Predicting the Effects of Short-Term Photovoltaic Variability on Power System Frequency for Systems with Integrated Energy Storage

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Predicting the Effects of Short-Term Photovoltaic Variability on Power System Frequency
for Systems with Integrated Energy Storage

by

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B.S. Stanford University, 2005
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written by Joshua White Traube
has been approved for the Department of Electrical Computer and Energy Engineering

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Date: ___________

The final copy of this thesis has been examined by the signatories, and we find that both the content and the form meet acceptable presentation standards of scholarly work in the above mentioned discipline.
Predicting the Effects of Short-Term Photovoltaic Variability on Power System Frequency for Systems with Integrated Energy Storage

The percentage of electricity supplied by photovoltaic (PV) generators is steadily rising in power systems worldwide. This rise in PV penetration may lead to larger fluctuations in power system frequency due to variability in PV generator output at time scales that fall between the inertial damping and automatic generation control (AGC) responses of power systems. To reduce PV generator variability, active power controls can be implemented in the power electronic inverters that interface PV generators to the power system. Although various types of active power controls have been developed, no standard methodology exists for evaluating the effectiveness of these controls at improving power system frequency regulation. This dissertation presents a method for predicting the effects of short-term PV variability on power system frequency for a PV generator with active power control provided by integrated energy storage. A custom model of a PV generator with integrated energy storage is implemented in a power system dynamic simulator and validated through experiments with a grid emulator. The model is used to predict the effects of short-term PV variability on the frequency of the IEEE 9-bus test power system modified to include a PV generator with integrated energy storage. In addition, this dissertation utilizes linear analysis of power system frequency control to predict worst-case frequency deviations as a function of the amount of energy storage integrated into PV generators. Through simulation and emulation on a scaled experimental prototype, the maximum frequency
deviation caused by the PV generator with a small amount of integrated energy storage is found to be approximately 33% lower than the maximum frequency deviation caused by the PV generator alone. Through linear analysis it is shown that by adding only 36.7 kWh of integrated energy storage to a 1.2 MW PV system, the worst-case frequency deviation on the IEEE 9-bus test system can be reduced 65% from 0.45 Hz to 0.16 Hz. The techniques presented enable estimation of the maximum PV penetration or minimum integrated energy storage requirement to meet a frequency regulation target for a particular power system. Integrated energy storage can then be compared to other active power controls in order to choose a method that meets frequency control requirements at minimum cost.
Contents

Chapter

1. Introduction .................................................................................................................. 1

2. Effects of PV generators on power system frequency control .................................. 8
   2.1 Principles of PV generator operation ...................................................................... 9
   2.2 Variability of power produced by PV generators ............................................... 13
      2.2.1 Variability of solar radiation .......................................................................... 13
      2.2.2 Relationship between solar radiation and PV generator output power .......... 15
   2.3 Frequency control of a single synchronous generator .......................................... 17
   2.4 Effects of PV variability on frequency of a single generator system ................... 21
   2.5 Frequency control of multi-generator power systems ......................................... 22

3. Dynamic modeling of PV generators in power systems ........................................... 25
   3.1 Choice of a power system simulator ...................................................................... 25
      3.1.1 Categories of MatDyn Code ......................................................................... 26
   3.2 Development of a PV model ................................................................................ 30
      3.2.1 Differential equations of a PV generator ....................................................... 31
      3.2.2 Implementation of a PV generator in MatDyn ............................................. 33
   3.3 Results and discussion .......................................................................................... 35
4. Experimental validation of the PV generator model........................................... 38
   4.1 The grid emulator concept............................................................................. 39
   4.2 Quantifying the transfer function from load power to frequency ............... 39
      4.2.1 Governor Modifications ........................................................................ 40
      4.2.2 Load step results.................................................................................... 42
      4.2.3 System Identification............................................................................. 43
   4.3 Implementation of the transfer function in the grid emulator ...................... 45
      4.3.1 Discretization of the transfer function.................................................. 45
      4.3.2 Microcontroller implementation ............................................................. 46
   4.4 Grid emulator hardware and sensing......................................................... 47
   4.5 PV generator hardware and controller ....................................................... 49
   4.6 Experimental setup....................................................................................... 50
   4.7 Experimental Results................................................................................... 51

5. PV generators with integrated energy storage ................................................. 54
   5.1 Types of energy storage .............................................................................. 55
   5.2 PV generator with integrated DC/DC electric vehicle battery charger ........ 55
      5.2.1 Hardware design.................................................................................... 59
      5.2.2 Operating modes .................................................................................. 61
   5.3 Extension of MatDyn PV generator model to include integrated energy storage64
   5.4 Experimental validation of the PV generator model with storage ............... 67
   5.5 Discussion..................................................................................................... 69
6. Effects of integrated energy storage on frequency control ................................................................. 71

6.1 Defining “worst case” variability ........................................................................................................ 72

6.1.1 Worst case variability for PV generators without energy storage ........................................... 75

6.1.2 Example of worst case variability without energy storage ............................................... 76

6.1.3 Worst case variability for PV generators with energy storage ...................................... 79

6.2 Relationship between storage time constant, required battery capacity, required charger power, and worst-case frequency deviation ........................................................................... 81

6.3 Discussion ........................................................................................................................................... 85

7. Conclusions ........................................................................................................................................ 86

7.1 Summary of contributions ..................................................................................................................... 87

7.2 Future research directions ..................................................................................................................... 90

8. Appendix A Modeling PV generators with integrated energy storage in DIgSILENT PowerFactory ........................................................................................................................................... 93

9. Bibliography ...................................................................................................................................... 100
Tables

Table 2.1: Parameters of load to frequency transfer function for single generator example........ 19

Table 2.2: Line parameters for IEEE 9-bus test system.............................................. 24

Table 2.3: Steady-state power flow solution for IEEE 9-bus test system.......................... 24

Table 3.1: Changes required to MatDyn .m files to accommodate PV generator ................. 35

Table 3.2: Default PV generator parameters for MatDyn simulation................................ 36

Table 4.1: Governor parameters for generators 1 and 3 ................................................. 41

Table 4.2: Parameters of the identified transfer function ................................................. 43

Table 4.3: Grid-emulator components ........................................................................... 48

Table 4.4: PV inverter component values........................................................................ 50

Table B.1: Exciter parameters for generator 3.................................................................. 94

Table B.2: Governor parameters for generators 1 and 3................................................. 94
Figures

Figure 1.1: Time scales for power systems operations (adapted from [5]) ................................. 3

Figure 1.2: Strategies for accommodating variability and uncertainty at different time scales and penetration levels. [9], [25]–[27]........................................................................................................... 5

Figure 2.1: Typical architecture of PV generators........................................................................... 10

Figure 2.2: PV cell equivalent circuit and unshaded i-v characteristic......................................... 11

Figure 2.3: PV array power-voltage characteristic, showing maximum power point ............. 11

Figure 2.4: Schematic of a typical three-phase grid-connected inverter ...................................... 12

Figure 2.5: Square-wave voltage produced by inverter switches and average value produced by filter for 60 Hz fundamental........................................................................................................ 12

Figure 2.6: Insolation measurements taken at 1-second sampling rate at Kalealoa, Oahu, Hawaii between January 16, 2011 and January 22, 2011 [54]. ................................................................. 14

Figure 2.7: Single-sided frequency spectrum of the data in Figure 2.6........................................... 15

Figure 2.8: Transfer function from insolation G to inverter output power $P_{\text{inv}}$, as a function of PV array rated power $P_{\text{rat}}$ and inverter efficiency $\eta_{\text{inv}}$ ....................................................................................................................... 16

Figure 2.9: Cutoff frequency of the transfer function in Figure 2.8 vs. PV array rating............. 16

Figure 2.10: Block diagram of frequency control for a non-reheat steam turbine and synchronous generator (adapted from [60]) ....................................................................................................... 18

Figure 2.11: Bode plot of load to frequency transfer function for single generator example....... 20
Figure 2.12: Frequency deviations caused by PV variability on hypothetical power system ...... 22

Figure 2.13: IEEE 9-bus test system............................................................................................................ 24

Figure 3.1: MatDyn function flow.............................................................................................................. 27

Figure 3.2: Basic architecture of most PV generators .................................................................................. 32

Figure 3.3: Large signal model of a PV generator integrated with a power flow network solver.32

Figure 3.4: Preliminary confirmation of the PV generator model by comparing to a negative load.
(a) 0.025pu DC bus capacitor with DC-link PI control, (b) 25pu DC bus capacitor with
DC-link proportional control.................................................................................................................. 37

Figure 4.1: IEEE general speed-governing system...................................................................................... 41

Figure 4.2: Generator speeds and powers after -0.5 pu load step at bus 8................................................. 43

Figure 4.3: Comparison of response from identified transfer function and MatDyn simulation . 44

Figure 4.4: Bode plot of simplified transfer function and original identified transfer function ... 45

Figure 4.5: Bode plot of continuous and discrete time transfer functions ................................................. 46

Figure 4.6: Expected vs. actual response of the grid emulator frequency to a change in power of
........................................................................................................................................................................... 47

Figure 4.7: Grid emulator schematic and control ......................................................................................... 48

Figure 4.8: PV inverter hardware................................................................................................................ 50

Figure 4.9: PV inverter controller ................................................................................................................ 50
Figure 4.10: (a): Laboratory setup with grid emulator and PV inverter feeding resistive load. (b): Grid emulator output voltage $v_{ge}$ (top, pink) and PV inverter output current $i_{pv}$ (bottom, cyan), showing operation at 60 Hz and 208 V$_{rms}$ with unity power factor.

Figure 4.11: Measured PV generator output power during partly cloudy conditions.

Figure 4.12: Frequency response of the IEEE 9-bus test system (simulated in MatDyn) to changes in PV power shown in Figure 4.11 vs. measured frequency of the grid emulator.

Figure 5.1: Block diagram of PV generator with integrated DC/DC electric vehicle chargers.

Figure 5.2: Performance of the PV inverter with integrated energy storage on the IEEE 9-bus test system (charger filter: 2nd order, $\tau = 10$ minutes).

Figure 5.3: DC-DC charger schematic.

Figure 5.4: Channels 1&2: modules 1&2 switch node voltage, channels 3&4: modules 3&4 inductor current, showing resonant transitions and phase shifting.

Figure 5.5: Demonstration of the charger’s three operating modes: (top) charging-only mode 1, used solely to charge the battery without grid support, (mid) charging and grid-support mode 2, used to simultaneously charge the battery and provide grid support, and (low) grid-support only mode 3, used to provide grid support without charging the battery.

Figure 5.6: Block diagram of high level controller for battery charger used to reduce the magnitude and speed of fluctuations in PV generator output power.

Figure 5.7: Comparison of synchronous generator 1 speed (a) and DC-link voltage (b) for a PV generator with and without energy storage.

