplished through a manual redispatch of on-line generation by system operators or via automatic adjustments by computerized control systems. Regulation, in turn, is effected by making sub-minute output adjustments exclusively through an automatic generation control (AGC) system.

Load following and regulation require sufficient capacity and ramp rates from dispatchable generation, upward or downward, to respond to system fluctuations, either from changes in load or variable solar output. Most of NV Energy's dispatchable generation is from natural gas-fired combined cycle units, as they are able to follow changes in loads faster than base load generation. As large-scale PV and DG penetration increases, capacity and ramp rate requirements will also rise due to the greater variability in "net load" (load demand minus PV generation) resulting from PV and DG. Conventional generators have to reserve more room to move up or down, more rapidly, to follow the combined variations.

Balancing Area Scheduling

The hourly generation schedules are comprised of hourly energy blocks with 20-minute ramps between hours; the ramping process begins 10 minutes before the end of each hour. A day-ahead schedule can be, for instance, created 14-38 hours ahead of time. These schedules are often adjusted in real time operations using hour-ahead forecasts. The hourly schedule is based on the hourly load forecast minus the PV and DG forecast; that is, the hourly forecast of net load.

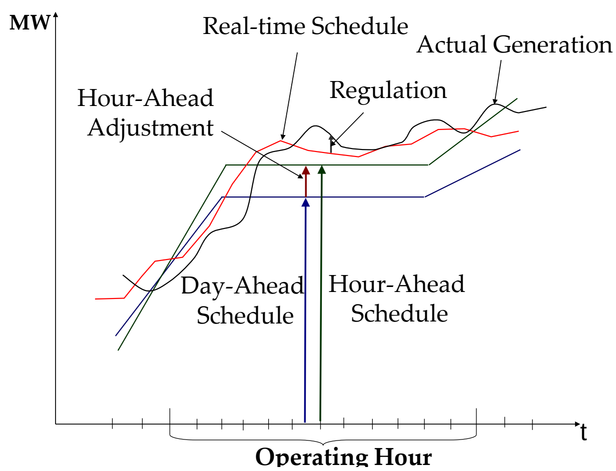
Generation redispatch and load following are conducted over regular intervals to track and assess changes in actual net load. Each new generation target is determined from a real-time forecast of net load. However, the system-specific information used by load following is dated several minutes before the beginning of each interval. Generating units, therefore, begin to move toward the new set point before entering a new interval. Units are required to reach the set point in the middle of the interval (e.g. 5 minutes after one begins in the case of 10-minute intervals). The units may ramp energy sequentially, not necessarily having a constant ramp rate throughout the entire interval.

In this study, a perfect hourly schedule of net load is simulated using 60-minute clock average of (load – solar generation). A 10-minute interval has been selected for NV Energy based on the operation practice and generator characteristics of the southern Nevada system. Real-time load and solar forecasts are determined from the 10-minute clock average of the time series, which sets the target for real-time dispatch/load following. The perfect schedule and dispatch does not reflect the impact of forecast errors. This way, the load following and regulation requirements will only be determined by the variability with load and solar, and not be affected by forecast errors. In the actual operation, any forecast errors will cause larger requirements on load following and regulation reserves, of which the impact will be investigated separately in a sensitivity study.

Automatic Generation Control

Under normal conditions, generation and load in a power grid must be regularly balanced in compliance with the NERC/WECC Control Performance Standards. Fluctuations and uncertainties can occur from load, variable renewable resources (wind and solar), as well as conventional generators (resulting from uninstructed deviations, failures to start up, and forced outages). During real time operation, generators under AGC are adjusted every 2 or 4 seconds (although their actual responses are slower) to match any variations in the system. These variations are inherently difficult to predict, so system dispatchers need appropriate automatic response and regulating reserves to combat rapid changes. Figure 22 illustrates how balancing area generators are scheduled and dispatched. The goal is to have actual generation closely match the amount of load in real time.

Figure 22. Balancing Area Scheduling and Dispatch



The difference between the actual net load and the real-time generation schedule is the amount that must be matched by AGC to maintain system frequency. Since actual generator responses to AGC occur on a sub-minute scale, minute-by-minute data series were applied. This should provide a sufficient time resolution in which to identify the impact of intermittent PV and DG outputs on regulating reserve requirements.

4.2 Objectives

The primary objective of the this task is to determine how variable large-scale PV and DG impacts regulation and load following requirements within NV Energy's southern system, and identify challenging operating hours by checking the ramp capabilities of the generation fleet to meet regulation requirements.

Results of the balancing requirements analysis are used in Section 5 to derive the additional costs, where applicable, associated with integrating DG and large-scale PV resources into the existing system. Results also are used to identify the type and cost of mitigation options needed to remedy any deficiencies in fleet capability.

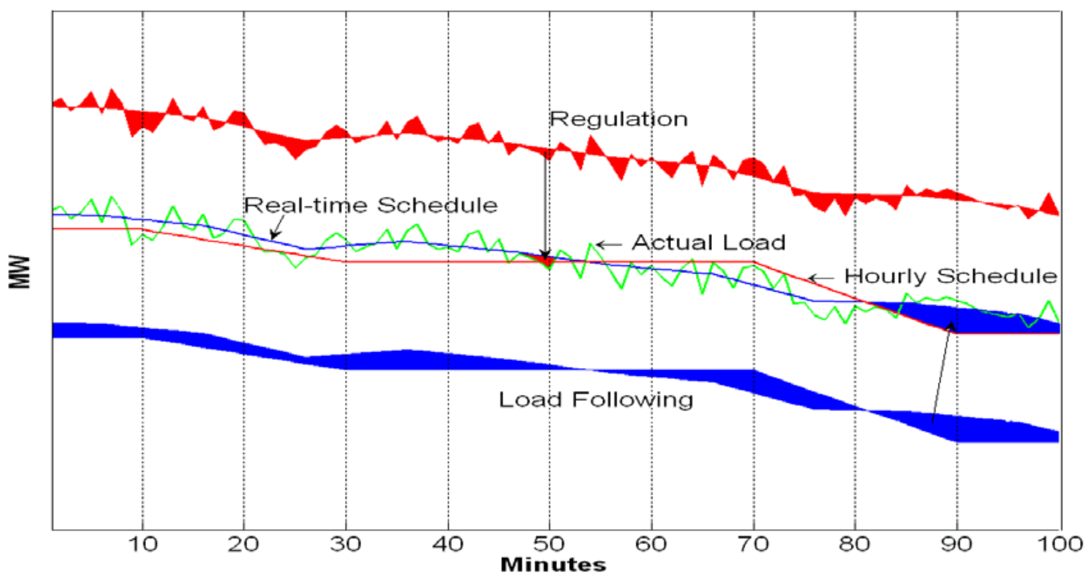
4.3 Balancing Requirements Methodology

Regulation Reserves

Regulation is interpreted as the difference between the actual system generation requirement (= actual net load) and the real-time generation schedule, illustrated in Figure 23 as the red area between the blue and green lines. Real-time schedules are determined by real-time forecasts. When large-scale PV and DG are involved, regulation can be calculated by:

Regulation = *[actual load – actual large PV – actual DG]*
– [real-time load forecast - real-time large PV forecast – real-time DG forecast]

Figure 23. Simulation of Hour-Ahead Schedules for Regulation and Load Following



In this study, as mentioned previously, a perfect real-time forecast is assumed. Thus, the regulation is calculated by the following formula (refer to Figure 23):

Regulation = *[actual net load] – [10 minute average of net load with ramps]*
= *[actual load – actual large PV generation – actual DG]*
– [10 minute average of (load – large PV generation – DG) with ramps]

Load Following

Load following is modelled as the difference between the hourly block energy schedule including 20-minute ramps (shown as the red line in Figure 23) and the real-time generation schedule. This difference is also shown as the blue area below the curves. Hourly generation schedules are determined by hourly load forecasts. When large-scale PV and DG are involved, load following can be calculated by:

Load Following = [real-time load forecast - real-time large PV forecast - real-time DG forecast]

- [hourly load forecast - hourly large PV forecast - hourly DG forecast]

In this study, as mentioned previously, a perfect hourly forecast is assumed. Thus, the load following component is calculated as follows (refer to Figure 23):

Load Following = [10 minute average of net load with ramps] – [60 minute average of net load with ramps]

= [10 minute average of (load – large PV generation – DG) with ramps]

- [60 minute average of (load – large PV generation – DG) with ramps]

Assessing Ramping Requirements

The ramping capability of units on AGC directly influences required regulation and load following capacity. If composite unit ramping capability is insufficient, more units and capacity are needed to follow the ramps. Hence, a simultaneous evaluation of capacity and ramp requirements is necessary to determine the actual reserve requirements[55].

The required ramping capability can be determined from the shape of the regulation/load following curves. The "swinging door" algorithm was used for this purpose.[56] This proven technical solution has been implemented in OSIsoft® PI Historian and is currently widely used to compress and store time dependent datasets.

[55] Y.V. Makarov, S. Lu, J. Ma, and T.B. Nguyen, "Assessing the Value of Regulation Resources Based On Their Time Response Characteristics", PNNL Project Report PNNL-17632, Prepared for CERTS and California Energy Commission, June 2008. [Online.] Available: http://www.pnl.gov/main/publications/external/technical_reports/PNNL-17632.pdf.

[56] Yuri V. Makarov, Shuai Lu, Bart McManus and John Pease, "The Future Impact of Wind on BPA Power System Ancillary Services", *IEEE Transmission and Distribution Conference 2008*, Chicago, April 2008.

Figure 24 illustrates the "swinging door" concept. A point is classified as a "turning point" whenever any point in the sequence falls outside of the admissible accuracy range $\pm\varepsilon\Delta G$. For instance, for point 3, one can see that point 2 stays inside the window *a-b-c-d*. For point 4, both points 2 and 3 stay within the window *a-b-e-f*. But for point 5, point 4 goes beyond the window and therefore point 4 is marked as a turning point.

Based on this analysis, points 1, 2, and 3 correspond to the different magnitudes of the regulation signal, π_1, π_2 and π_3, whereas the ramping requirement ρ_1, ρ_2 and ρ_3 at all these points are the same (Figure 25). The "swinging door" algorithm also helps to determine the ramp duration δ.

Figure 24. "Swinging Door" Algorithm

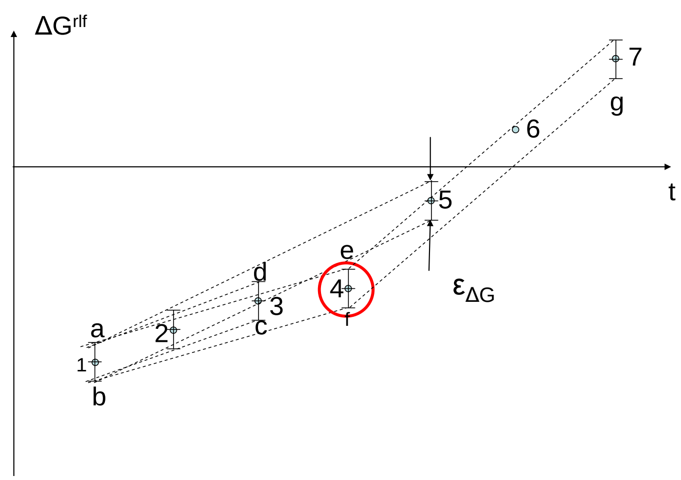
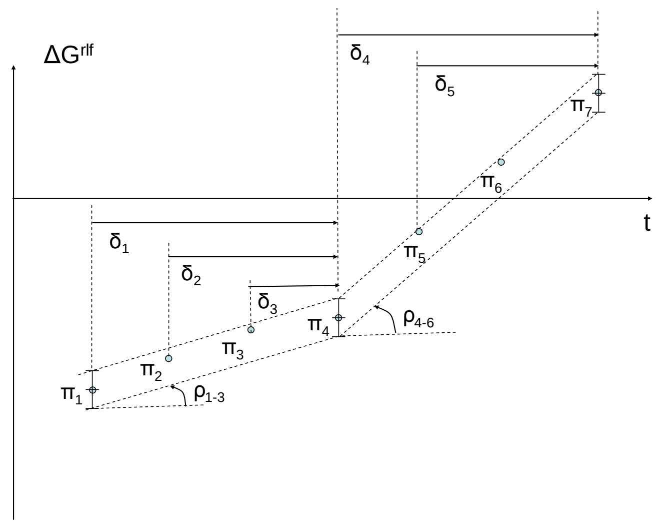
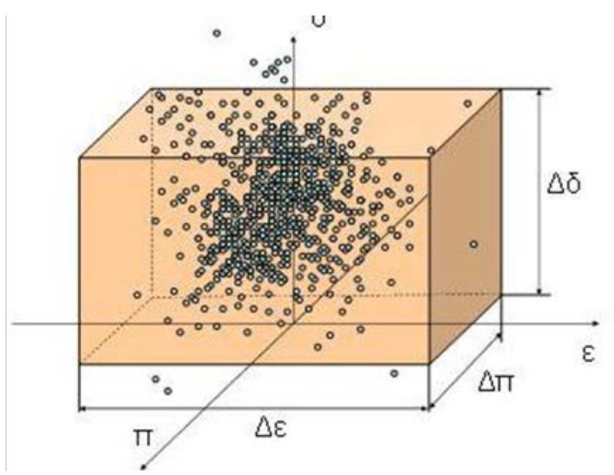


Figure 25. Capacity, Ramp Rate and Ramp Duration



To illustrate the idea of simultaneous evaluation of capacity, ramp and ramp duration requirements (or any two of the three properties), the capacity, ramp rate and ramp duration of the regulation/load following data series can be plotted in a three-dimensional space. For example, Figure 26 illustrates a plot of three dimensions (π, δ, ρ) associated with the requirements envelope.

Figure 26. Graphical Representation of the Reserve Requirements Envelope



The plot shown in Figure 26 facilitates the following steps.

1. Choose a percentile threshold, such as P% (P=97 in this study, explained in “Balancing Area Requirements), to define the percentage of all regulation/load following data points that will fall within the requirements envelope.

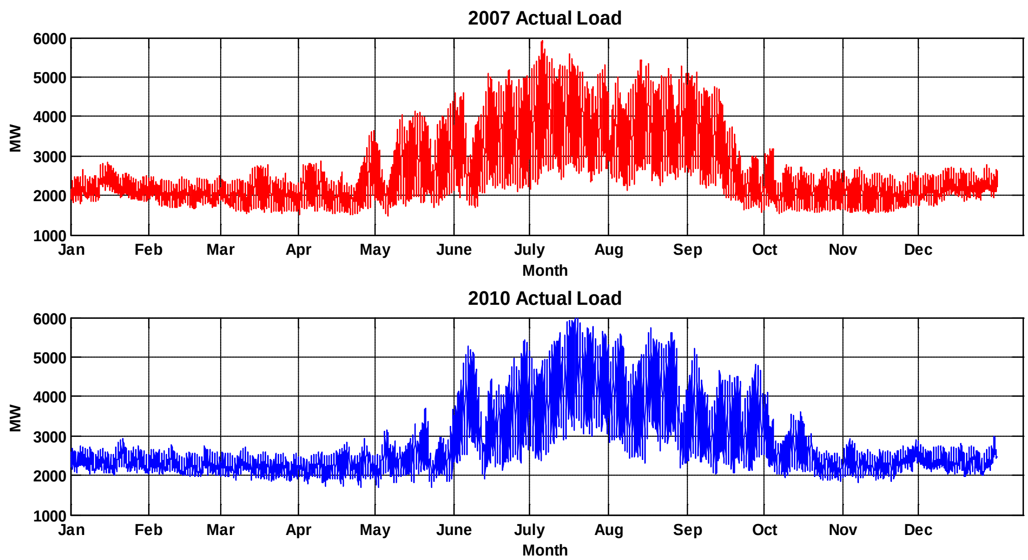
2. For the NV Energy balancing area and each balancing process (load following and regulation, respectively), construct a bounding box such that P% of points in the plot are within the box. Some percentage of the points, 100 - P%, will fall outside box boun daries. Accordingly, a certain percentage of extreme situations will not be balanced when the components of the requirements envelope exceed pre-defined values. The sizes of the bounding box are then determined as, for instance, $\Delta\pi$, $\Delta\ \rho$, and $\Delta\delta$. These reflect the capacity, ramp, and ramp duration requirements needed for each balancing service.

The percentage of uncovered data points by the requirements envelope along each axis can be determined based on the characteristics of the balancing resources. For example, generators are often limited by ramp rate and capacity but not the duration of ramps (longer ramps require more energy), therefore, 100 - P% is only allocated to the capacity and ramp axes in step 2 in this study.

Defining Study Seasons

The PV profile analysis indicates that PV output changes seasonally, due to both irradiance and cloud cover. Further, NPC hourly load patterns vary seasonally as well. However, the large number of high load days in the summer, late spring, and early fall suggest seasonal patterns do not follow traditional calendar days for the four seasons. Figure 27 illustrates the seasonal patterns for NV Energy southern system/balancing area loads in 2007 and 2010. The two years show somewhat comparable patterns, with 2007 showing higher late spring and early summer loads attributable mostly to hot weather.

Figure 27. Seasonal Load Patterns



From Figure 27, logical groupings were derived for three seasonal categories for the purpose of the study. Notably, NV Energy's service territory loads are dominated by winter and summer patterns - actual load patterns do not support assigning spring and fall seasons of equal duration. Accordingly, a shoulder period comprised of one month from the spring and fall months was assigned.

- **Winter Months**: Jan, Feb, Mar, Apr, Nov, Dec
- **Summer Months**: June, July, Aug, Sept
- **Shoulder Months**: May, Oct

Balancing Area Requirements

The increases in net load variance indicate that greater spinning reserves are needed for generation and load balance. Since this variability occurs relatively randomly, a higher level of operating reserves need to be maintained even for days with low net load variance.

However, many of highest variances can be eliminated, as NERC does not mandate generation and load to be balanced 100% of the time. Balancing area operators need not to plan for an absolute "worst case" when setting generation regulating reserves. Therefore:

- Regulation and load following requirements will be the capacity and ramp capability necessary to satisfy a certain percentage of regulation data and load following data
- The percentage needs to be high enough to meet CPS standards but does not have to cover the load/generation mismatch 100 percent of the time

In comparison, in a Bonneville Power Administration (BPA) study, the threshold was set at 99.5 percent; in a recent CAISO study, 95 percent. Both studies were conducted by PNNL and the percentile values were determined by the operation engineers of each system. Accordingly, the project team determined that a 97 percent balancing requirement should be applied, which eliminates the top three percent of the data points with the highest minute-by-minute net load variations in each hour.

4.4 Regulation Reserve Requirements of Case 1 (Committed Case)

As illustrating examples, histograms of regulation data are shown for each season of Case 1, i.e., the committed case, with 149 MW of large-scale PV and no DG. Non-Gaussian properties are shown in the histograms. Regulation reserve requirements calculated using methods in Section 4.3 are then derived and presented.

Distribution of Regulation Data

Figure 28, Figure 29 and Figure 30 present distributions of regulation data points for Case 1 (149 MW PV and 50 MW DG) for winter, summer and shoulder seasons. All of these distributions are non-Gaussian and indicate that highly intermittent PV and DG output and loads are confined to a small number of intervals.

Figure 28. Distribution of Regulation Data – Winter, Case 1

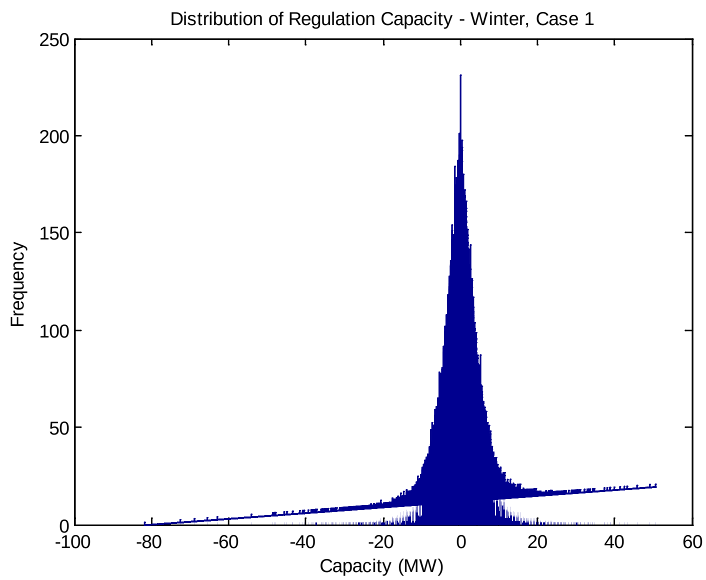


Figure 29. Distribution of Regulation Capacity Data – Summer, Case 1

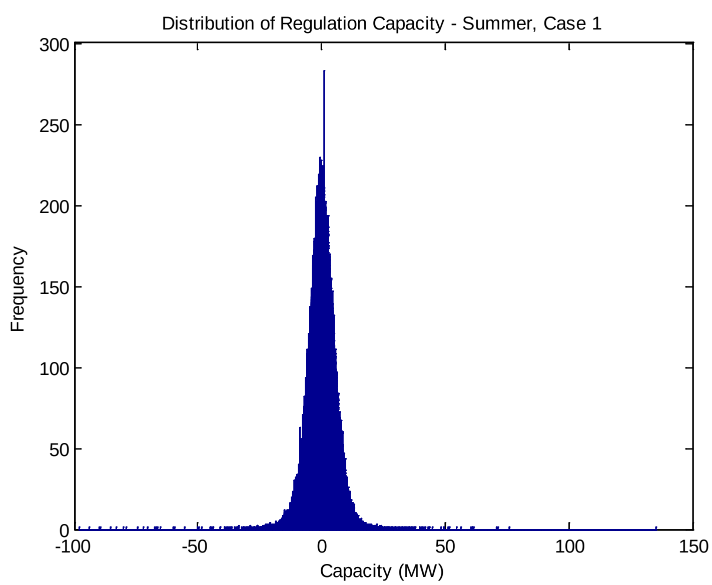
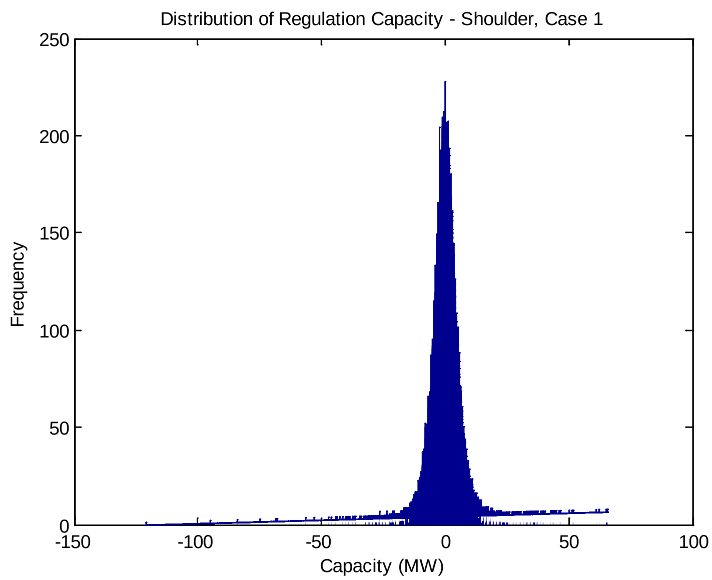


Figure 30. Distribution of Regulation Capacity Data – Shoulder, Case 1



Regulation Capacity Requirements

Regulation capacity requirements for Case 1 (“Solar”) and Base Case (0 MW PV and DG, “No Solar”) in the winter season are shown in Figure 31. The impact of solar generation on regulation in each hour can be observed. The upper diagram shows the maximum (among P% of total data points) upward regulation capacity required, while the lower diagram shows the downward, both in MW. The blue bars represent the solar case, and brown bars the Base Case. For solar Case 1, the maximum upward capacity requirement of 16 MW occurs in hour ending (HE) 15, during which also occurs the maximum downward requirement of 17 MW. During daytime hours (HE 6 AM through HE 18), PV power output causes higher upward and downward regulation requirements. During the nighttime, there is no impact, which is consistent with solar generation patterns, assuming energy storage is not used to mitigate regulation impacts.

Figure 31. Regulation Capacity Requirements – Winter, Case 1

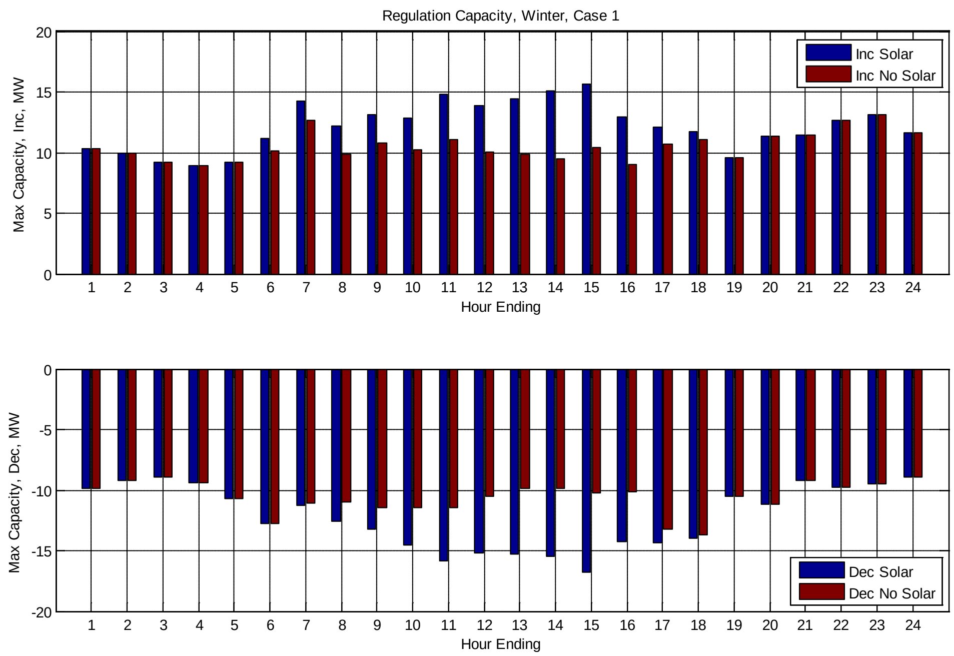


Figure 32 and Figure 33 show the regulation capacity requirements in the summer and shoulder seasons, respectively.

Figure 32. Regulation Capacity Requirements – Summer, Case 1

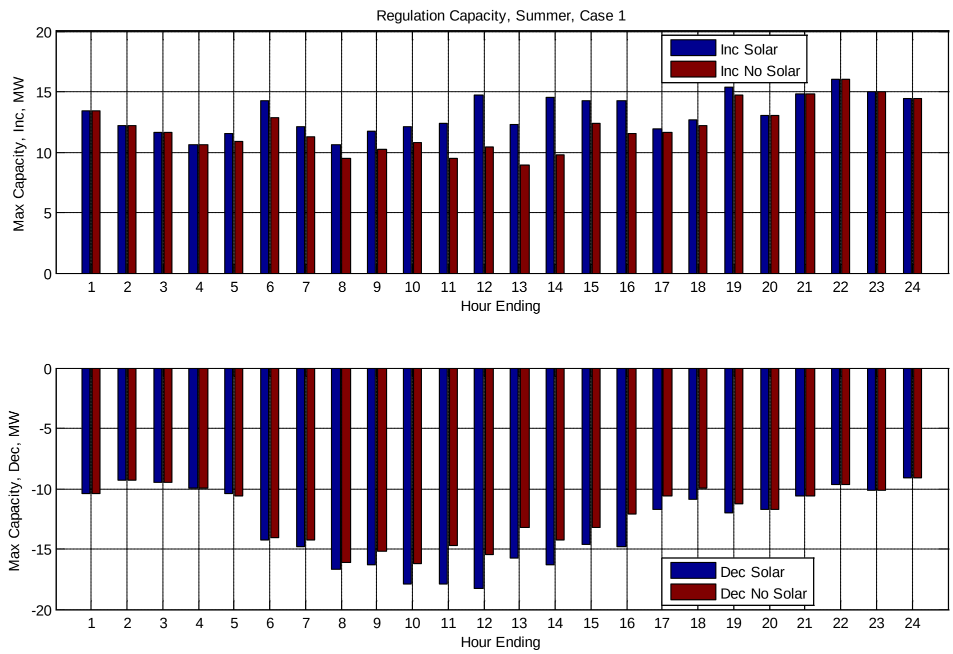
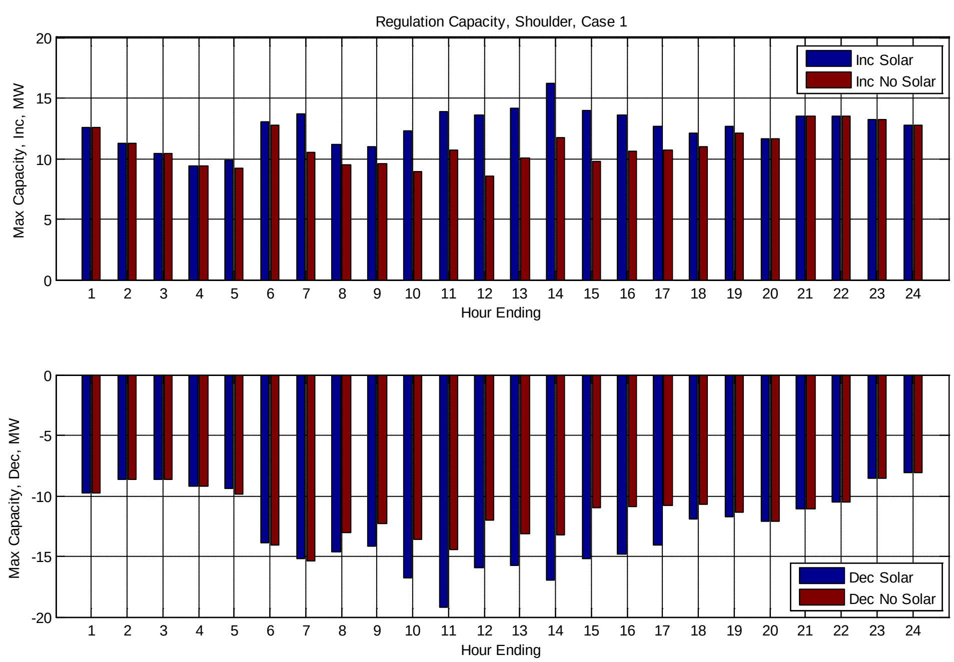


Figure 33. Regulation Capacity Requirements – Shoulder, Case 1



By comparing Figure 31 through Figure 33, one can see that the additional regulation capacity requirements caused by PV in the winter are relatively larger than in the summer and shoulder seasons, which could be explained by the more cloudy weather in the winter in the southern Nevada area.

Regulation Ramp Requirements

Figure 34 shows the hourly regulation ramp requirements in winter for Case 1 (dark blue bars) compared to Base Case (brown bars). It shows that the maximum upward regulation ramp requirement occurs during HE 15 at 15 MW/min. In the same hour, there also occurs the maximum downward regulation ramp requirement of 14 MW/min. Figure 35 and Figure 36 illustrate the regulation ramp requirements in summer and shoulder seasons, respectively.

Figure 34. Regulation Ramp Requirements - Winter, Case 1

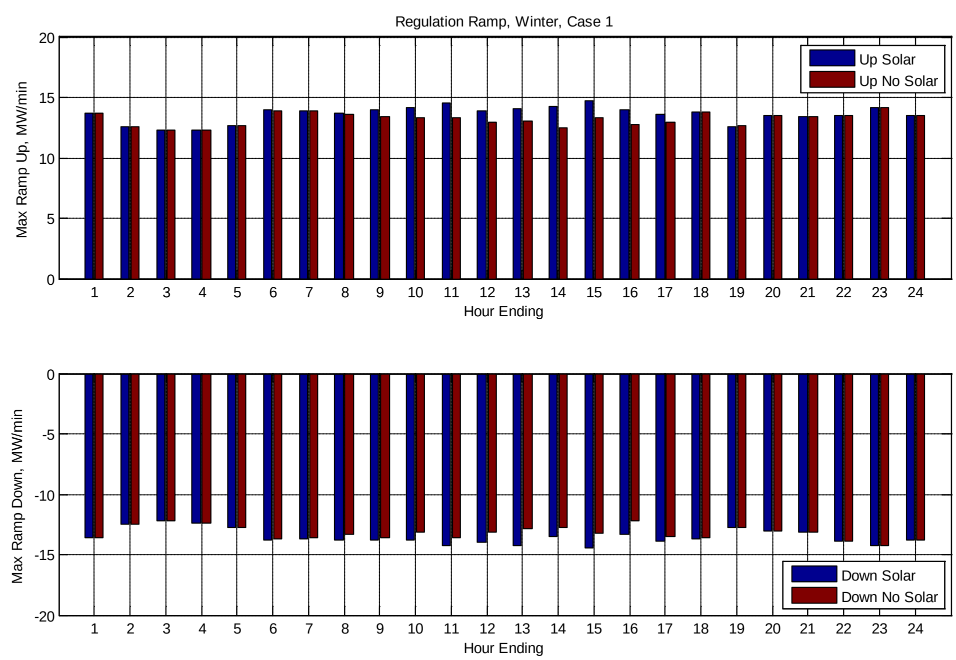


Figure 35. Regulation Ramp Requirements - Summer, Case 1

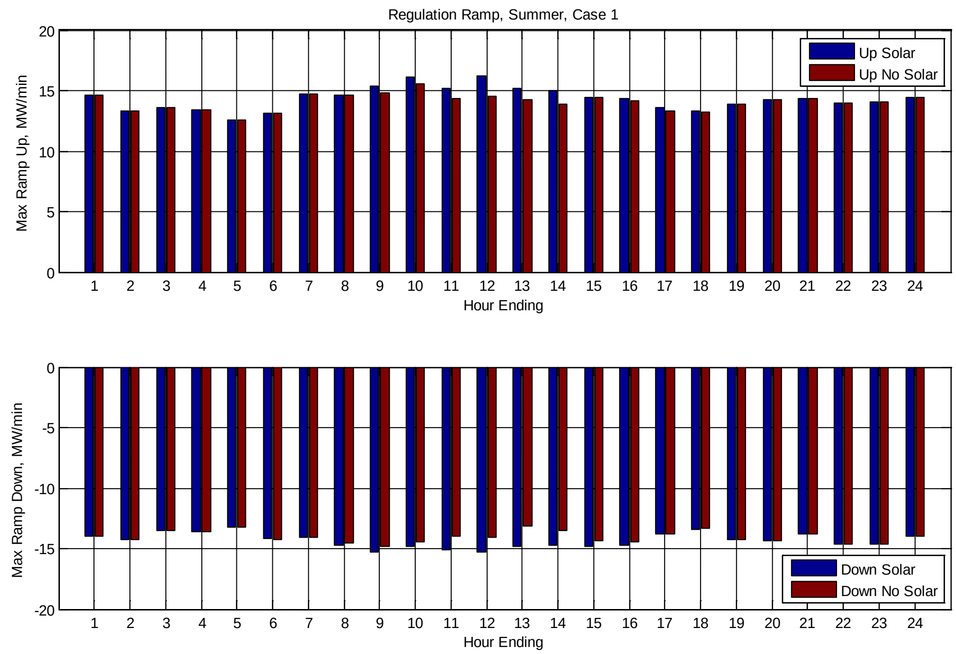


Figure 36. Regulation Ramp Requirements - Shoulder, Case 1

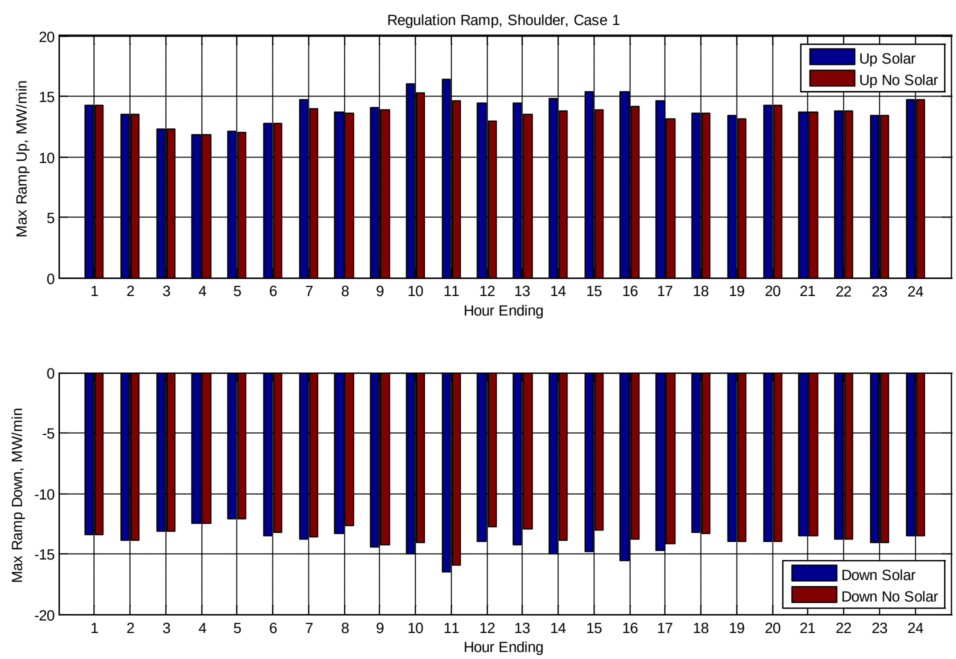


Figure 34 through Figure 36 demonstrate that the ramp requirements for regulation only increase slightly in the daytime hours for the committed case.

4.5 Load Following Reserve Requirements of Case 1 (Committed Case)

As illustrating examples, the histograms of load following capacity data points of Case 1 are presented in this section. The load following requirements are then calculated using methods presented in Section 4.3.

Distribution of Load Following Capacity Data

Figure 37, Figure 38 and Figure 39 shows the distribution of load following capacity for Case 1 in winter, summer and shoulder seasons, respectively. Similar to the regulation capacity data, these results do not follow Gaussian distribution.

Figure 37. Distribution of Load Following – Winter, Case 1

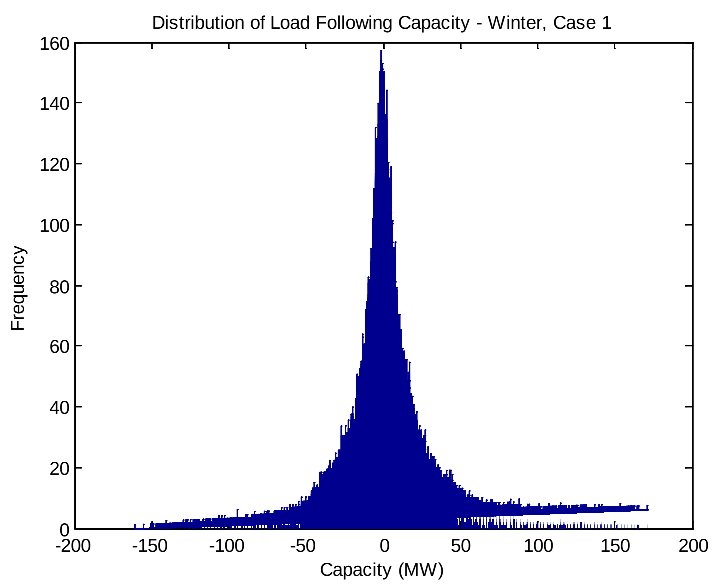


Figure 38. Distribution of Load Following – Summer, Case 1

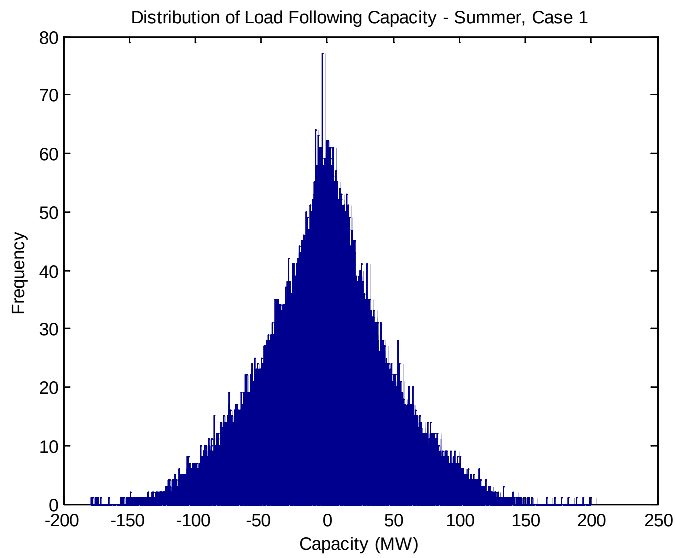
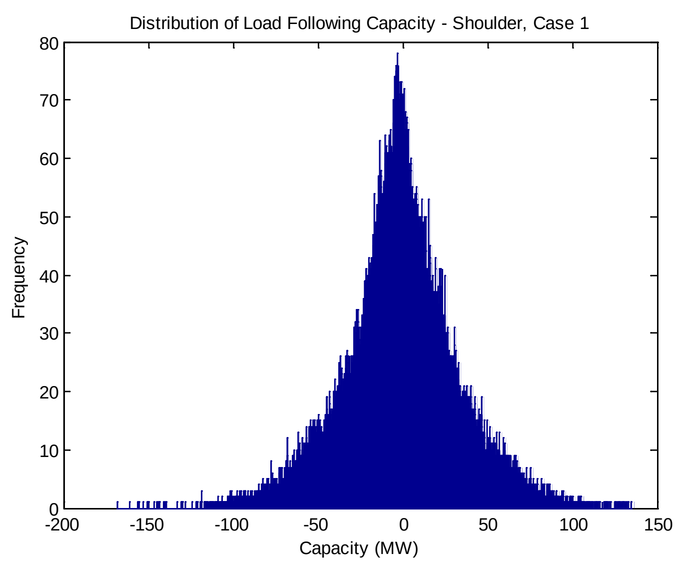


Figure 39. Distribution of Load Following – Shoulder, Case 1



Load Following Capacity Requirements

Load Following capacity requirements for Case 1 (150 MW PV, "Solar") and Base Case (0 MW PV and DG, "No Solar") in the winter season are shown in Figure 40. The impact of solar generation on load following in each hour can be observed. Similar to the regulation requirements charts, the upper diagram shows the maximum (among P% of total data points) upward load following capacity required, while the lower diagram shows the downward requirements, both in MW. The blue bars are for the solar case, and brown bars for the Base Case. For both Case 1 and Base Case, the maximum upward load following capacity requirement of 148 MW occurs during HE 17, and the maximum downward load following capacity requirement of 135 MW occurs also during HE 17.

Figure 40. Load Following Capacity Requirements – Winter, Case 1

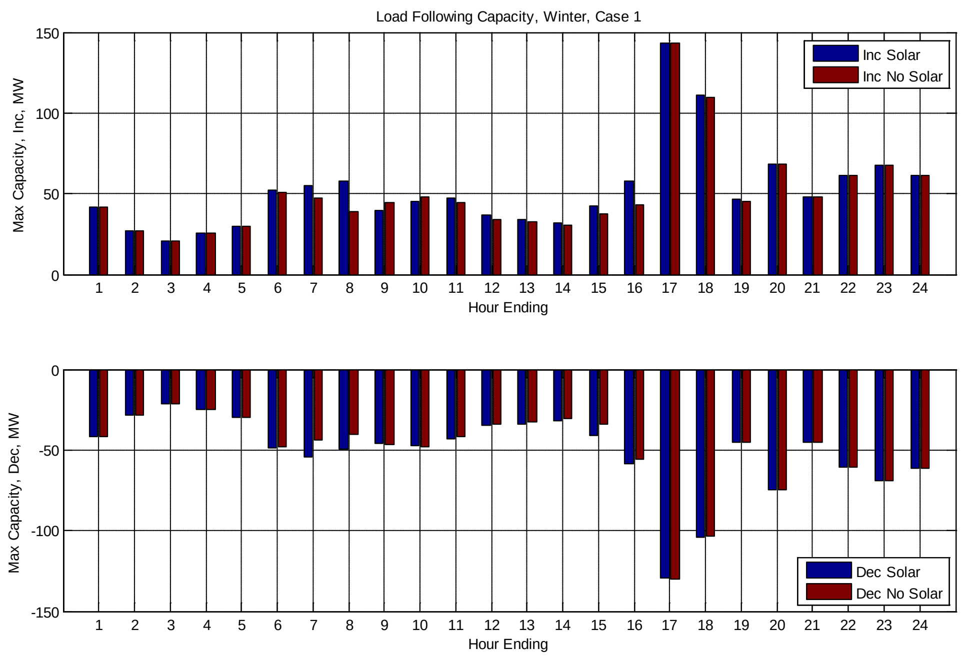


Figure 41 and Figure 42 show the load following capacity requirements in summer and shoulder seasons, respectively.

Figure 41. Load Following Capacity Requirements – Summer, Case 1

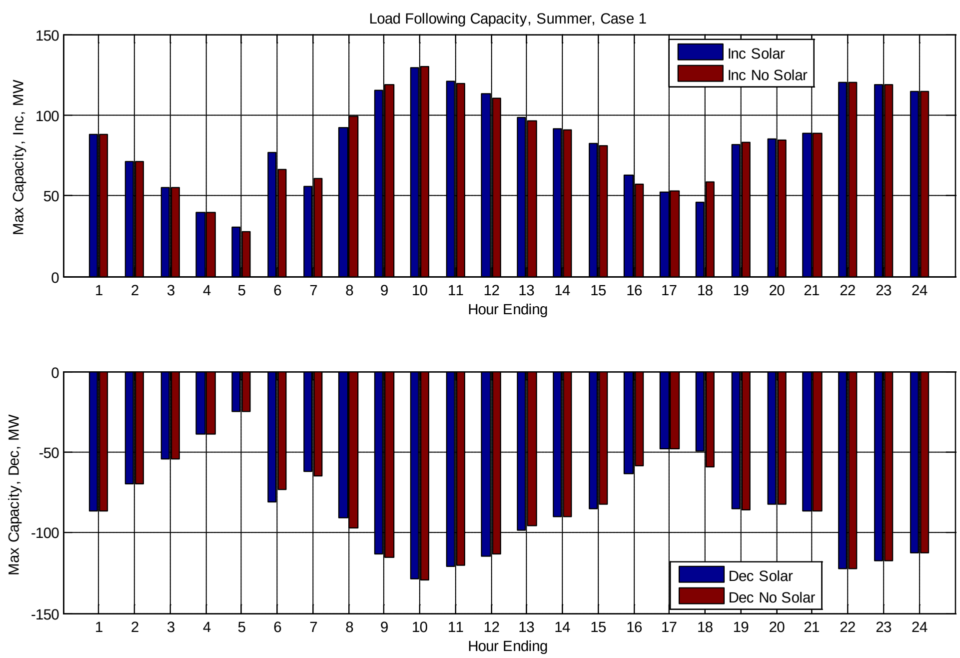
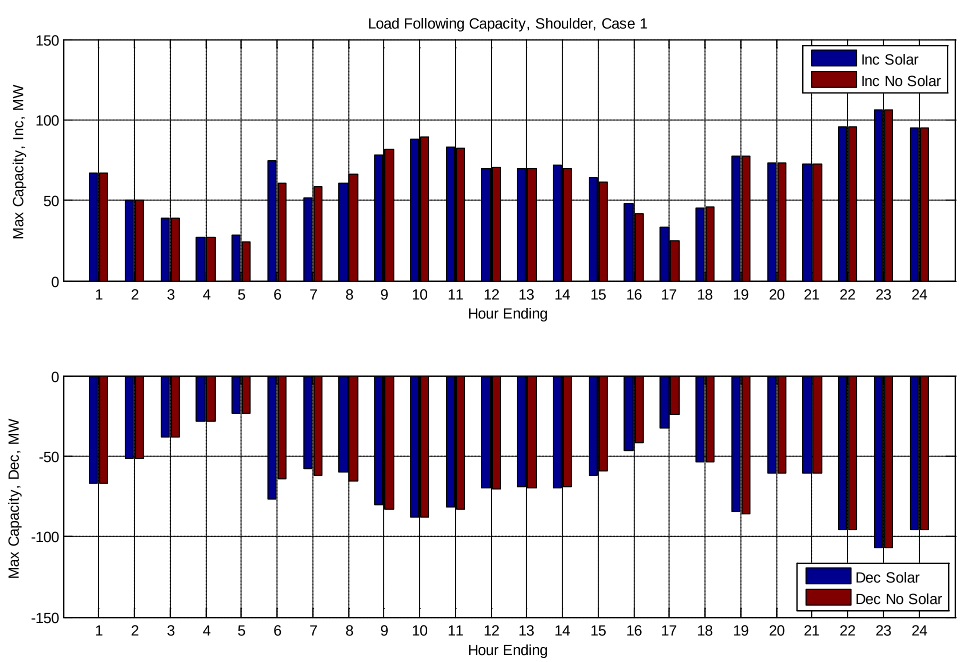


Figure 42. Load Following Capacity Requirements – Shoulder, Case 1



In all seasons, the impact of PV in Case 1 is minimal on load following capacity requirements. In fact, PV reduces the load following ramping requirements in some daylight hours, such as HE 7 to HE 10 (morning ramp of load) and HE 18 to HE 19 (evening ramp of load) in the summer and shoulder seasons. According to the definition of load following in Section 4.3, it is the difference between 10-minute interval average and 60-minute average (both with ramps) of net load, depicting the variation of net load within the hour at a 10-minute time scale. The fact that PV reduces load following capacity requirements in some hours means that the direction of 10-minute PV trends during these hours coincide with the 10-minute trends of the load itself. This explains why the periods when PV helps are the morning and evening ramps of load.

Load Following Ramp Requirements

Figure 43 shows the hourly load following ramp requirements in winter for Case 1 (dark blue bars) as compared to Base Case (brown bars). It shows that the maximum upward load following ramp requirement occurs during HE 17 (7.8 MW/min), and the maximum downward load following ramp requirement occurs during HE 16 (8.2 MW/min). PV contributes to the increase of down ramp requirement in HE 16. Figure 44 and Figure 45 show the load following ramp requirements in summer and shoulder seasons, respectively.

Figure 43. Load Following Ramp Requirements – Winter, Case 1

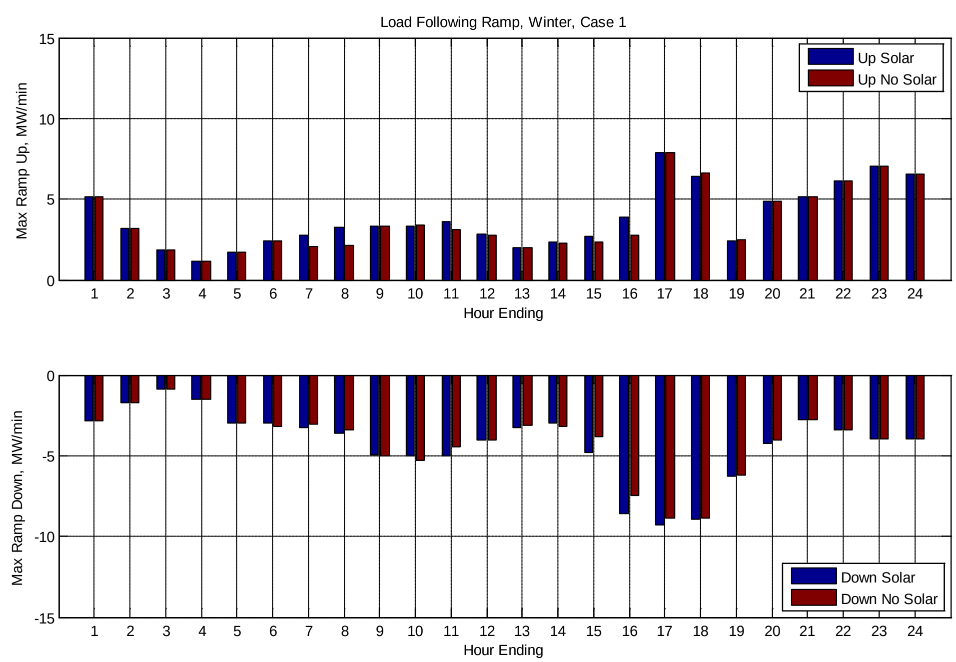


Figure 44. Load Following Ramp Requirements – Summer, Case 1

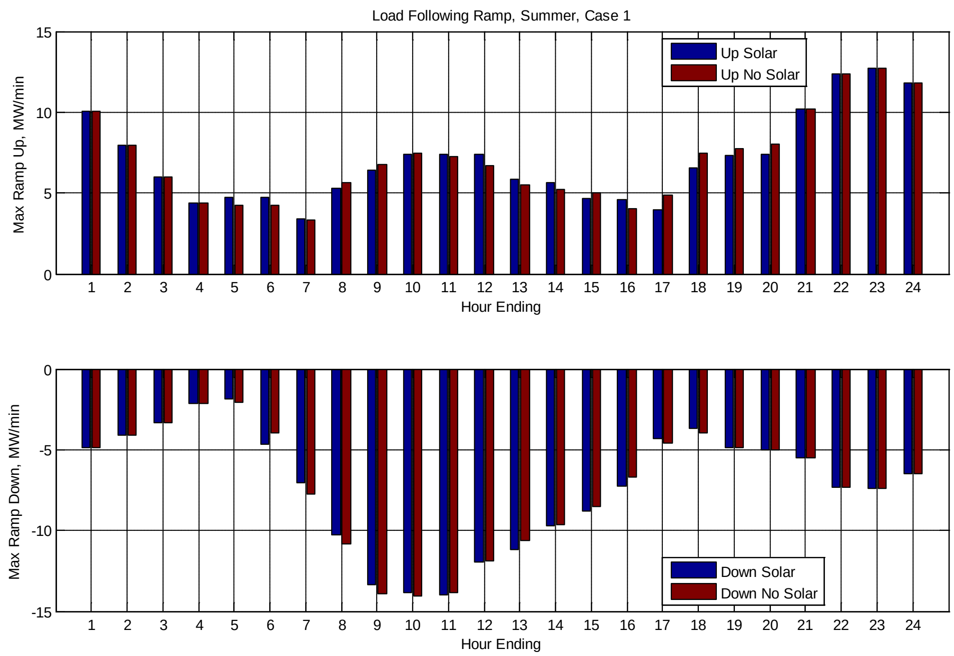


Figure 45. Load Following Ramp Requirements – Shoulder, Case 1

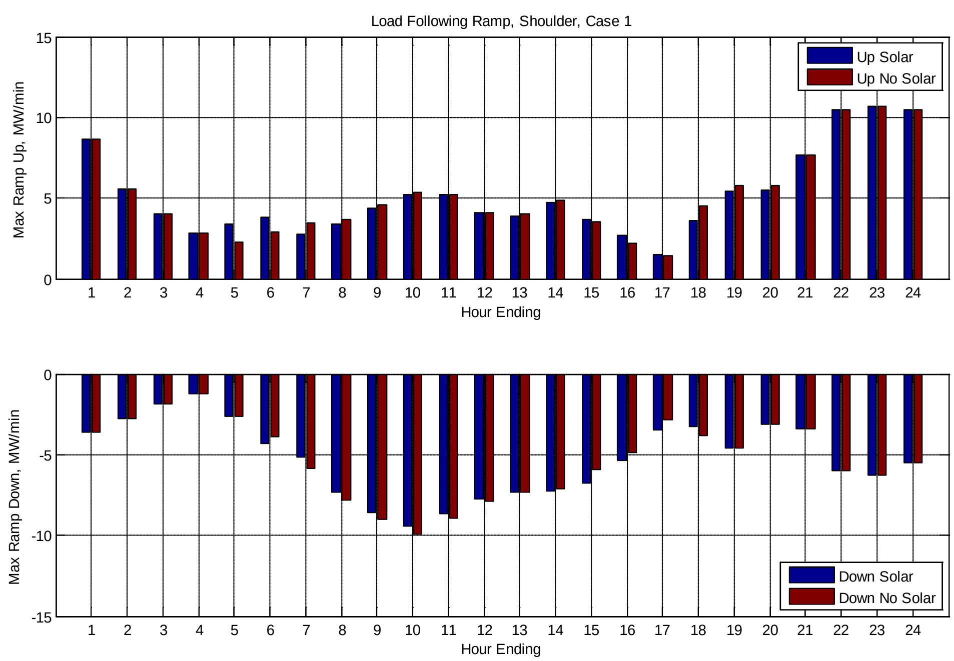


Figure 44 and Figure 45 confirm that in the summer and shoulder months, PV in Case 1 can reduce the load following ramp requirements when the 10-minute PV generation trend coincides with the load trend, such as during HE 7 to HE 10 (morning ramp of load) and HE 18 to HE 20 (evening ramp of load). In other hours, PV barely causes any increase in the ramp requirements when compared with Base Case. The observation is consistent with that from the PV impact on load following capacity requirements.

4.6 Solar Impacts on Regulation Requirements at Different Penetration Levels

This section investigates the relation between the additional regulation reserve requirements and different penetration of large PV and DG in the system.

Solar Impacts on Regulation Capacity Requirements

Figure 46 through Figure 48 illustrate the impact of solar generation on regulation capacity requirements for cases from 1A to 5A, in winter, summer and shoulder seasons, respectively. In these cases, large-scale PV in the system increases from 149 MW to 892 MW, while DG capacity keeps at 50 MW. Only requirements from HE 5 to HE 20 are shown since in the night hours PV has no impacts at all. It can be observed that with the increase of large PV in the system, total system regulation requirements increase significantly, which means the increase is caused by PV generation. Also, the requirements in the winter season increase most rapidly and become the largest among all seasons in high PV penetration cases. This is also consistent with the observation from Case 1 results that incremental reserve requirements are relatively higher than the other two seasons.

Figure 46. Regulation Capacity Requirements – Winter, Case 1A-5A

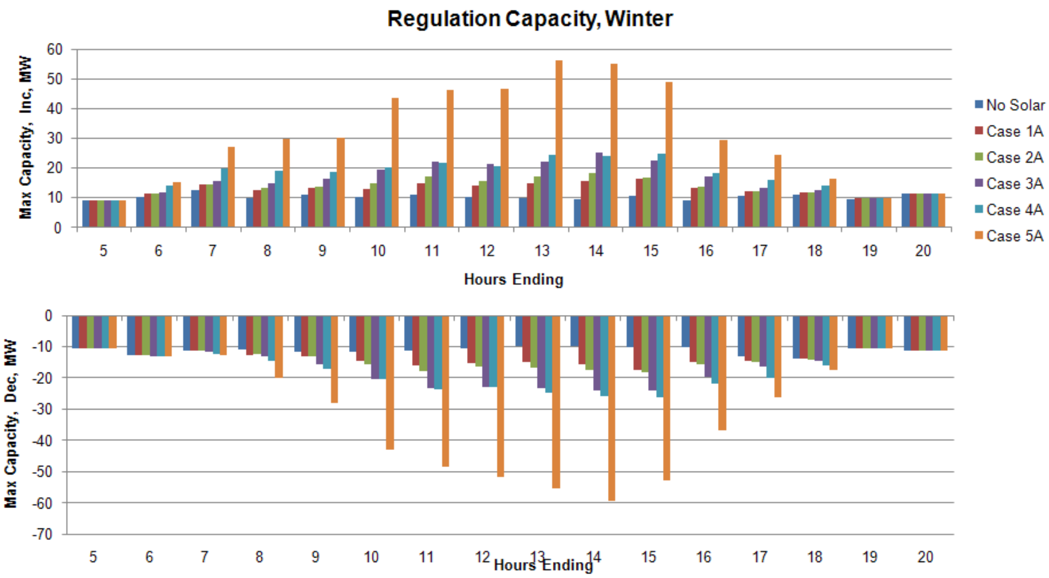


Figure 47. Regulation Capacity Requirements – Summer, Case 1A-5A

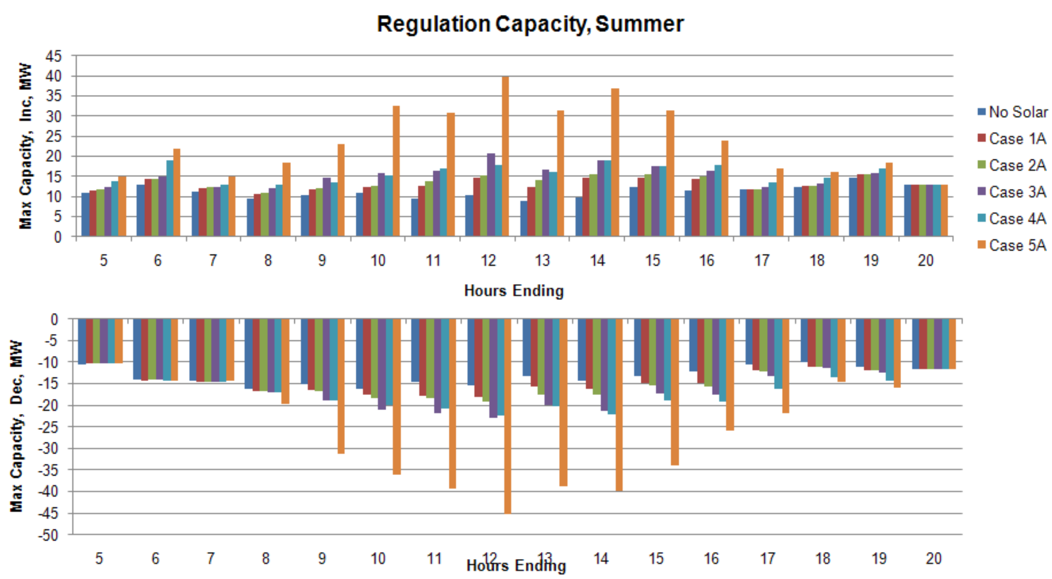


Figure 48. Regulation Capacity Requirements – Shoulder, Case 1A-5A

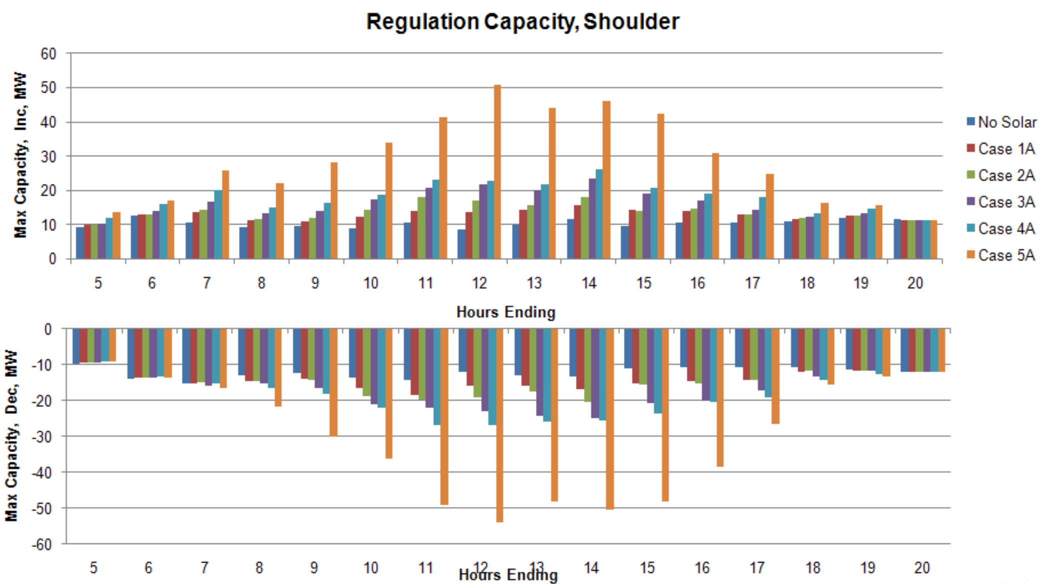


Figure 49 shows the regulation capacity requirements with various large PV penetrations in winter in the hour ending at 2 PM, which is one of the most challenging hours of the season. The line labelled as B1 is the average trend line depicting the relation between large PV and regulation capacity requirements. On average, about every 25 MW additional large PV requires 1 MW of regulation increase. The line R1 shows the trend when large PV increases with a larger diversity (by adding more PV sites, see the PV plant location chart in Figure 7). About every 35 MW additional large PV requires 1 MW regulation increase. Lines R2 and R3 are the trends when PV capacity increases on existing sites (see the PV plant location chart in Figure 7). Every 10 to 15 MW additional large PV would require 1 MW of regulation increase. The downward capacity requirements show similar trends as the upward requirements.

Figure 49. Trend of Regulation Capacity Requirements – Winter, Case 1A-5A

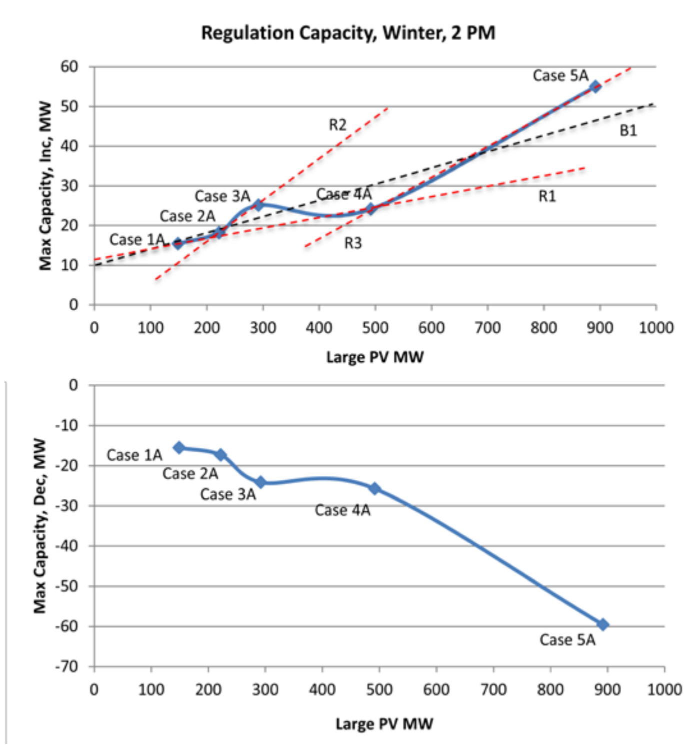


Figure 50 through Figure 52 compare the regulation capacity requirements for cases including Case 1A, 1B and 1C, with the same amount of large PV (149 MW) but different DG capacity (50 MW, 450 MW and 750 MW) in each season. Only results from HE 5 to HE 20 are shown since PV generation has no impact on the requirements in the night time. For most of the daylight hours in Case 1B and 1C, winter has the largest regulation capacity requirements than the other two seasons, which is similar to the impact of large PV. Only in HE 13 it requires the highest regulation capacity in the shoulder season, which could be caused by the randomness in the data.

Figure 50. Regulation Capacity Requirements – Winter, Case 1A-1C

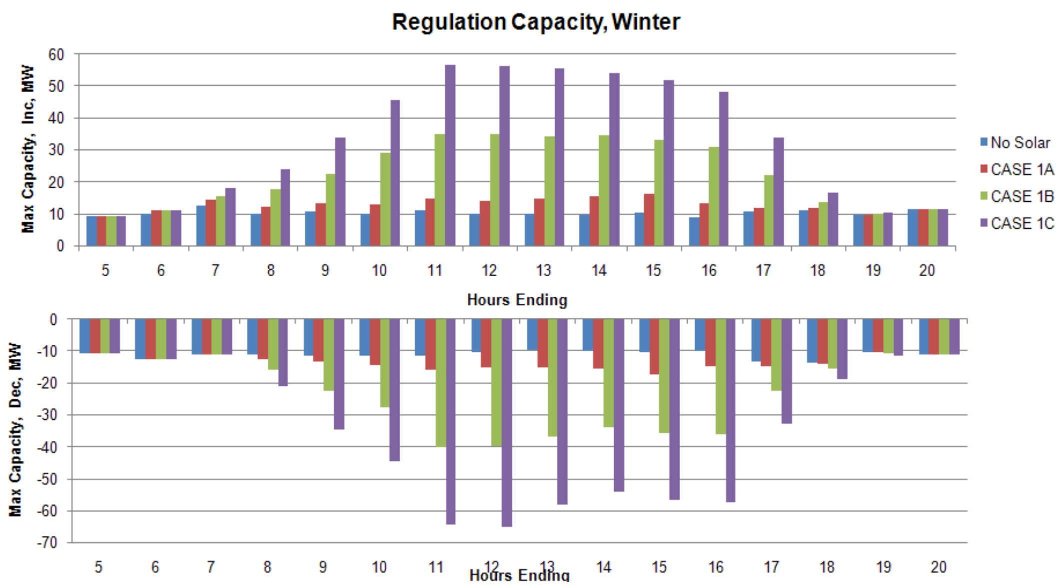


Figure 51. Regulation Capacity Requirements – Summer, Case 1A-1C

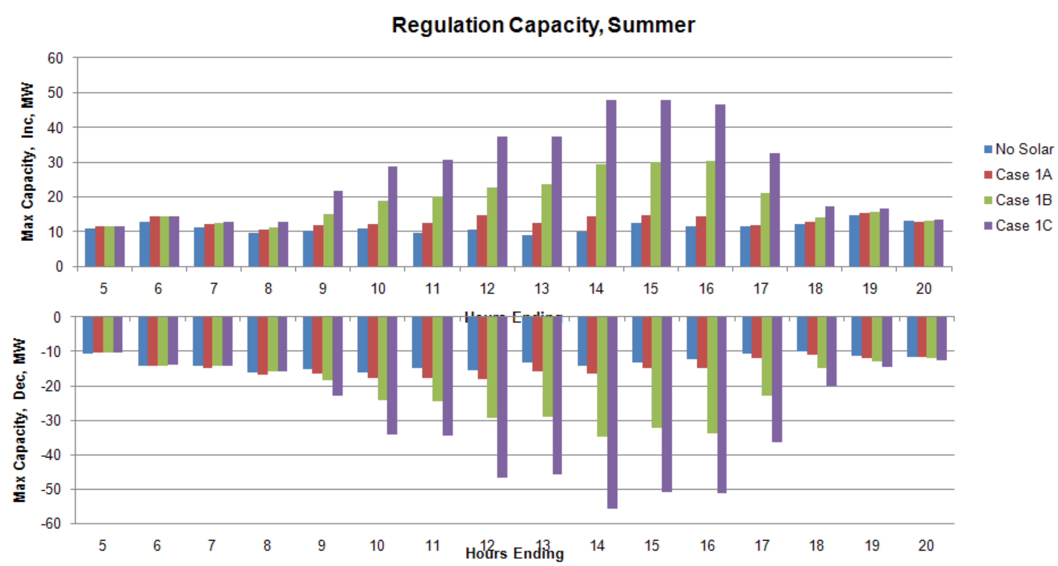


Figure 52. Regulation Capacity Requirements – Shoulder, Case 1A-1C

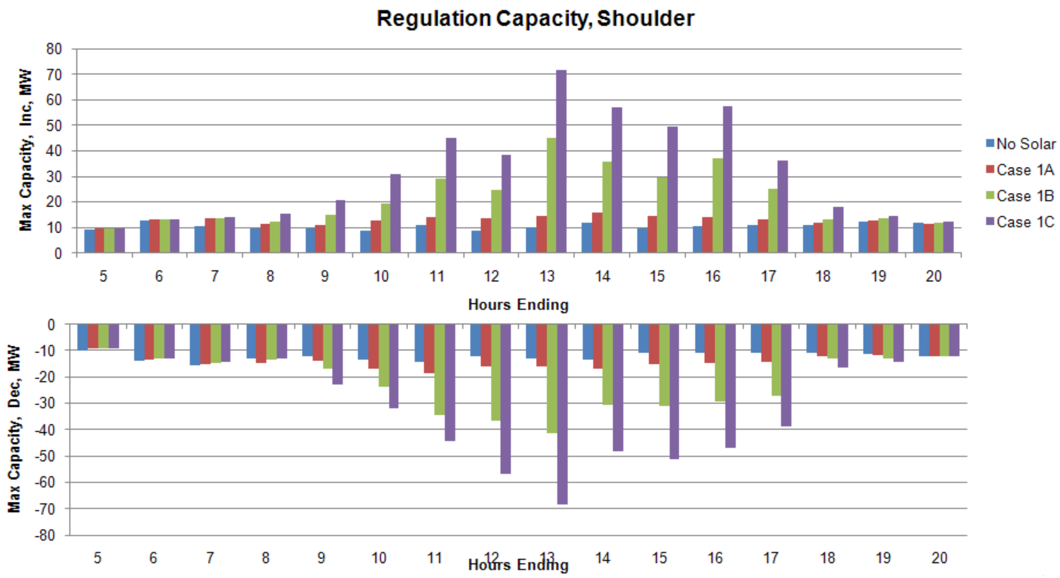
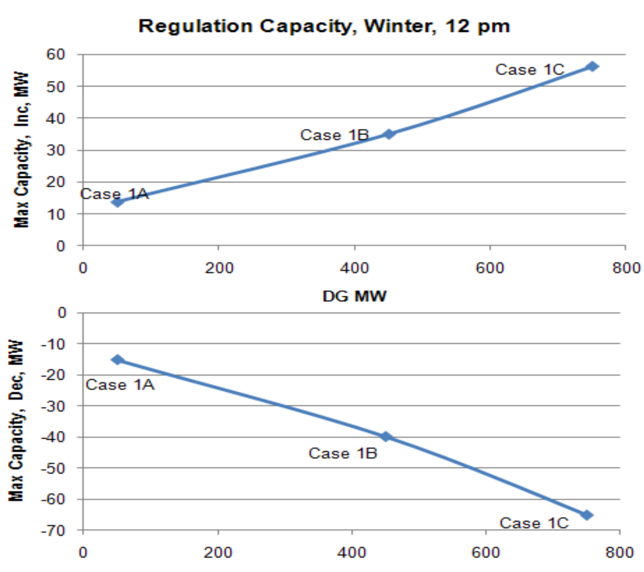


Figure 53 shows the regulation capacity requirements with increasing DG penetration in winter, in the hour ending at 12 PM, one of the most challenging hours. From Figure 53 one can see that regulation capacity requirements increase almost linearly with the increase of DG, with every 15 MW of additional DG requiring about 1 MW of regulation increase.

Figure 53. Trend of Regulation Capacity Requirements – Winter, Case 1A-1C



Solar Impacts on Regulation Ramp Requirements

Figure 54 through Figure 56 show the regulation ramp requirements for solar cases from Case 1A to Case 5A, in winter, summer and shoulder seasons, respectively. In these cases, large-scale PV capacity increases from 149 MW to 892 MW, while the amount of DG keeps at 50 MW. Only requirements from HE 5 to HE 20 are shown because in the night hours PV generation has no impacts at all. It can be observed that in Case 5A, regulation ramp requirements almost double the requirements for the system without solar, which means the requirements caused by PV become dominant. Also, winter season requirements become larger than the summer and similar to the shoulder in Case 5A.

Figure 54. Regulation Ramp Requirements – Winter, Case 1A-5A

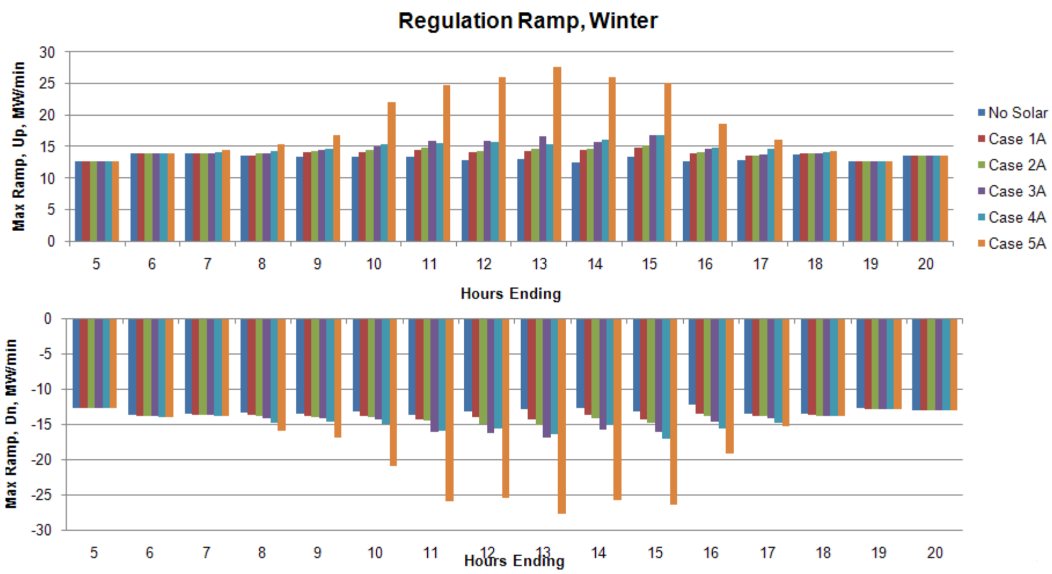


Figure 55. Regulation Ramp Requirements – Summer, Case 1A-5A

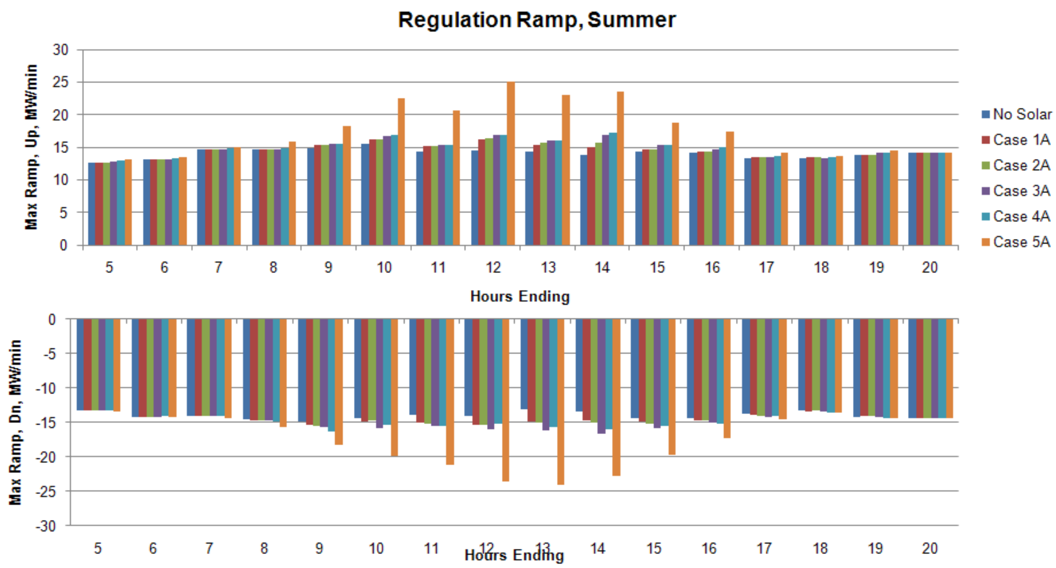


Figure 56. Regulation Ramp Requirements – Shoulder, Case 1A-5A

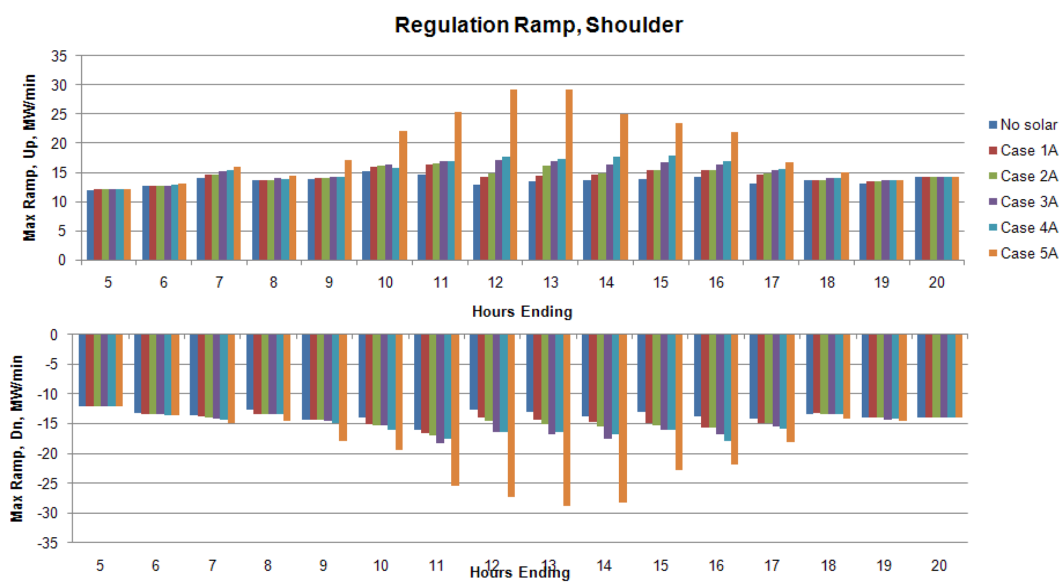


Figure 57 shows the regulation ramp requirements for Case 1A to 5A in winter in HE 14, one of the most challenging hours. Similar to the trends in capacity requirements, line B1 is the average trend line depicting the relation between large PV and regulation ramp requirements. On average, about every 75 MW additional large PV requires 1 MW/min of regulation ramp rate increase. Line R1 shows the trend when large PV capacity increases with a larger diversity (by adding more PV sites, see PV plant locations chart in Figure 7). About every 150 MW large PV requires 1 MW/min ramp increase. Lines R2 and R3 are the trends when PV capacity increases on existing sites with no increased diversity (see PV plant locations chart in Figure 7). Every 30 to 45 MW additional PV would require 1 MW/min of ramp increase.