Figure 5.8: Measured $P_{pv}$ and $P_{inv}$ with charger low-pass filter ($\omega_c = 1/16$ seconds) during partly cloudy conditions.
Figure 5.9: Simulated, measured, and expected inverter output power ($P_{inv}$) based on measured PV power ($P_{pv}$) during partly cloudy conditions. ................................................................. 69

Figure 5.10: Simulated vs. measured frequency for the PV inverter output power shown in Figure 5.9. ........................................................................................................................................ 69

Figure 5.11: Comparison of simulated frequency deviations during partly cloudy conditions for the IEEE 9-bus system with a standard PV generator vs. a PV generator with integrated energy storage. ........................................................................................................... 70

Figure 6.1: Example from [40] of the effects of wind & solar variability on power system frequency. ....................................................................................................................................... 74

Figure 6.2: Histogram of daily $\Delta P_{max}$ for a 1.2 MW PV generator, based on 380 days of insolation data. ....................................................................................................................................... 78

Figure 6.3: Worst case $\Delta P_{max}$ of all 380 days, for May 20, 2010 at approximately 12:45pm. .. 78

Figure 6.4: Histogram of daily $\Delta P_{max}$ for a 1.2 MW PV generator with integrated energy storage, based on 380 days of insolation data.................................................................................................................................................. 80

Figure 6.5: Worst case $\Delta P_{max}$ of all 380 days, for April 24, 2010 at approximately 1:01pm. .. 81

Figure 6.6: Example of $\Delta E_{max}$ and $\Delta f_{max}$ vs. $\tau_{hpf}$ and filter order .................................................................................................................................................. 83

Figure 6.7: $P_{batt,max}$ vs. $\tau_{hpf}$ and filter order .................................................................................................................................................. 84

Figure 6.8: Worst-case frequency deviation $\Delta f_{max}$ vs. energy storage available $\Delta E_{max}$ for the example system. .................................................................................................................................................. 84

Figure B.1: Generator speeds and powers after -0.5 pu load step at bus 8 for MatDyn simulation (top) and PowerFactory simulation (bottom). .................................................................................................................................................. 96
Figure B.2: PowerFactory simulation of generator speeds and powers for system with PV generator on bus 8 during irradiance ramp from 0 to 1000 W/m$^2$ .................................................. 97

Figure B.3: High-pass filter control frame for battery energy storage ........................................... 98

Figure B.4: Generator speeds and powers for simulation of a PV generator with integrated energy storage in PowerFactory (top) and MatDyn (bottom). ...................................................... 99
Chapter 1
Introduction

To achieve long-term energy security and sustainability, electricity generation must be decarbonized. Mature technologies to generate carbon-free electricity can be divided into three categories: nuclear, firm renewables (hydroelectric, geothermal, biomass), and variable renewables (wind and solar). Out of these three categories, variable renewables have seen the largest growth over the past several decades and are widely considered to have the greatest growth potential in the future. From 2005 to 2010, the global installed capacity of wind turbines grew 305% from 60 GW to 183 GW and the capacity of solar photovoltaic (PV) plants grew 875% from 4 GW to 35 GW [1]. By 2035, the electricity produced from wind turbines is estimated to account for 7.3-13.4% of the world’s total electricity supply, and PV plants are expected to produce 2.3-4.3% [2].

From a power systems operation standpoint¹, variable renewable generators differ from traditional generators in three primary respects:

1. The fuel source for variable renewable generators is not controllable, and therefore the power output of variable renewable generators cannot be increased by adding more fuel, as it can for traditional generators. Furthermore, as the wind and sunlight vary in strength, the power output of variable renewable generators fluctuates and deviates from its forecasted value. The fluctuation of power output from renewable

¹ Variable renewable generators also affect the long-term capacity planning of power systems, but this dissertation focuses solely on operations. For information on the effects of variable renewables on power system planning, see [3], [4].
generators is defined as variability, and the deviation from forecasted prediction is
defined as uncertainty [5]. Both variability and uncertainty must be taken into account
during daily operation of a power system to ensure that there is enough electricity
supply to meet demand.

2. Variable renewable generators are often connected to the distribution system rather
than the transmission system, which can have negative effects on voltage regulation
because the distribution system was not originally designed to accommodate
generation [6], [7].

3. For variable renewable generators, the interface between the “prime mover” (i.e. the
wind turbine or PV array) and the electric power system is not a synchronous
machine, as it is for all traditional generators. This means that variable renewable
generators do not contribute to the synchronous inertia of the power system, which
has significant implications for frequency control and recovery after a contingency
such as a sudden loss of generation, load, or transmission [8].

As the installed capacity of variable renewable generators rises, modifications must be
made to power system operations practices in order to accommodate the three characteristics
mentioned above. As shown in Figure 1.1, different operations practices apply to different time
scales, but the goal of each practice is the same: to balance electricity supply with electricity
demand in order to maintain constant power system frequency\textsuperscript{2,3}. At daily intervals, schedules
determine which generators to dispatch to meet the expected load while minimizing cost subject
to various technical constraints such as generator planned outages and transmission congestion.

\textsuperscript{2} The relationship between supply-demand balance and frequency is explained in Section 2.1.
\textsuperscript{3} Maintaining constant voltage is also important, especially at the distribution level, but is not the focus of
this dissertation. For information on distribution system voltage control with high penetrations of variable
renewables, see [6], [7]
During the day, economic dispatch occurs at intervals of several minutes to an hour to adjust the scheduled generation to the observed load. Finally, some generators regulate their outputs in real-time to balance the second-to-second and minute-to-minute variations in load.

![Time scales for power systems operations](image)

Figure 1.1: Time scales for power systems operations (adapted from [5])

In systems with variable renewable generators, the variability and uncertainty of these generators combines with the variability and uncertainty of the load, leading to larger errors in matching electric supply with electric demand. Furthermore, the variability and uncertainty of renewable generation tends to be statistically larger than that of load, and can occur at time
scales ranging from a few seconds to several years [9]–[16]; therefore modifications must be made to power systems operations practices at all time scales. Figure 1.2 shows various strategies for accommodating variability and uncertainty at different time scales and penetration levels\(^4\). Depending on the penetration level, certain accommodation strategies are more important than others. For example, at low penetration levels accurate forecasting of wind and solar power enables system operators to schedule other generators more precisely, thereby minimizing area control error (ACE) [18], [19]. At mid-level penetrations, accurately quantifying the capacity value of variable resources enables system planners to decide how much other generation they need to build [20]. At high penetration levels, additional control algorithms and integrated energy storage enable better frequency regulation [21]–[24]. This dissertation focuses on the effects of variability at the regulation time scale (seconds to minutes) on small power systems with high penetrations of PV generators.

\(^4\)The word penetration has various meanings in the literature related to the amount of a variable renewable resource installed on a particular power system relative to the size of the system. The simplest definition of penetration is the ratio of nameplate capacity of variable renewable generators to nameplate capacity of all types of generators. However, this simple metric is not a good gauge of whether or not the system will incur operational difficulties due to the variability and uncertainty of renewable generators, because both renewable and traditional generators do not always operate at their nameplate ratings. A better definition is the ratio of the maximum AC power output from variable renewable generators over a given time period to the coincident electric load on the power system, known as maximum instantaneous penetration. This metric can be made even more constricting by substituting minimum load for coincident load or excluding electricity exports [17].
Significant research and development effort is currently being spent on improving variable generator control algorithms to reduce power system impacts in the regulation time frame by implementing such “advanced control” strategies as ramp limits, peak-power limits, active power droop, active power smoothing, and inertia emulation [28]–[37]. However, it is very difficult to quantify the improvements made by these controls on power systems with high penetrations of variable renewable generators, because few such power systems actually exist today\(^5\). A few studies have used computer simulations to compare the power system impacts of variable generators with and without advanced controls [21], [22], [24]. These studies generally focus on the impacts of wind turbines because on most power systems wind capacity exceeds PV capacity by a significant degree. However, on some smaller, isolated power systems such as the

\(^5\) The penetration of wind power in some European countries, including Ireland, Spain, Germany, and Denmark is quite high [17], [38]. Denmark and Germany have strong transmission ties to other countries that greatly reduce the impacts of wind variability. Ireland and Spain have made special efforts to accommodate variability through advanced forecasting and occasional curtailment, but the vast majority of their wind turbines do not implement any dynamic active power controls.
island of Lanai, Hawaii, the penetration of PV generators is reaching levels where maintaining
grid frequency during fluctuations in PV power output has become a concern [39]. Furthermore,
although PV and wind generators are both categorized as variable generators, the variability of
PV generators generally occurs at a faster time scale than that of wind generators [12]. Therefore
dedicated studies are required to examine the impacts of PV generators on power systems and
the improvements made by advanced controls.

Although a few studies have attempted to examine the effects of PV generators on power
systems at the regulation time scale using computer simulations [24], [40]–[44], none consider
the improvements that could be made by advanced controls. Furthermore, these studies either use
commercial simulation programs such as GE’s Positive Sequence Load Flow (PSLF), Siemens
“Power System Simulator for Engineering” (PSS/E), or Manitoba Hydro’s “Power System
Computer Aided Design” (PSCAD), or they utilize custom made models. Commercial software
packages, although proficient at simulating power systems dominated by synchronous machines,
do not usually contain accurate models of PV generator dynamics. Conversely, custom models
can include highly accurate models of PV generators but they do not usually contain the
powerful algorithms required for solving non-linear power system load flow equations. Finally,
none of the aforementioned studies have examined the improvements made by incorporating
energy storage or advanced controls into PV generators.

This dissertation presents three methodologies for evaluating the effects of active power
controls for PV generators (provided by integrated energy storage) on power system frequency.

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6 Page 56 of [40] contains the following statements: “There are also present limitations in the quality and
capability of the PV inverter models in use and the operational controls and response capability of PV resources to
be modeled.” “Continued work is necessary to enable effective modeling of high penetration PV scenarios using
tools such as GE MAPS and GE PSLF.” “This need has been recognized by the power systems modeling community
and efforts are currently underway to develop standard models for PV generators for power systems simulators [45].
The first method utilizes a power system dynamics simulator that is adapted to include an accurate model of a PV generator with integrated energy storage. The second method utilizes a grid emulator to experimentally observe the impacts of PV generators with integrated energy storage on power system frequency. The final method utilizes small-signal linear analysis techniques to predict worst-case frequency deviations as a function of the amount of energy storage integrated into PV generators. The goal of this dissertation is to demonstrate three ways to predict the impacts of PV generators on power system frequency and to quantitively evaluate the effectiveness of one method of reducing those impacts. This method can then be compared to other methods in order to choose the most cost effective manner to meet renewable energy targets while maintaining power system reliability.
Chapter 2

Effects of PV generators on power system frequency control

Quantifying the effects of PV generators on power systems is a large task requiring the work of many researchers. For practical reasons, the scope of this dissertation is therefore limited to studying the effects of PV generators on power system frequency control for small power systems with high penetrations of PV. Such power systems are becoming prevalent on many tropical islands (such as Hawaii) that have abundant solar resources, relatively low peak loads, and high electricity rates due to the cost of transporting fuel.