Figure 57. Trend of Regulation Ramp Requirements – Winter, Case 1A-5A

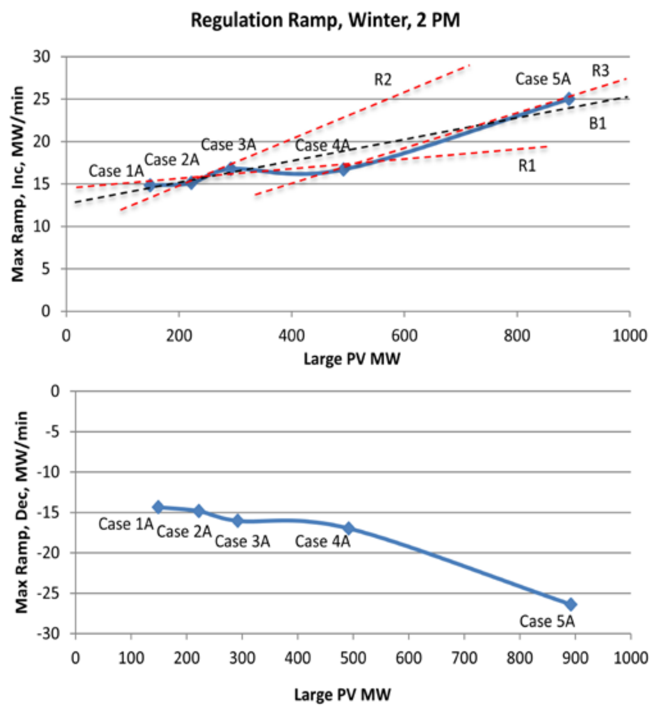


Figure 58 through Figure 60 compare the regulation ramp rate requirements in winter, summer and shoulder seasons with the increase of DG penetration.

Figure 58. Regulation Ramp Requirements – Winter, Case 1A-1C

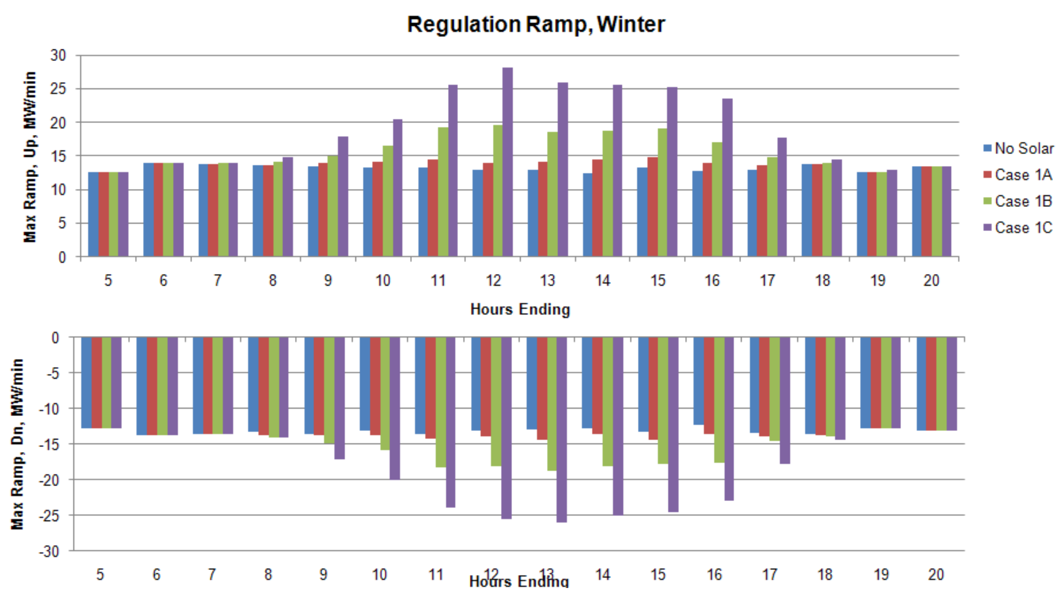


Figure 59. Regulation Ramp Requirements – Summer, Case 1A-1C

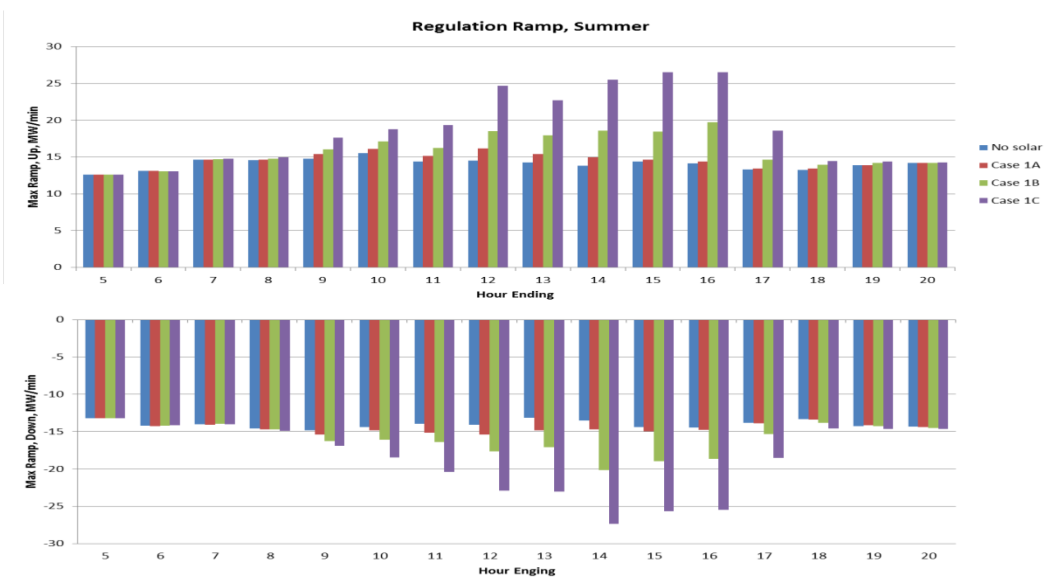
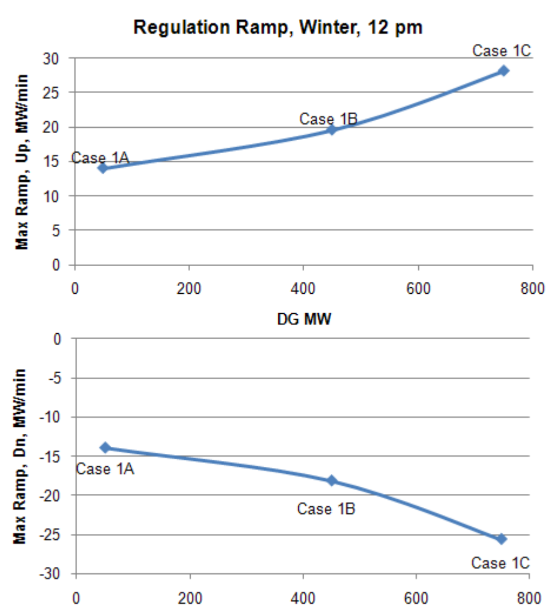


Figure 60. Regulation Ramp Requirements – Shoulder, Case 1A-1C

Figure 61 shows the regulation ramp rate requirements increase with DG penetration in winter in HE 12. From Figure 61 we can see that for DG penetration less than 500 MW, every 65 MW DG requires about 1 MW/min ramp increase, and for DG penetration larger than 500 MW, every 35 MW DG requires about 1 MW/min ramp increase.

Figure 61. Trend of Regulation Ramp Requirements – Winter, Case 1A-1C



Summary of Solar Impacts on Regulation Requirements

Based on the above analysis we can summarize the impact of PV generation on regulation requirements as follows:

1) Higher regulation capacity and ramp requirements shift from summer months to winter and shoulder months with the increase of solar penetration, which is caused by higher reserve requirements for solar power in the winter and shoulder months resulting from the weather pattern in the southern Nevada area.

2) In the most challenging hours, through the study cases, regulation capacity requirements increases from +/-10 MW to +/-70 MW (600% increase); regulation ramp requirements increased from +/-15 MW/min to 30 MW/min (100% increase). Regulation requirements are dominated by the variability of PV in high PV penetration cases.

3) Increase of PV capacity on the same sites without diversity increase causes larger regulation capacity and ramp requirements increase. Capacity requirements fall in 10 to 15 MW PV requiring 1 MW of regulation increase. Ramp requirements range from 30 to 45 MW PV, which requires a 1 MW/min of ramp increase.

4) Increasing PV capacity by expanding the number of sites causes smaller regulation capacity and ramp requirements to increase. Each 35 MW of new large PV requires and additional 1 MW of regulation ramping capability. Thus, 150 MW of large PV would require a 1 MW/min increase in regulation ramping capability.

5) The average regulation requirements from PV in all cases are: about 25 MW PV requires 1 MW of regulation capacity increase; about 75 MW PV requires 1 MW/min of regulation ramp increase.

4.7 Solar Impacts on Load Following Requirements at Different Penetration Levels

This section investigates the relation between the additional load following reserve requirements and different penetration levels of large PV in the system.

Solar Impacts on Load Following Capacity Requirements

Figure 62 through Figure 64 illustrate the impact of the solar generation on load following capacity requirements at different solar penetration levels in winter, summer and shoulder seasons. The capacity of large PV increases from 149 MW to 892 MW from Case 1A to 5A. DG capacity keeps at 50 MW in all these cases.

Figure 62. Load Following Capacity Requirements – Winter, Case 1A-5A

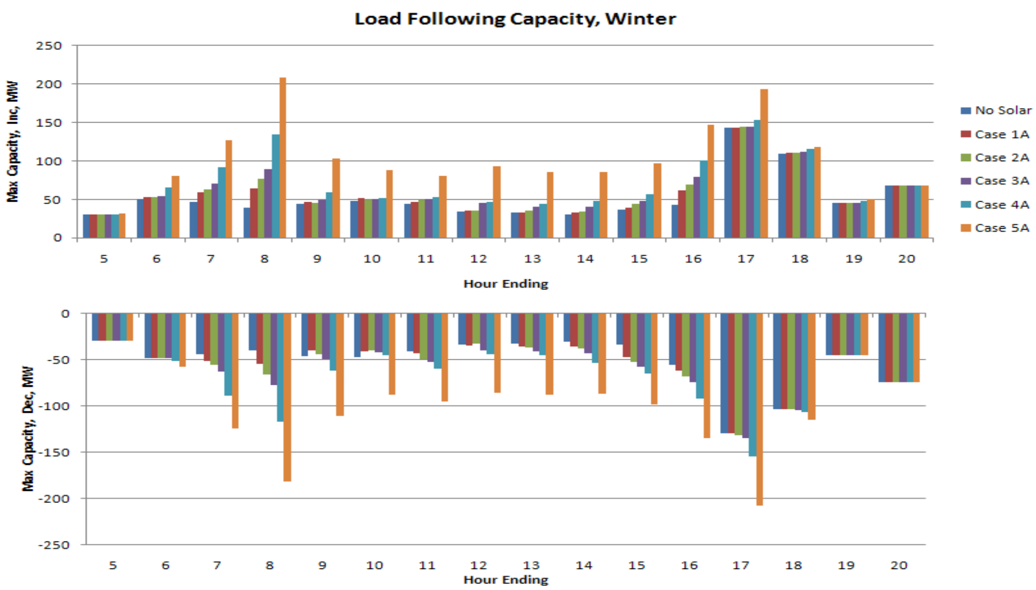


Figure 63. Load Following Capacity Requirements – Summer, Case 1A-5A

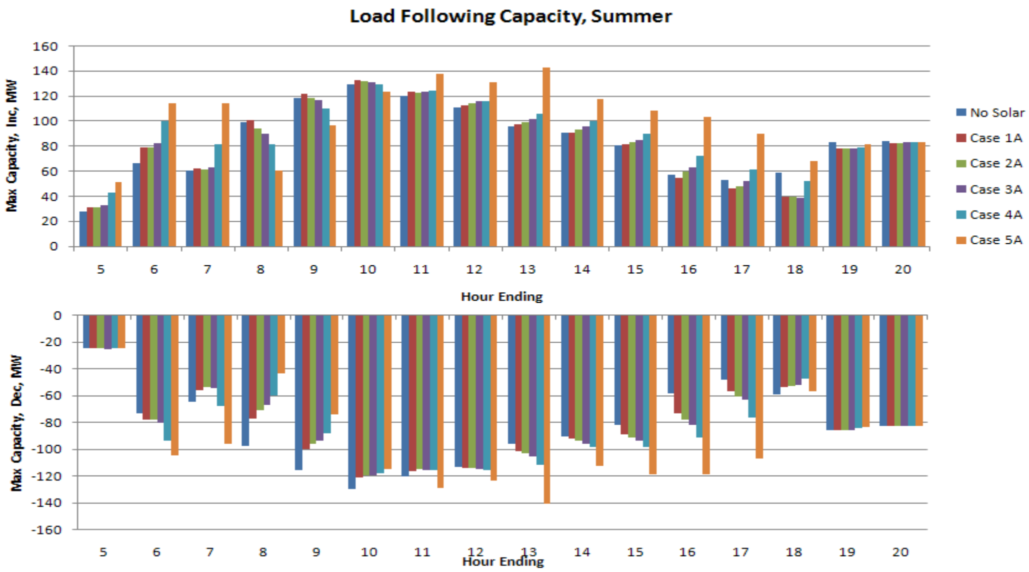
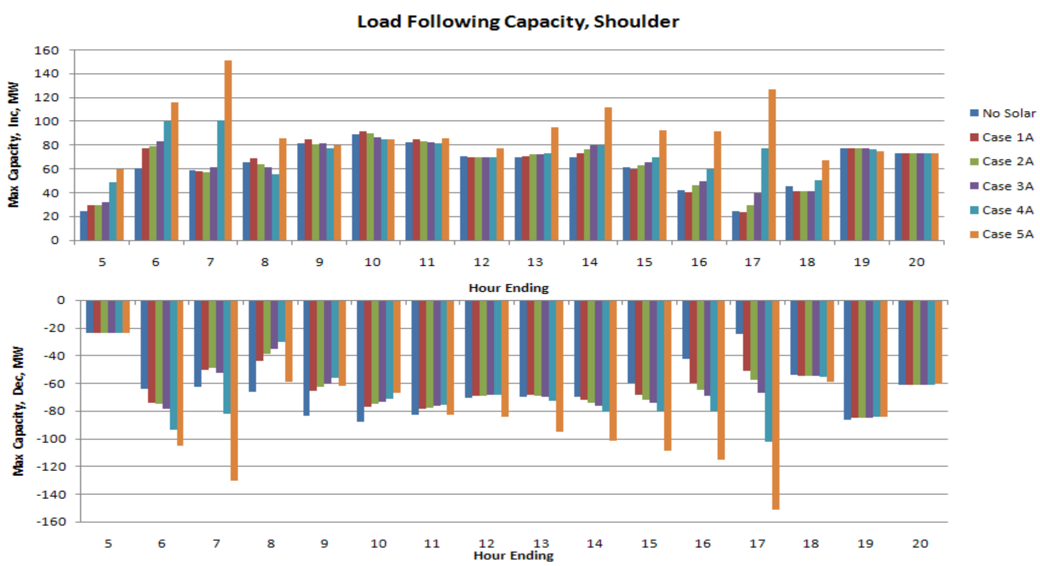


Figure 64. Load Following Capacity Requirements – Shoulder, Case 1A-5A



It can be observed from Figure 62 to Figure 64 that the impact of solar on load following capacity requirements has different patterns in each season. In the winter, through all daylight hours, the requirement increases with solar penetration, but at a different rate in each hour. In the summer, during HE 8, 9, 10 and 18, the requirement actually decreases with more PV generation in the system. In other words, solar power helps to reduce the load following capacity requirements in these hours. In the shoulder months, solar power also helps in HE 8, 9, 10 and 11. In all of the three seasons, more solar power causes larger increase in load following during the start of morning load ramp-up. The impact is relatively more prominent at the end of the morning ramp when load starts to become flat (identified by smaller load following requirements in the "No Solar" case or Base Case), such as HE 8 in winter and HE 7 in the summer and shoulder months. Another observation is that in higher PV penetration cases, the load following capacity requirements become the largest in winter, while the largest requirements in the Base Case ("No Solar") occur in summer. Overall, however, the increase of load following capacity requirements caused by PV is much less significant than that of regulation. For example, in the winter months, the load following capacity requirements are +/-140 MW without PV, while they become +/-210 MW (50% increase) with 892 MW large PV and 50 MW DG in Case 5A.

Solar Impacts on Load Following Ramp Requirements

Figure 65 through Figure 67 compare the load following ramp rate requirements with various levels of large PV penetration in the winter, summer and shoulder seasons. The amount of large PV increases from 149 MW to 892 MW from Case 1A to 5A, while the amount of DG keeps at 50 MW in these cases.

Figure 65. Load Following Ramp Requirements – Winter, Case 1A-5A

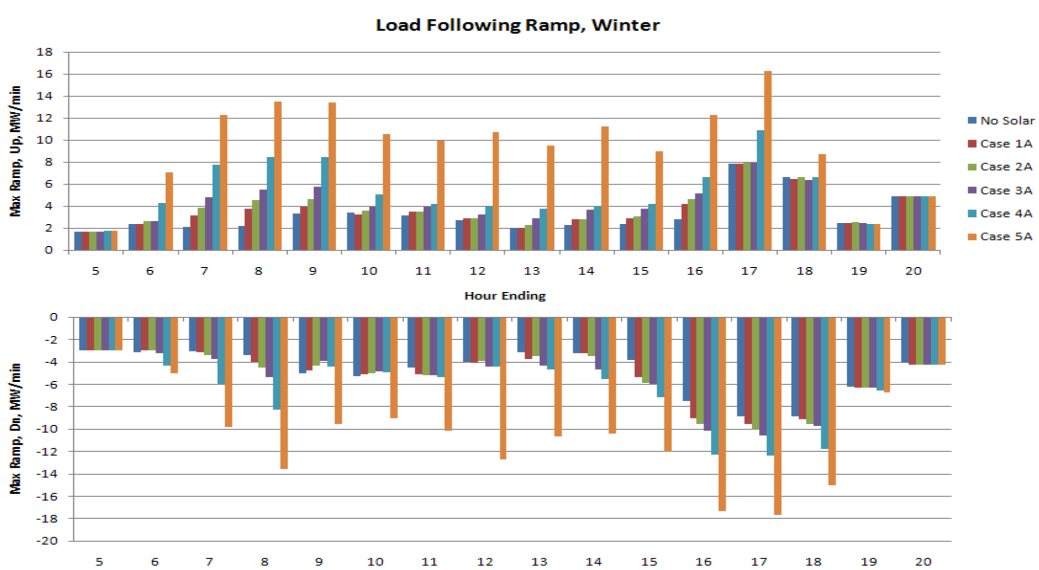


Figure 66. Load Following Ramp Requirements – Summer, Case 1A-5A

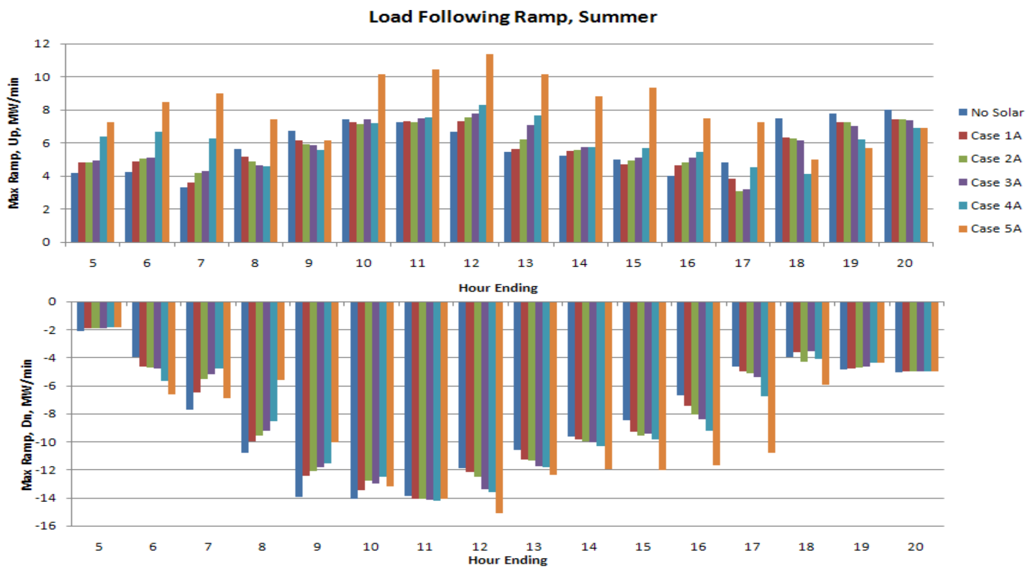
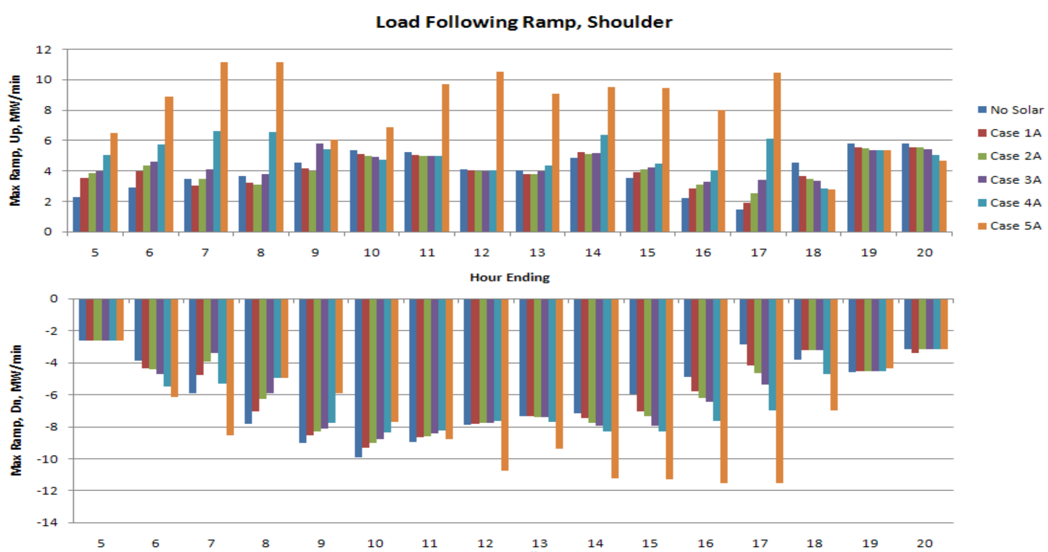


Figure 67. Load Following Ramp Requirements – Shoulder, Case 1A-5A



Similar to PV impacts on load following capacity requirements, it can be observed from Figure 65 to Figure 67 that the impact of solar on load following ramp requirements has different patterns in each season. Generally, the impact is relatively more prominent in the winter months that the other two seasons. In higher PV penetration cases, the load following ramp requirements become the largest in winter, while summer holds the largest requirements in the Base Case ("No Solar"). In many hours in the summer and shoulder months, solar power actually reduces load following ramp requirements. Overall, the increase of load following ramp requirements caused by PV is much less significant than that of regulation. For example, in the winter months, which are affected more by PV, the load following ramp requirements are +/- 9 MW/min without PV, while they become +/-18 MW/min (100% increase) with 892 MW large PV and 50 MW DG in Case 5A.

Summary of Solar Impacts on Load Following Requirements

Based on the above results, the impact of the solar generation on load following requirements can be summarized as follows:

1) Highest load following capacity and ramp requirements shift from summer months to winter months as solar penetration increases and PV variability within the hour becomes dominant.
2) The impact from solar power on load following requirements is less significant as compared to that on regulation, which can be explained by the relative magnitudes of minute-to-minute variability and within-hour variability of load and PV generation. In many hours (usually when solar power ramps coincide with load ramps) solar power actually reduces load following requirements, especially in lower PV penetration cases. In high PV penetration cases, within-hour variability of PV starts to be dominant and this helping effect will diminish.
3) In the most challenging hours in winter, through the study cases, load following capacity requirements increase from +/-140 MW to +/-210 MW (50% increase); and ramp requirements increase from +/- 9 MW/min to +/-18 MW/min (100% increase).

4.8 Balancing Area Reserve Requirements

Current NV Energy Reserve Requirements

The approach that NV Energy schedulers currently use to meet reserve requirement for contingency reserves and frequency regulation is outlined below.[57]

[57] NV Energy reports that these levels are sufficient to remain compliant with NERC performance standards under CPS-1 and CPS-2.

1. Assign 427 MW for contingency reserves, of which 50% must be spinning and 50% non-spinning.
2. Assign an additional 25 MW for regulating reserves, of which 100% must be fully spinning (prior to new DG or PV).
3. Make same-day, real-time adjustments based on load forecast error for load following and generation unavailability.

The approach to specify reserve requirements in this study, for the production cost simulation, adds an adjustment of regulation reserve, which includes:

1. Assign 427 MW for contingency reserves, of which 50% must be spinning and 50% non-spinning.
2. Assign an additional 25 MW for regulating reserves, of which 100% must be fully spinning (prior to new DG or PV).
3. Identify the additional amount of upward regulating reserve for each case, using the methodology outlined in Section 4.3. Use spinning reserve to fulfill the additional regulation requirements.

Load following occurs through real-time dispatches every 10 minutes and both spinning and non-spinning reserve (such as peaking units) can be used to meet this requirement. Load following reserve was not specified in the production cost simulations due to the limitation of the software. However, the analysis results for load following requirements help to understand the impact of solar on the load following time scale and provide guidance to real-time evaluation of resource sufficiency during operations.

Downward regulation reserve requirements were also not modeled in the production cost simulations due to the limitation of the software.

Reserve Requirements for PV and DG Scenarios

The reserve value used in the Section 5 production cost analysis is derived using the following assumptions:

- Total Reserve (TR) = Contingency Reserve (CR) + Regulating Reserve (RR)
- CR can be both 50% spinning and 50% non-spinning
- RR should be 100% spinning

Note: the additional RR reserves for the solar cases are applied only for daylight hours. For the night hours, reserves are the same as the Base Case. Table 7 presents the upward reserve requirements by season.

Table 7. Upward Regulating Reserve Capacity Requirements Used in Production Cost Simulations

Case	Regulation (MW)		
	Winter (1, 2, 3, 4, 11, 12)	Summer (6, 7, 8, 9)	Shoulder (5, 10)
Base	25	25	25
1A	26	26	26
2A	28	26	28
3A	30	27	30
4A	36	29	36
5A	66	50	66
1B	45	40	45
4B	50	45	50
1C	67	58	82
3C	68	59	84

4.9 Impact of Forecast Errors on Balancing Reserve Requirements

The regulation and load following requirements analysis presented above has been based on ideal hourly schedules and real-time dispatch, which is equivalent to having perfect hourly and real-time forecasts of load and solar generation in operations. The results provide non-biased (by forecast errors) information on the actual variability of net load (load – solar output) and how much the variability would affect regulation and load following reserve requirements. Of course, perfect forecast is unattainable in the real world. This section shows the reserve requirements under different solar penetration cases when load and solar generation forecast errors are considered.

The following forecast data were used to determine generation schedules: hourly day-ahead load forecast data provided by NV Energy and day-ahead solar generation forecast data provided by SNL. A Monte Carlo type of simulation was performed to cover the impact of randomness in the day-ahead forecast errors. 20 groups of hourly forecast data (for both load and solar) were produced based on the same stochastic characteristics for the Monte Carlo simulations. A linear regression model was used to generate real-time forecasts for load and solar with a 20-minute look-ahead time.

As an example to show the impact of forecast errors, Figure 68 through Figure 75 compare the regulation and load following requirements for Case 5A in the winter season, with forecast errors and with perfect forecasts, respectively.

Figure 68. Regulation Capacity Requirements – Winter, Case 5A, with Forecast Errors

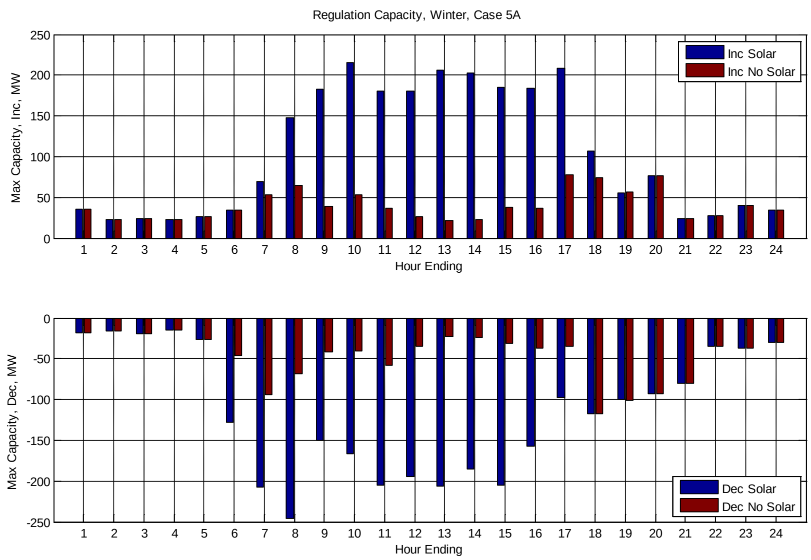


Figure 69. Regulation Capacity Requirements – Winter, Case 5A, Perfect Forecasts

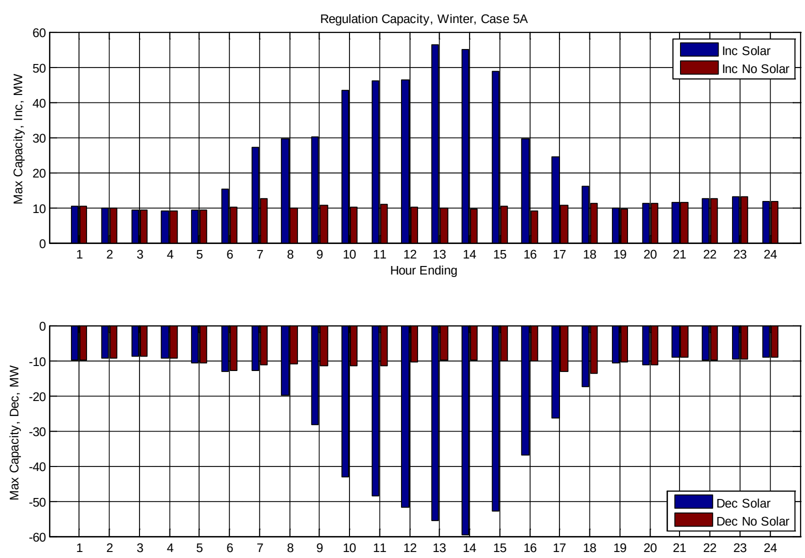


Figure 70. Regulation Ramp Requirements – Winter, Case 5A, with Forecast Errors

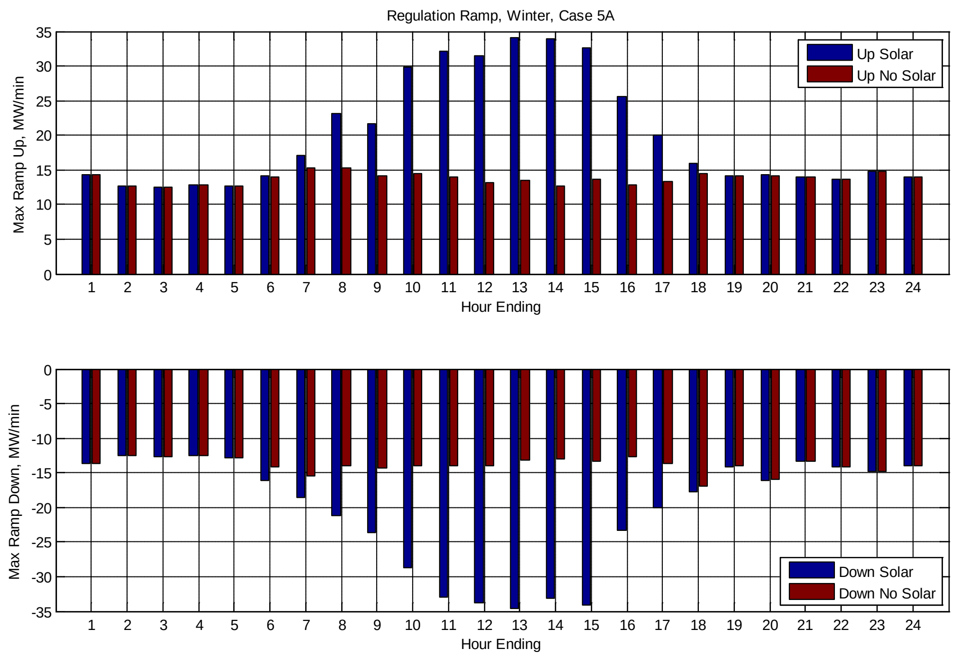


Figure 71. Regulation Ramp Requirements – Winter, Case 5A, Perfect Forecasts

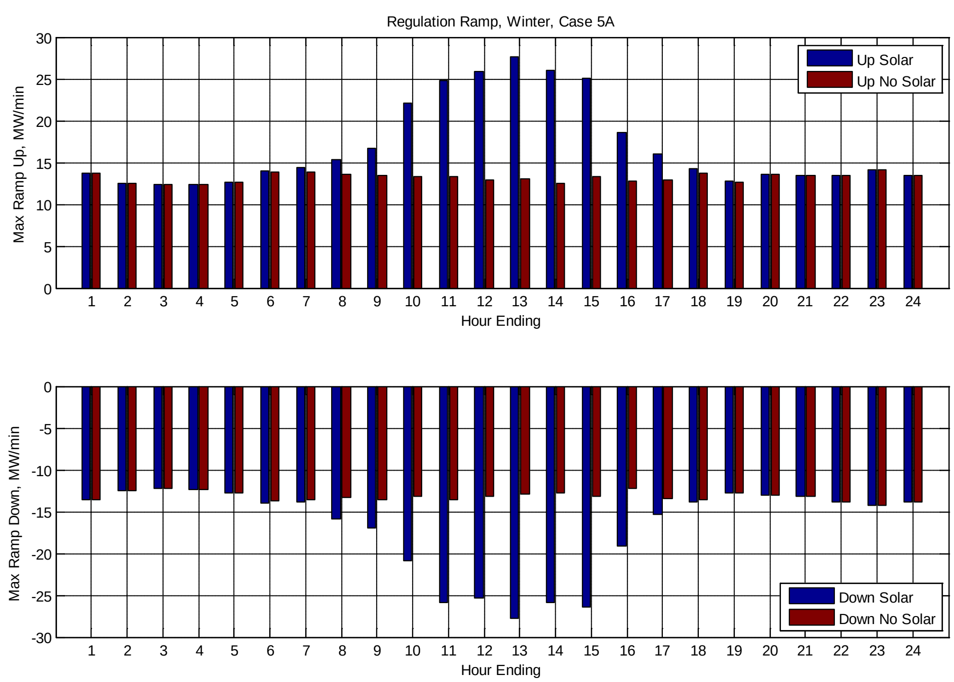


Figure 72. Load Following Capacity Requirements – Winter, Case 5A, with Forecast Errors

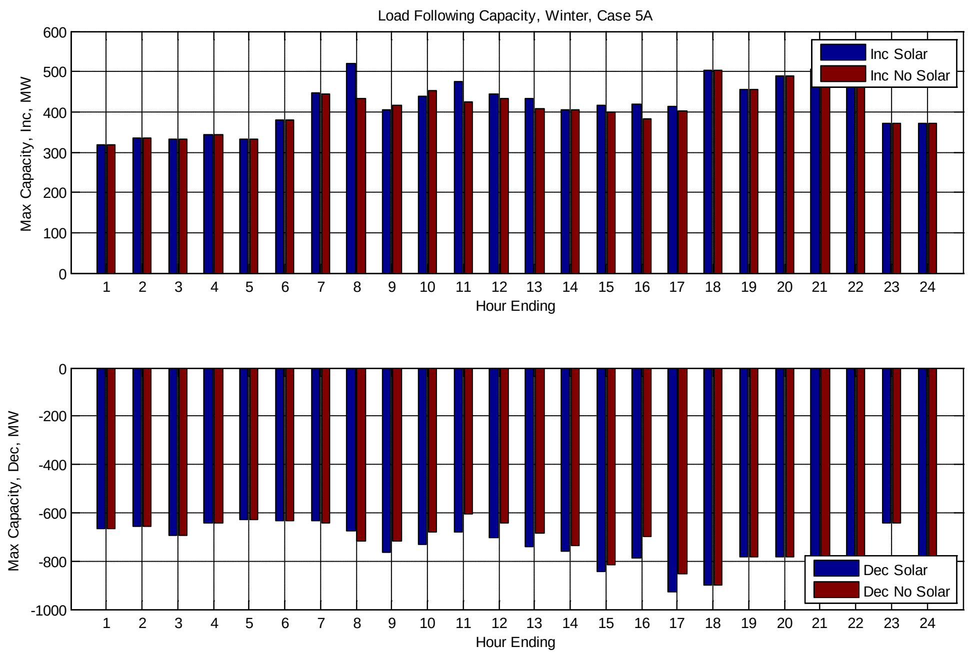


Figure 73. Load Following Capacity Requirements – Winter, Case 5A, Perfect Forecasts

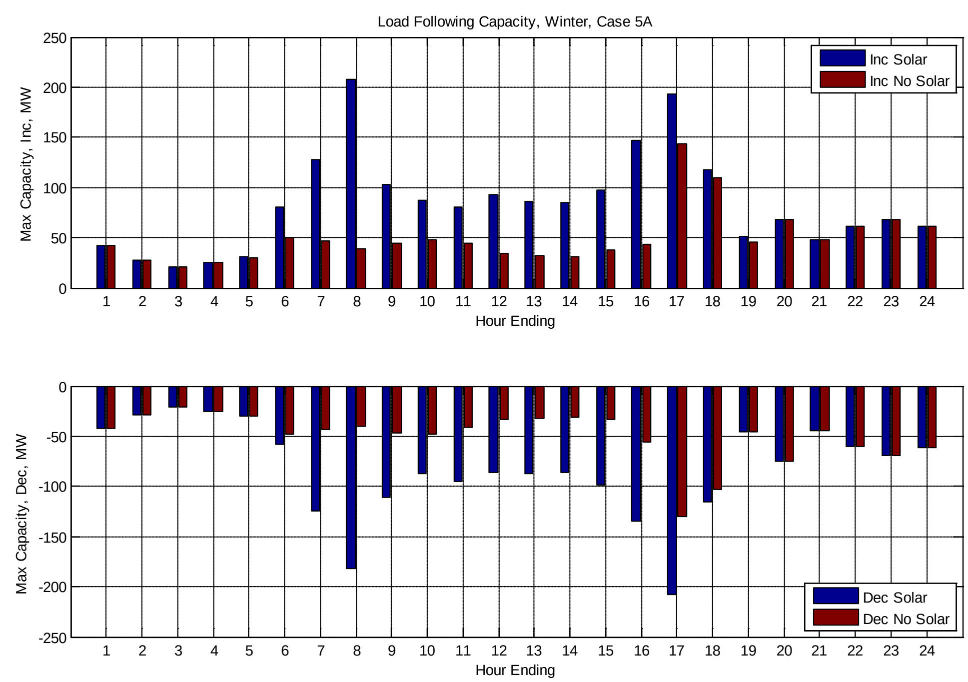


Figure 74. Load Following Ramp Requirements – Winter, Case 5A, with Forecast Errors

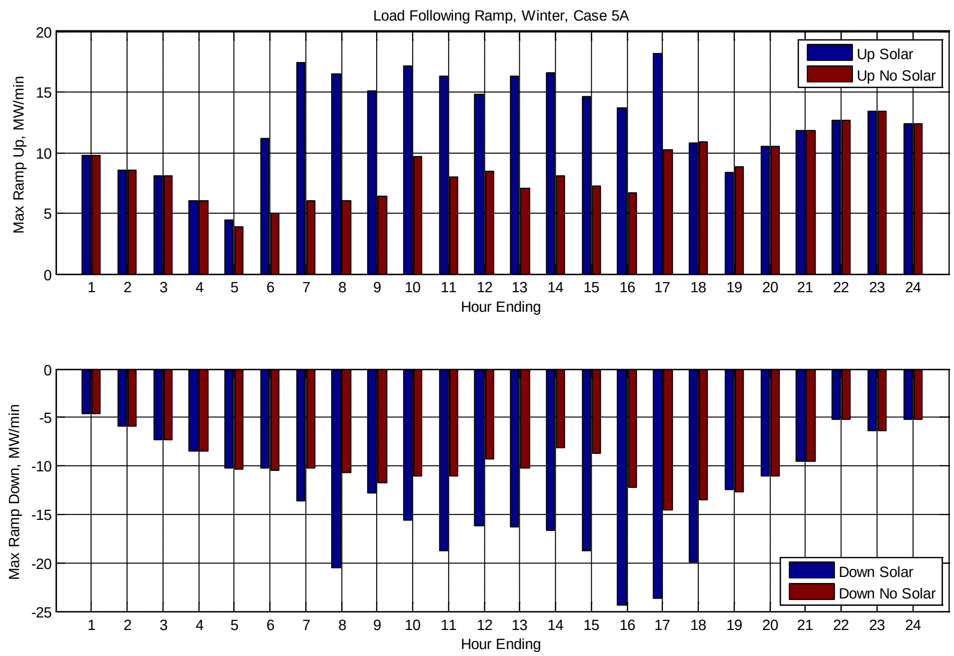
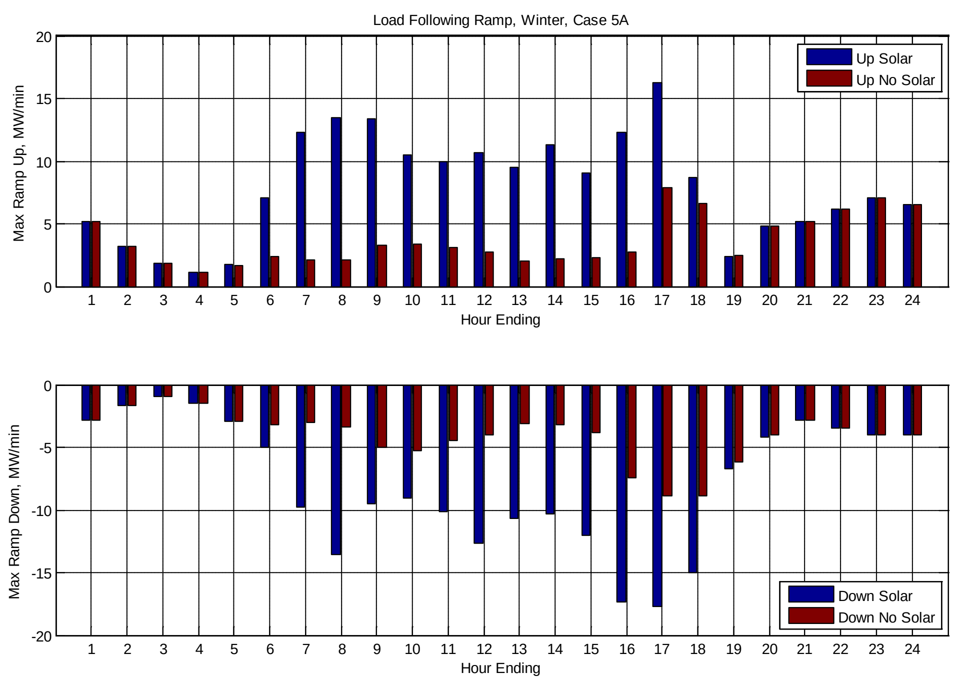


Figure 75. Load Following Ramp Requirements – Winter, Case 5A, Perfect Forecasts



The following can be observed in Figure 68 through Figure 75 for Case 5A (with 892 MW large PV and 50 MW DG):

(1) Maximum load following capacity requirements increase by 750 MW, caused by day-ahead forecast errors. The impact from solar on load following capacity requirements becomes very minimal when forecast errors are considered, because the requirements are dominated by day-ahead forecast errors.

(2) Maximum regulation capacity requirements increase by 190 MW, caused by real-time forecast errors.

(3) Maximum load following and regulation ramp rate requirements increase slightly by 6-8 MW/min compared with results with perfect forecasts.

Therefore, better forecasts will reduce to a large extent the amount of capacity requirements on regulation and load following and result in lower operating cost. However, the benefit on of improved forecasts on ramp requirements will not be as significant as capacity.

4.10 Identifying Challenging Operating Hours

To identify the challenging operating hours, the capacity of balancing reserves and ramp capability of the online generators are compared against the requirements derived from system operation processes and modeling approaches described in Section 4.3.

Evaluation of Challenging Operating Hours

In real-time operations, both regulation and load following reserve requirements should be met to ensure sufficient flexibility of the generation fleet is available to cover within hour variations of load and solar. Because regulation is to compensate for sub-minute variability, regulating reserve must be provided by AGC and be available all the time, so that it can be dispatched automatically whenever needed. In contrast, load following is to follow the slower trend over a certain period (in the NV Energy study it is assumed as 10 minutes), therefore, load following reserve can be determined from real-time forecast and deployed both manually and automatically.

Regarding regulation and load following operations, the following changes in real-time could be expected under the solar cases:

(1) If no changes were made to the current operation practice, less reserve from AGC would be available for load following purpose, resulting from increased regulation requirements. This means more operator interventions would be required to perform load following.

(2) The integration of solar generation essentially displaces energy that otherwise would be supplied by conventional generators; mostly combined cycle units in the NV Energy system. As a result, these generators either will completely shut down or operate at a lower capacity factor. Because conventional units operate at lower output levels when displaced by renewable generation, there is ample upward load following reserve capacity (through AGC and manual dispatch). At the same time, since generators are dispatched at a lower output, the room between minimum power levels and the actual operating point will be reduced, which will likely limit the downward capacity.

Despite of the above potential issues, it is shown in the balancing reserve requirements analysis that regulation requirements increase much more significantly than load following in the solar cases. The system should have no real difficulty to meet load following capacity and ramp requirements, especially if operators are provided with good day-ahead and real-time forecasts. A bigger concern of operational challenge is whether the generation fleet can follow quickly enough with the rapid changes in PV output, as identified in the regulation ramp requirements.

Based on the above discussion, challenging operating hours were identified in this study based on the following data:

- Capacity and ramp rate requirements of regulating reserves
- Available capacity and ramping capability of regulation units (units that are on AGC) at the corresponding time

To determine the capability of units to meet challenging hour requirements, the following approaches were applied:

- Dispatch data of AGC units were used to determine their base operation points in each hour
- Capacity limits, ramping capability of AGC units were used to calculate the regulation capability of the fleet

Selection of Challenging Days

Production costing models such as the PROMOD apply dispatch logic that tends to over-commit online generation. As a result, in many hours there is limited capability for generators to provide downward regulation. This contrasts the process by which NV Energy schedules generation for day-ahead operation. To obtain more realistic dispatching results, NV Energy day-ahead scheduling software (GENMAN) was used to produce the hourly generation dispatches. Two days deemed to be most challenging were selected for each season and case study. The impact of generator minimum up and down time is accurately reflected in this two-day analysis. The two days expected to create the greatest operational challenges were selected based on the following rationale.

1. The two days chosen include Sunday and the Monday, as the transition from Sunday to Monday usually causes operational challenges, even without large PV and DG.

2. For the summer season, July 7th and 8th were selected, as these were the days close to the 2007 summer peak. In the winter, November 11th and 12th were selected, among days with the lowest load peak. In the shoulder months, May 12th and 13th were selected, as each has a load peak close to the highest in the season.

Operating Reserve Requirements

According to the Western Electricity Coordinating Council (WECC), standard power systems are required to maintain the following types of reserves:[58]

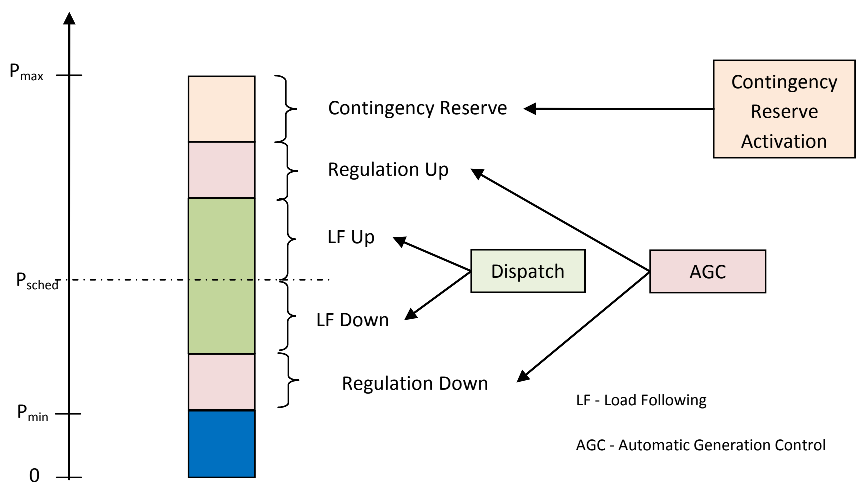
- **Operating Reserve** – is the generation capacity above the one needed to supply firm system demand that is required to provide for regulation, to balance against the load forecasting error and equipment forced and scheduled outages, and to maintain local area reliability. It consists of spinning reserve and non-spinning reserve.
- **Spinning Reserve** – Unloaded generation that is synchronized, automatically responsive to frequency deviations, and ready to serve an additional demand. It consists of regulating reserve and contingency reserve.

[58] "WECC Standard BAL-STD-002-0 – Operating Reserves." [Online.] Available: http://www.nerc.com/files/BAL-STD-002-0.pdf

- **Non-Spinning Reserve** – (1) The generating reserve, which is not connected to the system but capable of serving the demand within a specified time from its activation; and (2) Loads or exports that can be removed from the system in a specified time.
- **Regulating Reserve** – An amount of reserve responsive to automatic generation control (AGC), which is sufficient to provide normal regulating margin.
- **Contingency Reserve** – The capacity available to be deployed by a balancing authority (BA) to meet the North America Electric Reliability Corporation (NERC) and WECC contingency reserve requirements. Increasing penetration of wind and solar generation leads to growing uncertainties in the reserve requirements."

Balancing area operators typically schedule and allocate generation capacity via the unit commitment (UC) process, as illustrated in Figure 76.

Figure 76. Reserve Allocation in the Unit Commitment Process



Generation Fleet Ramping Characteristics

The unit commitment and scheduling process is accomplished recognizing generating unit limits and output capability. Each generating unit has specific (fixed) physical characteristics that determine the capability of each unit to respond to changes in system load in the up or down direction.[59]

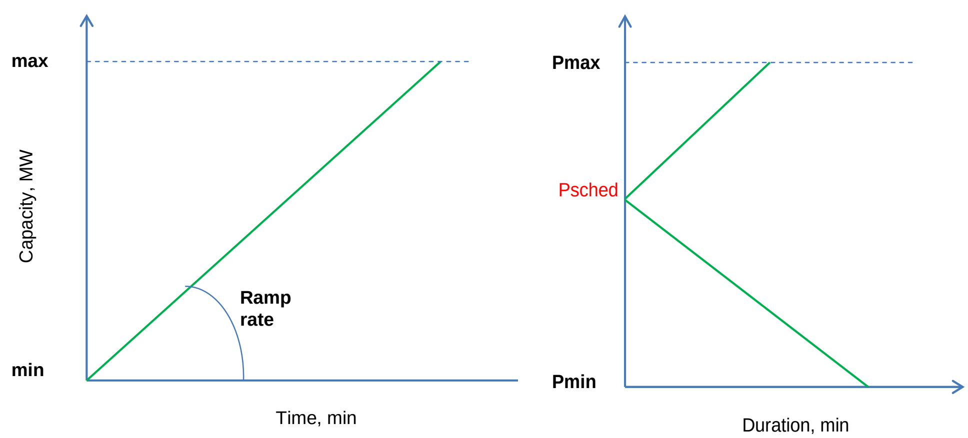
- Minimum generation – Pmin (MW)
- Maximum generation – Pmax (MW)
- Maximum ramp rate – R (MW/min)

Time-specific characteristics are:

- Scheduled operating point - Psched (MW)
- Regulation reserve (upward and downward)
- Contingency reserve – Pcont (MW)

Simplified ramping characteristic of a generation unit is shown in Figure 77. Some units can have segments with different maximum ramp rates, but for simplicity, a linear ramping characteristic appears in Figure 77.

Figure 77. Single Unit Ramping Attributes



The individual ramping capability of each unit can be combined to calculate total ramping capability of the entire generation fleet. Figure 78 illustrates the composite ramping capability of the entire generation fleet.

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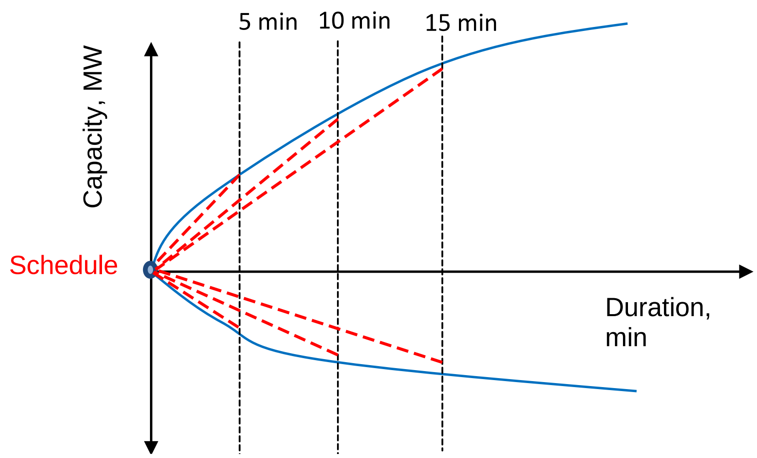
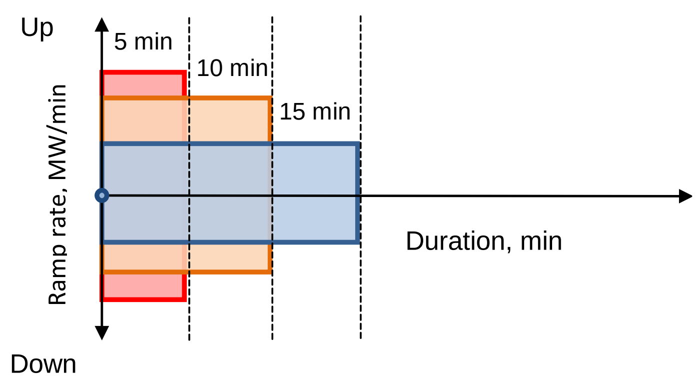
[59] Once units are committed for operation, typically on a day-ahead basis, automated systems will continually optimally adjust unit output to minimize total costs of production, including fuel and variable operating and maintenance expense. This real-time process is commonly referred to as economic dispatch (EC).

Figure 78. Calculating Generation Fleet Ramping Capability



The maximum available system ramping capability versus duration is derived from the angle of the red dotted line and time axis in Figure 78. The result is illustrated in the simplified example in Figure 79.

Figure 79. Generation Fleet Ramping Capability - Ramp Rate vs. Duration



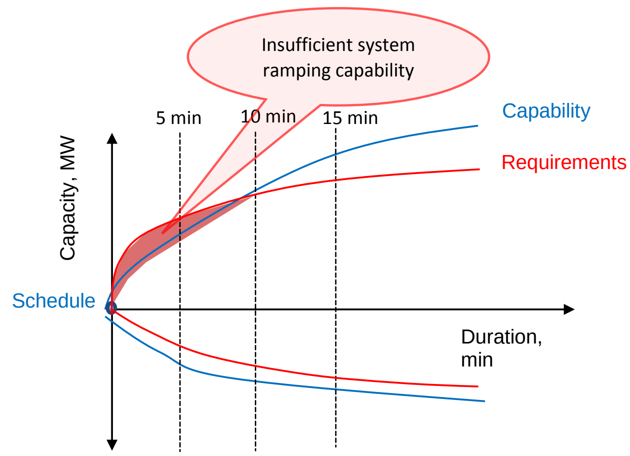
The ramping capability needed for regulation can be derived from the shape of the regulation curve, as described in Section 4.3.

Assessing Adequacy of Ramping Capability

This section compares regulation ramp requirements to the ramp capability of NV Energy's generation fleet. Insufficient ramping capability is identified when the ramp requirements exceed generation fleet ramping limits. Figure 79 illustrates how such a deficiency could occur;

the area in red highlights the magnitude and duration of the interval when regulation ramp requirements exceed fleet capability.

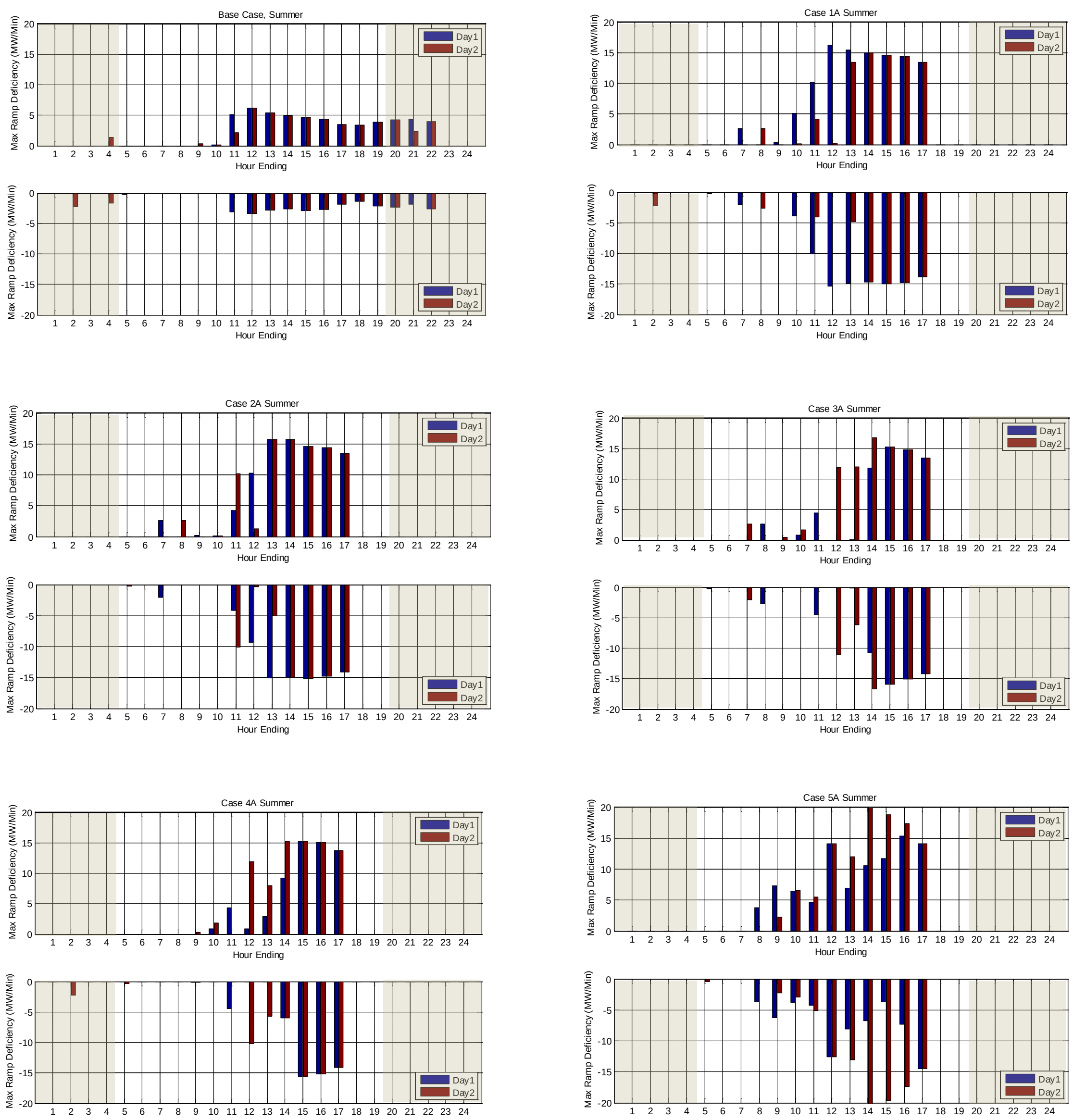
Figure 80. Ramping Requirements Versus System Capability



Ramping Capability Adequacy Results

Results of maximum ramp deficiency from the ramping analysis are presented in Figure 81. The blue and red bars are the hours in which ramping deficiency has been identified. Blue bars represent day one and red bars represent day two. The values that appear for up or down violations are the maximum for any hour – it is possible some hours have more than one violations. The shaded areas are night hours when solar power has no impact at all. The complete set of simulation results for the Base Case (no solar generation) and Case 1A to 5A are presented in Appendix D, including winter, summer, and shoulder seasons.

Figure 81. Ramp Rate Deficiencies – Summer, Base Case and Cases 1A – 5A



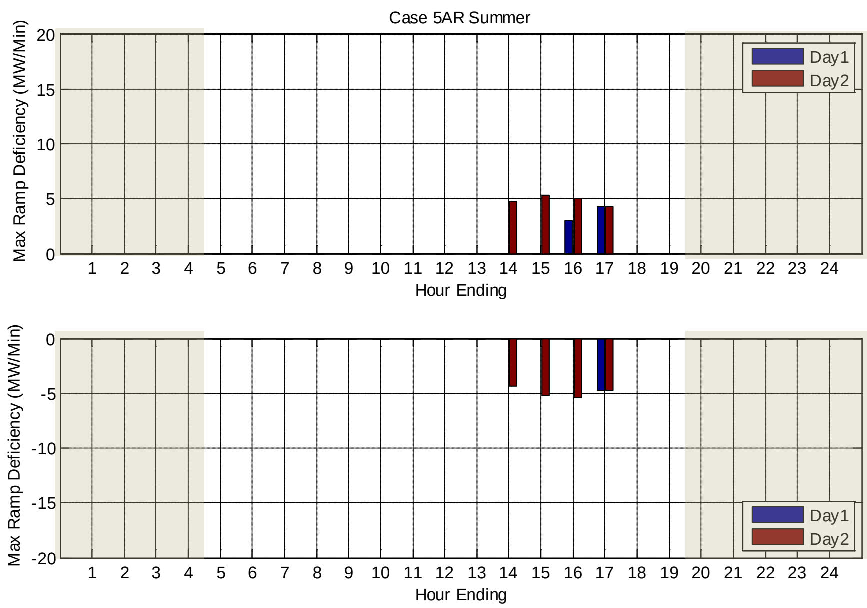
It can be observed that for Base Case maximum ramp deficiency is about +/-5MW/min. Results indicate that renewable generation capacity in Cases 1A through 4A creates a maximum ramp deficiency of +/-16 MW/min. For Case 5A, the ramp deficiency increases to 20MW/min or greater during noontime. Further, the duration of the deficiencies in Case 5A is much higher than other case study results. Nonetheless, the ramp deficiency results in the summer do not necessarily follow the same trend as regulation ramp requirements in different solar penetration cases.

After a detailed look at the GENMAN unit commitment results, it was found that the ramp deficiencies were, in many cases, caused by insufficient regulation capacity allocation on the AGC units. The regulating reserve requirements were put in the scheduling software as part of the required spinning reserves, which can be met by any online generators; therefore, the AGC units do not necessarily get sufficient allocation of the upward room needed for regulation. At the same time, downward regulation requirements are not specified in the scheduling software at all.

Generation Redispatch to Resolve Ramping Deficiency

To mitigate the above deficiencies, one of NV Energy's 50 MW combustion turbines/peaking units in the Clark Station was committed in the hours with ramping deficiency, and the combine cycle units on AGC were backed down to provide additional regulation ramping capability. The addition of a single combustion turbine was sufficient to reduce ramping deficiencies to base case levels in all solar cases. Figure 82 illustrates the drop in ramping deficiency from approximately 20 MW/min (Figure 81) to 5 MW/min for Case 5A when a single 50 MW combustion turbine is committed. Similar results were obtained for the lower PV penetration cases. The complete set of simulation results for adjusted schedule (summer, winter and shoulder seasons) can be found in Appendix E.

Figure 82. Ramp Deficiency Mitigation Result – Summer, Cases 5A



The findings of challenging operating hour analysis include the following:

(1) All ramp deficiency cases can either be reduced or removed after a peaking unit is started and AGC generators are redispatched.

(2) Ramp deficiencies were results of scheduling software incapable of precisely enforcing regulation requirements.

(3) Ramp deficiencies, therefore, do not mean the generation fleet cannot accommodate the solar power being studied.

(4) From the days checked, it shows that the NV Energy generation fleet is able to accommodate the studied solar cases, but with higher operating cost because of increased unit startups and lower efficiency.

Other mitigation options are available to address regulation ramping deficiency, including fast-response battery storage, hydroelectric storage and use of Hoover ramping capability.[60] The level of detail, modeling requirements and time needed to fully evaluate these options were

[60] NV Energy's Hoover hydro allocation currently is used as a peak shaving resource. Use of Hoover for frequency regulation would reduce the Company's ability to schedule capacity during higher cost peak hours.

outside the scope of this study. The study team proposes to evaluate these mitigation options and commitment scheduling following the completion of this study.

4.11 Generator Cycling and Movements

Background

With an increasing penetration level of solar generation in NV Energy's southern Nevada system, it is expected that the balancing requirements to compensate for solar power variability will be larger in magnitude; meanwhile, generators providing load following and regulation services may also need to move up or down more frequently. This section provides a synopsis of the generator cycling and movements analysis performed by PNNL[61]. The analysis develops two effective metrics to quantitatively evaluate the cycling and movements of conventional generators for providing balancing services, which include (1) mileage and number of direction changes in balancing service (load following and regulation); and (2) ramp (or half-cycle) analysis. The results demonstrate a significant impact of increased solar capacity on balancing service provided by conventional generator movements. Busy hours of balancing requirements are also identified for different study cases. This study provides a basis for evaluating the wear and tear of the conventional generators in the solar integration process.

Methodologies & Simulation Results

Two methods were developed to evaluate the cycling and movements of conventional generators for providing balancing services. The regulation and load following data used in the evaluation are the same as those used to perform balancing requirements analysis in Section 4.

(1) Mileage of Generator Movements for Regulation and Load Following

The first metric is to compute the total mileage travelled in MW and total number of direction changes that conventional generators need to do to balance the variable load and solar. Such computation is performed for each operating hour throughout the entire study year. In this way, busy hours that require more balancing services and movements can be observed easily. For a particular period of time like a day or a month, the required mileage and number of direction changes can be accumulated for comparison. Figure 83 compares the daily average

[61] R. Diao, S. Lu, P. Etingov, Y. V. Makarov, J. Ma and X. Guo. "NV Energy Solar Integration Study: Cycling and Movements of Conventional Generators for Balancing Services", PNNL-20594, Pacific Northwest National Laboratory, Richland, WA, July 2011.

mileages and direction changes required for regulation in each operating hour, for Base Case (no solar PV) and Case 5A (892 MW of large PV and 50 MW of DG). Considering that generators do not need to move when load/generation mismatch is less than a certain threshold, regulation ramps with magnitudes less than 20 MW were not counted. Busy hours including morning peak, afternoon peak and midnight peak with more frequent and larger generator movements can be identified. A significant increase in mileage of regulation from 8:00 am to 5:00 pm is observed for Case 5A, consistent with the daylight period when PV has power output.

Figure 84 depicts the trend of the yearly-accumulated regulation mileages and number of direction changes with respect to installed large-scale PV capacity. Linear curve fitting using least square method is used to approximate the simulated points in each trend plot. The slope of the fitted linear curve can provide important information regarding additional wear and tear cost caused by increased capacity of large-scale PV. For example, an increase of 1 MW in PV installed capacity can approximately cause 7.9 more direction changes and 170 MW of mileage increase (both up and down) in regulation process throughout the year. It is clearly shown that more PV generation will cause more regulation mileages and direction changes, indicating that conventional generators need to move more frequently to balance the variable resources.

Figure 83. Daily Average of Mileage and Direction Changes for Regulation - Base Case and Case 5A

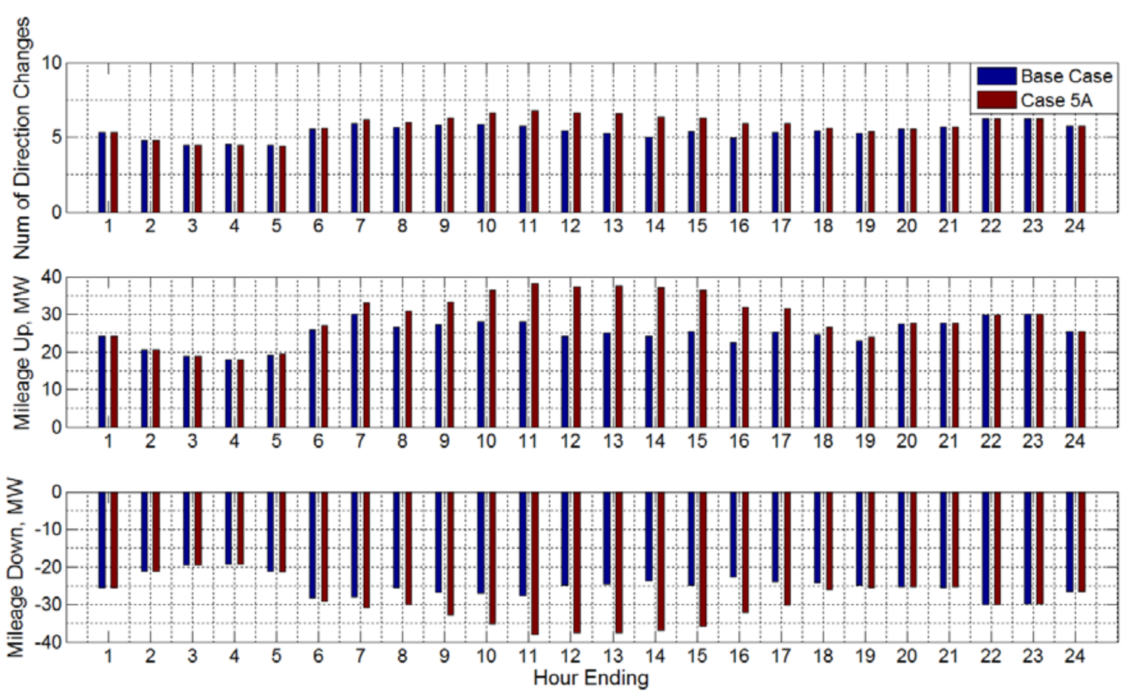
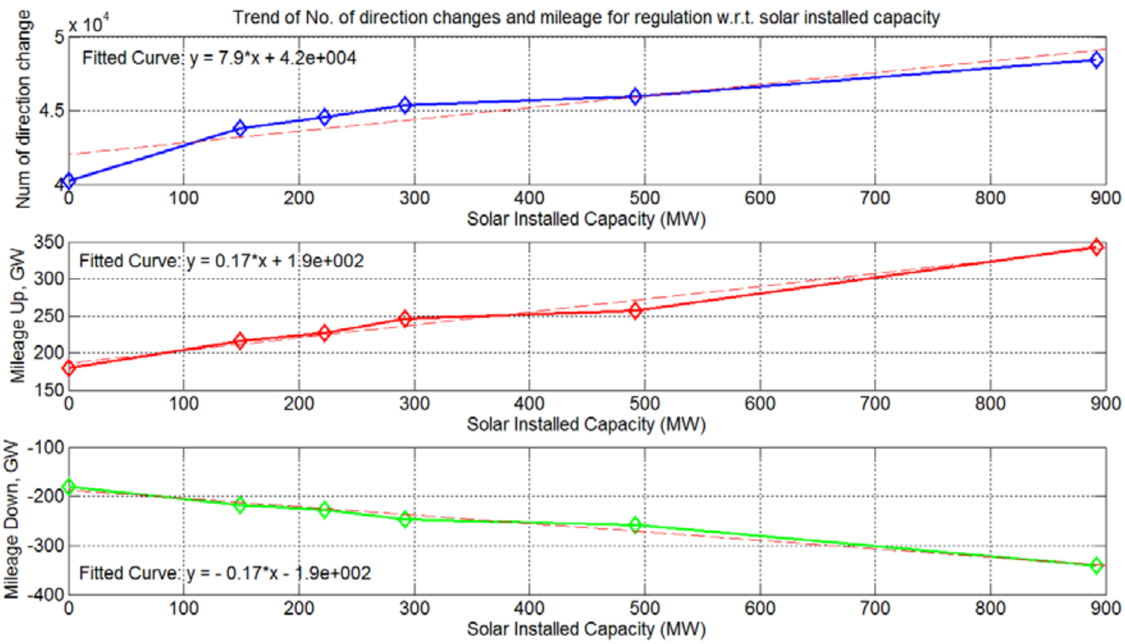


Figure 84. Trend of Yearly Regulation Direction Changes and Mileage - Base Case, Case 1A - 5A



(2) Balancing Service Ramp Statistics

The second metric adopts the idea of half-cycle analysis, which can be used to evaluate and compare balancing requirements for different scenarios. After identifying the turning points (indicating direction changes) in load following or regulation curve, the magnitude between two adjacent turning points along the magnitude axis is defined as half-cycle magnitude (+/-). The distance between the two turning points along the time axis is the duration of each half-cycle. Half-cycle ramp rate is then calculated as the ratio between half-cycle magnitude and half-cycle duration. A three-dimensional histogram with respect to duration and ramp rate can be generated for comparison to evaluate how many times a ramp with certain ramp rate and duration occurs throughout a year. Table 8 and Table 9 compare the regulation half-cycle occurring frequency for Base Case and Case 5A. As can be observed in Table 9, more solar generation can cause higher frequency of regulation movements.

Table 8. Regulation Half-cycle Analysis for Base Case

(No color: 0 cases; Green: 1~9 cases; Yellow: 10~99 cases; Orange: 100~999 cases; Red: >1000 cases)

Regulation half-cycle duration in minutes	Regulation half-cycle ramp rate in MW/min																	
0	-45	-40	-35	-30	-25	-20	-15	-10	-5	5	10	15	20	25	30	35	40	45
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	1	2	8	352	2261	2217	370	4	3	0	1	1	2	0
3	0	0	0	0	0	1	1	19	1331	1348	15	1	1	0	0	0	0	1
4	0	0	0	0	0	0	0	4	815	743	5	2	1	1	0	0	0	0
5	0	0	0	0	0	0	0	2	400	409	2	0	1	0	0	0	0	0
6	0	0	0	0	0	0	0	0	223	188	1	0	0	0	0	0	0	0
7	0	0	0	0	0	1	0	0	74	86	1	1	0	0	0	0	0	0
8	0	0	0	0	0	0	0	2	39	41	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	20	31	1	0	0	0	0	0	0	0
>=10	0	0	0	0	0	0	0	0	27	27	0	0	0	0	0	0	0	0

Table 9. Regulation Half-cycle Analysis for Case 5A

(No color: 0 cases; Green: 1~9 cases; Yellow: 10~99 cases; Orange: 100~999 cases; Red: >1000 cases)

Regulation half-cycle duration in minutes	Regulation half-cycle ramp rate in MW/min																	
0	-45	-40	-35	-30	-25	-20	-15	-10	-5	5	10	15	20	25	30	35	40	45
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	2	1	1	6	8	38	579	2466	2422	608	31	9	2	1	4	2	1
3	0	2	1	0	6	16	46	212	1693	1747	207	51	13	5	2	3	3	3
4	1	1	1	4	7	16	37	148	1186	1137	170	27	22	8	1	2	1	1
5	0	0	0	4	4	19	26	108	867	855	107	32	22	8	5	0	0	0
6	0	0	0	4	5	10	31	79	566	556	78	22	11	7	2	1	0	0
7	0	0	0	0	2	6	16	54	385	345	60	20	7	2	0	0	0	0
8	0	0	0	1	1	3	12	37	272	279	48	10	4	1	1	0	0	0
9	0	0	0	0	0	3	8	25	189	201	31	5	3	0	0	0	0	0
>=10	0	0	0	0	1	1	8	35	470	447	29	4	0	0	0	0	0	0

5 System Impacts and Integration Costs

5.1 Overview

The balancing area analysis in Section 4 evaluated the capability of NV Energy's generation in southern Nevada to accommodate increasing amounts of PV and DG. Results of the analysis determined that additional generation reserves are needed to meet higher regulation and load following requirements caused by integration of variable PV and DG output. It included a determination as to whether existing generation resources could meet higher reserves requirements within the existing unit operating and loading limits, and whether mitigation is needed to avoid potential violations of generation operating limits.

In this section, the results of the balancing area studies are used to determine the additional production cost, including fuel and other operating costs, for each of the ten case studies. It includes the cost of mitigation when the existing system in southern Nevada is unable to accommodate additional PV and DG.

5.2 Methodology

The results of the Section 3 PV and DG output profile analysis and Section 4 balancing area studies are required to predict changes in production costs for increasing amounts of PV and DG. The hourly PV and DG profiles prepared by SNL – hourly profiles are derived by summing the 60 minute-by-minute output – are used to identify hourly decreases in load in the production simulation database. In the simulation model, PV and DG are represented as load modifiers, where net loads equal native load minus hourly load modifiers.

Input from the Section 4 balancing area studies are used in the production simulation studies to determine how energy costs vary as a function of increasing PV and DG penetration. Section 4 results indicate variable PV and DG output can increase regulation while longer term ramping (up and down) increase the amount of generation that must be committed to follow load within generation operating limits. The net change in generation unit operating profiles and costs can be derived by comparing base case production cost results (PV and DG is excluded from the base case) to those completed for each of the ten case studies.

The following lists key generating output parameters that may be impacted by increases in large PV and DG and those which will cause production costs to vary:

- Number of units committed to meet load and operating reserves
- Unit capacity factor
- Number of starts per unit
- Average unit heat rate
- Amount of "dump" or excess energy

Each of these parameters can increase (or decrease) production costs in several ways. As the number of generating units committed increases due to higher operating reserves needed for regulation or load following, units tend to operate at less efficient heat rates. The number of starts may also increase since unit output cannot drop below minimum levels.

The process employed to determine how these parameters changed for each case study is outlined below:

- Conduct PROMOD production cost studies for the base case using 2011 generation data, including modeling generation operating constraints (e.g. minimum capacity, minimum and maximum runs times, ramp rates)
- Calculate change in production costs for each PV/DG case compared to a base case (base case includes existing NV Energy generation mix and actual 2007 loads, but excludes all PV and DG)
- Identify increase in operating reserves needed for regulation, load following, and solar forecast error
- Update case studies with measures and options needed to mitigate the impact of intermittency and thermal generation displaced by PV/DG output
    - Mostly combined cycle generation is displaced by PV/DG output
    - Operating reserves are increased to meet additional regulation and load following: PV/DG integration costs (combined cycle generation)

5.3 Assumptions

Navigant's derivation of PV and DG impacts include only those categories that impact NV Energy's costs; non-quantifiable or third-party impacts are excluded. Further, all cost and benefits are derived incrementally; that is, fuel, emissions and other costs and benefits are derived by assuming PV and DG impacts based on incremental as opposed to average costs.

The analysis does not examine the costs and benefits of DG ownership from the customer perspective, nor does it compare the relative economics of competing PV and DG technologies.

The following assumptions were used in the production simulation runs, both for the base case model and combined PV/DG scenarios:

- A modified version of NV Energy's 2011 Mid-Carbon Case is used as the base case.
- Model data is based on current inputs (mostly 2011 data) except for hourly loads, where 2007 hourly data is used to align with 2007 PV and DG hourly output profiles.
- Resource supply is based on 2011 generation mix and fuel price estimates.
- The production simulation model (PROMOD) is run as a two-company model; NPC and SPPC. Each company is connected to an external market (SPPC is connected to California-Oregon Border and NPC is connected to the Mead hub). However, ON-Line is not present in the model preventing energy interchange between SPPC and NPC. Thus, only results for the NV Energy's southern Nevada service territory were investigated.
- Off-system purchases are allowed but external sales are precluded.[62]

5.4 Base Case Costs

Base case production costs reflect those of a hypothetical system, one which includes a 2011 resource mix and 2007 loads. The NV Energy system experienced its all-time peak in 2007, as hot weather combined with a more favourable economic climate to cause electricity consumption to be robust, particularly during the summer peak. Since 2007, NV Energy's resource mix has changed and now includes Harry Allen combined cycle unit among other changes. Hence, results derived for the hypothetical 2007 system should not be construed as an accurate comparison or reconciliation of actual 2007 energy costs. Further, 2007 base case energy costs reflect those of the NPC territory – SPPC service territory loads and generation resources are excluded from the production simulation analysis. For the base case model, total energy costs are approximately $1.04 billion, which is comparable to NV Energy 2011 production costs for current loads.

[62] External purchases are an important input to the production simulation model, as several resources, including NV Energy's Hoover allocation, are located outside of the Company's balancing area, and therefore are modeled as external purchases. Up to 1700 MW of NV Energy's resources are classified as external purchases in the model.

5.5 Scenario Analysis

Production simulation analyses were completed for each of the ten penetration scenarios and compared to base case results. It is misleading to compare the *total* production costs for each case, as total production costs decline as PV and DG penetration levels increase. However, generating unit performance and output data for each case provide important insights on generating unit behaviour, including the potential for generators to operate less efficiently as they adjust output levels to meet higher reserve requirements. The following sections present key results obtained from the production simulation analysis for the case study scenarios

Combined Cycle Unit Performance

NV Energy's fleet of large combined cycle units is used during most hours to provide regulation and follow load.[63] These units also provide a substantial amount of contingency reserve required by NERC standards. The characteristics and operating parameters for NV Energy's combined cycle units located in its southern balancing area are listed in Table 10.