For example, a 1.2 MW photovoltaic plant was installed in 2009 on the island of Lanai, Hawaii to help serve a 5 MW peak load [39]. Due to concerns over PV variability affecting system frequency, the PV generator output power was limited to 600 kW until an energy storage system could be installed, and the remaining variability was accommodated by fast-ramping diesel generators. However, monitoring of power system frequency showed that limiting the PV generator output power may not have been necessary, as frequency variations during the day were no greater than those at night. By extension, if the Lanai power system was capable of maintaining frequency with 600 kW of PV, it might also have been capable of maintaining frequency with 1.2 MW of PV, rendering the expensive energy storage system unnecessary. However, the project planners lacked a method of quantifying the magnitude of the impact of PV variability on system frequency, and so decided to be conservative. This unfortunately resulted in unnecessary capital expense (for the energy storage system) and operating expense (for the diesel
fuel required to provide the additional 600 kW of power that the PV generator was not providing).

The purpose of this dissertation is to put forth a methodology for predicting frequency variations on small power systems due to variations in PV generator output power, and to quantify the amount of energy storage required to reduce these variations to a desired level. This goal is accomplished by incorporating a dynamic model of a PV generator into a power systems simulator (Chapter 3), validating the model against experimental results (Chapter 4), extending the model to include energy storage (Chapter 5), and using the combined, validated model to make predictions of power system frequency variation as a function of the amount of energy storage available (Chapter 6). The remainder of this chapter provides background on PV generators, power system frequency control, and the interaction between them.

2.1 Principles of PV generator operation

Like all electrical generators, PV generators contain a power production stage and a power conversion stage. Power production is performed by a PV array, which generally consists of parallel-connected strings of series-connected PV modules (panels), as shown in Figure 2.1. Each PV module contains multiple PV cells that are generally connected in series and which convert sunlight into direct current by the photoelectric effect [46]. Figure 2.2 shows the equivalent circuit for a PV cell and its unshaded current-voltage (i-v) characteristic. When multiple cells are connected in series, the i-v characteristic grows horizontally to produce the module i-v characteristic. Modules connected in series will further lengthen the voltage axis to produce the string i-v characteristic. Parallel connection of multiple strings will lengthen the current axis to produce the array i-v characteristic.
Figure 2.3 shows the unshaded power-voltage (p-v) characteristic of a PV array. As shown, the power is maximized by operating at the voltage known as the “maximum power point voltage” $v_{mpp}$. $v_{mpp}$ is a function of PV array architecture but also of many environmental variables such as solar radiation (insolation), cell temperature, and partial array shading. Therefore PV generators employ “maximum power point tracking” (MPPT) algorithms whose objective is to keep the PV array voltage at the level that maximizes power production. A comparative study of the effectiveness of various MPPT algorithms has been conducted in [47].
PV arrays convert light into direct current (DC), which must then be converted to alternating current (AC) in order to be transmitted in a power system. This conversion process is accomplished via a DC/AC power electronic converter known as an inverter. Figure 2.4 shows a typical schematic for a three-phase voltage-source inverter (VSI), which is currently the industry standard inverter type, although single-phase inverters are used for residential scale PV generators. The power electronic switches (Q1-Q6) are generally integrated-gate bipolar transistors (IGBTs) for utility-scale PV generators, but metal-oxide-semiconductor field-effect transistors (MOSFETs) are sometimes used for residential scale PV generators. In either case, the switches are modulated in such fashion as to produce a high-frequency (>10kHz) variable-duty square wave across the output filter of the inverter. The purpose of the output filter is to
average the switched waveform to its fundamental value as shown in Figure 2.5, which results in sinusoidal output voltage and current.

![Schematic of a typical three-phase grid-connected inverter](image)

**Figure 2.4:** Schematic of a typical three-phase grid-connected inverter

![Square-wave voltage produced by inverter switches and average value produced by filter for 60 Hz fundamental](image)

**Figure 2.5:** Square-wave voltage produced by inverter switches and average value produced by filter for 60 Hz fundamental.

Voltage-source inverters may be either voltage- or current- controlled, depending on the application. Most grid-connected inverters are current-controlled, although voltage-control schemes have been proposed [48]. For current-controlled inverters, the current through one of the filter inductors is sensed and compared to a sinusoidal reference. The resulting current error is compensated and modulated to produce the firing pulses for the inverter’s power electronic switches. This feedback is referred to as the “inner current loop” and generally has high bandwidth (>1kHz).
The sinusoidal current reference for the inner current loop is produced from a magnitude and angle. The angle is generally derived from a phase-locked loop (PLL) which determines the angle of the grid voltage waveform. For three-phase inverters the most common algorithm used by the PLL is discussed in [49]. For single-phase inverters, different algorithms can be used [50], [51] but all perform the same function, which is to resolve the angle of the grid voltage. This angle may then be either advanced or delayed in order to produce the desired power factor for the PV generator output. The magnitude of the sinusoidal current reference is produced by an outer voltage feedback loop which controls the voltage of the PV array to track the maximum power point voltage. If the PV array voltage exceeds \( v_{mpp} \), the magnitude of the current reference is increased; conversely, if the PV array voltage falls below \( v_{mpp} \), the magnitude of the current reference is decreased. The bandwidth of this outer voltage loop is usually about 10% of the bandwidth of the inner current loop.

Due to the high switching frequency of power electronics relative to power system fundamental frequencies (50-60 Hz), the dynamics of PV power conversion are generally considered to have negligible impact on power system operations [43], [52]. However, the dynamics of PV power production are slower and can therefore impact power system operations, as discussed below.

2.2 Variability of power produced by PV generators

2.2.1 Variability of solar radiation

Variability of PV output power is caused primarily by variability of solar radiation incident on the photovoltaic array. The amount of solar radiation, also known as insolation, impinging on a PV array is the product of numerous spatial and temporal factors, including

\[7\] At higher penetration levels, however, displacement of the rotating inertia from traditional generators by PV generators is cause for concern, as is discussed in [53].
altitude, latitude, season, time of day, array orientation and tilt, and weather. Of these factors, weather is the only one that affects PV power output at time scales relevant to power system frequency control.

The variability of insolation can be visualized by creating a frequency spectrum of insolation measurements taken at a known sampling rate. In order for this technique to be useful, the sampling rate must be fast enough to capture the time scale of interest. This work focuses on the frequency regulation time frame of several seconds to several minutes, and thus a sampling rate of 1 second is sufficient. Figure 2.6 shows insolation measurements taken at a 1 second sampling rate at Kalealoa, Oahu, Hawaii between the dates of January 16, 2011 and January 22, 2011 [54]. Figure 2.7 shows the frequency spectrum of this data, with obvious peaks at 24 hours, 12 hours, and 8 hours. As shown, the frequency content at time frames of less than 5 minutes is not negligible, although the magnitude decreases at faster time scales.

Figure 2.6: Insolation measurements taken at 1-second sampling rate at Kalealoa, Oahu, Hawaii between January 16, 2011 and January 22, 2011 [54].
2.2.2 Relationship between solar radiation and PV generator output power

Although insolation is proportional to PV generator output power in steady state, there are some considerations that must be taken in order to use insolation data in dynamic studies. Insolation data is generally measured at a single point location, while PV generator output power is dependent on insolation upon the entire PV array. The effects of partial array shading are therefore not captured by insolation data. PV array partial shading has been studied extensively [55], but the effects depend on the electrical configuration of the array and are therefore difficult to generalize. In [56], a simple method for converting insolation data into expected power output is developed based on empirical observations at six PV plants of various size. The authors derive a transfer function from insolation to power output that is dependent on the geographic area of the PV array, which is in turn proportional to the rated power of the PV generator. The transfer function from insolation $G$ (kW/m$^2$) to inverter output power $P_{inv}$ (MW), shown in Figure 2.8, takes the form of a 1st order low-pass filter with DC gain dependent on PV array rating and inverter efficiency and pole location dependent on the geographic area covered by the array in

![Single-sided frequency spectrum of the data in Figure 2.6](image)
hectares, which is proportional to PV array rating\(^8\). Figure 2.9 shows the cutoff frequency of the low-pass filter as a function of PV array rating. As shown, for PV arrays larger than 1 MW much of the higher frequency content of the insolation measurements will be attenuated, but variability will still occur within the frequency regulation timeframe. For PV arrays larger than 10 MW, all of the frequency content of the insolation measurements in the timeframe of interest will be attenuated. Furthermore, research has shown that geographic dispersion of multiple PV arrays further reduces aggregate variability [57], [58]. These effects explain why this dissertation is specifically looking at the effects of PV variability on frequency control of small, isolated power systems.

\[
\begin{align*}
G \, [\text{kW/m}^2] & \rightarrow \frac{P_{\text{rat}} \cdot \eta_{\text{inv}}}{\left(\sqrt{4.6 \cdot P_{\text{rat}}} \right) \cdot \frac{1}{2\pi \cdot 0.020}} \cdot s + 1 \rightarrow P_{\text{inv}} \, [\text{MW}]
\end{align*}
\]

Figure 2.8: Transfer function from insolation \(G\) to inverter output power \(P_{\text{inv}}\), as a function of PV array rated power \(P_{\text{rat}}\) and inverter efficiency \(\eta_{\text{inv}}\)

\[
\begin{align*}
\text{Cutoff frequency [Hz]} & \rightarrow 5 \, \text{min} \\
\text{PV array rated power [MW]} & \rightarrow 0 \, \text{MW} \quad 1 \, \text{MW} \quad 2 \, \text{MW} \quad 3 \, \text{MW} \quad 4 \, \text{MW} \quad 5 \, \text{MW}
\end{align*}
\]

Figure 2.9: Cutoff frequency of the transfer function in Figure 2.8 vs. PV array rating

\(^8\) The constant of proportionality is dependent on the configuration of the PV array. In [56] all PV arrays had vertical-axis tracking with ground coverage ratios of \(\approx 0.18\)
2.3 Frequency control of a single synchronous generator

In order to understand the effects of PV generators on power system frequency, one must first understand how the frequency of a power system is controlled. The dynamics of frequency control are best explained by examining the case of a power system supplied by a single synchronous generator. In such a machine, the frequency of the generated voltage is proportional to the rotational velocity of the rotor, while the magnitude of the generated voltage is proportional to the magnitude of the rotor’s magnetic field \[59\]. The output current, and thus output power, is determined by the load. Mechanical torque \(T_m\) is delivered to the rotor via a prime mover such as a steam or hydroelectric turbine. The mechanical torque is opposed by an electromagnetic torque \(T_e\) produced by the load current flowing through the stator windings. In steady state, the mechanical and electromagnetic torques are equal, resulting in a constant rotational velocity and therefore constant output frequency due to Newton’s 2\(^{nd}\) law of motion (2.1), where \(J\) is the moment of inertia and \(\omega\) is the rotational velocity. An increase in load causes an increase in electromagnetic torque, which will decrease the rotational velocity of the rotor and therefore decrease the output frequency unless opposed by an equal increase in mechanical torque from the prime mover. Conversely, a decrease in load will cause the output frequency to increase unless opposed by an equal decrease from the prime mover. The goal of frequency control is therefore to modulate the mechanical torque from the prime mover in order to keep the output frequency constant despite changes in load.

\[
J \cdot \frac{d\omega}{dt} = T_m - T_e
\]  

(2.1)

Figure 2.10 shows a typical block diagram of a frequency control loop for a non-reheat steam turbine connected to a synchronous generator. The mechanical and electrical torques have been converted to powers by multiplying by the nominal frequency, under the assumption that
frequency variations are small. The power reference $P_{\text{ref}}$ is provided by a proportional-integral (PI) controller acting on the frequency error. The proportional part of this controller is commonly known as “primary frequency control” or “droop control”, while the integral part is known as “automatic generation control” or AGC. The power reference $P_{\text{ref}}$ is followed by the prime mover subject to the mechanical time constants of the governor ($1/\omega_g$) and turbine ($1/\omega_t$), thereby producing the mechanical power $P_m$. The remainder of the loop follows an adaptation of Newton’s 2nd law of motion where the inertia $J$ has been replaced by the constant $M$, taking into account the conversion of torques to powers. In addition, the parameter $D$ has been added to the inertia block to represent the relationship between frequency and load that is typical of induction motor loads, namely that as the frequency of the voltage supplied to the motor decreases, the power drawn by the motor also decreases. Conversely, as the frequency supplied increases, the motor power increases. This characteristic is helpful from a frequency control point of view but the effects are entirely dependent on the proportion of motor loads on the power system.

$$P_m = \frac{1}{\omega_g} \frac{1}{1+s/\omega_g} + \frac{1}{\omega_t} \frac{1}{1+s/\omega_t} + M \frac{s}{M s + D}$$

Figure 2.10: Block diagram of frequency control for a non-reheat steam turbine and synchronous generator (adapted from [60])

9 It is worth noting that most generator control diagrams also include saturation blocks to limit the maximum and minimum power (torque) output of the generator and the maximum ramp rate. These blocks have been omitted from Figure 2.10 for the sake of maintaining linearity in the simplified example, but the value of the AGC gain $K_i$ will later be chosen to respect a 30% per minute ramp rate following a decrease in frequency equal to $1/K_p$.