Table 10. Combined Cycle Unit Data

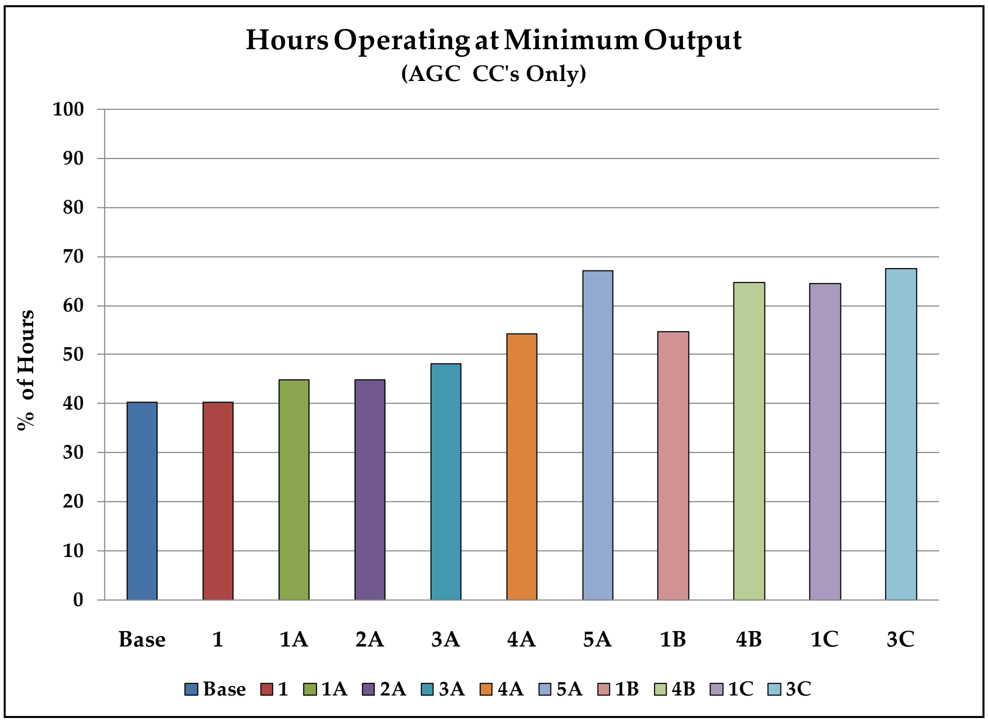
Plant Name	Unit Number	Minimum Capacity	Maximum Capacity	Regulation Cap Range	Reg Response Time	Reg Range Up/Down
		MW	MW	MW	MW/min	MW/Hour
Harry Allen_1x1	1	100	240	150-225	4	240
Harry Allen_2x1	1	271	524	330-460	4	240
Lenzie 1_1x1	1	100	240	150-225	4	240
Lenzie 1_2x1	1	300	601	330-460	4	240
Lenzie 2_1x1	2	150	226	150-225	6	360
Lenzie 2_2x1	2	300	601	330-460	6	360
Higgins_1x1	1	100	240	150-225	4	240
Higgins_2x1	1	320	599	330-460	4	240
Silverhawk_1x1	1	320	240	150-225	5	240
Silverhawk_2x1	1	320	599	330-460	5	240

Comparing the percentage of hours NV Energy's combined cycle generating units are on-line against the percentage of hours these units are operating at minimum load provides an indication of unit operating efficiency. It also suggests whether a unit will be able to serve

[63] Note that NV Energy's allocation of Hoover does not provide regulating reserves, as it is used predominantly for peak shaving.

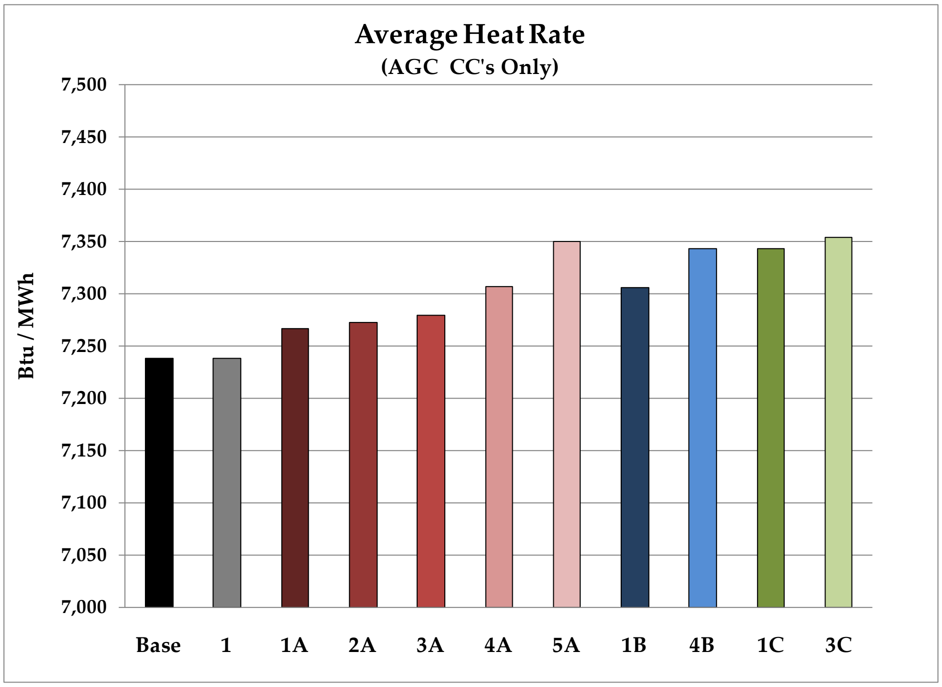
increasing amounts of variable load, particularly for down ramping when units are operating at minimum load. Figure 85 presents the on-line hours, and the hours units operate at minimum load for all large combined cycle units. The high percentage of hours in which combined cycle generation operates at minimum load – over 50 percent for the higher penetration cases – confirm the premise that units have limited down ramping capability. Figure 85 implies a decline in unit efficiency for combined cycle generation, as heat rates are higher when units operate at minimum load levels.

Figure 85. Combined Cycle Performance



The impact of operating thermal generation at or near minimum operating limits is a corresponding increase in heat rate. Figure 86 illustrates the level at which composite heat rates for NV Energy's combined cycle generating fleet increase for PV and DG output levels from 149 MW to 1042 MW. The units included in the chart are those which provide regulating and load following capability and which are dispatched via automated generation control (AGC). The increase in unit heat rates is due to energy displacement from PV and DG output coupled with the increase operating reserve requirements, which cause a greater number of combined cycle units to be scheduled in NV Energy's day-ahead unit commitment process.

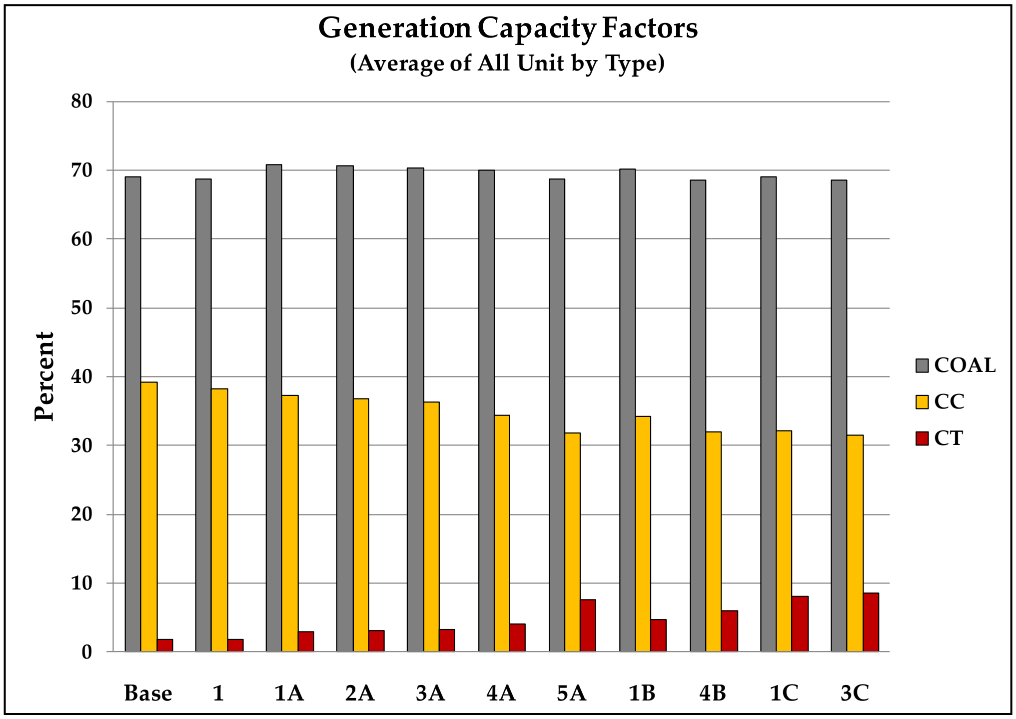
Figure 86. Combined Cycle Heat Rates



Section 4 results indicate that about 1 MW of additional thermal generating capacity must be reserved and on line for each 35 MW of variable renewable capacity that is installed in NV Energy's southern Nevada balancing area. These additional reserves cause combined cycle units to collectively operate at lower capacity factors. Further, as the amount of PV and DG capacity increases, the higher operating reserves and energy displacement causes combustion turbines to operate at higher capacity factors.

Figure 87 presents the composite capacity factor for NV Energy's generation by type: the three major generators by type include base load coal, regulating combined cycle and combustion turbine peaking units. Notably, coal-fired generation operates at nearly a constant capacity factor, as most coal generation that supplies NV Energy's southern Nevada balancing area is from the Navajo plant. The remaining generation is mostly must-take generation from Qualifying Facilities, which also is must-take. Hence, virtually all generation impacts caused by integration of PV and DG are from combined cycle and combustion turbine generating capacity.

Figure 87. Generation Capacity Factors



PV Energy Curtailment

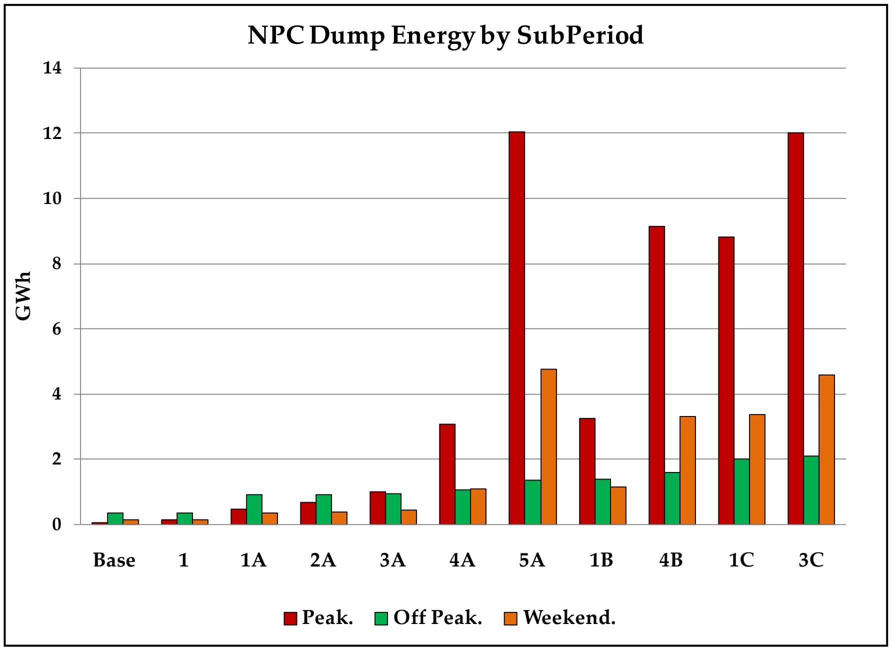
Large volumes of variable resources are expected to force thermal units to reach their operating threshold; that is, at minimum and maximum output limits, and maximum ramping capability. Because generation cannot these limits, the energy must either be "dumped" or PV output curtailed. Figure 88 presents the amount of dump energy associated with each of the case studies.

Figure 88 yields several key observations, including:

- External sales are constrained in the model, causing dump energy to increase modestly for high PV/DG penetration scenarios (up to 18 GWh), and
- Higher levels of dump energy indicate that combined cycle units are operating at minimum capacity levels but above minimum system load, as units cannot operate below minimum capacity levels

- Much of the dump energy occurs during winter months, when loads are lower and fewer units are on-line to meet load and reserve requirements

Figure 88. Dump Energy



As noted, the system within NV energy's balancing area is unable to dump energy because it cannot "violate" unit operating limits. Further, there is no certainty that this excess energy could be sold to entities outside the Company's balancing area. Thus, all dump energy is deemed to be energy that must be curtailed by restricting PV output during those hours when dump energy conditions exist. Notably, the amount of PV energy curtailment is small – less than 1 percent of total PV energy output for Case 5. Greater curtailment may be required, as it may be difficult for NV Energy operators to predict exactly the hours when curtailment may be required. Hence, a greater number of curtailment hours and energy may occur, particularly for the higher penetration cases.

5.6 Cost of Higher Operating Reserves

Estimating the incremental cost of renewable PV and DG is a challenge due to the manner in which output is represented in production simulation models. All DG and PV output is included as load modifier inputs in the production simulation model. Increasing levels of PV and DG will cause *total* production costs to decline, as these units do not consume fuel or otherwise increase energy costs. Thus, indirect methods are needed to determine how production costs are impacted by renewable, variable generation. One approach is to identify changes in incremental costs as net loads decline. The difference in marginal costs[64] between the base case and PV/DG scenarios provides insight as to how total costs vary between the cases. However, marginal costs provide only a snapshot of changes in incremental costs between the base case and PV scenarios, and do not properly account for changes in resource mix and fuel costs caused by PV and DG energy displacement. An alternate approach is to increase native load (i.e. NPC area load) by an amount equal to the combined PV and DG output and compare production costs between the two cases.

The approach evaluated and applied in this study identifies how production costs vary as a function of increases in operating reserves derived in Section 4 for increasing levels of PV and DG. This approach is deemed appropriate as the primary impact of variable PV and DG is that an increase in operating reserves is required to meet increases in regulation, load following, and PV forecast error. If a consistent relationship emerges between increases in operating reserves versus cost for all cases, then the formula can be applied for all PV or DG penetration scenarios.

Production cost study results presented in the prior section indicate the primary impact of higher operating reserves is an increase in the heat rate of thermal generation used for regulation and load following. Figure 89 confirms that higher operating reserves causes the operating efficiency of NV Energy's regulating capacity to decline, as measured by heat rate, relative to the amount of PV and DG capacity installed.[65] Virtually all regulating capacity is provided by combined cycle units and to a lesser degree, combustion turbines. The increase in the composite heat rate of regulating units is due to combined cycle generation operating at reduced capacity factor and the increasingly greater use of combustion turbine generation as PV and DG capacity increases; combustion turbines operate at a much higher heat rate than combined cycle generation. Both combined cycle generation and combustion turbines use natural gas as a fuel source, so the cost of regulating generation increases as a function of heat rate. Capacity factor for coal-fired generation is nearly constant among cases and does not measurably impact the composite system heat rate. At the highest PV and DG penetration levels (1042 MW), the composite system heat rate for regulating generation capacity degrades by about five percent compared to the base case when PV & DG capacity is zero.

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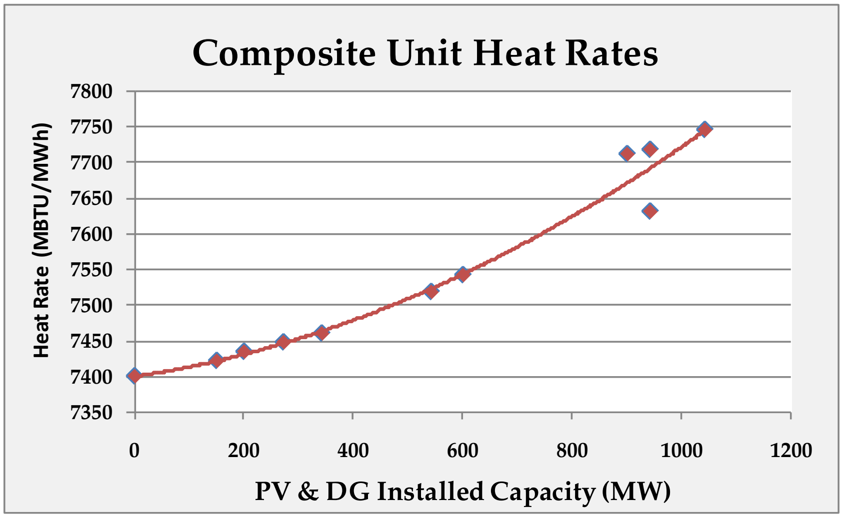
[64] Incremental and marginal costs are used interchangeably.

[65] Generation heat rate is a measure of how much fuel is consumed to produce a unit of energy, typically in kWh or MWh. A higher heat rate means that more fuel, measured in British Thermal Units or BTUs, is needed to produce the same amount of energy as compared to a generating unit with a lower heat rate.

Figure 89. Composite Heat Rate (Regulating Capacity)



5.7 Integration Costs

The impacts of integrating solar power resources on power system operations include: (1) variability and uncertainty of solar power output, and (2) displacement of energy production from conventional generation. The first causes an increase in balancing capacity and ramp rate requirements. Increasing generation reserves to meet these requirements reduces generation efficiency. Also, the increased number of cycles for meeting solar variability causes wear and tear on the conventional units. Both contribute to the cost of renewable resource integration. Displacement of energy also reduces generation capacity factor and efficiency, and more start-ups. This efficiency impact is reflected in the increase in overall heat rate. The efficiency impact is reflected in the increase in overall heat rate of conventional generation fleet. More start-ups will lead to accelerated maintenance. Therefore, the fuel cost increases to serve the same amount of energy required by net load in the solar scenarios. The additional fuel cost and the increased maintenance cost are the two major components in the solar integration cost.

Section 4 results identified the additional regulation reserves needed to meet higher regulation requirements, and provides information needed to the production cost model to estimate changes in production cost. Results of the production cost analysis indicates the heat rate of regulating units used for operating reserves increases by up to five percent above the base case. The higher heat rates cause the cost of fuel to operate these units to increase at a rate commensurate with the increase in unit heat rates.

In extreme cases, on-line generators are dispatched at their minimum level and do not have room to move downward. Curtailment on solar output may become the most economical solution, if the excessive energy cannot be sold to other entities. The cost of PV curtailment should therefore be considered as a third part of the integration cost.

The mitigation approach to address system ramping deficiencies is the fourth component in the integration cost.

Accordingly, total integration cost for NV Energy's service territory is derived via the following formula:

Integration Cost = *Incremental Fuel Cost for Energy Displacement from PV Output & Higher Reserves*
+ Generation Unit O&M (Wear and Tear)
+ PV Energy Curtailment
+ Mitigation (Ramping Deficiencies)

where,

$$Fuel\ Cost = \left(\sum_{i=0}^{n} \Delta\ Heat\ Rate\ of\ AGC\ Units(i) * Ave\ Cost\ of\ AGC\ Units(i) \right) / Energy(PV + DG)(i)$$

and

$$Mitigation = \left(\sum_{i=0}^{n} (Ave\ Cost\ of\ MRCT\ Units(i) - Ave\ Cost\ of\ CC\ Units(i)) \right) / Energy(PV + DG)(i) + \sum_{i=0}^{n} PM\ of\ CT\ Units(i)) / Energy(PV + DG)(i) + Accelerated\ Maintenance\ (CT)$$

i = *Case 1 . . . Case 10*

where,

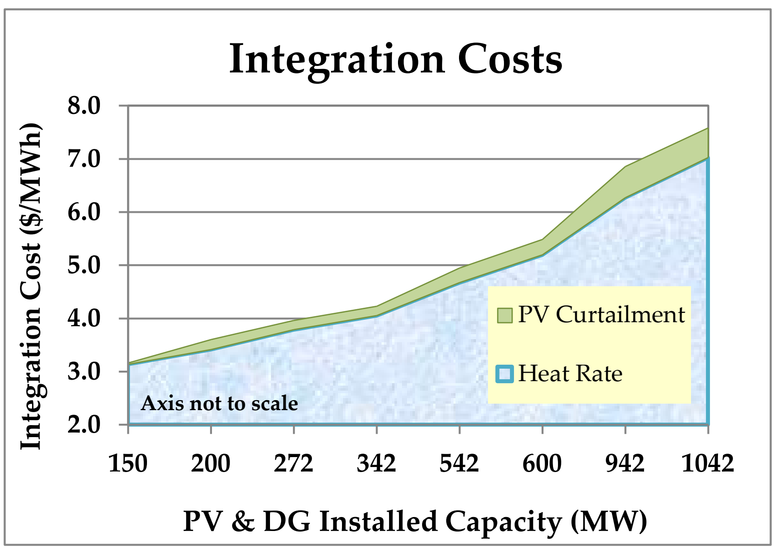
Incremental Fuel Cost = Additional fuel for drop in unit efficiency and increased CC & CT starts to serve the same amount of energy as required by net load
CC = Combined cycle generating units
AGC = Generating units on automatic generation control (i.e., combined cycle units)
CT = Combustion turbine generating units
MRCT = Must run combustion turbine units (to meet ramping deficiencies)
PV Energy Curtailment = Amount of energy exceeding thermal generation limits
Generation Unit O&M = Incremental O&M for higher cycling (value not derived)
PM = Cost of accelerated scheduled maintenance of CT used for ramping deficiencies
Ave Cost = Expressed in $/MWh
Energy(PV + DG) = Total energy produced by PV and DG
Accelerated Maintenance = Advancing scheduled overhaul of CT due to run hours

Fuel cost in the above expression includes fuel burned for additional unit starts due to variable renewable output.

Cost of Higher Operating Reserves and PV Curtailment

Figure 90 presents the incremental production costs – i.e. integration costs – for cases evaluated in this study. Integration costs caused by increasing operating reserves and modest curtailment of PV output range from a low of $3/MWh for low renewable penetration to a high of just under $8/MWh for the higher penetration cases. The curtailment of PV output is required during hours when on line generation is operating and minimum levels, and system load net of PV is below the collective output of NV Energy's on-line generation. During these hours, the Company would be required to curtail PV output unless the power could be otherwise sold to entities outside the Company's balancing area.

Figure 90. Integration Costs



Mitigation Cost for Ramping Deficiencies

The cost of operating combustion turbines to meet increased regulation ramping deficiency requirements and additional maintenance adds approximately $3 to $5/MWh. These costs include approximately $2 to $6 million annually for must running combustion turbines to address regulating capacity deficiencies, and $0.8 million for accelerated maintenance of these units. However, the level of detail in both the data and methods applied – a minute-by-minute simulation of the balancing area for the entire year is needed to accurately predict deficiency impacts and costs – are based on the additional cost incurred to commit and must-run a 50 MW gas turbine on days when ramping deficiencies occur, plus the additional maintenance associated with the higher number of operating hours. Accordingly, the additional costs for regulation ramping are preliminary and will be updated following the completion of this report, when more sophisticated tools that were not available at the time of study become available.[66]

5.8 Operations and Maintenance

The production costing analyses conducted for the case studies indicate that NV Energy's generation mix will be adversely affected by the integration of renewable resources. These impacts include a larger number of starts and shut downs, an increase in ramping (up and down), and higher operations at minimum load levels when compared to the base case. The production costing studies confirm that a higher level of operating reserves is needed to meet increased regulation and load following, resulting in higher production costs for energy produced.

The production simulation runs do not include the cost of the increased wear and tear caused by thermal and other physical stresses on the plant's mechanical systems. In particular, the thermal stresses associated with increased up and down ramping of generation, mostly combined cycle units, will result in additional maintenance. After extensive and continued operation in this mode, some plant components may need to be replaced, thereby incurring potentially high capital investments. Other indirect costs include the higher cost of replacement energy when units are shut down for maintenance or replacement of capital equipment.

Only a limited amount of data is available showing the relationship between increased wear and tear and cost of accelerated maintenance or capital replacement. At this time, NV Energy does not have data that can rigorously support a methodology to determine these costs. Notably, the O & M impact of renewable generation is being studied as part of the ongoing NREL Western Wind and Solar Integration Study – Phase 2 that is scheduled for completion in 2012.[67] When completed, NV Energy proposes to re-evaluate the relationship between the shift

[66] Building upon the results of this study, NV Energy will apply PNNL's Resource Integration Model (RIM), currently under development, to perform the minute-by-minute simulation analyses.

[67] NV Energy is participating in this study, which includes a substantial portion of Nevada as an area with significant potential for variable wind and solar. A key objective in the Phase 2 study is to predict how increasing cycling and ramping of fossil generation

in generating operating modes caused by variable renewables and the resulting O & M cost impact. These additional costs, where applicable, would be added to any other integration costs presented in this report.

5.9 Mitigation Options

DG costs include those needed for distribution system integration. These costs exclude those related to transmission impacts or increases to generation fuel costs due to changes in unit commitment, economic dispatch schedules, or additional wear and tear on generation caused by a higher amount of ramping and load following for higher DG penetration.

Three mitigation options deemed to be the most cost-effective choices were evaluated. Each is described below:

1. **Cycle or Back Down Base Load Generation:** This option assumes generation that normally operates in a base load mode of operation – that is, is not scheduled to ramp up or down in response to rapid changes in load or PV output – is allowed to operate at lower levels to avoid violating balancing area regulation rules, such as dumping energy to adjacent balancing areas when on-line generation is operating at minimum output limits. In exchange, other higher cost generation may operate due to the slow response rates of base load generation to changes in load. Typically, base load generation is coal-fired units costing approximately $25/MWh on average. The replacement power resulting from the avoidance of dumping energy may cost up to $100/MWh (or higher).

2. **Schedule Simple Cycle Gas Turbines:** This option assumes simple cycle gas turbines[68] that normally are not committed in day-ahead schedules is dispatched in order to avoid violating balancing area regulation rules; again, due to dumping energy when on-line generation is operating at minimum limits. This is the mitigation option used to address regulation ramping deficiencies in Section 4.

3. **Install Fast-Response Energy Storage Systems**: This option includes the installation of fast-response energy storage systems, capable of responding to rapid changes in load of PV output (regulation) or to provide short-term load following support; that is, one hour

[68] NV Energy owns and operates twelve 50 MW gas turbines in its NPC balancing area. These units typically are not committed to operate in day-ahead schedules except for emergencies, when other generation is off line or when loads are very high.

at full rating of energy storage device. The cost of this option includes the costs of the energy storage device, interconnection to NV Energy's delivery system, and operating costs. Currently, the cost of flywheel technology with 15-minute storage capacity is approximately $2000/MW. If 25 MW of regulating capacity were needed to mitigate ramping deficiencies, the total cost would be $50 million plus site cost and transmission interconnection facilities.

4. **Use Hoover Hydroelectric Allocation as a Regulating Resource:** NV Energy's Hoover hydroelectric allocation currently is used as a peak shaving resource. Several years earlier, Hoover was operated as a regulating resource, but now is scheduled at fixed output during peak hours to maximize economic value. The Hoover allocation likely would provide sufficient regulating capability for regulation, but reduce the Company's ability to schedule capacity during higher cost peak hours.

In addition to the above, improved PV forecasting and unit commitment scheduling methods may reduce operating reserve requirements or help mitigate ramping deficiencies. The Company proposes to evaluate these options, and the mitigation options listed above, following the completion of this study.

6 Conclusions

Based on the results of the technical and economic analyses of renewable PV and DG case studies presented herein, Navigant offers the following findings and conclusions.

6.1 Summary Assessment

The study team determined that integration of DG and large-scale PV on NV Energy's system in southern Nevada increases regulation and load following requirements that must be supplied by NV Energy's generating resources, mostly from combined cycle and combustion turbine units. These higher requirements increase the amount of generation committed in day-ahead schedules, degrade unit efficiency, and accelerate operations and maintenance, all of which increase energy costs. Balancing area limits for traditional unit dispatch and operation are exceeded at all renewable generation levels, and system upgrades or other mitigation is necessary to accommodate variable renewable output. For capacity levels exceeding those evaluated in this study (1042 MW), NV Energy generation alone may not be capable of meeting regulation and load following requirements associated with variable resources.

6.2 Key Findings

Specific study findings include:

- Analytical methods using ground-based and satellite data were developed and successfully applied to estimate minute-by-minute large PV output profiles at ten sites in southern Nevada, and for smaller PV distributed over greater Las Vegas.
- The level of intermittency for large PV arrays is mitigated for some – but not all – instances when installations are distributed over a large geographic area; the highest offsets occur for similarly sized plants and when distances between plants increase.
- Rigorous analytical methods and models were successfully applied to predict system incremental balancing requirements including capacity and ramp rate, using minute-by-minute time scale (and longer) data for the integration of renewable resources.
- These models predict that large PV and DG installations will cause balancing area requirements to increase for all PV and DG penetration level *after* three percent of the highest changes in minute-by-minute net load (native load minus PV output) in each hour are excluded from the analysis.

- The performance impacts associated with variable PV and DG output occur regardless of the type of renewable generation installed – all PV and no DG, or vice-versa.
- Production cost simulation models confirm that integration of PV and DG will cause NV Energy's generation to operate less efficiently; further, units' cycling range and the number of unit starts also increase, resulting in higher operation and maintenance costs.
- The annual cost of operating reserves needed to integrate 200 MW to 1000 MW of large PV and DG capacity ranges from $2 to $20 million, or $3 to $8 per MWh of PV and DG capacity. Forecast error and must running combustion turbines when ramping deficiencies occur increase these costs.
- Additional costs may apply to DG, where local distribution constraints caused by clustering or where DG is installed on feeders susceptible to degraded performance, as outlined in the December 2010 DG Study.
- The addition of large amounts of DG does not appear to cause violation of steady state voltage, transient voltage stability, or thermal loadings.

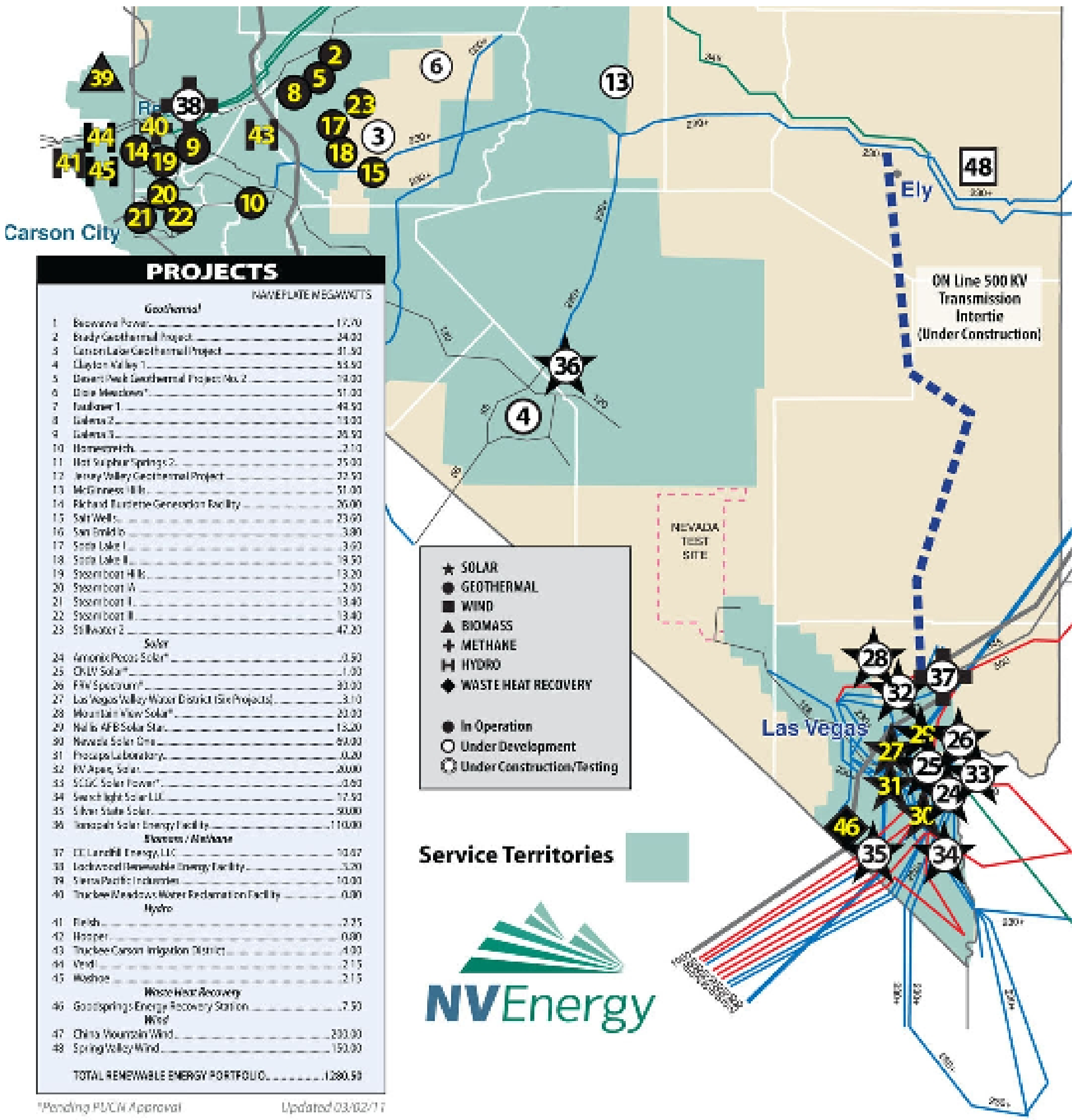
6.3 Next Steps

The results presented herein were developed using sophisticated tools and analytical methods. Inherent in advanced studies of this nature is a degree of variability that accompanies the prediction of system performance impact and cost. Due to the lack of historical solar output data, the analysis was based on a simulated solar output for a single year. Also, an accurate forecast of system load and solar output was assumed. The results presented herein, therefore, should be deemed the minimum requirements. Accordingly, the study team recommends that NV Energy apply a reasonable level of margin to minimize risk as large PV and DG is installed on its system. For example, integration costs cited above exclude any additional reserve requirements for days where PV output is not accurately forecasted; for example, due to unexpected cloudy days during winter and shoulder months. As the Company and system operators gain more experience in the impact of variable renewable output, which could lead to new approaches for forecasting day-ahead PV output on cloudy days and improved generation scheduling tools, we anticipate the methods used to predict renewable integration impacts and costs will be refined. These refinements are expected to reduce the cost of integration and increase the amount of variable renewable capacity that can be installed in NV Energy's service territory.

The Company proposes to build upon the results of studies presented herein to address the issues outlined above and to assess mitigation options. Specific studies and analyses the Company proposes to perform are listed below.

- Conduct studies with Pacific Northwest National Labs (PNNL) for additional detailed minute-by-minute system simulation studies using PNNL's Resource Integration Model (RIM) software.
- Conduct studies with Sandia National Laboratory (SNL) to evaluate unit commitment stochastic methods to further evaluate generation unit commitment and scheduling impacts of large-scale variable renewable generation. The Study may include enhancing NV Energy's scheduling software and forecasting methods.
- Investigate mitigation options to address regulation deficiencies and to increase the amount of PV and DG that can be installed. Options may include battery storage, pumped storage hydro and combustion turbines. The Company has engaged SNL to conduct an Energy Storage Integration Study to determine the benefits and cost effectiveness of using energy storage in the NVE's balancing area to meet regulation needs and also to defer T&D asset and generation O&M improvement.
- Update production costing studies once the new regulation feature is available from Ventyx (PROMOD)

APPENDIX A. UTILITY SCALE RENEWABLE PROJECT PORTFOLIO



Appendix B: Bulk Power & Transmission System Analysis

The following presents the results of the bulk transmission studies, which evaluated the impact of incremental DG - large PV is excluded as impacts are evaluated in System Impact Studies completed as part of Interconnection Requests. These studies evaluate DG impact in greater detail and rigor than preliminary results presented in the December 2010 DG Study.

Objectives

Potential Impacts included in the evaluation include:

1. Post-contingency, steady state thermal capacity deficiencies and bus voltage violations
2. Dynamic voltage or generator instability due to reactive power deficits
3. Voltage Flicker

The transmission studies are limited to NV Energy's balancing area

Navigant conducted limited transmission studies with up to 15 percent DG penetration to determine if DG installed on the distribution system can impact transmission system performance. High level findings indicate that voltage swings on the transmission system are significant; thereby confirming our conclusion that detailed studies of NV Energy's transmission system and bulk power grid should be undertaken. As noted earlier, detailed studies of transmission impacts was beyond the scope of the DG investigation, but are addressed herein.

Methodology

Approach follows methodology, assumptions, and criteria employed by NV Energy for transmission interconnection requests.

1. Conduct solar PV voltage stability analysis for 110 MW solar PV projects that are under development and 940 MW expected (simulated) Solar PV Generation.

2. Analytical methods follow the same process used to evaluate requests for generator interconnection under NVE's Open Access Transmission Tariff ("OATT")

3. Employ the GE-Positive Sequence Load Flow ("PSLF") and PSSE 32 PTI Siemens programs for steady state and transient analysis.

4. WECC starting base case that models the transmission system of the western United States for the year studied

5. Base Case power flow model used to study the interconnection includes all approved NV Energy and WECC system improvements

4. Test Voltage flicker for Solar PV generation addition with PSSE 32 PTI-Siemens software solutions for switching studies (TYSL).

- Switching studies ensure that the voltage flicker caused by a generation trip is no greater than 3 %, reference to GE flicker chart/curve DESM 17.101 and NV Energy Voltage Fluctuation Criteria

Assumptions

Key Assumptions include:

- Focus is on incremental impacts associated with DG (after PV is installed)
- Single balancing areas (South)
- DG drops off-line following major power system disturbances (no ride-through)
- Large PV and DG are at fixed power factor (displace conventional units that provide Var support)
- DG & PV will displace conventional generation (need to identify units that will be assumed off-line due to displacement)

Assumptions and methods employed in the limited transmission analysis included:

1) Conducting steady state transmission load flow studies of the Southern region, for peak load (summer) and light load (spring) cases. The following conditions applied:

    - Single (n-1) and double (n-2) contingencies, including those most likely to result in low bus voltages;

- Up to 15% inverter based DG, equally distributed at 230 kV Las Vegas area substations, connected to low voltage busses; and
- Assumed subsequent loss of on-line DG for contingency events (e.g., post-contingency low bus voltages causes DG tripping).

2) Use of an DG inverter model based on industry averages, including unity power factor;
3) Increasing DG penetration levels from 250 MW to 1,000 MW in the Southern region; and
4) Conducting dynamic studies to identify potential system voltage or generation instabilities.

The initial studies that Navigant conducted to examine DG impacts on NV Energy's Southern distribution system did not include a set of exhaustive analyses normally associated with comprehensive transmission studies, nor did it examine the impact of variable output from renewable generation. Such studies should be completed to fully assess DG impacts.

Findings

Specific findings of DG steady state and dynamic impacts are summarized below. Results include DG impact of voltage flicker at the transmission level – voltage flicker at the distribution level was included.

Transient Analysis

- No Adverse System Impacts were identified as a result of the transient stability analysis.
- Lenzie-Northwest 500 kV line was tripped and all voltages and frequencies stayed within WECC Reliability guidelines.

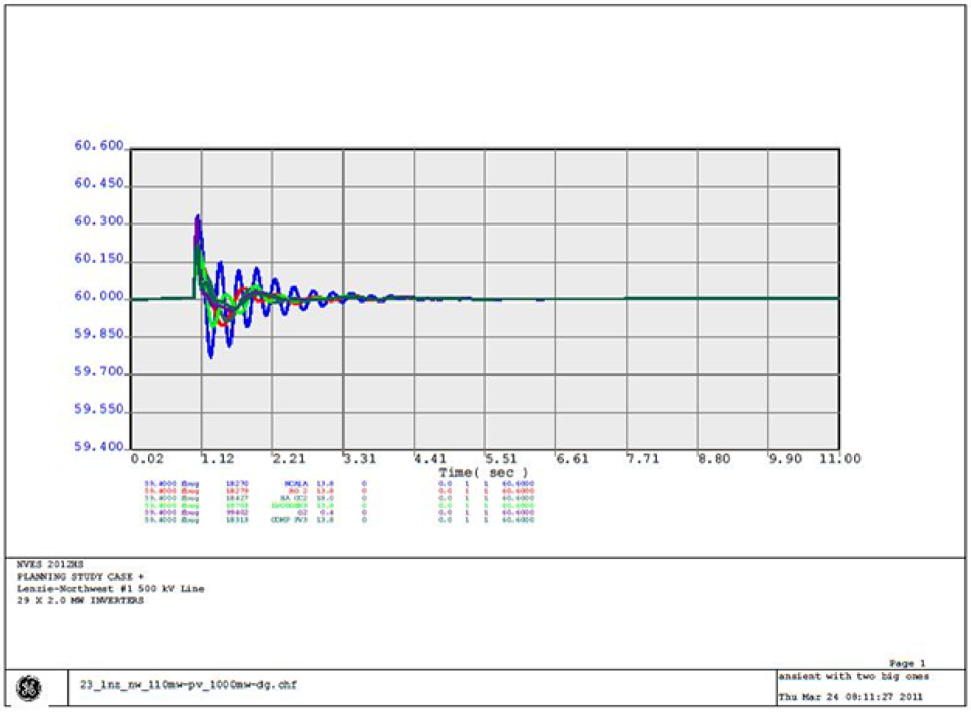
Steady State Analysis

- No Adverse System Impacts were identified for thermal capacity or voltages for base case and contingency analysis (n-0, n-1 & n-2, where applicable)

Voltage Flicker

- Switching studies for Company 91 detected 1.077 % of voltage flicker in the Study Case #3 (Solar PV power plant switching from ON to OFF)

Figure 91. Transient Analysis



Related findings include:

- Preliminary steady state results indicate post-contingency voltages reach undesirable levels when 15 percent (of NV Energy Southern area load) of inverter based DG is located in the greater Las Vegas area; this includes voltage swings outside NV Energy's balancing area.

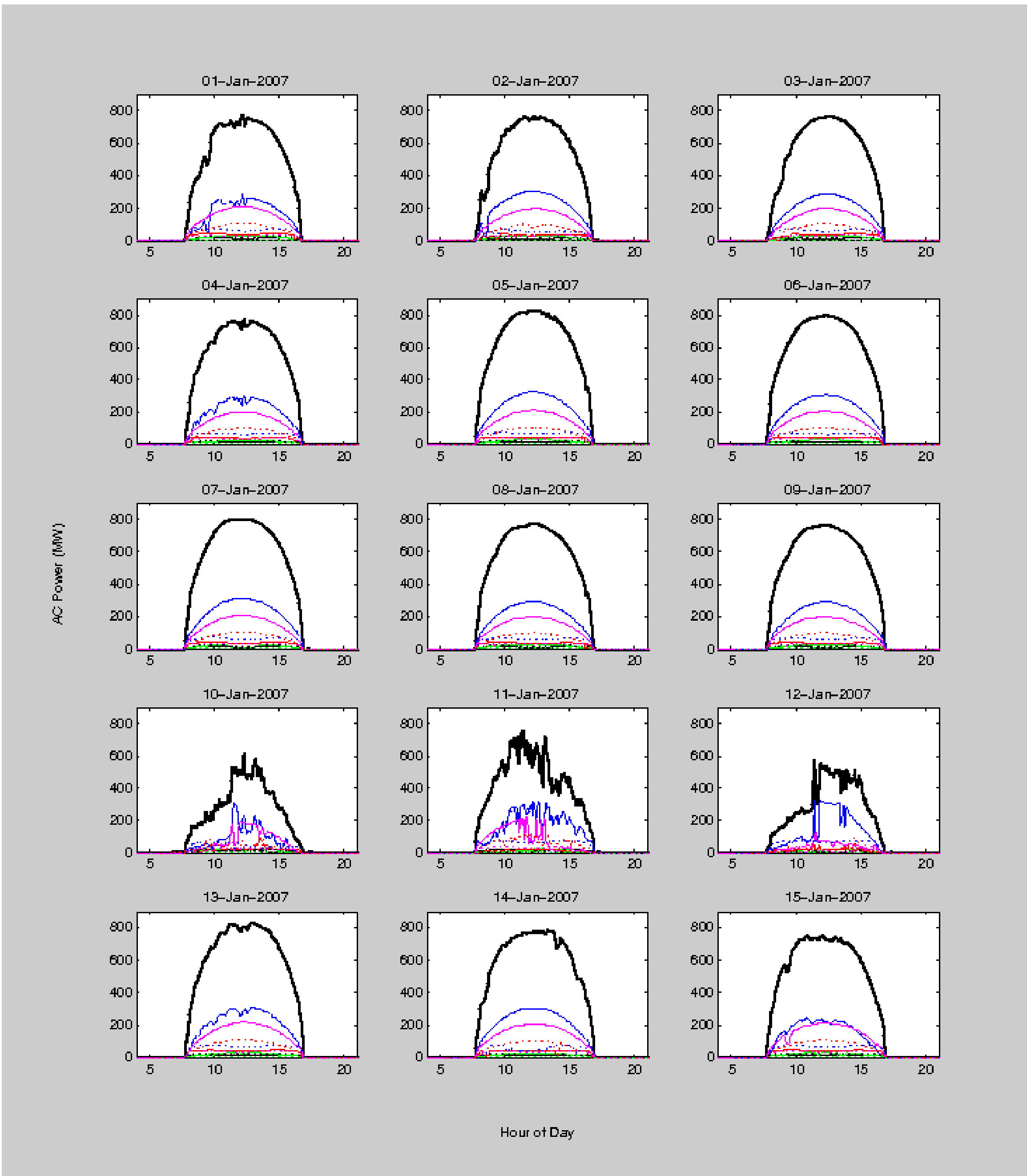
- The studies were performed under idealized conditions. When the impact of large imports, interface transfers, and generation placed off-line due to DG output, voltage variances are likely to be greater; and

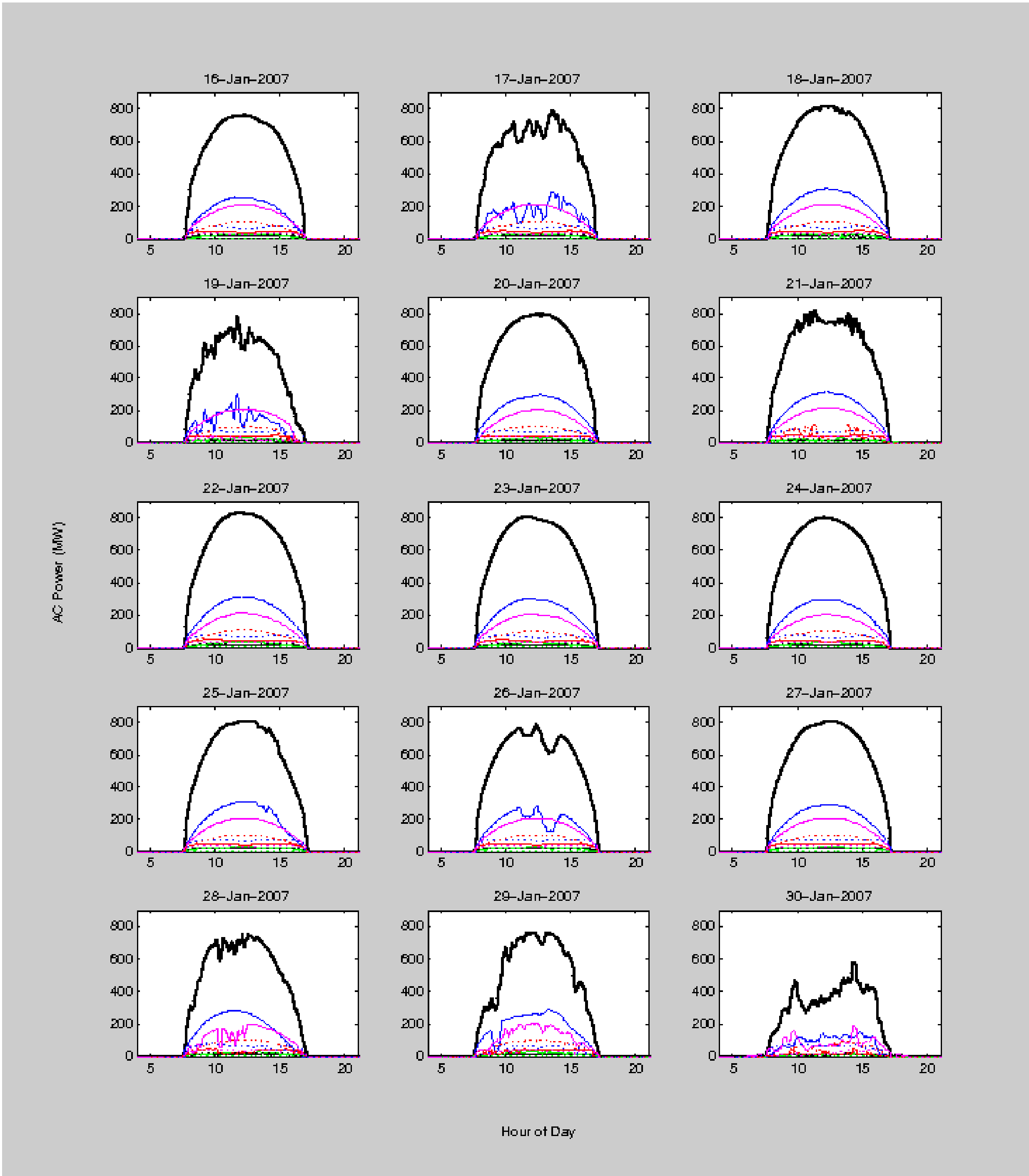
- Similarly, when approved and proposed large-scale renewable and variable resources enter commercial operation, both voltage and thermal violations may occur.

Accordingly, distribution-level DG will be evaluated in combination with new larger generation in the *Large-scale PV Integration* study that Navigant is currently conducting in conjunction with SNL, DOE, and NV Energy.

APPENDIX C. PV OUTPUT PROFILES

PV Power Output Profiles by Location (Case 5)

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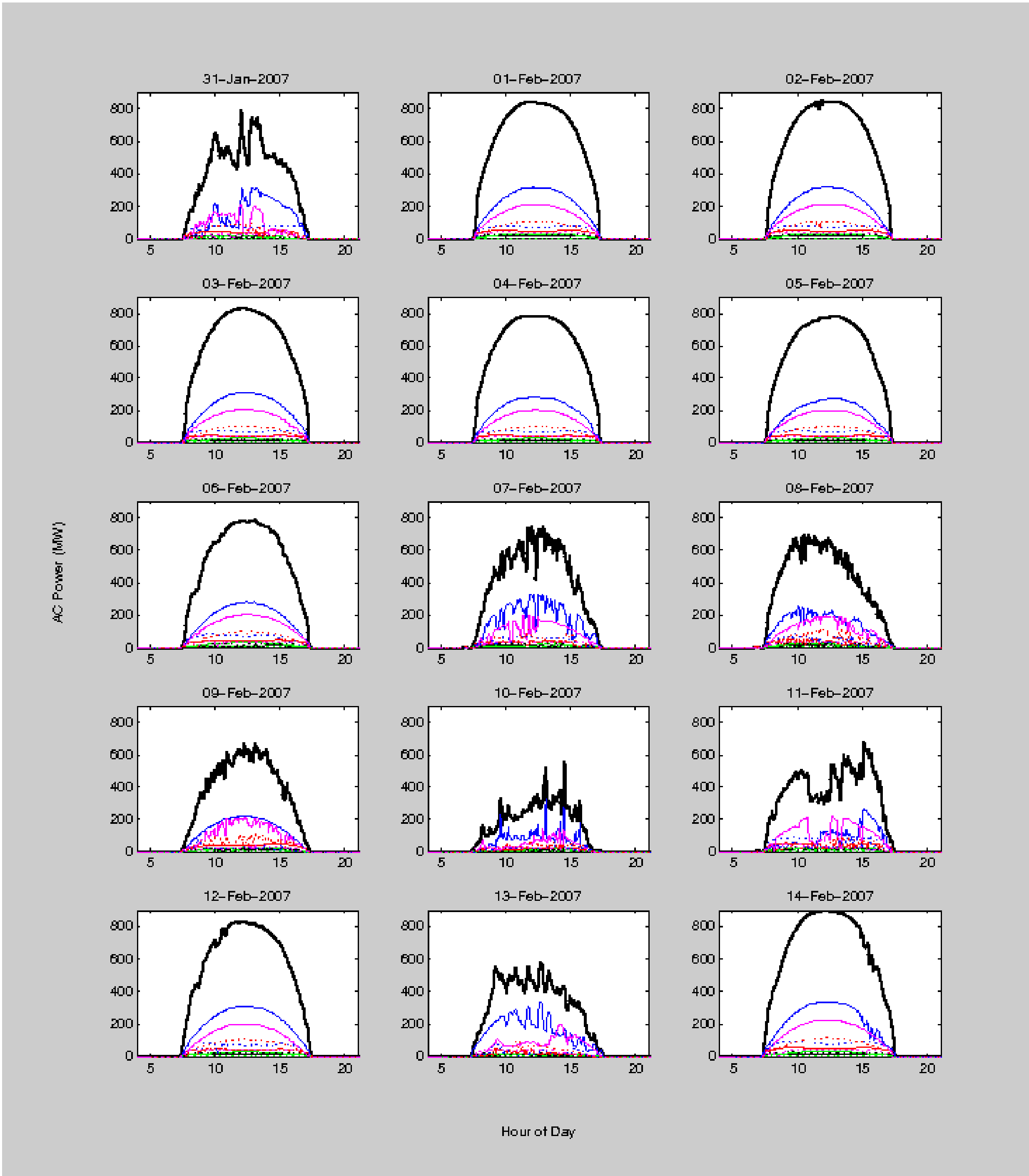
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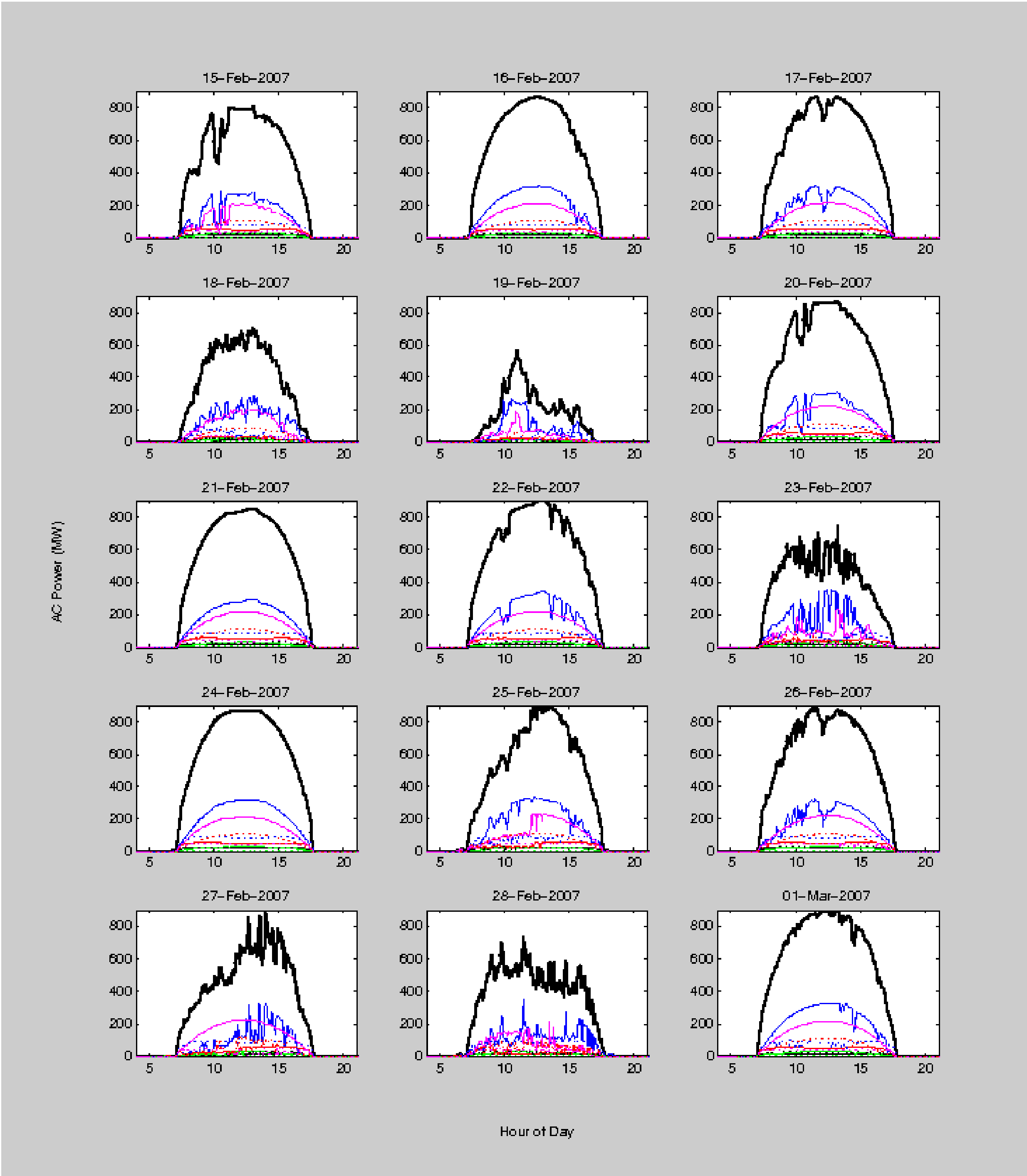
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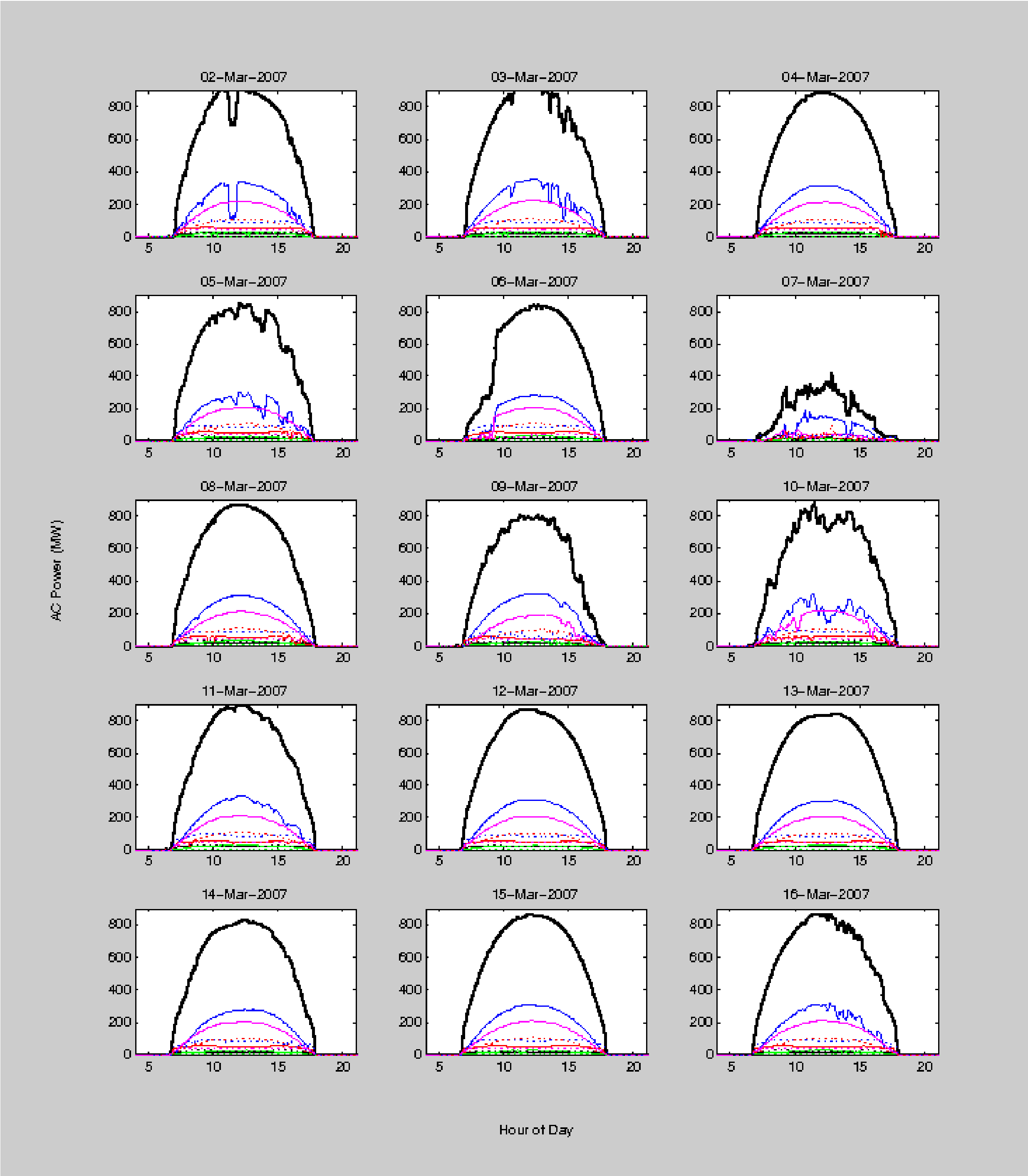
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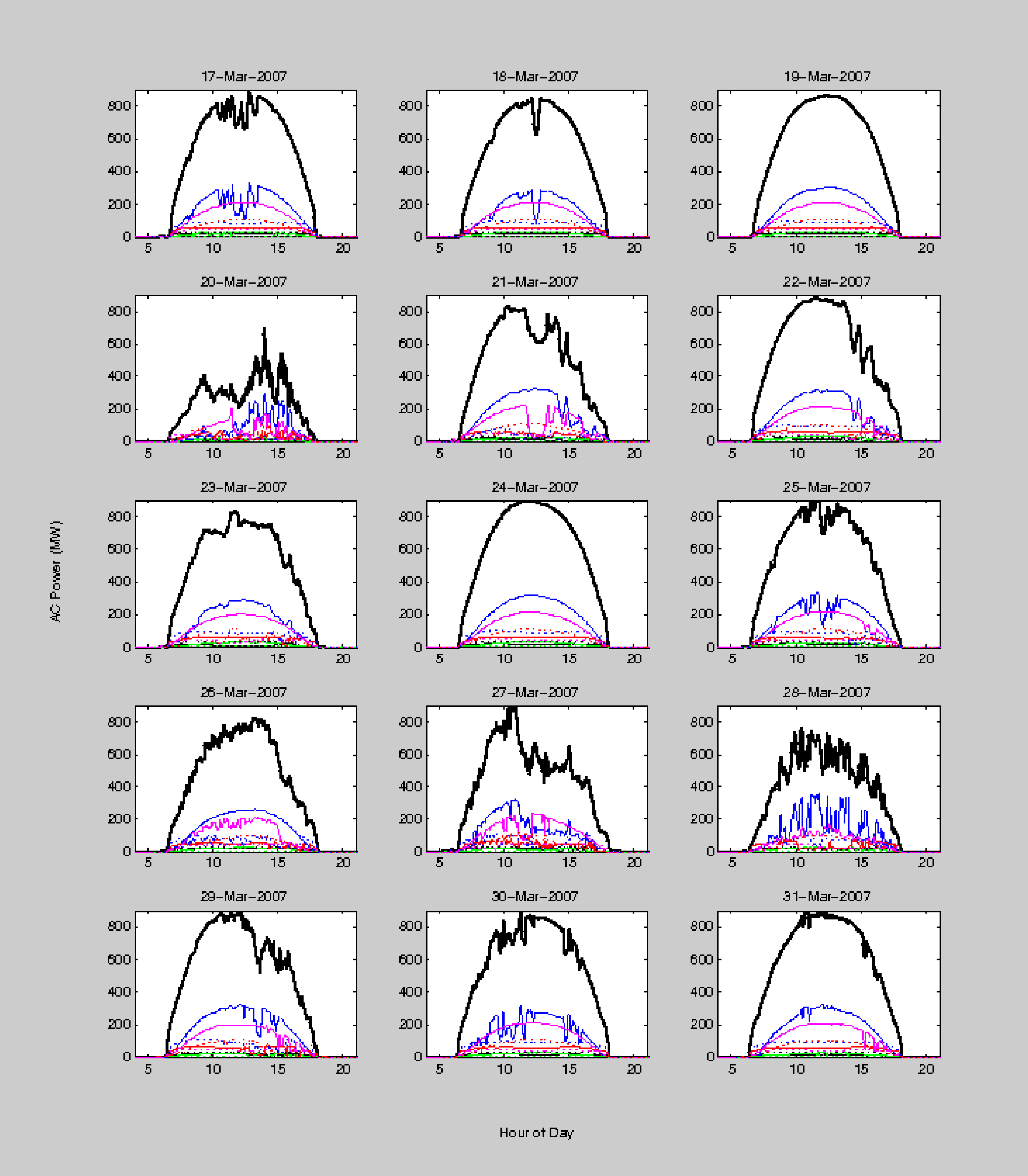
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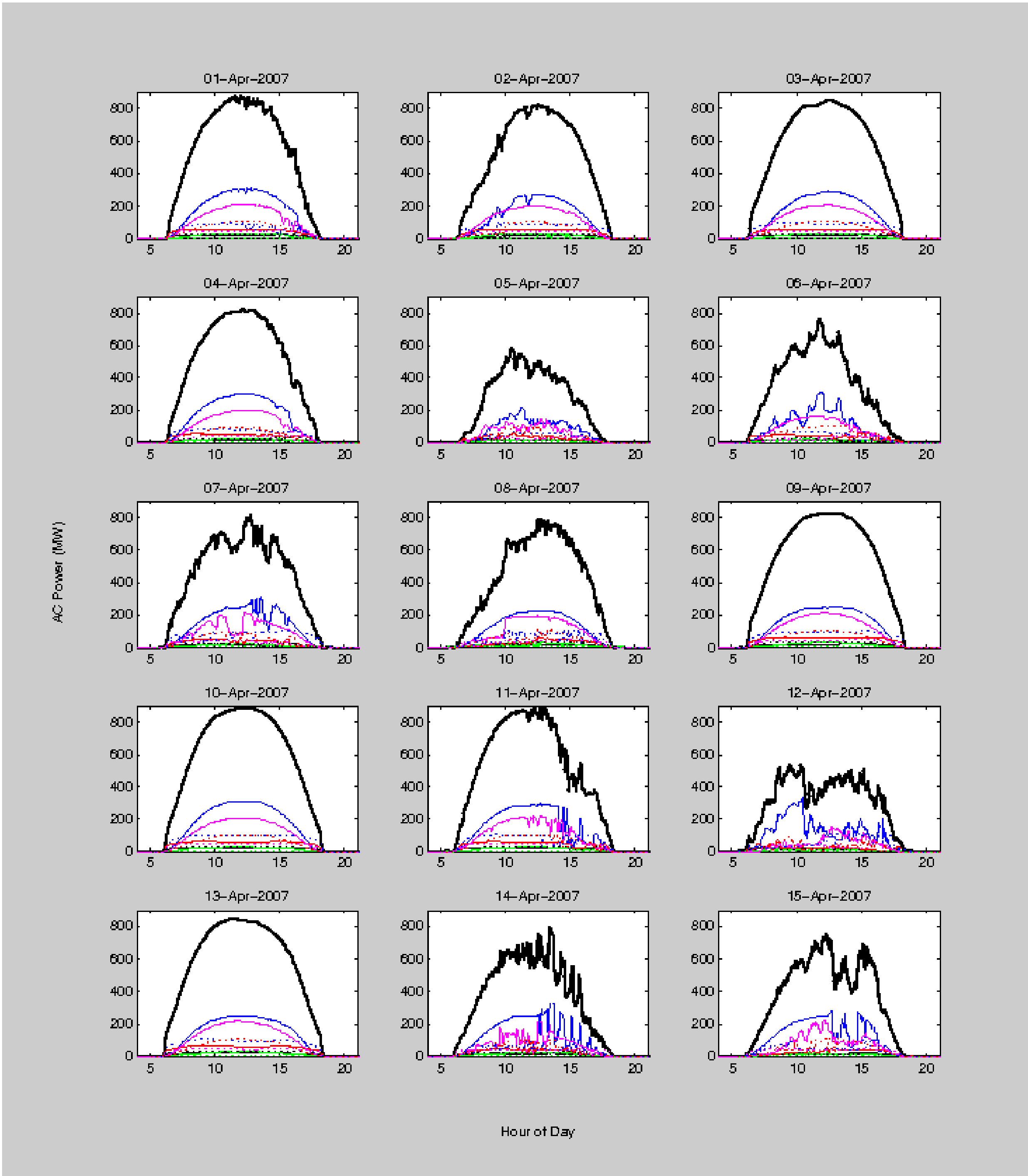

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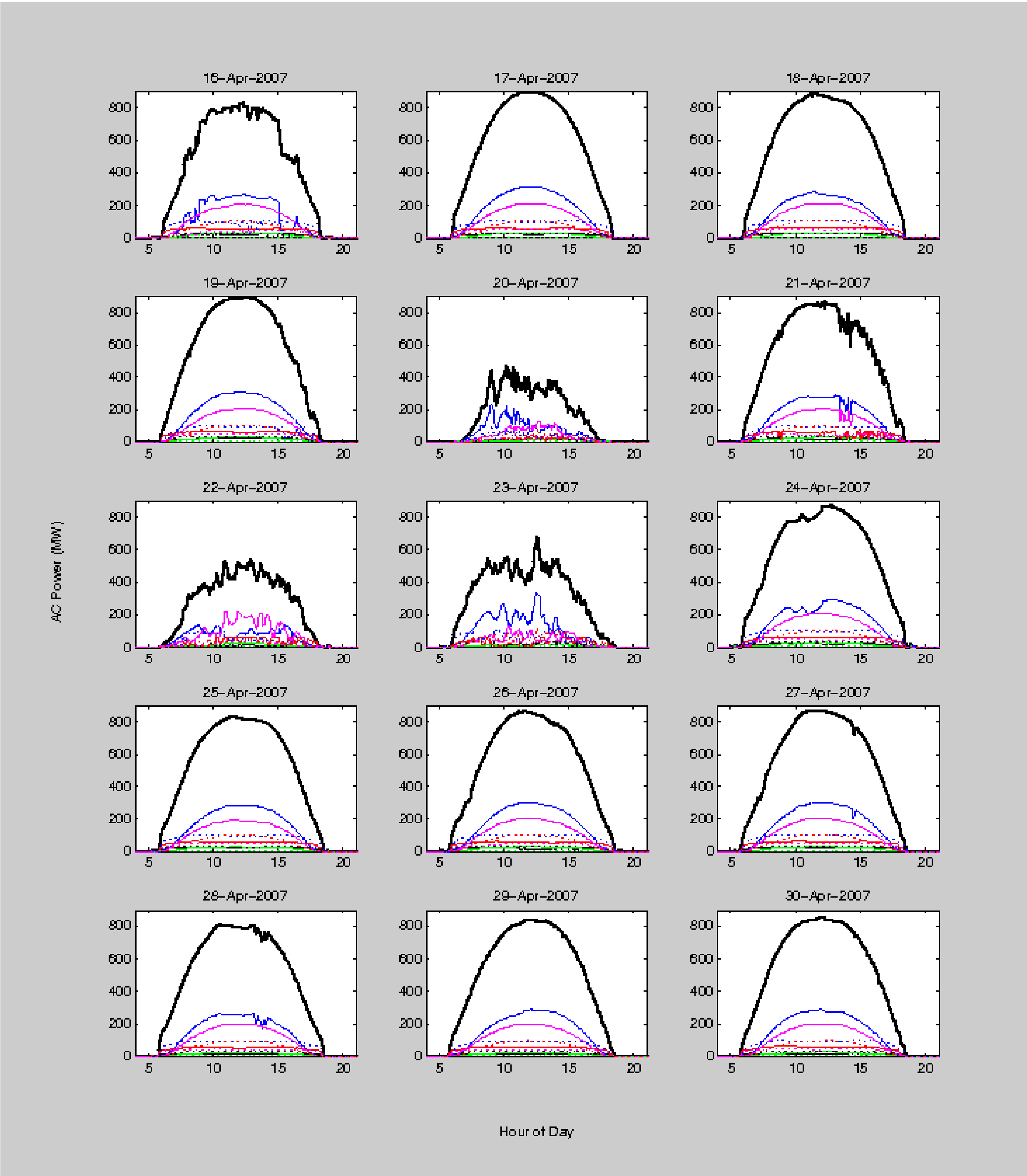
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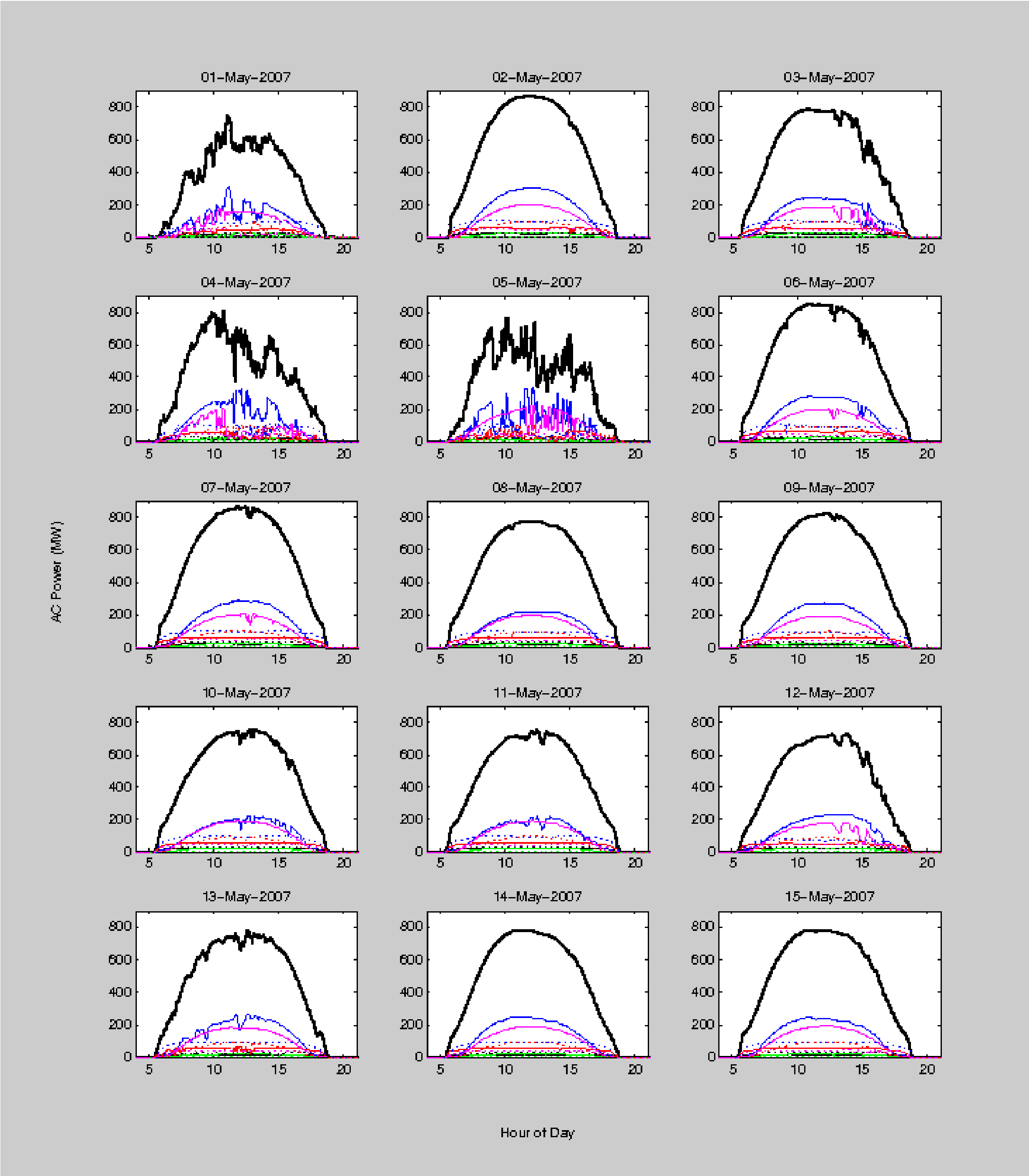
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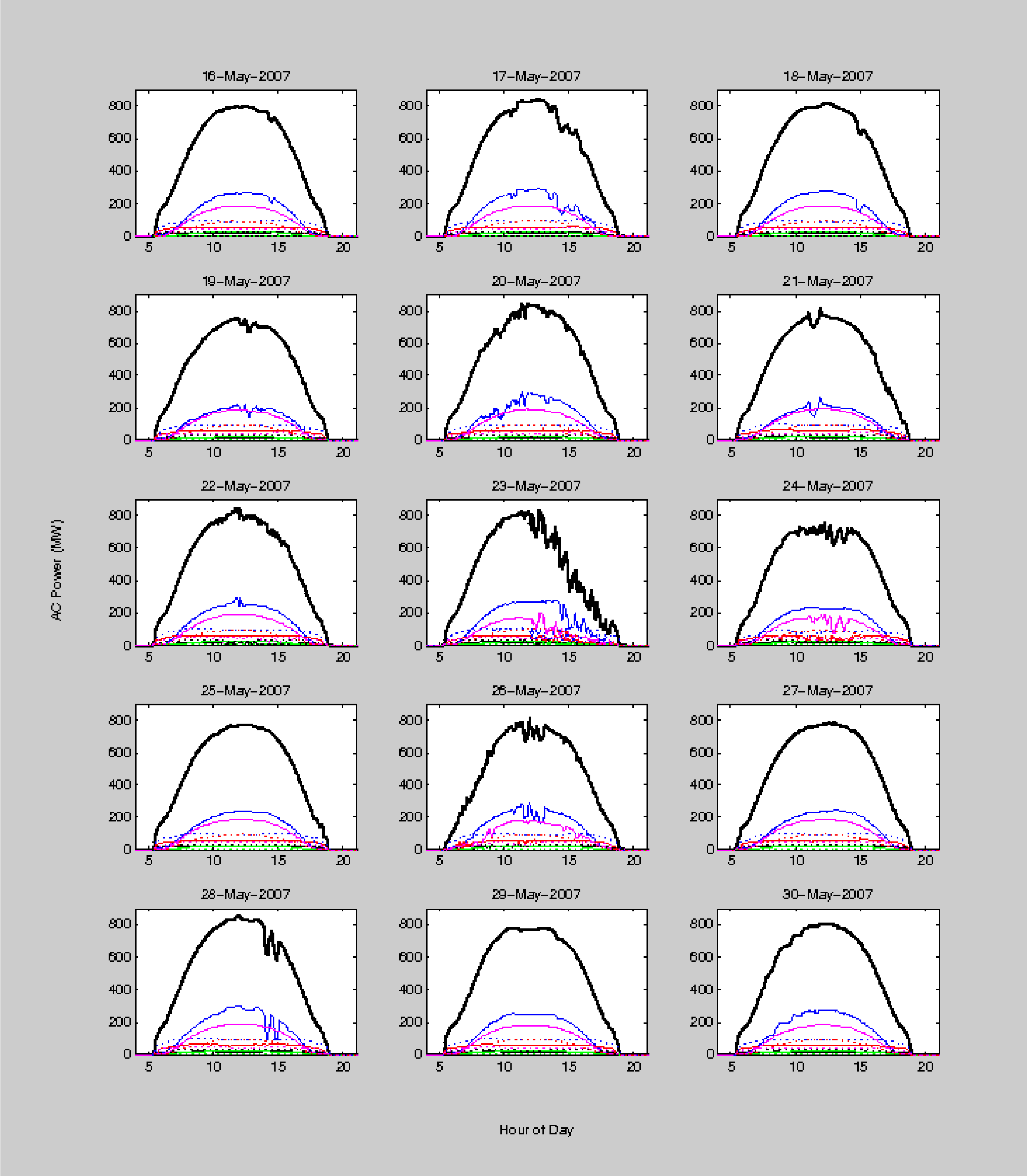
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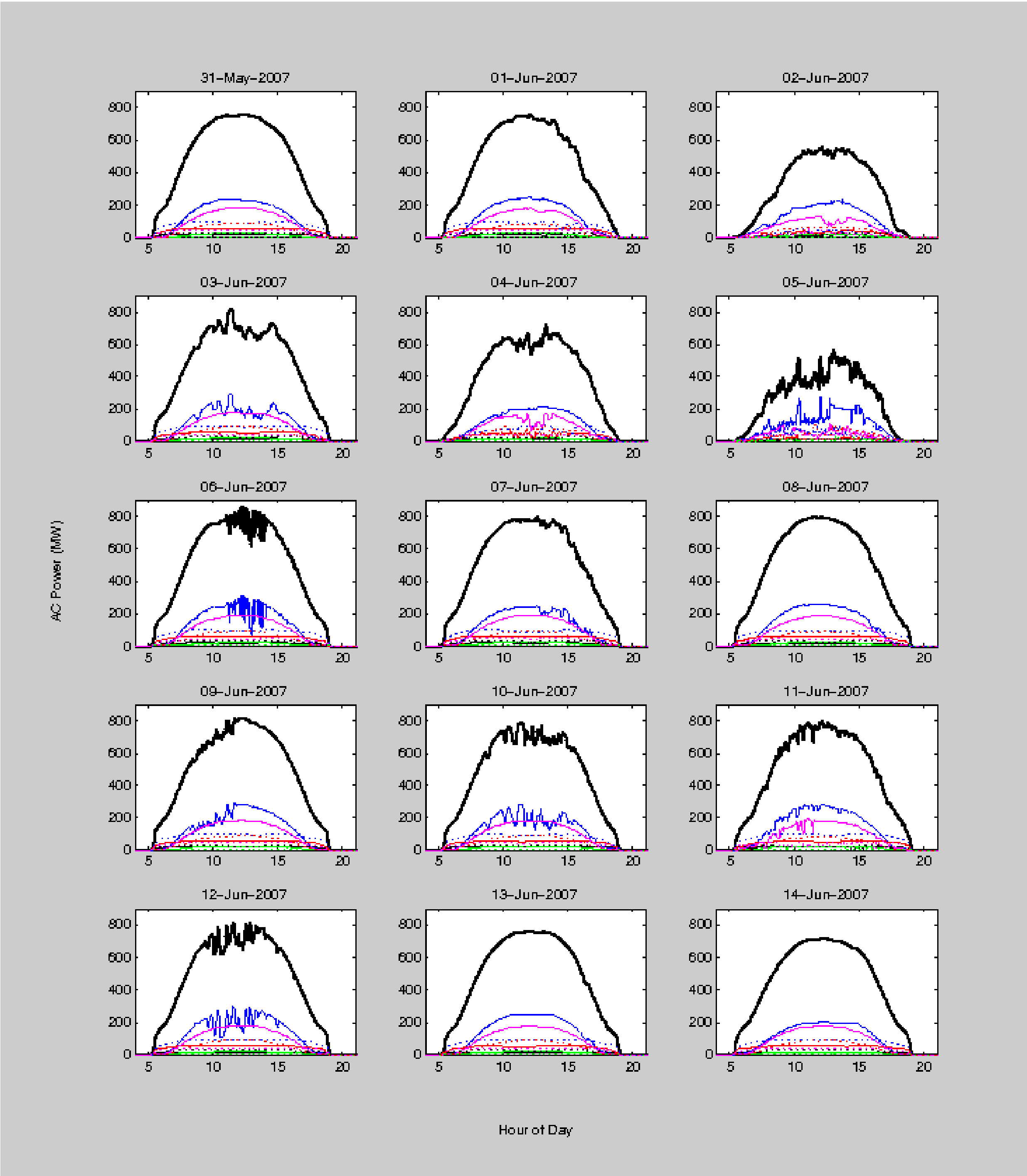
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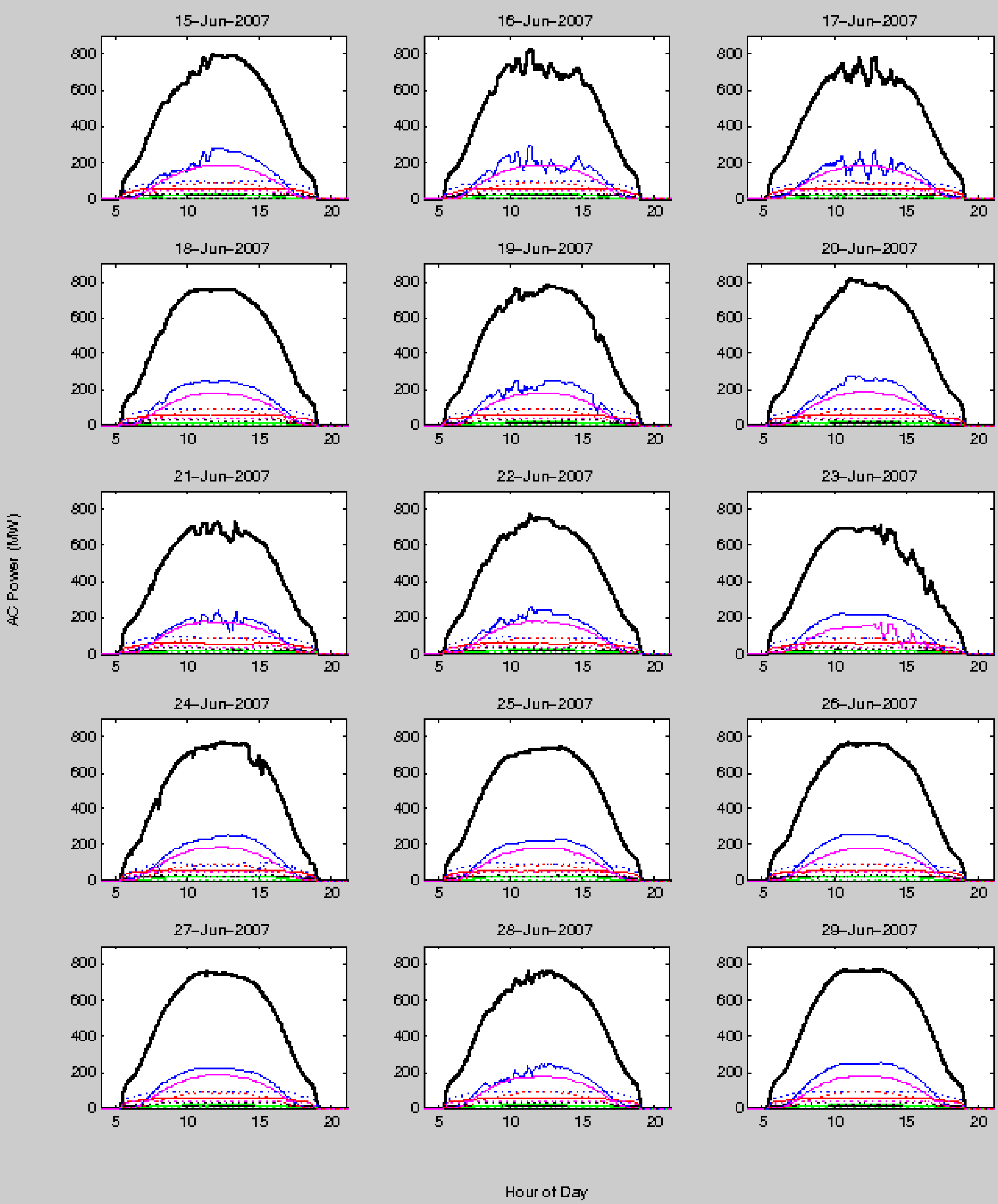
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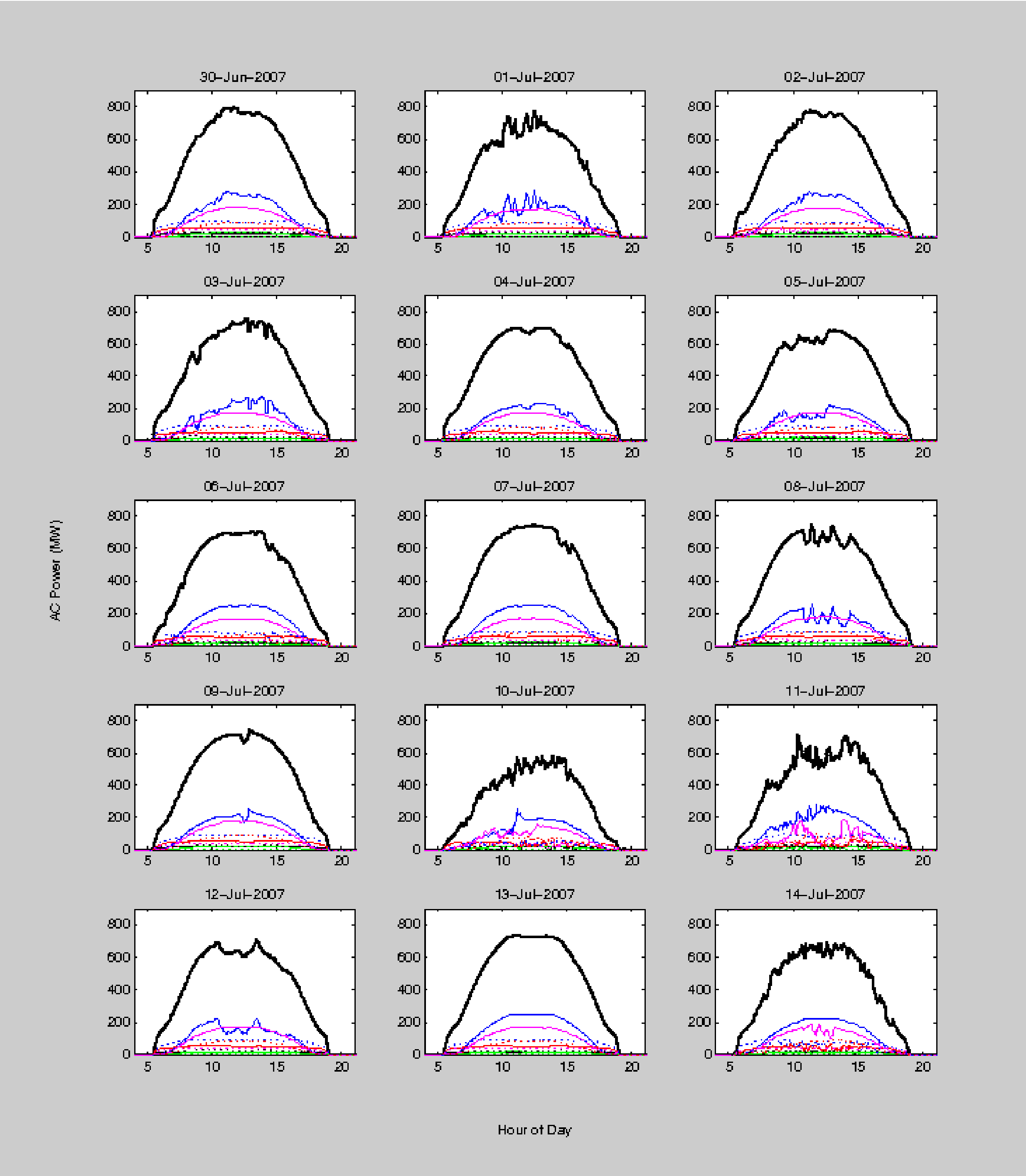
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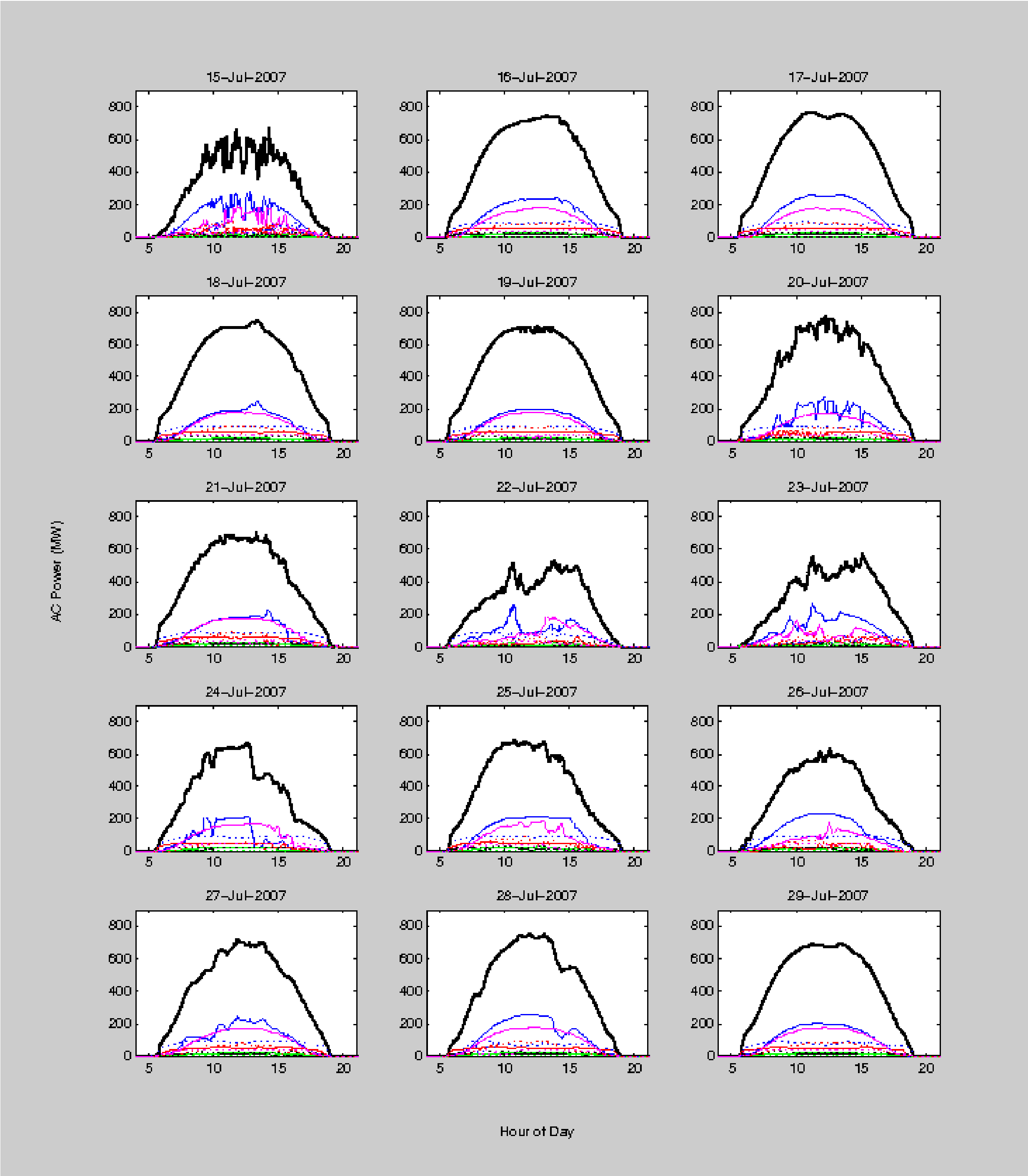