10 $M = J \cdot \Omega \cdot \left( \frac{2}{P} \right)$, where $\Omega$ is the nominal mechanical frequency in rad/s and $P$ is the number of machine poles.
For the system shown in Figure 2.10, the closed loop transfer function from load power $P_e$ to output frequency $f$ can be derived analytically, as has been done in (2.2). A bode plot of (2.2) with the values specified in Table 2.1 is shown in Figure 2.11, where the powers have been normalized to a per-unit basis. The values of $K_p$ and $K_i$ selected were chosen to represent a relatively flexible generation resource that can ramp as fast as 30% per minute. The values of $\omega_g$ and $\omega_t$ were computed from the constants $T_1$ and $T_3$ specified for mechanical-hydraulic governors in [61], and the value of inertia $M$ was chosen to be typical of a condensing steam generator operating at 1800 rpm [62]. A relatively conservative value was chosen for $D$, representing a power system with a lower than average percentage of inductive motor loads.

\[
\frac{f(s)}{T_p(s)} = -\frac{1}{Ms + D} \cdot \frac{K_i/s + K_p}{1 + s\left(1/\omega_g + 1/\omega_t\right) + s^2/\omega_g\omega_t} = \frac{-1}{Ms + D} \cdot \frac{K_i/s + K_p}{1 + s\left(1/\omega_g + 1/\omega_t\right) + s^2/\omega_g\omega_t} \tag{2.2}
\]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>$M$</td>
<td>0.04</td>
<td>pu-s$^2$</td>
</tr>
<tr>
<td>$D$</td>
<td>0.05</td>
<td>pu-s</td>
</tr>
<tr>
<td>$K_p$</td>
<td>0.3333</td>
<td>pu/Hz</td>
</tr>
<tr>
<td>$K_i$</td>
<td>0.0017</td>
<td>pu-s/Hz</td>
</tr>
<tr>
<td>$\omega_g$</td>
<td>10</td>
<td>rad/s</td>
</tr>
<tr>
<td>$\omega_t$</td>
<td>3.3</td>
<td>rad/s</td>
</tr>
</tbody>
</table>

Table 2.1: Parameters of load to frequency transfer function for single generator example

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11 Pages 435 - 438
Figure 2.11: Bode plot of load to frequency transfer function for single generator example

Figure 2.11 reveals the following salient features of (2.2):

1. Fluctuations of $P_e$ (load) with a period greater than approximately 15 minutes are suppressed by the integral action of the PI controller.

2. Fluctuations of $P_e$ (load) with a period less than approximately 1 second are suppressed by the inertia of the turbine and generator.

3. Fluctuations of $T_e$ (load) with a period of several seconds to several minutes are not well suppressed and will result in corresponding fluctuations of output frequency.

In a power system with non-dispatchable generators such as PV, the dispatchable generators must supply the difference between the load power and the power produced by the non-dispatchable generators. Therefore from the viewpoint of the dispatchable generator, the power output from PV generators represents a negative load, and fluctuations in output power from PV generators are equivalent to fluctuations in load. Thus, for the simple example shown
above, if PV generator output power fluctuates at periods of several seconds to several minutes, then the frequency of the power system will also fluctuate.

### 2.4 Effects of PV variability on frequency of a single generator system

Based on the analysis in Section 2.3 above, a rough way of determining whether PV variability will affect power system frequency is to compare the frequency spectrum of PV power to the closed-loop load-to-frequency response of the power system. For the sake of providing a simple hypothetical example the following assumptions will be made.

1. The single synchronous generator described in Section 2.3 is representative of the power system on the island of Lanai, Hawaii.
2. The base power for the power system is equal to 5 MW, which is the peak load on the Lanai system.
3. The insolation measurements shown in Section 2.2 are representative of the insolation incident on Lanai’s 1.2 MW PV array. Specifically the insolation data recorded on January 19th and January 22nd, 2011 will be used.
4. The relationship between insolation and output power for the La Ola PV plant can be described by the low-pass filter of Figure 2.8, with $P_{rat} = 1.2$ MW and $\eta_{inv} = 0.95$.

With these assumptions the frequency deviation due to PV variability can be calculated by passing insolation data through Figure 2.8 and (2.2). Figure 2.12 shows this process for insolation data from January 19th and January 22nd, 2011. As shown, the variability of insolation due to movement of the sun in the sky does not cause frequency deviations, but variability due to passing clouds can occur at frequencies near the peak of Figure 2.11, thereby resulting in fluctuations in system frequency. This analysis establishes that PV variability has effects on power system frequency control for the hypothetical single-generator power system. Real power
systems, however, are made up of multiple generators, with load power and frequency control responsibility shared amongst them according to both the physical structure of the transmission network and the settings of various controllers, as described below.

Figure 2.12: Frequency deviations caused by PV variability on hypothetical power system

2.5 Frequency control of multi-generator power systems

In multi-generator power systems, each generator has its own set of parameters and dynamic equations that determine how it responds to changes in frequency. In addition, the total load on the power system is shared by the generators according to the structure of the transmission network and the actions of the generator governors. Due to the large number of variables and interconnected equations, frequency control of multi-generator power systems is typically analyzed using time-domain computer simulations. The simulations are initialized at nominal frequency and with generator loading determined by the steady-state power flow.
solution, which can be found using a power flow solver such as the MatPower [63]. At some time during the simulation, an event changes the load on one or more generators, which results in a change in generator speed. The generators respond according to their individual parameters and dynamic equations. For large, sudden load events such as faults, the generator speeds can differ significantly and some generators may experience pole slip [65]. However, for the much slower load events caused by PV variability, the system remains synchronized and generator speeds remain proportional to the system frequency. The relationship between PV variability and frequency for multi-generator power systems may therefore be analyzed using traditional simulators by treating PV power as a network disturbance.

Because the technical parameters of most real power systems are not publically available, this dissertation uses the IEEE 9-bus test system for all analyses. Figure 2.13 shows a one-line diagram of the IEEE 9-bus test system, which contains synchronous generators on buses 1-3, loads on buses 5, 6, and 8, and the transmission network shown. The base power is 100 MVA, and the values of the loads and line admittances are provided in Table 2.2. The steady-state power flow solution is shown in Table 2.3. The dynamic models used for the generator governors and exciters are discussed in Chapter 3.

12 The power flow solver combines load and line information into a collection of non-linear equations that can be solved using a mathematical method such as Newton-Raphson, as described in [64].
Figure 2.13: IEEE 9-bus test system

<table>
<thead>
<tr>
<th>From bus</th>
<th>To bus</th>
<th>R (pu)</th>
<th>X (pu)</th>
<th>B (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>4</td>
<td>0</td>
<td>0.0576</td>
<td>0</td>
</tr>
<tr>
<td>4</td>
<td>5</td>
<td>0.017</td>
<td>0.092</td>
<td>0.158</td>
</tr>
<tr>
<td>5</td>
<td>6</td>
<td>0.039</td>
<td>0.17</td>
<td>0.358</td>
</tr>
<tr>
<td>3</td>
<td>6</td>
<td>0</td>
<td>0.0586</td>
<td>0</td>
</tr>
<tr>
<td>6</td>
<td>7</td>
<td>0.0119</td>
<td>0.1008</td>
<td>0.209</td>
</tr>
<tr>
<td>7</td>
<td>8</td>
<td>0.0085</td>
<td>0.072</td>
<td>0.149</td>
</tr>
<tr>
<td>8</td>
<td>2</td>
<td>0</td>
<td>0.0625</td>
<td>0</td>
</tr>
<tr>
<td>8</td>
<td>9</td>
<td>0.032</td>
<td>0.161</td>
<td>0.306</td>
</tr>
<tr>
<td>9</td>
<td>4</td>
<td>0.01</td>
<td>0.085</td>
<td>0.176</td>
</tr>
</tbody>
</table>

Table 2.2: Line parameters for IEEE 9-bus test system

<table>
<thead>
<tr>
<th>Bus</th>
<th>Voltage</th>
<th>Generation</th>
<th>Load</th>
</tr>
</thead>
<tbody>
<tr>
<td>#</td>
<td>Mag (pu)</td>
<td>Ang (deg)</td>
<td>P (MW)</td>
</tr>
<tr>
<td>1</td>
<td>1</td>
<td>0</td>
<td>71.96</td>
</tr>
<tr>
<td>2</td>
<td>1</td>
<td>9.666</td>
<td>163</td>
</tr>
<tr>
<td>3</td>
<td>1</td>
<td>4.767</td>
<td>85</td>
</tr>
<tr>
<td>5</td>
<td>0.975</td>
<td>-4.021</td>
<td>-</td>
</tr>
<tr>
<td>6</td>
<td>1.003</td>
<td>1.922</td>
<td>-</td>
</tr>
<tr>
<td>8</td>
<td>0.957</td>
<td>-4.354</td>
<td>-</td>
</tr>
</tbody>
</table>

Table 2.3: Steady-state power flow solution for IEEE 9-bus test system
Chapter 3
Dynamic modeling of PV generators in power systems

3.1 Choice of a power system simulator

Many software packages exist that are capable of simulating power system dynamics. The electric power industry relies on commercial software packages such as Siemens’ “Power System Simulator for Engineering” (PSSE) or General Electric’s “Positive Sequence Load Flow” (PSLF). While extremely powerful, these packages are very expensive and require significant operator training. Other commercial simulators such as PowerWorld or PSCAD are lighter weight and more graphical but still proprietary. To maximize flexibility and replicability, this work utilized the open-source, Matlab-based simulator MatDyn [66], which is an extension of the popular Matlab-based power flow tool MatPower.13 As described below, MatDyn can be modified to include a model of a PV generator and observe the effects of PV variability on system frequency.