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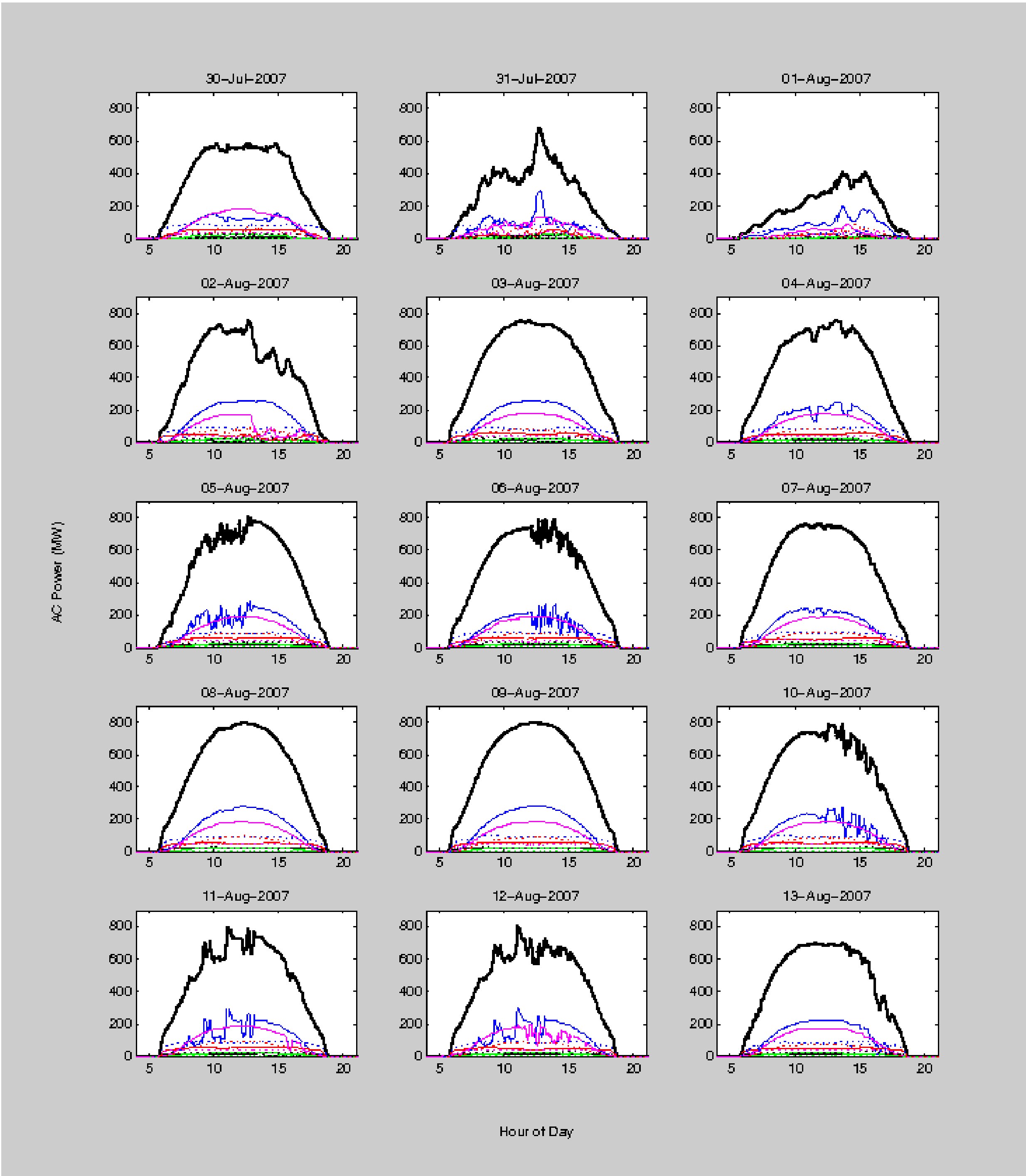
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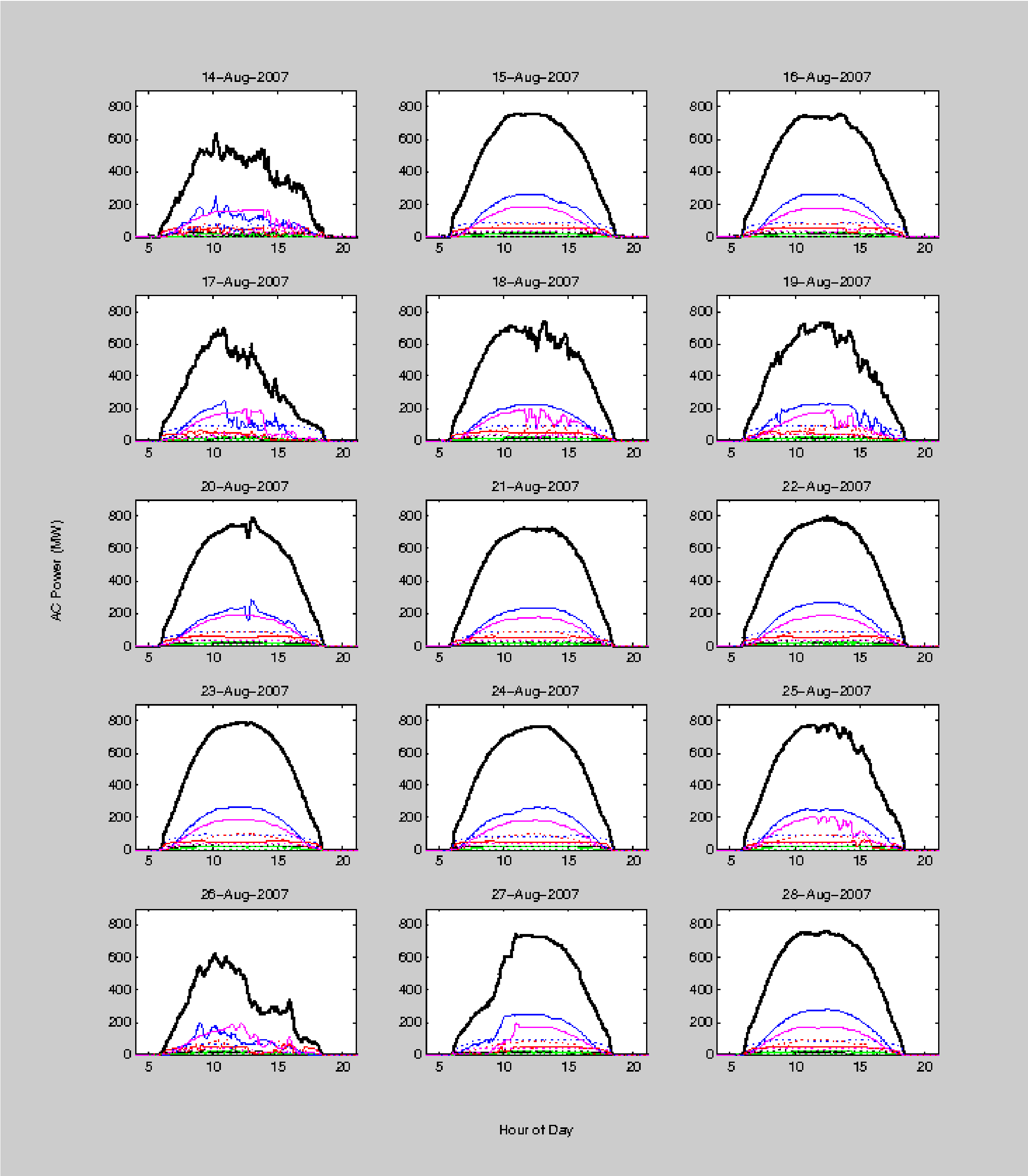
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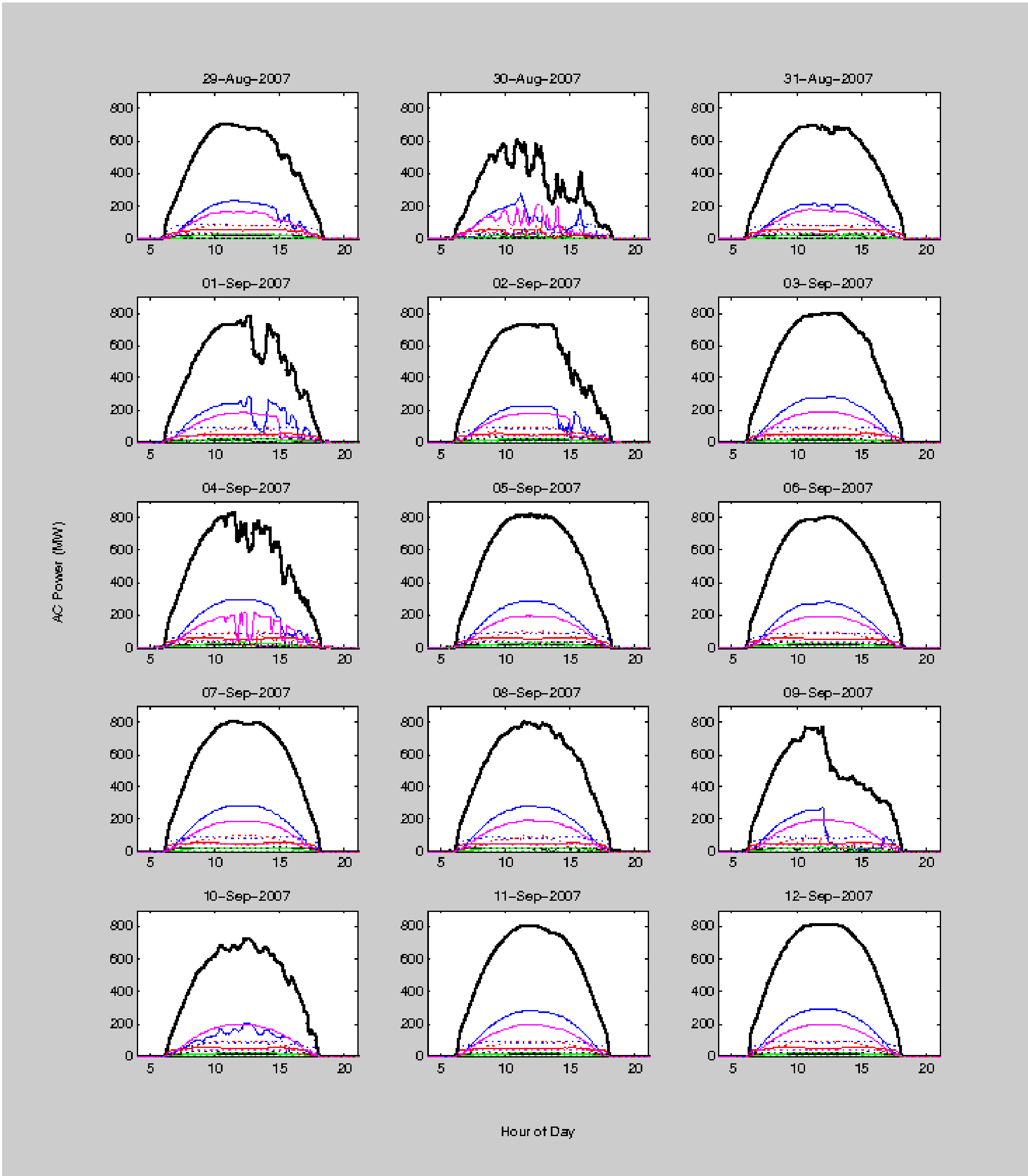
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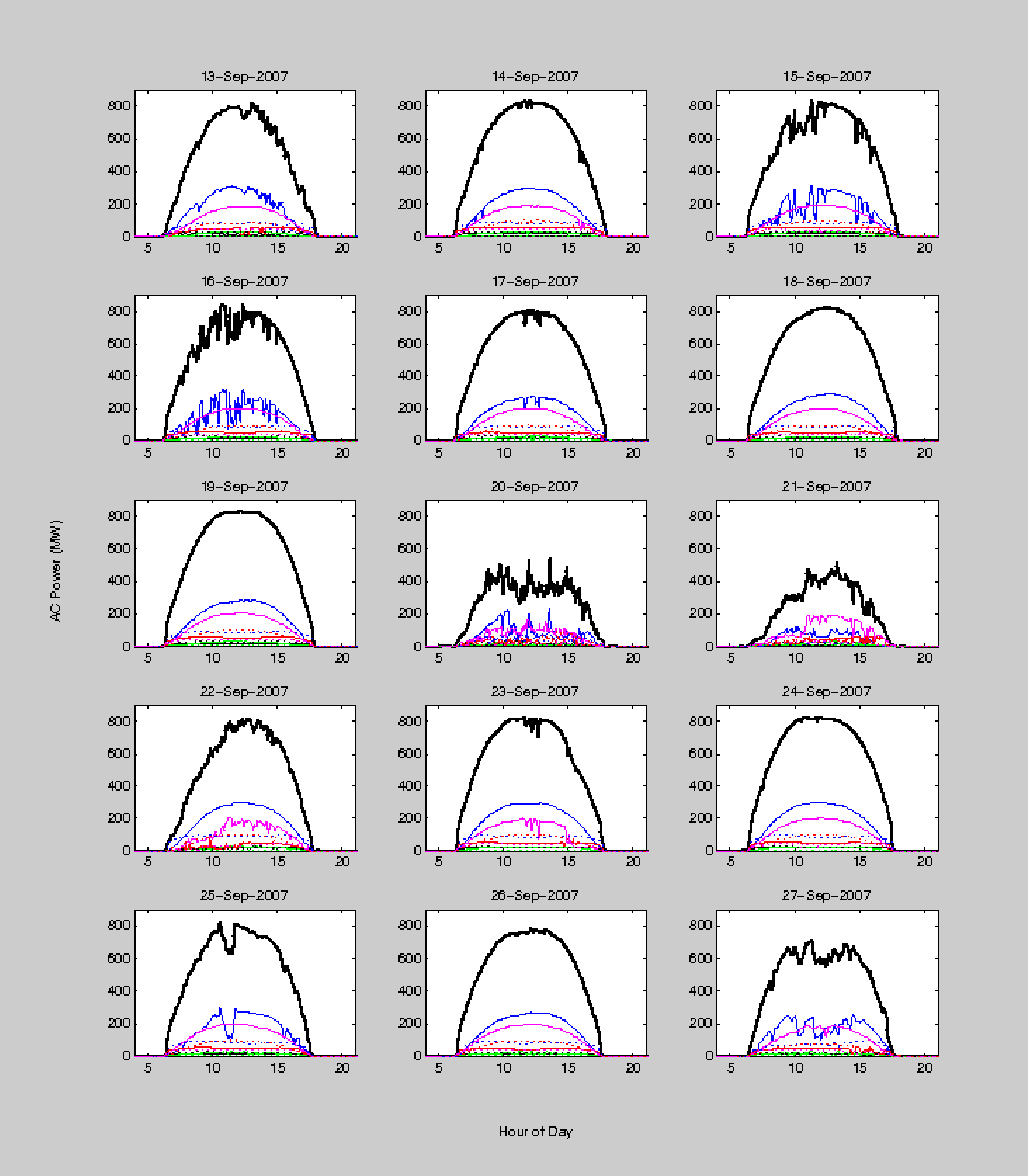
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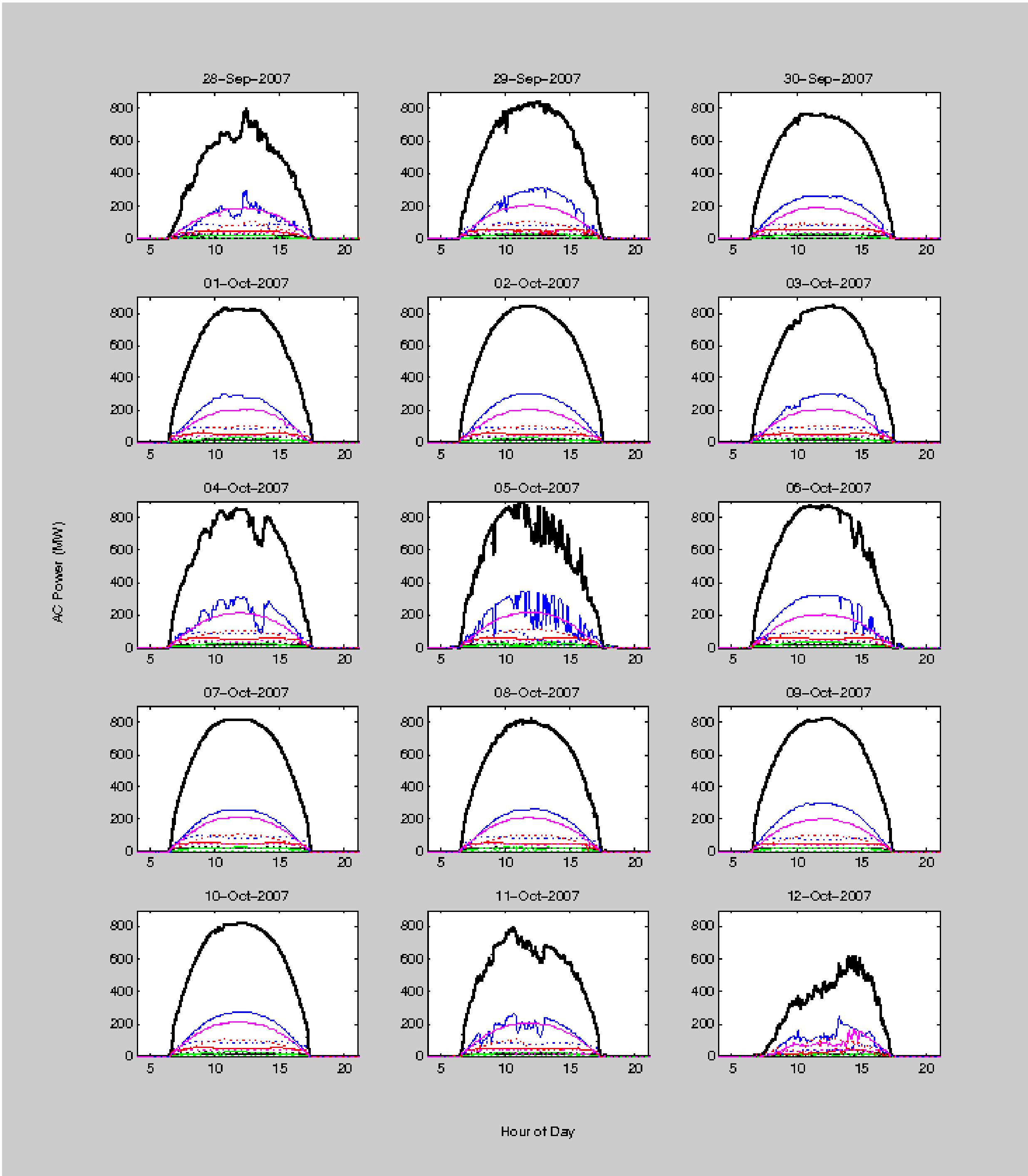
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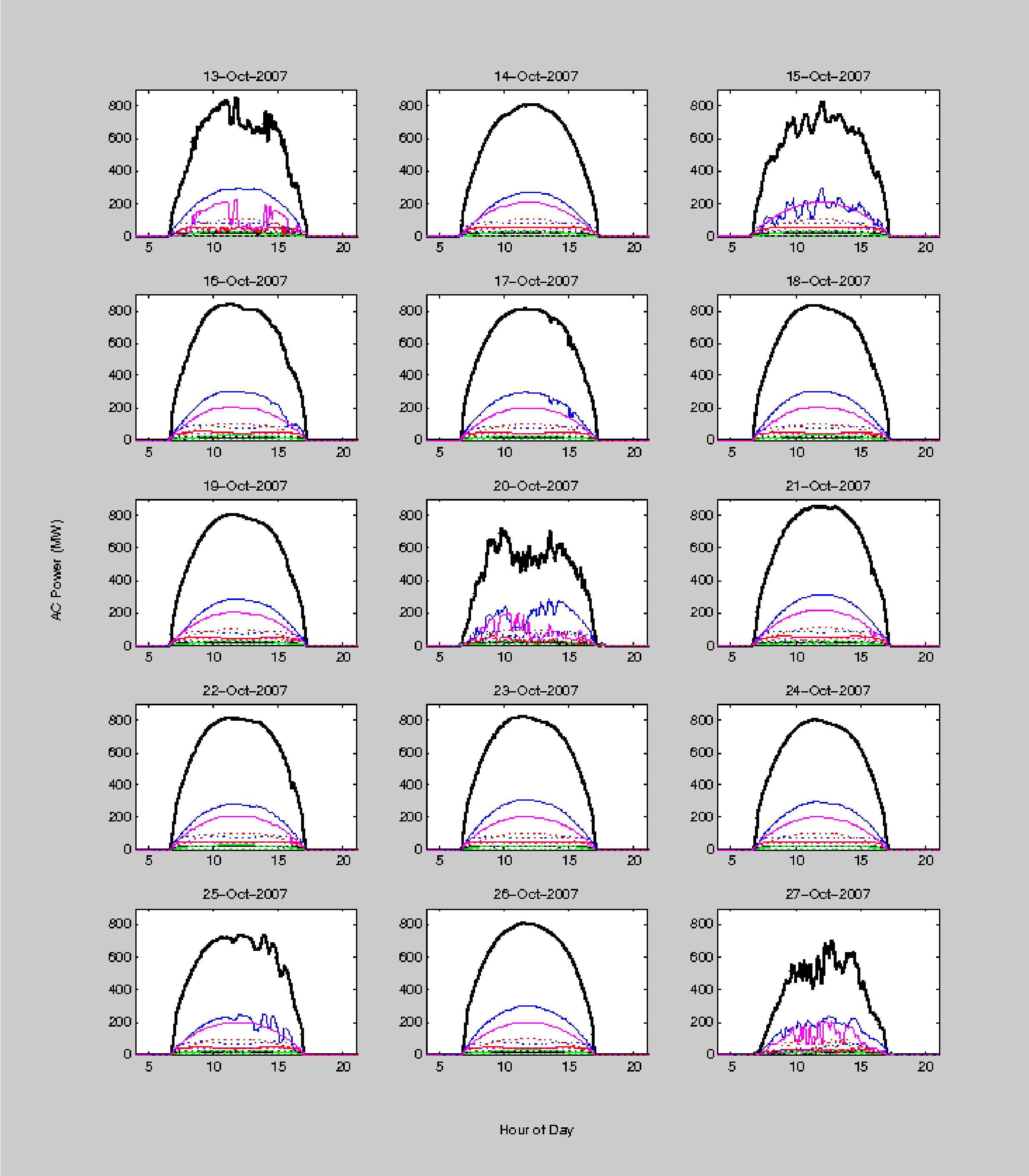
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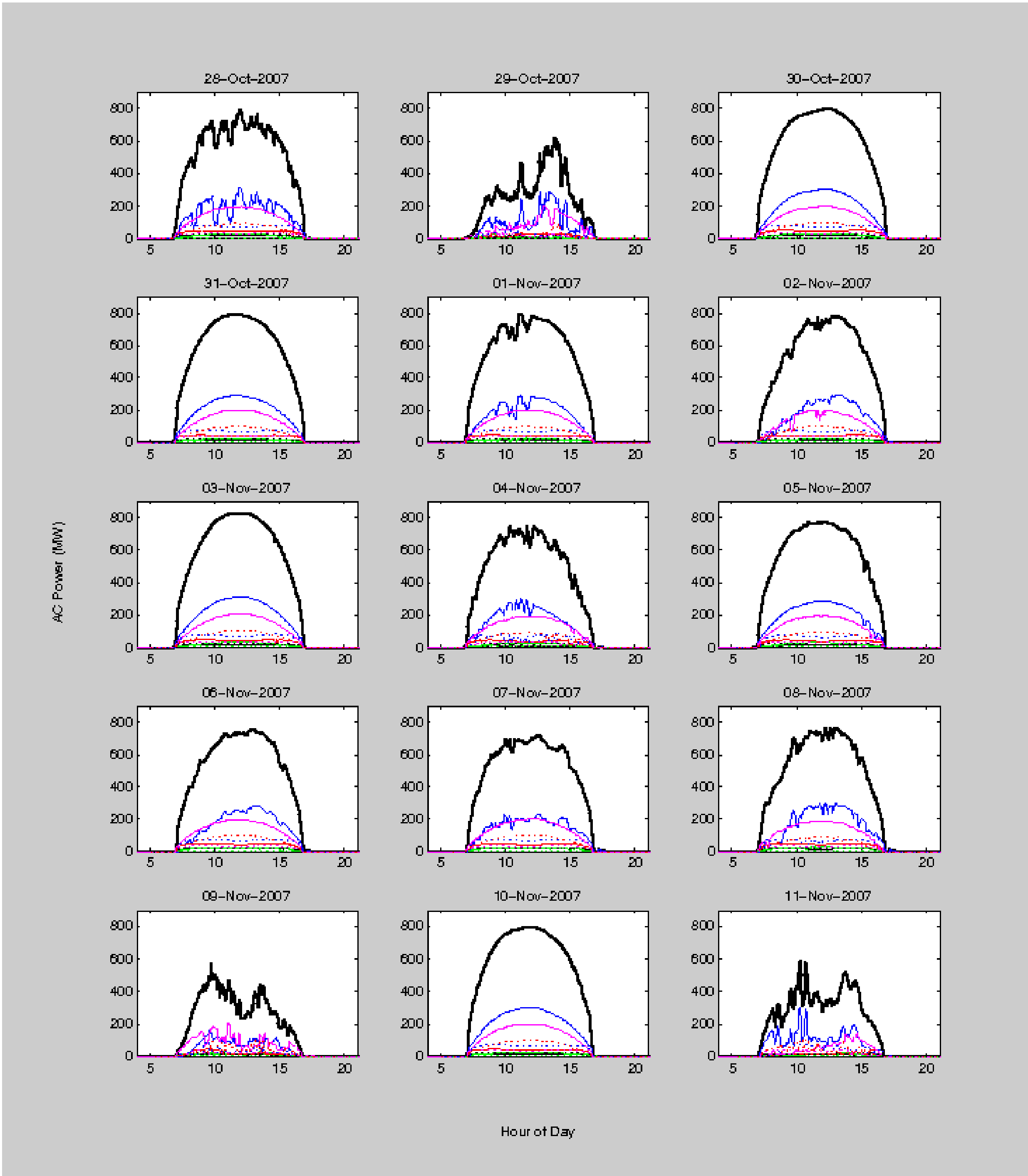
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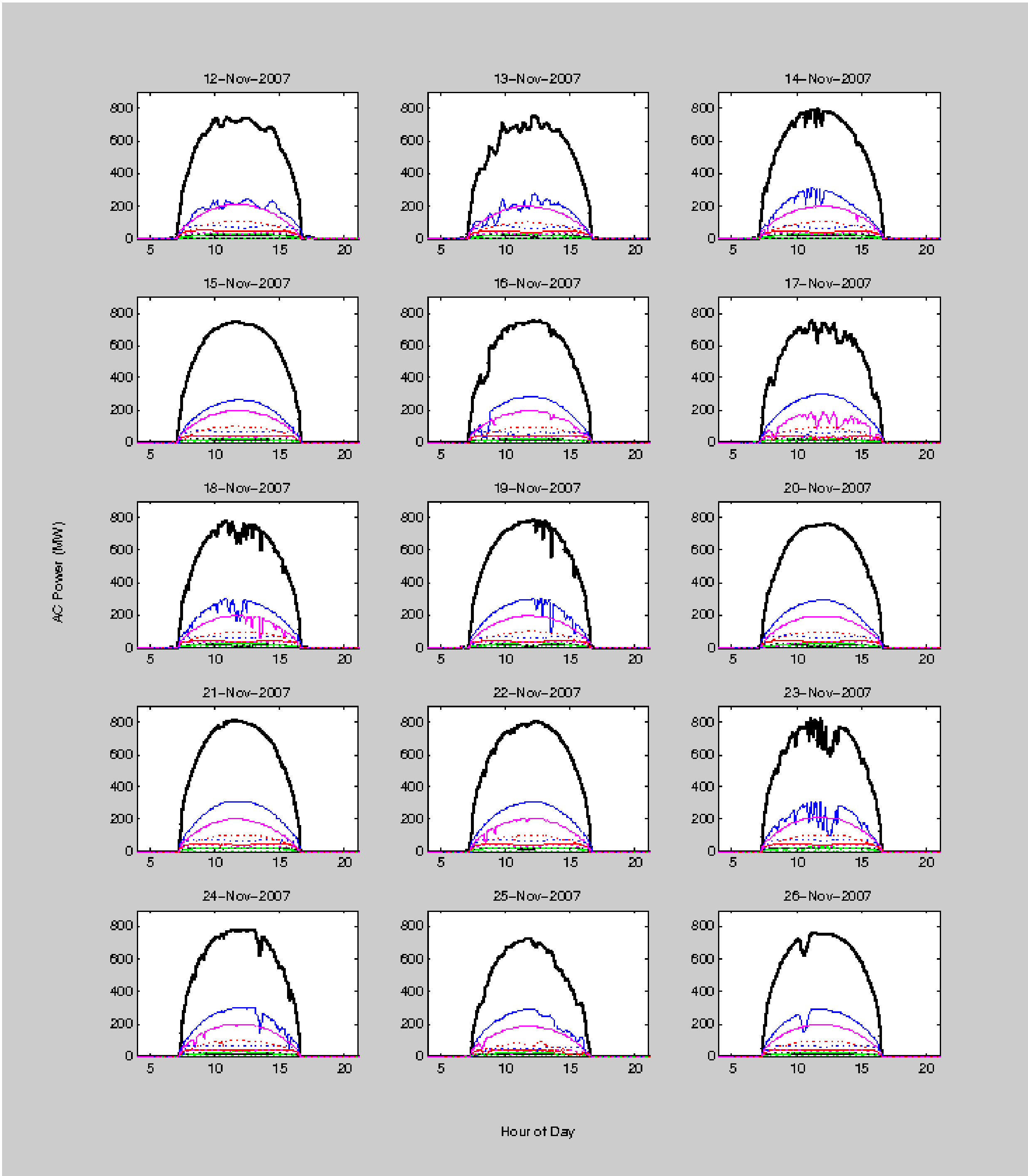