MatDyn contains three dynamic entities – generators, governors, and exciters – which are defined by parameters and state-space equations. Simulations are initialized by loading the parameters for the dynamic entities, static data related to the transmission network, and event data containing changes in line or bus parameters that are to occur at specific times during the simulation. The initial conditions are established by running MatPower’s power flow solver and setting the states of all dynamic entities according to the power flow solution.

---

13 At a later date a license was obtained for DIgSILENT PowerFactory, and the analysis presented in this chapter was replicated in that tool for verification purposes. The results are shown in Appendix A. Nevertheless, MatDyn is a much more transparent platform and is recommended if the results of this thesis are to be replicated.
MatDyn’s main loop solves the differential and algebraic equations of each dynamic entity using one of the five integration solvers that are included with the software. The updated states of the generators and the augmented network admittance matrix are then used to compute the bus voltages, which are used to compute the generator load powers. Computation of bus voltages is accomplished algebraically by making two simplifying assumptions, as described in [66]. Bus voltages are fed back to the exciters, generator powers to the generators, and generator speeds to the governors in order to compute the state variables for the next time step.

A variety of dynamic models for exciters, governors, and generators are available in MatDyn and described in [67]. In addition, new dynamic models can be added, as has been done in [68]. The MatDyn platform is therefore well suited for the implementation of a PV generator model that can be used to evaluate the stability of power systems with high penetrations of PV power.

3.1.1 Categories of MatDyn Code

In order to modify MatDyn to include a dynamic model of a PV generator, a more in-depth knowledge of the MatDyn code is required. The MatDyn code consists of a collection of .m files that fall into one of four basic categories: initialization, power flow, dynamic models, and integration solvers. Initialization functions prepare the parameters for the simulation. Power flow functions solve for bus voltages and generator powers based on loads, network admittances, and generator angles. Dynamic model functions calculate the derivatives of the states of generators, governors, and exciters based on their linear differential equations. Integration solvers calculate the states of generators, governors, and exciters by integrating the derivatives according to the particular algorithm chosen from [67]. In addition, the file “rundyn.m” is MatDyn’s main executable file responsible for running the simulation and plotting the results.
Figure 3.1 presents an overview of the MatDyn simulator, and the functions of the .m files in each of the four categories are described below.

![Figure 3.1: MatDyn function flow](image)

1. Initialization
   a. **Loaddyn.m** – loads general simulation parameters, typically contained in a “casefile” in the “Cases\Dynamic” subfolder (for example, “case9dyn.m”). General parameters consist of the nominal frequency of the power system being simulated, the step size to use for constant step size integration solvers, and the length of the simulation.
   b. **Loadgen.m** – loads the dynamic parameters of all generators from the casefile. Different types of generators will have different parameters, as described in [67]. For example, the simple (type 1) generator model only has parameters for inertia, load damping, and d- and q-axis reactance, while the more complex (type 2) model has additional parameters for transient reactance and winding resistance.
c. “Loadexc.m” – loads the dynamic parameters of all exciters from the casefile. In addition to a simple constant excitation system, MatDyn includes a model for the IEEE DC1A excitation system, which is described in [69]. Additional types of exciters may be added by the user if desired, as described in [67].

d. “Loadgov.m” – loads the dynamic parameters of all governors from the casefile. In addition to a simple constant power governor, MatDyn includes a model for the IEEE general speed governing system described in [61].

e. “Loadevents.m” – loads the type and time of occurrence of all events that occur during the simulation. Event data is passed as an argument to rundyn.m. Events can take one of two forms: a change in bus parameters such as real or reactive power demand, or a change in line parameters such as resistance or reactance. A complete list of bus and line parameters is provided in [70].

f. “Mdoption.m” – specifies additional parameters for the simulation, such as which integration solver to use and what the tolerance, maximum, and minimum step sizes should be for variable step-size solvers. Also specifies whether or not rundyn.m should plot the results of the simulation or print them to the Matlab console.

2. Power Flow

a. “runpf.m” – runs MatPower’s power flow algorithm (located in the MatPower folder) to find the initial bus voltages and generator powers for the simulation. runpf also returns the branch data that is used by AugYBus.m to construct the augmented Y-bus matrix. For more information on runpf.m, see [70].
b. “AugYBus.m” – constructs augmented Y-bus matrix from bus, branch, generator, and load admittances. Uses MatPower’s “makeYbus.m” to construct the basic Y-bus matrix from bus and branch data, then augments with load and generator admittances. Finally uses LU factorization to factor the augmented Y-bus matrix so that it can be used to algebraically solve for bus voltages, as described in [66]. For more information on the purpose of the Y-bus matrix in power flow algorithms, see [64].

c. “MachineCurrents.m” – calculates d- and q-axis currents for all generators based on bus angles, generator angles, back-EMF voltages, and generator reactances, as described in [64].

d. “SolveNetwork.m” – solves for all bus voltages from the generator currents and augmented Y-bus matrix, as described in [64].

3. Dynamic Models

   a. “GeneratorInit.m” – initializes generator states (angle, frequency, and back-EMF) from initial power flow solution

   b. “Generator.m” – calculates derivatives of generator angle, frequency, and back-EMF according to the dynamic equations of the generator model. Required inputs include excitation voltage, governor power reference, and electrical power output.

   c. “GovernorInit.m” – initializes governor states from governor parameters and initial generator frequency.

   d. “Governor.m” – calculates derivatives of governor states from governor parameters, previous states, and generator frequency according to the dynamic equations of the governor model.
e. “ExciterInit.m” – initializes exciter states from exciter parameters and initial bus voltage.

f. “Exciter.m” – calculates derivatives of exciter states from exciter parameters, previous states, and bus voltage according to the dynamic equations of the exciter model.

4. Integration Solvers – the integration solvers included in MatDyn are described in depth in [67].

3.2 Development of a PV model

Previous works have developed PV models for power system simulations, but depending on the time scale of the simulation certain dynamics may be included or excluded. For many studies, such as [71], PV generators are simply considered as a source of active power proportional to the insolation on the array, with no dynamics at all. Other studies such as [72] include the dynamics associated with voltage sensing and reactive power control but not with the bandwidth of the PV inverter control loops. In [73], a simplified model of a PV generator is proposed that represents the bandwidth of the inverter as a low-pass filter but neglects dynamics associated with the DC-link. In this dissertation, a PV generator model that includes both inverter and DC-link dynamics is developed for MatDyn and used to analyze the relationship between PV variability and power system frequency. Because this dissertation focuses on the relationship between frequency and active power, reactive power control is not included in the PV model.

Although MatDyn was created to simulate the dynamics of traditional generators, the simple code layout and open-source nature make it possible to extend the program to include a dynamic model of a PV generator. Furthermore, the PV generator model can be constructed in such a way as to take advantage of MatDyn’s default power flow and integration functions.
Accomplishing this requires two distinct steps: (1) determining the relevant differential equations for a PV generator, and (2) creating a user-defined model in the MatDyn code that accurately represents the differential equations of a PV generator while using the same inputs and outputs as for synchronous generators. The challenge lies in defining the states of the PV generator dynamic model, as these states differ significantly from the states of synchronous generators but must nevertheless be passed through the MatDyn integration and power flow functions in the same manner.

### 3.2.1 Differential equations of a PV generator

The vast majority of grid-connected PV generators consist of a PV array, maximum power point tracker (MPPT), DC-link capacitor, voltage source inverter (VSI), and LC output filter, as shown in Figure 3.2. MPPT dynamics are often non-linear and vary considerably with the particular algorithm used [47]. In the interest of developing a simple PV model, it is assumed that the PV array is operated at constant voltage and MPPT dynamics are ignored. This assumption can be somewhat justified by the fact that the maximum power point voltage of PV cells does not vary much with insolation, although it does vary significantly with temperature [74]. Because this dissertation focuses on short-term effects of variable insolation on power system frequency, PV cell temperature and therefore maximum power point voltage are assumed to be constant. This simplification reduces the MPPT and PV array to an insolation-dependent power source as shown in Figure 3.3. The VSI can be considered as a power sink whose power is transferred to the grid via a current feedback loop around the output filter inductor current $i_L$ with bandwidth $\omega_{gen}$. For unity power factor controllers the output current is in phase with the grid voltage and its magnitude is determined by a feedback loop around the DC-link voltage.

The PV generator model can therefore be represented as in Figure 3.3, and the equations of the PV generator can be written according to (3.1)-(3.5). (3.1) captures the dynamics of the
DC-link voltage, where the difference in power input from the PV array and power output to the grid flows into the capacitor $C_{dc}$. (3.2) and (3.3) represent a PI controller which produces a power reference $P_{ref}$ for the VSI based on the DC-link voltage error. (3.4) translates the power reference into a current reference by dividing by $U_{est}$, the complex conjugate of the estimated AC bus voltage, and also captures the closed-loop behavior of the VSI current controller with bandwidth $\omega_{gen}$. $U_{est}$ is derived from (3.5), which simply follows the AC bus voltage $U_{bus}$ with some bandwidth $\omega_{exc}$ which is chosen to be significantly greater than $\omega_{gen}$. Because $U_{bus}$ is a complex number, $\omega_{exc}$ also approximates the bandwidth of the PV inverter’s phase-locked loop (PLL).

![Figure 3.2: Basic architecture of most PV generators](image)

![Figure 3.3: Large signal model of a PV generator integrated with a power flow network solver](image)
\[ s \cdot v_{dc} = \frac{P_{pv} - P_{gen}}{v_{dc} \cdot C_{dc}} \]  

(3.1)

\[ s \cdot x = k_i \left( v_{dc} - V_{ref} \right) \]  

(3.2)

\[ P_{ref} = x + k_p \left( v_{dc} - V_{ref} \right) \]  

(3.3)

\[ s \cdot i_L = \omega_{gen} \left( \frac{P_{ref}}{U_{est} - i_L} \right) \]  

(3.4)

\[ s \cdot U_{est} = \omega_{exc} \left( U_{bus} - U_{est} \right) \]  

(3.5)

### 3.2.2 Implementation of a PV generator in MatDyn

In order to implement the PV generator model in MatDyn, (3.1)-(3.5) must be coded into the .m files representing the dynamic models of a governor, generator, and exciter. By inspection of (3.1)-(3.4) it can be seen that the states of the PV generator are the DC-link voltage \( v_{dc} \), the filter inductor current \( i_L \), and the PI controller integrator state \( x \). \( P_{ref} \) is an intermediary calculation, while \( V_{ref}, C_{dc}, k_i, k_p, \) and \( \omega_{gen} \) are generator parameters. The inputs to the system are \( U_{est}, \) a voltage, and \( P_{pv}, \) a power. This is similar to the inputs to the synchronous generator model, where \( U_f \) is the field voltage provided by the exciter and \( P_m \) is the power command provided by the governor. However, instead of providing a field voltage, the exciter for a PV generator must only provide an estimate of the AC bus voltage, which can be done easily by passing the AC bus voltage through a first-order low-pass filter with bandwidth \( \omega_{exc}, \) as described by (3.5).