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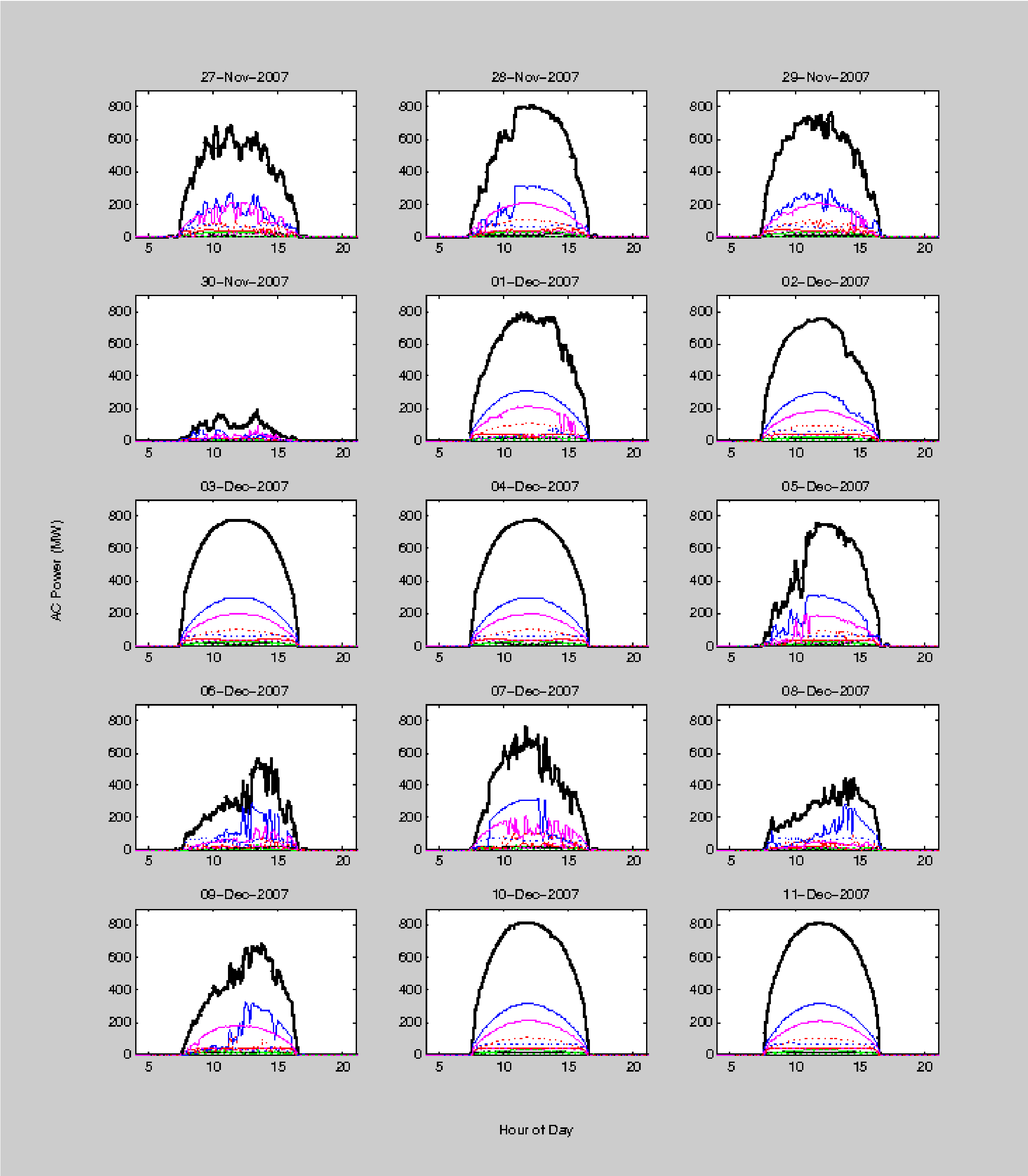

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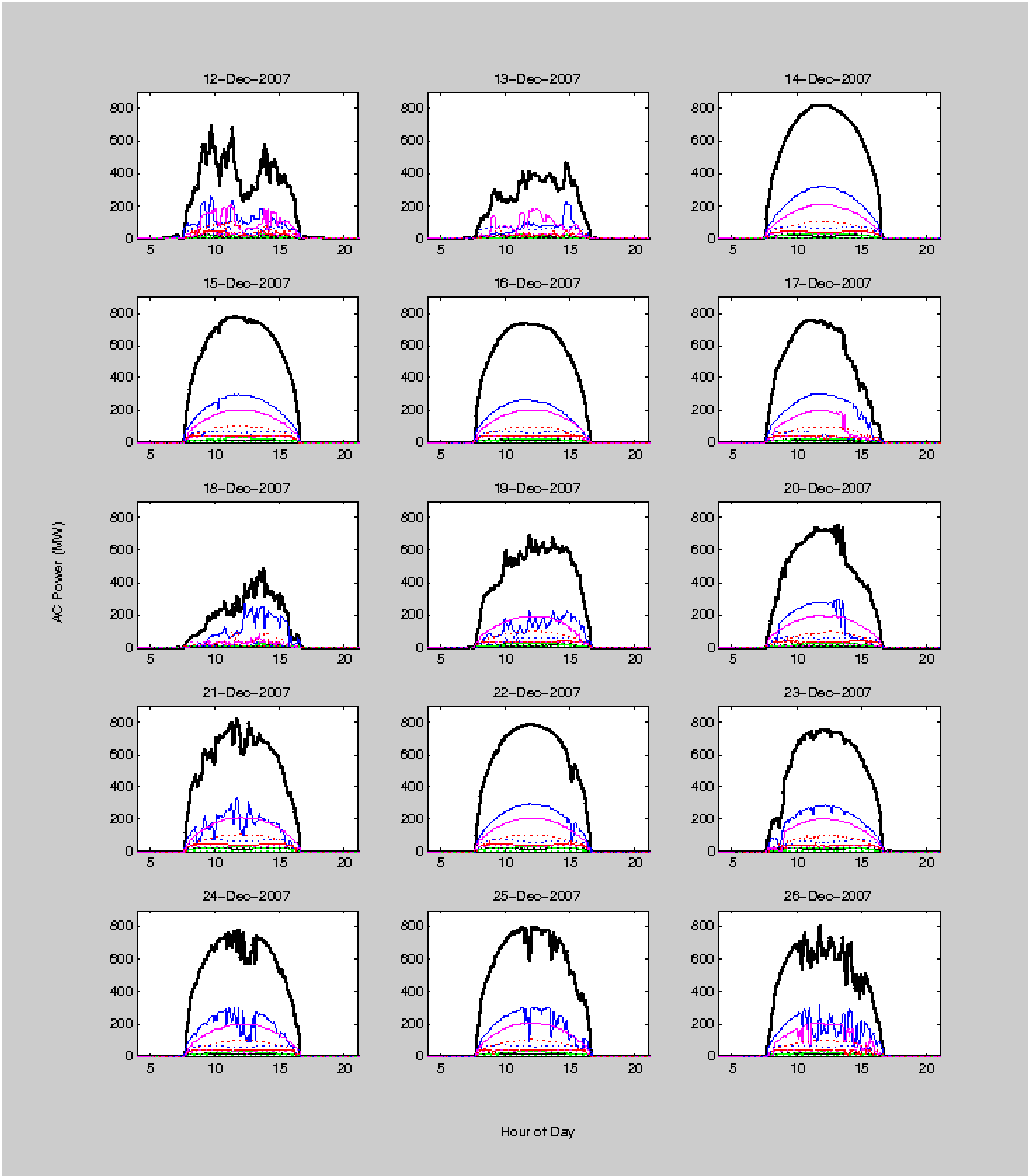
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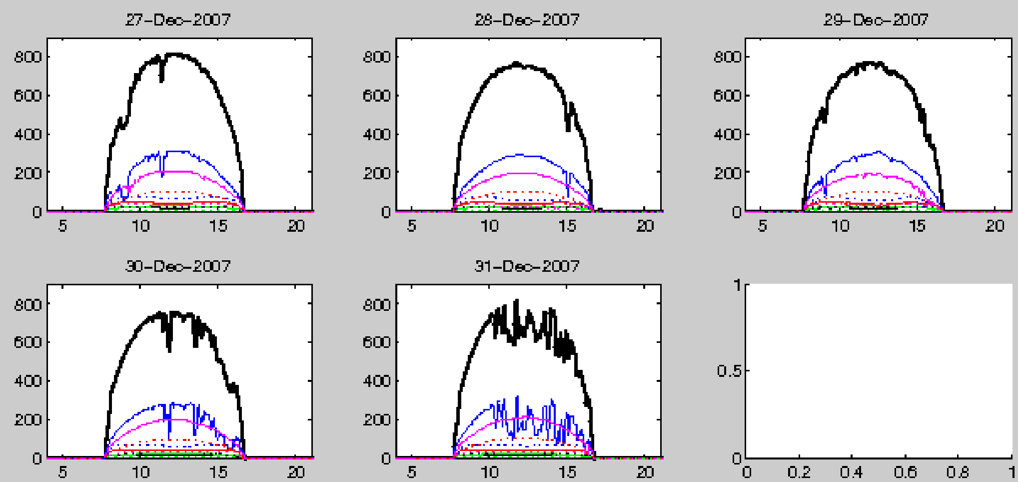
Hour of Day


27-Dec-2007
28-Dec-2007
29-Dec-2007
30-Dec-2007
31-Dec-2007

APPENDIX D. REGULATION RAMP RATE DEFICIENCY

Figure 92. Regulation Ramp Deficiency - Base Case (Winter, Summer and Shoulder)

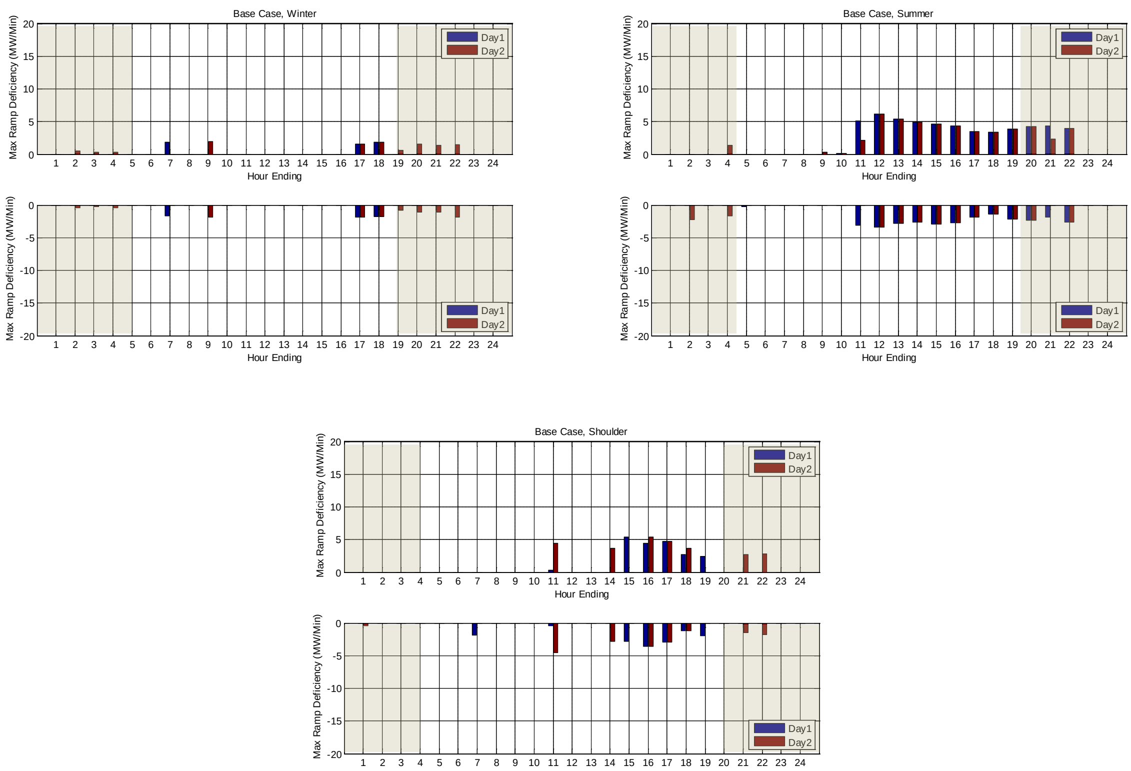
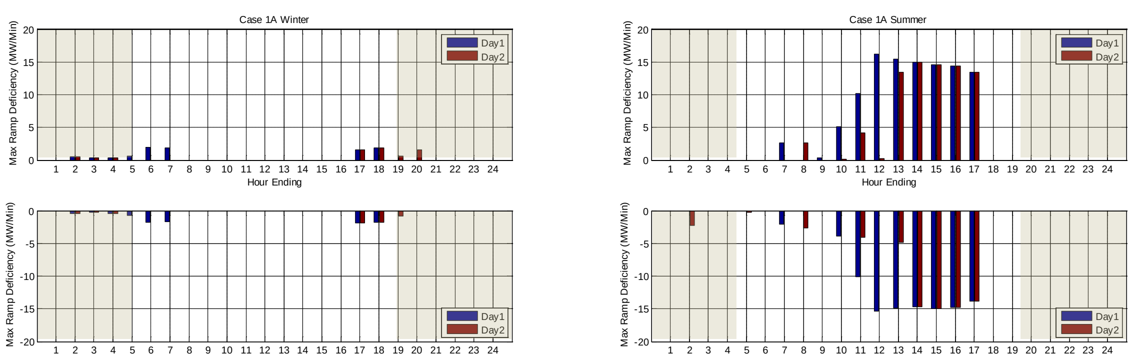


Figure 93. Regulation Ramp Deficiency - Case 1A (Winter, Summer and Shoulder)



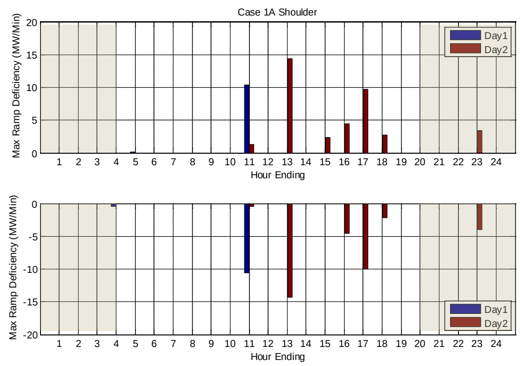


Figure 94. Regulation Ramp Deficiency - Case 2A (Winter, Summer and Shoulder)

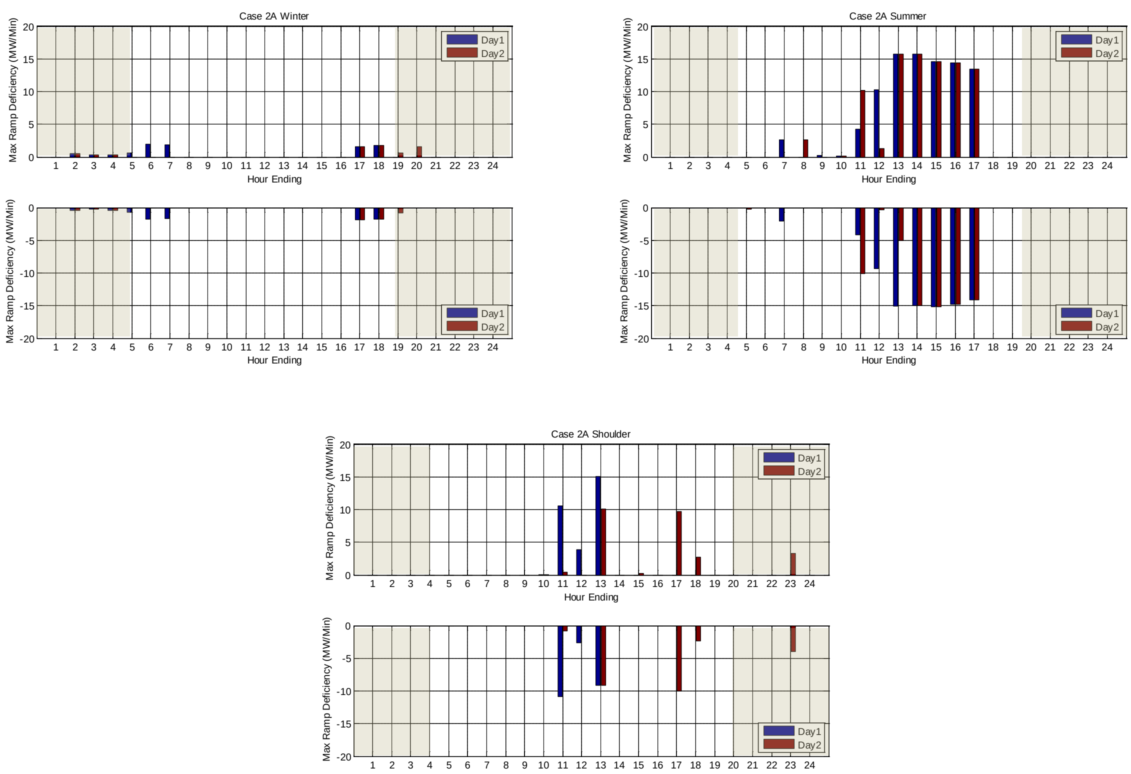


Figure 95. Regulation Ramp Deficiency - Case 3A (Winter, Summer and Shoulder)

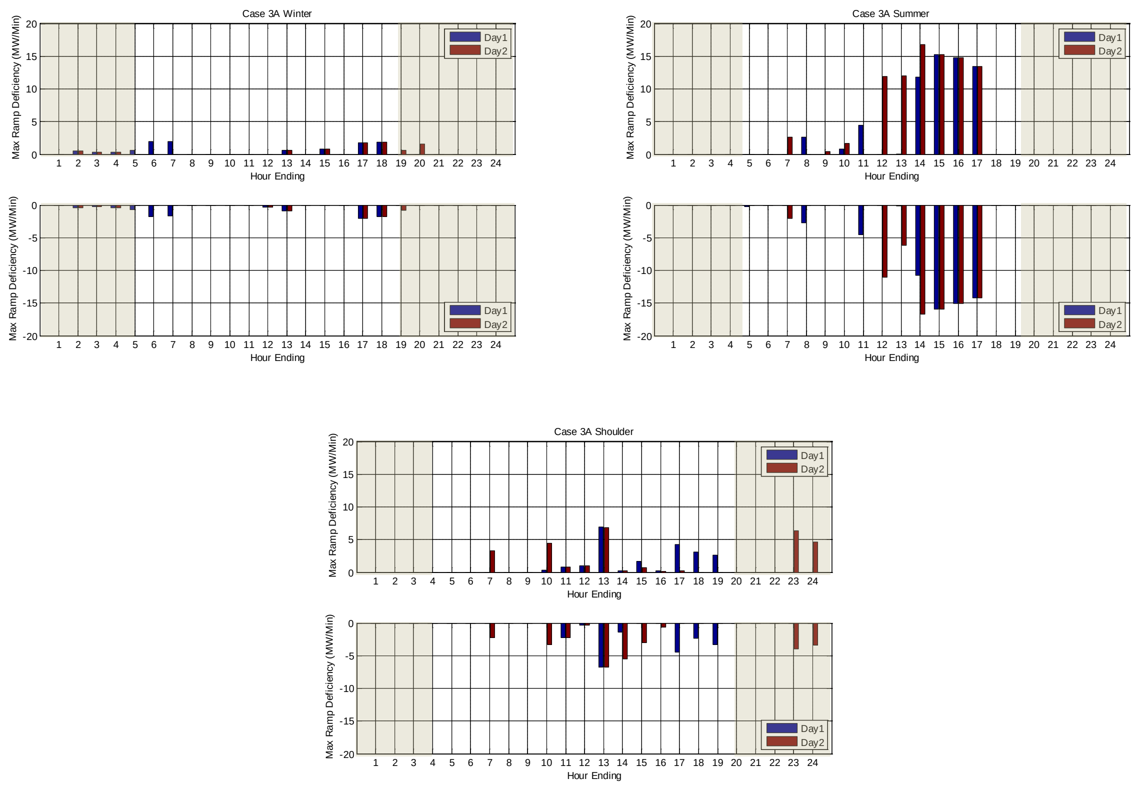
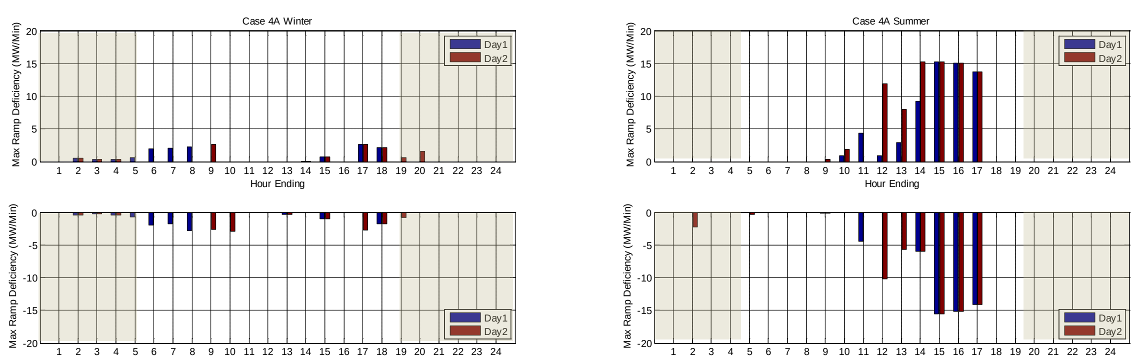


Figure 96. Regulation Ramp Deficiency - Case 4A (Winter, Summer and Shoulder)



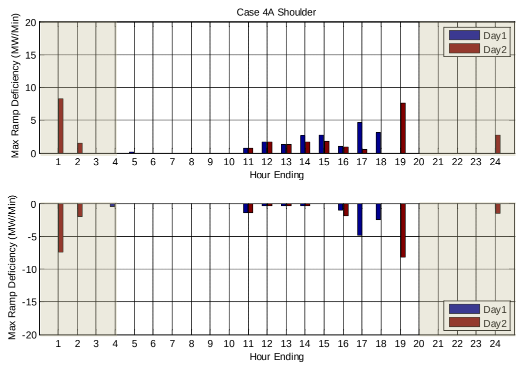
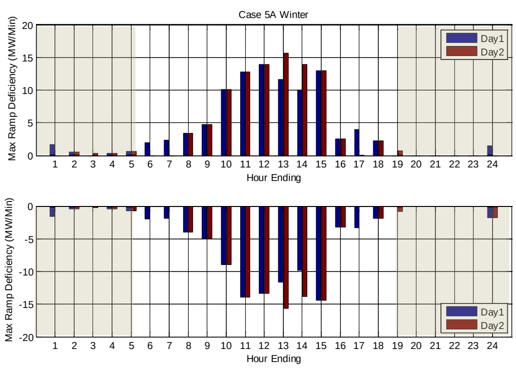
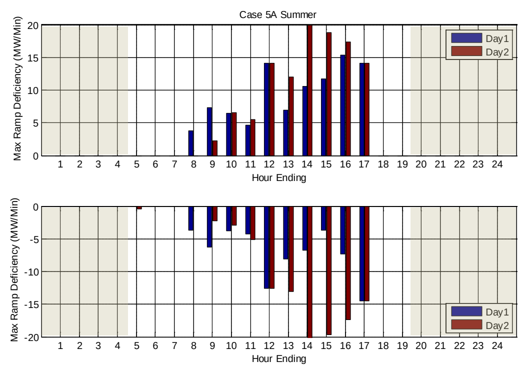
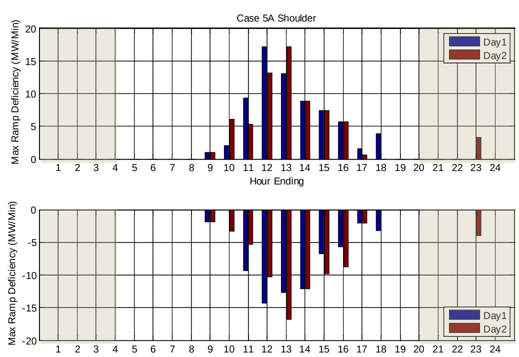


Figure 97. Regulation Ramp Deficiency - Case 5A (Winter, Summer and Shoulder)

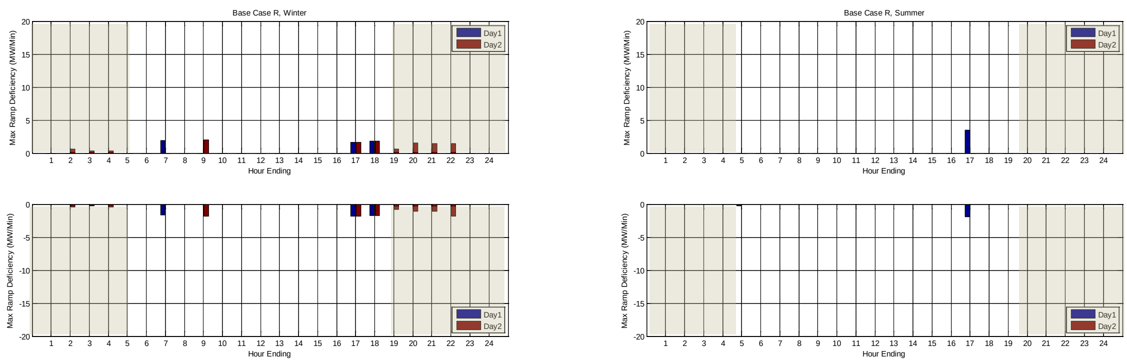






APPENDIX E. REGULATION RAMP RATE DEFICIENCY AFTER GENERATION REDISPATCH

Figure 98. Ramp Rate Deficiency after Generation Redispatch – Base Case (Winter, Summer and Shoulder)



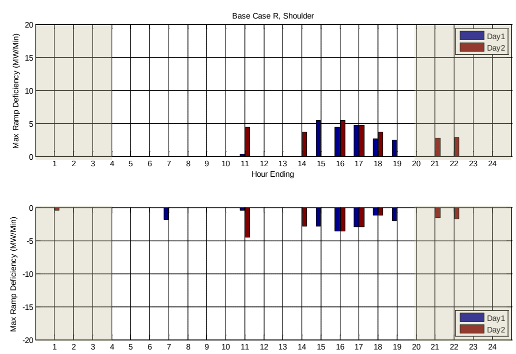


Figure 99. Ramp Rate Deficiency after Generation Redispatch – Case 1A (Winter, Summer and Shoulder)

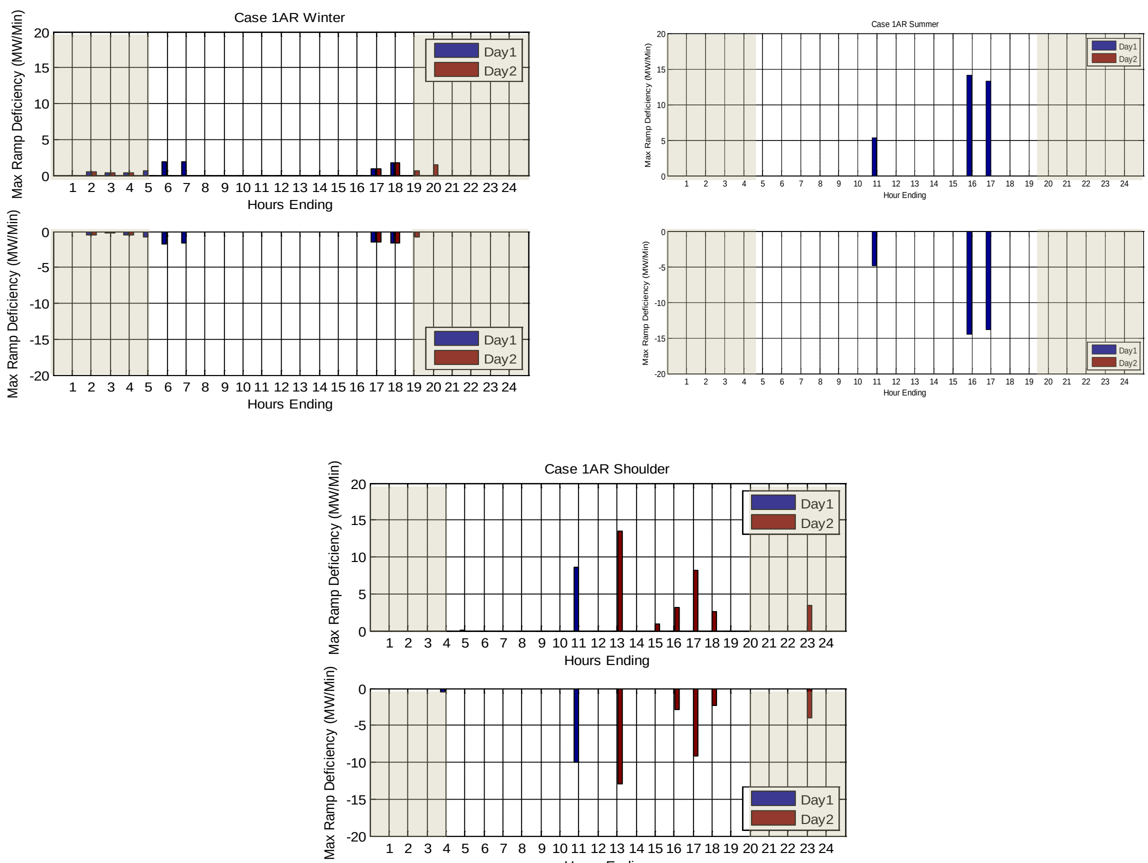
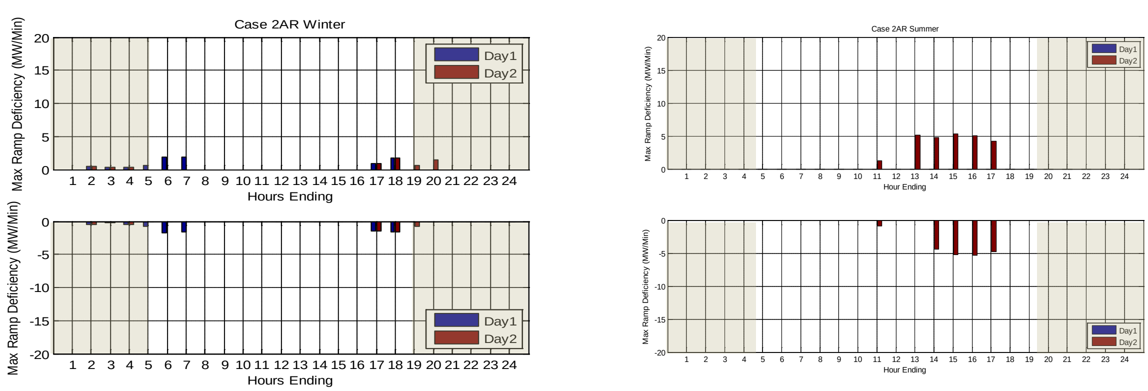


Figure 100. Ramp Rate Deficiency after Generation Redispatch – Case 2A (Winter, Summer and Shoulder)



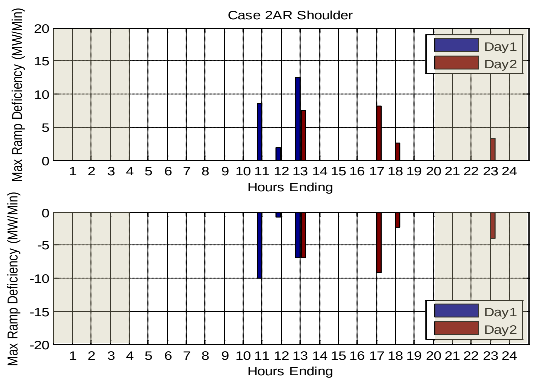


Figure 101. Ramp Rate Deficiency after Generation Redispatch – Case 3A (Winter, Summer and Shoulder)

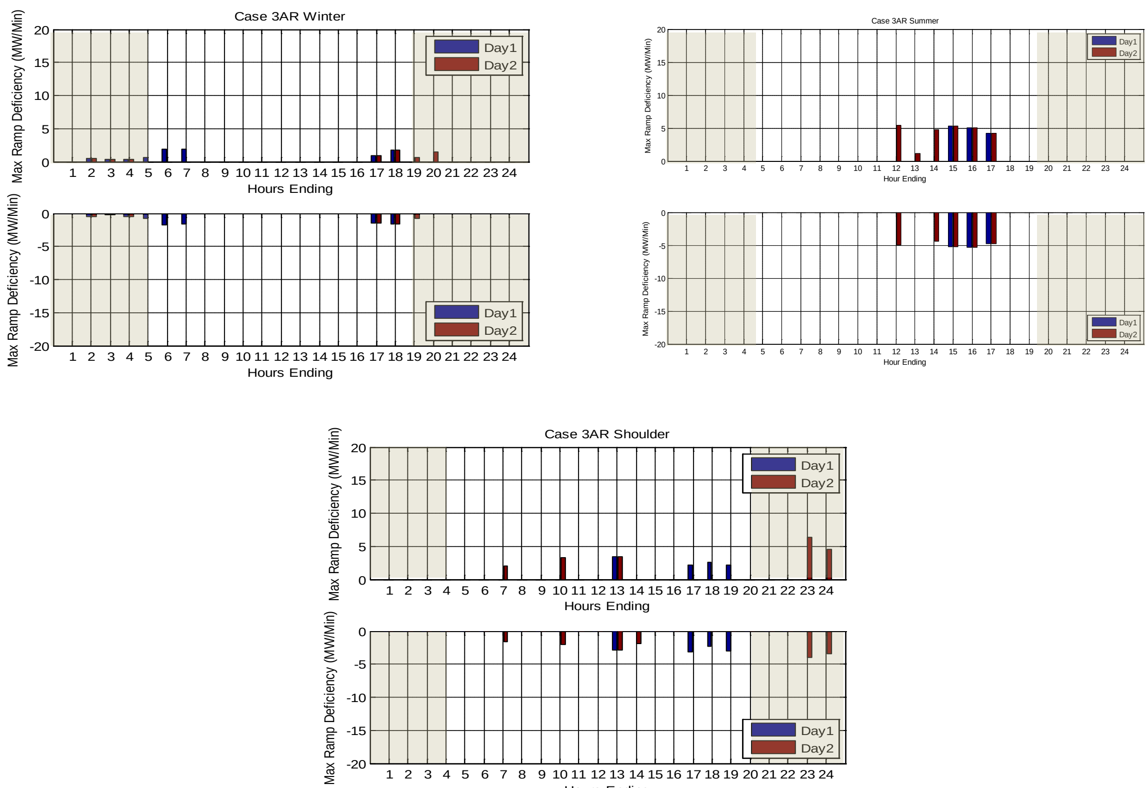


Figure 102. Ramp Rate Deficiency after Generation Redispatch – Case 4A (Winter, Summer and Shoulder)

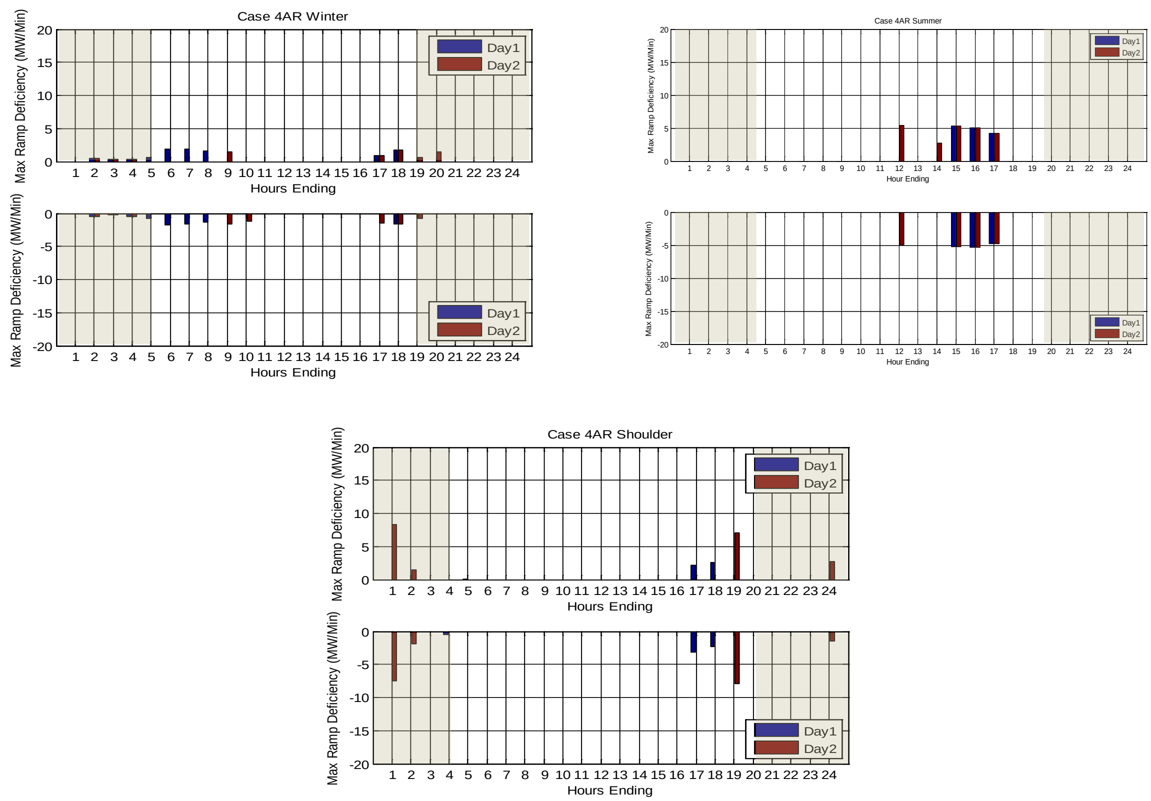
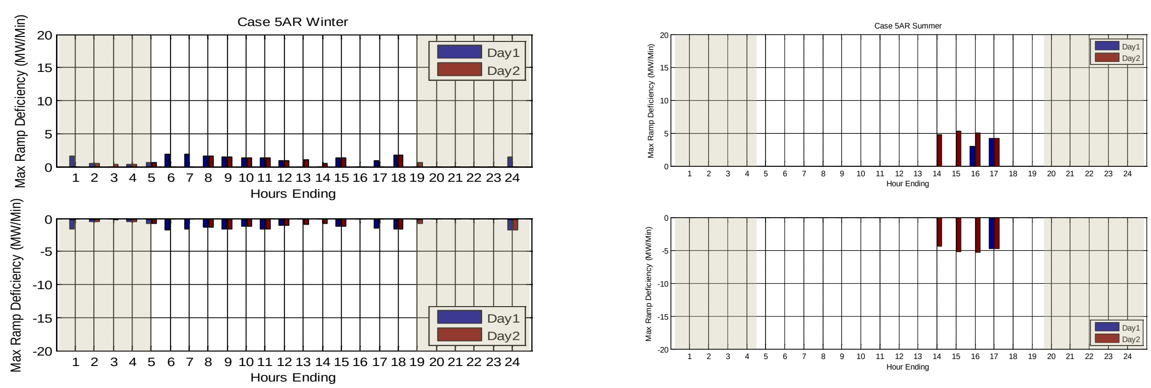
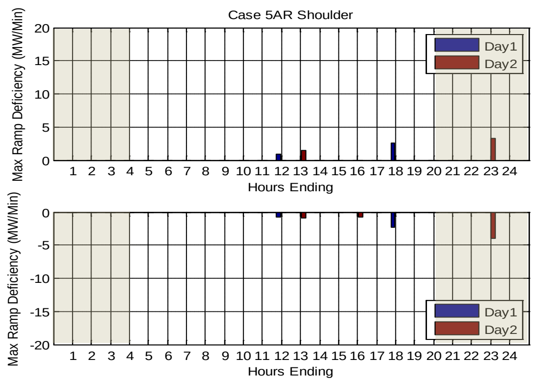


Figure 103. Ramp Rate Deficiency after Generation Redispatch – Case 5A (Winter, Summer and Shoulder)




Case 5AR Shoulder
Max Ramp Deficiency (MW/Min)
Day1
Day2
Hours Ending
Max Ramp Deficiency (MW/Min)
Day1
Day2
Hours Ending

Pacific Northwest
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