Providing \( P_{pv} \) is not as simple, because \( P_{pv} \) is dependent on solar insolation and not on frequency. A governor model for the PV generator therefore must disregard its natural input (frequency), and instead process a separate input that is time-dependent but not determined by
dynamic equations. Such an input is more akin to an event (such as a change in load) than it is to a dynamic state, but unfortunately MatDyn only supports events that are changes to bus and line parameters – not to generator parameters. Therefore in order to accurately capture $P_{pv}$, rundyn.m had to be modified to include a global variable that is updated by the main iterative loop and accessed by the PV generator. Because $P_{pv}$ does not depend on frequency, it can be processed directly in Generator.m and the governor model for the PV generator can be ignored.

Based on the discussion above, the pseudocode for the PV dynamic model in Generator.m is the following:

1. Read $V_{ref}$, $C_{dc}$, $k_i$, $k_p$, and $\omega_{gen}$ from generator parameters vector
2. Read $U_{est}$ from exciter states vector
3. Read $P_e$ from input arguments
4. Read $P_{pv}$ from global variable in this time step
5. Read $V_{dc}$, $i_L$, and $x$ from generator states vector
6. Calculate $dV_{dc}/dt$, $dx/dt$, $P_{ref}$, and $di_L/dt$ based on (3.1)-(3.4)

The pseudocode for the PV dynamic model in Exciter.m is:

1. Read $\omega_{exc}$ from exciter parameters vector
2. Read $U_{bus}$ from input arguments
3. Read $U_{est}$ from exciter states vector
4. Calculate $dU_{est}/dt$ based on (3.5).

In addition to the changes to Generator.m and Exciter.m, small changes were required to other MatDyn files in order to accommodate the PV generator. Table 3.1 describes all the changes required to MatDyn files.
### MatDyn Filenames | Required Changes
--- | ---
**MachineCurrents.m** | • Add method of calculating PV generator output power by multiplying PV generator output current (state) by bus voltage.

**Mdoption.m** | • Change integration method to “6”, a custom method to accommodate solar generator (described in RungeKuttaFehlberg_solar.m)

**rundyn.m** | • Add $P_{pv}$ global variable and update in main loop
• Add PV generator filter capacitance to augmented Y-bus matrix
• Add integration method 6 (described in RungeKuttaFehlberg_solar.m)

**SolveNetwork.m** | • Load PV generator current from state vector

**case9dyn.m** | • Add generator parameters for PV generator
• Add governor parameters for synchronous generators

**Exciter.m** | • Add bus voltage estimator equations & parameters for PV exciter.
• Take absolute value of bus voltage for synchronous generator excitors.

**ExciterInit.m** | • Add PV generator equations & parameters
• Initialize PV generator states

**Generator.m** | • Pass complex bus voltage U to exciters instead of magnitude abs(U). This is required to allow PV generator to track power factor.

**GeneratorInit.m** | • Add PV generator equations & parameters
• Initialize PV generator states

**RungeKuttaFehlberg_solar.m** | • Pass complex bus voltage U to exciters instead of magnitude abs(U). This is required to allow PV generator to track power factor.

| Table 3.1: Changes required to MatDyn .m files to accommodate PV generator |

### 3.3 Results and discussion

For preliminary confirmation of PV generator model operation, simulations were conducted with the PV generator to observe the effects of a sudden increase in PV power on the generator speeds of the IEEE 9-bus test system. MatDyn’s default parameters were used for all loads, lines, and synchronous generators on the system, and the Runge-Kutta-Fehlberg algorithm was used as the network solver, with the modification described in Table 3.1. Bus 8 was chosen as the location of the PV generator because it is centrally located between synchronous generators. The parameters of the PV generator, shown in Table 3.2, were chosen to be representative of typical bandwidths and component values. The value of the filter capacitor $C_f$ was chosen such that 0.01 pu of reactive power is produced by the PV generator at 60 Hz and 1 pu bus voltage when there is no insolation. At time $t=5$ seconds into the simulation, the power input from the PV array was increased from 0 MW to 50 MW (0.0 pu to 0.5 pu) in 5 seconds,
and the results were compared to a second simulation with no PV generator but with an equivalent decrease in load on bus 8 over the same time period. Because the change in PV power or load occurs relatively slowly (compared with a fault, for example), all synchronous generators on the system remain synchronized, and the speed of any generator can be used to determine the system frequency. For the remainder of this dissertation the speed of generator #1 will therefore be used as a proxy for system frequency. Figure 3.4a shows a comparison of generator 1 speed for the PV model case and the equivalent load decrease case. As shown, the speed response is very similar in both simulations, which can be attributed to the relatively fast response and lack of significant energy storage in the basic PV generator model. For comparison, Figure 3.4b shows the same simulation where the size of the DC-link capacitor has been increased by three orders of magnitude and the integral action of the DC bus voltage control has been removed, allowing the DC-link voltage to rise 0.5 pu. These changes effectively add energy storage to the PV generator, which results in a lagging and less steep response in generator speed. A more in-depth analysis of the effects of adding energy storage to PV generators will be provided in Chapter 5.

<table>
<thead>
<tr>
<th>Parameter</th>
<th>$\omega_{\text{gen}}$ (rad/s)</th>
<th>$\omega_{\text{exc}}$ (rad/s)</th>
<th>$C_{\text{dc}}$ (pu)</th>
<th>$k_i$</th>
<th>$k_p$</th>
<th>$C_f$ (pu)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Value</td>
<td>$2\pi \cdot 100$</td>
<td>$2\pi \cdot 500$</td>
<td>.025</td>
<td>10</td>
<td>10</td>
<td>2.65e-5</td>
</tr>
</tbody>
</table>

Table 3.2: Default PV generator parameters for MatDyn simulation
Figure 3.4: Preliminary confirmation of the PV generator model by comparing to a negative load. (a) 0.025pu DC bus capacitor with DC-link PI control, (b) 25pu DC bus capacitor with DC-link proportional control.
In order to validate the MatDyn PV generator model it is desirable to compare simulation results to experimental results. This task, however, presents a problem of scale. The PV generators present in laboratories are typically rated between 1 and 10 kW, whereas the power systems that feed most laboratories are rated to thousands of MW. A laboratory scale PV generator will therefore have no measureable effect on the frequency of a large power system, nor could any effect be separated from the myriad other effects, for example of varying loads. Furthermore, the dynamic parameters of most power systems are not publically available and therefore could not be programmed into MatDyn.

One solution to this problem would be to conduct experiments using an islanded microgrid consisting of a few small synchronous generators, a PV generator, and some constant loads. The frequency of the microgrid could then be measured in the presence of variations in output power from the PV generator, and the results compared with a MatDyn simulation. Such experiments have been conducted in prior work [74], although the results were not used to validate simulation models.

Although the microgrid approach provides a feasible method of validating the MatDyn PV generator model, it has the disadvantage of not being representative of an actual power system. The dynamics of small synchronous generators and their controllers differ significantly from larger generators, and the transmission networks of larger power systems are typically more complex than those of microgrids. The remainder of this chapter therefore discusses an
alternative approach, in which a second inverter is used to emulate the frequency of a larger power system in the presence of changes in output power from a PV generator, and the results are compared with MatDyn simulations.

4.1 The grid emulator concept

The simplest approach to emulating the response of power system frequency to changes in PV power is to approximate a transfer function between load power and frequency for a particular bus on the system. This approach assumes that PV power appears as a negative load to synchronous generators, as discussed in Section 2.3. Section 2.1 showed that the transfer function between load power and frequency typically looks like a band-pass filter, where fluctuations in load power on a time-scale of minutes are suppressed by secondary frequency control (AGC), while sub-second fluctuations in load power are suppressed by the inertia of synchronous generators. Fluctuations in load power on a time-scale of seconds typically result in fluctuations in frequency. If the transfer function from load power to frequency could be quantified for a particular bus, then a voltage source inverter could be programmed to measure its output power and change its frequency according to the transfer function. For the remainder of this dissertation such an inverter will be called a “grid emulator.” Note that the grid emulator only captures the frequency dynamics of a power system – its output voltage is held to a constant rms value using traditional voltage control techniques.

4.2 Quantifying the transfer function from load power to frequency

For single-generator power systems, the transfer function from load power to frequency can be found analytically, as shown in Section 2.1. However, for multi-generator power systems, the transfer function will depend on the location of the load relative to the location of the generators on the transmission network, in addition to the dynamic parameters of the generators.
and their governors. In addition, although the transfer functions of multi-generator power systems will be higher order, it is of interest to only quantify the dominant poles and zeros, as is done in [72], in order to simplify calculations in the grid emulator microprocessor. For these reasons it is more expedient to use numerical estimation techniques to find the transfer functions of multi-generator power systems.

### 4.2.1 Governor Modifications

The IEEE 9-bus power system was used as an example that captures the complexity of multi-generator power systems while still remaining simple enough to comprehend intuitively. In addition, a model of the IEEE 9-bus power system is distributed with MatDyn, which makes replicating the simulations in this dissertation more straightforward. However, the model of the IEEE 9-bus power system that is distributed with MatDyn does not include dynamic models for the generator governors, and therefore some modifications must be made to the MatDyn code in order to accurately capture frequency dynamics in simulations.

Figure 4.1 shows the IEEE general speed governing system that is implemented by MatDyn, and which was taken from [61]. This reference also provides guidance for selection of the parameters $T_1$, $T_2$, and $T_3$ based on governor type. For this dissertation mechanical-hydraulic governors were used for all generators. In order to represent typical conditions on real power systems, governors were only implemented for generators 1 and 3, while generator 2 remained at constant power. The parameters in case9dyn.m therefore required the changes listed in Table 4.1. Assuming generators 1 and 3 to be fast-start, fast-ramp generators, the gain $K$ was chosen such that ramp rates approached but did not exceed a 30%/minute restriction, and the maximum and minimum powers were chosen to be 100% and 0%, respectively. The “freq” parameter was also changed from 50 to 60 to accurately represent North American power systems.
Because the MatDyn governor model does not include AGC, changes also had to be made to the dynamic equations in the Governor.m file. Upon investigating this file, it was noticed that the dynamic equations in the code did not match the block diagram shown in Figure 4.1. The code equations implied a transfer function of \( \frac{(K+sT_2)}{(K+sT_1)} \), which differs slightly from the transfer function shown in Figure 4.1. The code was therefore modified to accurately match the block diagram, which resulted in the state space representation in canonical controllable form of \( A = -1/T_1, \quad B = 1, \quad C = K(T_1-T_2)/T_1^2, \quad D = KT_2/T_1 \). An integrator was also added between the transfer function block and the summation block of Figure 4.1 to represent AGC. These two modifications together produced (4.1) and (4.2), where \( \omega_{err} \) is the input to the governor, \( P \) is the output, and \( x \) is an internal state.
\[ s \cdot x = \frac{-x}{T_1} + \omega_{err} \] (4.1)

\[ s \cdot P = \frac{x \cdot K \cdot (T_1 - T_2)}{T_1^2} + \frac{K \cdot T_2 \cdot \omega_{err}}{T_1} \] (4.2)

4.2.2 Load step results

To quantify the transfer function from load power to frequency using system identification, the load power must be given as an input to the simulation and the frequency must be taken as an output. For simplicity, a load ramp from 0 to -0.5 pu starting at time \( t=0 \) and ending at time \( t=1 \) second was chosen as the input. Bus 8 was chosen as the location of the load change, as it is about equidistant from all three generators. In MatDyn, the load change is represented as an event structure that is passed to the rundyn function; the format for the event structure is given in [67]. A 120-second simulation was run and the output powers and speeds of all three generators were logged. Figure 4.2 shows the results of the simulation, demonstrating that the generators remain synchronized and system frequency peaks at \( 1.025 \times 60 \text{Hz} = 61.5 \text{Hz} \), largely due to the extra load created by the load damping coefficients of the generators (parameter \( D \)), which were not changed from the values distributed with MatDyn. The frequency then decreases as generators 1 and 3 decrease their output powers according to their governor dynamics, which were modified as described in Section 4.2.1. This is representative of power system primary and secondary frequency control [8].
4.2.3 System Identification

The load and frequency data from the simulation were then used in Matlab’s system identification tool to match a 2-pole, 1-zero, 1st order band-pass transfer function. Equation (4.3) and Table 4.2 present the form and parameters of the identified transfer function, and Figure 4.3 shows the match between the simulated output and the output of the transfer function.

\[
H_{fp}(s) = \frac{\Delta f(s)}{\Delta P(s)} = \frac{A \cdot \left(1 + \frac{s}{\omega_z}\right)}{\left(1 + \frac{s}{\omega_{p1}}\right) \left(1 + \frac{s}{\omega_{p2}}\right)}
\]

<table>
<thead>
<tr>
<th>Parameter</th>
<th>Value</th>
<th>$\omega_z$</th>
<th>$\omega_{p1}$</th>
<th>$\omega_{p2}$</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>-0.0032</td>
<td>1.43e-5 rad/s</td>
<td>.014 rad/s</td>
<td>.694 rad/s</td>
</tr>
</tbody>
</table>

Table 4.2: Parameters of the identified transfer function
To facilitate implementation in the microcontroller, the identified transfer function was further simplified by moving the frequency of its zero to DC, which yielded the simplified transfer function of equation (4.4). Figure 4.4 shows a bode plot of the original and simplified transfer functions, showing a good match at frequencies above $\omega_z$.

$$H_{p simple}(s) = \frac{\Delta f(s)}{\Delta P(s)} = \frac{A \cdot s}{\omega_z} \left( \frac{1 + \frac{s}{\omega_p}}{1 + \frac{s}{\omega_{p1}}} \right) \left( 1 + \frac{s}{\omega_{p2}} \right)$$

Figure 4.3: Comparison of response from identified transfer function and MatDyn simulation
Figure 4.4: Bode plot of simplified transfer function and original identified transfer function

4.3 Implementation of the transfer function in the grid emulator

4.3.1 Discretization of the transfer function

The simplified transfer function of equation (4.4) was then implemented in the microcontroller of the grid emulator. This was accomplished by finding a discrete time representation of the transfer function at a sampling frequency $f_{\text{samp}}$ of 60 Hz using the forward Euler approximation, yielding the transfer function of equation (4.5). Figure 4.5 shows a bode plot of the discrete time transfer function vs. the original continuous time version, showing a good match in magnitude for the entire frequency range. It was assumed that changes in PV power due to passing clouds are significantly slower than the sampling rate of 60 Hz.
\[ H_{fP,\text{simple}}(z) = \frac{\Delta f(z)}{\Delta P(z)} = \frac{A \cdot \omega_{p1} \cdot \omega_{p2}}{\omega_{z} \cdot f_{\text{samp}}} \left( z^{-1} - z^{-2} \right) \]

\[ 1 + \left( \frac{\omega_{p1} + \omega_{p2} - 2 f_{\text{samp}}}{f_{\text{samp}}} \right) z^{-1} + \left( 1 - \frac{\omega_{p1} + \omega_{p2}}{f_{\text{samp}}} + \frac{\omega_{p1} \cdot \omega_{p2}}{f_{\text{samp}}^2} \right) z^{-2} \]

4.3.2 Microcontroller implementation

The discrete time transfer function of equation (4.5) was then converted to a difference equation which was programmed into the grid emulator microcontroller. The output of the difference equation, \( \Delta f \), was added to the nominal frequency and then converted to a period value for the timer that determines the sinusoidal reference voltage. Figure 4.6 shows the expected vs. actual response of the grid emulator frequency to a step change in power of -0.5 pu. The grid emulator frequency was sampled at 10 Hz due to limitations in the data acquisition software, but it is actually updated at 60 Hz inside the microcontroller.
4.4 **Grid emulator hardware and sensing**

The grid emulator is implemented with a standard single-phase H-bridge inverter with LC output filter, as shown in Figure 4.7. Parameter values are given in Table 4.3. Sensing of output power is accomplished by sampling the output voltage and current 256 times per fundamental period. The amplitude of the fundamental value of the output current is then calculated by Fourier analysis, as shown in (4.6). A similar approach could be taken to calculate output voltage, but that is unnecessary because the output voltage phase angle is defined to be zero, so the imaginary part of (4.6) would be zero. Therefore the peak value of the voltage in each fundamental period is equal to the real part of the fundamental voltage amplitude, so long as the amount of noise and harmonics in the sampled signal is small compared to the magnitude of the fundamental. The real and reactive powers can be found from the output current and voltage fundamental amplitudes by (4.7) and (4.8).
Figure 4.7: Grid emulator schematic and control

Table 4.3: Grid-emulator components

<table>
<thead>
<tr>
<th>Component</th>
<th>Details</th>
<th>Manufacturer</th>
<th>Part Number</th>
</tr>
</thead>
<tbody>
<tr>
<td>$C_{dc}$</td>
<td>2 x 275 $\mu$F, 500V film</td>
<td>AVX Corporation</td>
<td>FFVI6J2756KJE</td>
</tr>
<tr>
<td>Q1-Q4</td>
<td>1200V, 150A</td>
<td>Infineon</td>
<td>FF150R12ME3G</td>
</tr>
<tr>
<td>Gate drivers</td>
<td>Isolated &amp; protected</td>
<td>Concept</td>
<td>2SP0115T2A0</td>
</tr>
<tr>
<td>$L_{f1}, L_{f2}$</td>
<td>290 $\mu$H</td>
<td>TSC International</td>
<td>70-54-32 (core)</td>
</tr>
<tr>
<td></td>
<td>33 turns, 4 x 15 AWG</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>3.5 mm gap length</td>
<td></td>
<td></td>
</tr>
<tr>
<td>$R_d$</td>
<td>1 $\Omega$, 100 W</td>
<td>Ohmite</td>
<td>L100J1R0E</td>
</tr>
<tr>
<td>$C_f$</td>
<td>20 $\mu$F, 450 V</td>
<td>EPCOS</td>
<td>B32676E4206K</td>
</tr>
<tr>
<td>Microcontroller</td>
<td>16-bit, 50 MIPS</td>
<td>Microchip</td>
<td>dsPIC33FJ64GS610</td>
</tr>
</tbody>
</table>

$$i_{out,\text{fund}} = \frac{1}{256} \sum_{n=1}^{256} i_{out}(n) \cdot \sin \left( \frac{2\pi \cdot n}{256} \right) + j \cdot \sum_{n=1}^{256} i_{out}(n) \cdot \cos \left( \frac{2\pi \cdot n}{256} \right)$$  \hspace{1cm} (4.6)

$$P = \frac{v_{\text{max}} \cdot \text{Re}\left[ i_{\text{fund}} \right]}{2}$$  \hspace{1cm} (4.7)

$$Q = \frac{v_{\text{max}} \cdot \text{Im}\left[ i_{\text{fund}} \right]}{2}$$  \hspace{1cm} (4.8)
4.5 PV generator hardware and controller

The PV generator consists of a PV array and a voltage-source inverter with output filter. The PV array was implemented with two parallel strings of 12 170W PV modules connected in series (EcoSolarGy SDM-170/X-72M), producing an open-circuit voltage of 460V at 25°C and 1000 W/m². The inverter was implemented using the same hardware as the grid emulator, except the LC output filter was replaced by an LCL output filter as shown in Figure 4.8. All components remained the same as the grid emulator except $C_f$, $L_{f3}$, $L_{f4}$; details of the new components are given in Table 4.4.

The PV inverter controller is shown in Figure 4.9. The PV array voltage $V_{pv}$ is regulated to a constant value by modulating the magnitude of the filter inductor current reference $i_{ref}$ via a standard PI controller with a sampling frequency of 240 Hz and bandwidth of 10 Hz. The PLL is implemented using the zero-crossing detection method [50], and the inverter is operated at unity power factor by regulating the angle of $i_{ref}$ to the grid angle $\alpha$. $C_f$ is sized to attenuate switching harmonics and does not significantly affect the angle of $i_{L1}$. The inner feedback loop around the PV inverter current regulates the current in $L_{f1}$ and $L_{f2}$ using a PI controller with a sampling frequency of 30 kHz and a bandwidth of 500 Hz. Although the PI controller does not eliminate steady-state error at the fundamental frequency as a PR controller would [75], it has a better response over a wider range of frequencies. This characteristic is beneficial because grid emulator frequency is expected to vary more than the frequency of a typical power system.
4.6 Experimental setup

The PV inverter and grid emulator were connected in parallel to a resistive load as shown in Figure 4.10a. The purpose of the resistive load is to dissipate slightly more than the maximum amount of power that can be produced by the PV inverter, which enables the grid emulator to be fed with a uni-directional DC power supply. The grid emulator controls the voltage across the load and provides the difference between load power and PV generator power. Because the AC output voltage of the grid emulator is kept constant and the load is resistive, changes in grid emulator frequency do not cause changes in power dissipated by the load. Figure 4.10b shows an oscilloscope waveform of the grid emulator output voltage \( v_{ge} \) and PV generator output current.
As the insolation on the PV array varies the PV inverter changes the magnitude of its output current in order to keep the DC-link voltage constant. Because the load power is constant, this results in equal but opposite changes in grid emulator output power. The grid emulator senses its output power with a sampling frequency of 60 Hz and changes the frequency of its output voltage waveform according to the transfer function $H_{\text{IP,simple}}(z)$.

![Diagram of grid emulator and PV inverter system](image)

**Figure 4.10**: (a): Laboratory setup with grid emulator and PV inverter feeding resistive load. (b): Grid emulator output voltage $v_{ge}$ (top, pink) and PV inverter output current $i_{pv}$ (bottom, cyan), showing operation at 60 Hz and 208 Vrms with unity power factor.

### 4.7 Experimental Results

Experiments were conducted on a day with partly cloudy weather conditions. The grid emulator output power $P_{ge}$ and frequency $f_{ge}$ were recorded at a sampling rate of 10 Hz, and the load power $P_{\text{load}}$ was set to 1.75 kW at a voltage of 220 Vrms. The base power for per-unit measurements was arbitrarily chosen to be 2 kW. Figure 4.11 shows the measured PV generator output power ($P_{\text{load}} - P_{ge}$) in the presence of varying insolation due to passing clouds. This measured data was used as an input to a MatDyn simulation of the IEEE 9-bus test system with a PV generator at bus 8. The frequency of the MatDyn simulation was then compared to the measured frequency of the grid emulator. Figure 4.12 shows the simulated and measured frequencies, indicating that the grid emulator is accurately replicating the frequency of the IEEE 9-bus test system in response to changes in PV generator output power. Note that Figure 4.12
does not validate the MatDyn power system model of the IEEE 9-bus test system because the grid emulator is specifically programmed to mimic the simulated system. Rather it is assumed that the MatDyn model of the power system being studied is an accurate representation of the physical system\(^\text{14}\). The grid emulator is used to emulate the simulation model so that the effects of PV generators on power system frequency may be verified experimentally.

In summary, the following steps were taken to replicate the frequency of the IEEE 9-bus test system with a grid emulator:

1. Simulate a change in load on bus 8 of the IEEE 9-bus test system and record the response of generator speed. The change in load should be slow enough that all generators remain synchronized.
2. Use the recorded change in load and generator speed data to determine the transfer function from load to frequency for bus 8 of the IEEE 9-bus test system using system identification techniques.
3. Simplify and discretize the transfer function such that it can be easily programmed into the grid emulator microcontroller while still retaining key dynamics.
4. Connect the grid emulator to a load and a PV inverter operating in standard grid-connected mode.
5. During partly-cloudy conditions, record PV inverter power and grid emulator frequency. Grid emulator power can be used as a proxy for PV inverter power if the load is constant.
6. Compare the recorded grid emulator frequency to simulation results for the IEEE 9-bus test system when the power at bus 8 is modulated according to the recorded PV inverter power.

\(^{14}\) An overview of the importance of and procedures for validating power system models is provided in [76]
Figure 4.11: Measured PV generator output power during partly cloudy conditions

Figure 4.12: Frequency response of the IEEE 9-bus test system (simulated in MatDyn) to changes in PV power shown in Figure 4.11 vs. measured frequency of the grid emulator.
Chapter 5
PV generators with integrated energy storage

The results of Chapter 4 indicate that significant frequency deviations can occur for high penetrations of PV on the IEEE 9-bus test system. One method of reducing these frequency deviations is to use more flexible generators that can better counteract the variability of PV generators. For example, the Lanai power system is supplied by fast-ramp diesel generators, which is suspected as the reason why PV variability did not affect system frequency in [39]. It is left to future work to determine whether or not increased flexibility is the most cost-effective method of suppressing frequency deviations due to PV variability. The remainder of this dissertation will concentrate on another method – integrating energy storage into PV generators to reduce PV variability.

As was discussed in Section 2.2.2, larger PV arrays have lower variability due to the low-pass filtering effect created by their size. However, as shown in Figure 2.9, the time constant of this filter is inadequate to suppress PV variability that occurs at a time scale of 5 minutes for PV arrays less than 5 MW in size. The idea of integrated energy storage is to add just enough energy storage to a PV system to implement a low-pass filter whose time constant is a function of the amount of energy storage, rather than the size of the PV array. This chapter uses MatDyn simulations and grid emulation to explore the relationship between the amount of energy storage required, the time constant of the resulting filter, and the improvement in frequency deviations for the IEEE 9-bus test system.
5.1 Types of energy storage

Many methods have been proposed to integrate energy storage into PV generators. These methods can be divided into two main groups: those employing AC/DC converters [77]–[80] and those employing DC/DC converters [30], [81]–[86]. The advantage of the former type is that the storage resource can be controlled independently from the PV inverter if desired; the disadvantage is that AC/DC power conversion is generally less efficient than DC/DC conversion. Furthermore, the actual means of storing electricity can include batteries [30], [78]–[82], [84], [87]–[90], super/ultra capacitors [83], [85], [91], back-up generators [77], [92], or any combination thereof. Generally super/ultra capacitors are used to smooth out very fast fluctuations in PV power, while back-up generators are used to avoid constraints on battery state-of-charge (SoC) or power limits. Batteries are by far the most popular type of energy storage, as they provide a good balance of power, capacity, and efficiency. Unfortunately, batteries are also expensive, so attempts have been made to optimize battery size [89], [93] or somehow externalize battery cost. One popular method of externalizing the cost of batteries is by utilizing electric vehicles (EVs) and/or plug-in hybrid electric vehicles (PHEVs) [90], [94], [95]. In such a scenario, the owner of the vehicle pays the upfront cost of the battery and then is somehow reimbursed when the battery is used to mitigate PV variability while the vehicle is charging [96].

The energy storage system described in this dissertation utilizes a DC/DC battery charger that was designed for an electric vehicle charging application with a Li-ion PHEV battery. The system has been described in depth in [30], [93], [95] and will be summarized below.

5.2 PV generator with integrated DC/DC electric vehicle battery charger

A block diagram of the PV generator with integrated DC/DC electric vehicle battery chargers is shown in Figure 5.1. As shown, the chargers are connected to the internal DC bus of
the PV generator, between the maximum power point tracker (MPPT) and the inverter\(^{15}\). The voltage of this bus is regulated at a constant level by the inverter. Both the charger and the inverter support bi-directional power flow, which enables the system to operate in a variety of modes, as described in [95]. However, for the purposes of reducing PV variability only unidirectional power flow through the inverter to the grid is required.

![Block diagram of PV generator with integrated DC/DC electric vehicle chargers](image)

**Figure 5.1**: Block diagram of PV generator with integrated DC/DC electric vehicle chargers

Typical operation of the system is as follows. During sunny conditions the vehicle batteries are charged at constant current and the charging power is provided by the PV array, thereby putting no additional load on grid infrastructure. When a cloud passes over the array, the inverter commands the chargers to curtail charging or even source current from the batteries in order to limit the rate of change of inverter output power. Conversely, as the cloud clears the PV array, the inverter commands the chargers to increase charging in order to compensate for

---

\(^{15}\) This system was specifically designed for the case when the MPPT is separate from the inverter.
increased PV power. After the cloud passes, the chargers return to a normal constant current algorithm, thereby ensuring that the vehicle batteries are charged in approximately the same amount of time as required for grid-connected chargers with equal power ratings. The power provided to the vehicle batteries is therefore equal to some constant DC reference plus the output from a high-pass filter of the PV power. The time constant of this high-pass filter determines the ramp rate of PV inverter output power and thus the magnitude of frequency deviations caused by PV variability.

Figure 5.2 shows an example of this behavior for the hypothetical IEEE 9-bus test system located on Lanai, Hawaii. The insolation data is the same as that used in Section 2.2 for July 19th, 2011. The rated power of the PV array is 1.2 MW, and the combined power reference for all chargers is determined from a 2nd order critically damped high-pass filter with a time constant of 10 minutes. The DC reference for the combined charger power is 100 kW, or as much power is available from the PV array in the early morning and late evening. As shown, the inverter output power $P_{\text{inv}}$ is much smoother than the PV array power $P_{\text{pv}}$, which results in significantly lower frequency deviations on the IEEE 9-bus test system (in the frequency plot, the frequency deviations that would be produced by $P_{\text{pv}}$ without energy storage are shown in a dashed line).

$E_{\text{batt}}$ is the total energy stored in the vehicle batteries, which is assumed to start from zero at the beginning of the day. $\Delta E_{\text{batt}}$ is the change in battery energy caused by the high pass filter, ignoring the DC power reference. In this example, $\Delta E_{\text{batt}}$ is approximately ±2% of the total energy stored in the batteries over the course of the day, indicating that the SoC fluctuations caused by the high pass filter are relatively small. The impact of these SoC fluctuations on battery life is discussed in [97], using insolation data from a day with more variability. For the purposes of this example it is assumed that the rated power of the DC chargers and the available
energy storage in the vehicle batteries is sufficient to meet the reference, although in reality such a system is subject to constraints on charger power, number of available vehicles, and battery SoC.

Figure 5.2: Performance of the PV inverter with integrated energy storage on the IEEE 9-bus test system (charger filter: 2\textsuperscript{nd} order, \(\tau = 10\) minutes)
5.2.1 Hardware design

To demonstrate the concept described above the system of Figure 5.1 was assembled using a 100 kW Satcon® Solstice® inverter & MPPT system, a Toyota® Prius® 10 kWh lithium-iron-phosphate plug-in battery conversion kit, and a custom 10 kW DC-DC battery charger designed and constructed by the University of Colorado. In the demonstration system, the inverter is responsible for maintaining the DC bus voltage at 575 V. It also senses the power from the PV array and issues a command to the charger (via controller area network (CAN) bus) to absorb or deliver a certain amount of power to/from the vehicle battery. The charger fulfills the inverter’s request subject to constraints on charger power rating and battery SoC. The battery implements the Mini-BMS\textsuperscript{16} system in order to maintain voltage balance among all cells.

Similar to the converter described in [98], the 10 kW charger is a four-phase, current-controlled, bidirectional synchronous buck, as shown in Figure 5.3. Zero voltage switching quasi-square-wave (ZVS-QSW) operation is maintained across all operating points by allowing resonant transitions between the inductor and the switched-node capacitance, as shown in Figure 5.4 [99]. MOSFETs operated at 30 kHz are used as the switching devices. In each 2.5 kW module, the resonant components consist of a 120 μH inductor and three 6.8 nF capacitors connected in parallel at the switch node between the power MOSFETs.

Each module is controlled by a PIC microcontroller that implements a feedback loop around the average inductor current designed for a crossover frequency of 1 kHz and phase margin of 65 degrees, utilizing a discrete-time PI compensator. The current reference for this feedback loop is provided via serial peripheral interface (SPI) from a central microcontroller that communicates with the inverter. The central controller is also responsible for monitoring battery

\textsuperscript{16} http://www.cleanpowerauto.com/MiniBMS.html
SoC and synchronizing and phase shifting the modules’ pulse-width modulators (PWMs) to cancel input and output ripples, as shown in Figure 5.4.

Figure 5.3: DC-DC charger schematic
5.2.2 Operating modes

The charger can operate in one of three operating modes: charging only (mode 1), charging with grid support (mode 2), or grid support only (mode 3). In charging-only mode 1, the battery is charged at the full rated power of the charger, and all commands from the inverter are ignored. In charging with grid support mode 2, the battery is charged at less than the full rated power of the charger, leaving the remaining power margin to provide grid support functions. In grid-support only mode 3, the charger only follows commands from the inverter. Generally, mode 3 is used when the battery is fully charged, to limit inverter ramp rate but provide no DC power to the battery. Figure 5.5 shows an example of experimental results for charger operation in all three modes. The stair-step line is the current command from the inverter, and the slightly noisy line is the actual charger current. The actual current may differ from the reference by up to 0.25A due to the resolution of the charger digital current regulator.

A typical example of the use of the charger’s three modes to simultaneously charge the battery and provide grid support functions is as follows. When the vehicle is first plugged in, its SoC is less than 100%. Therefore the inverter commands the charger into mode 2 (charging with
grid support) to simultaneously charge the battery and limit the ramp rate of inverter output power. When the inverter senses a rapid change in PV power, it compensates by commanding the charger to either increase or decrease the power to the battery. When the charger senses that the battery is fully charged, it notifies the inverter and the inverter commands the charger into mode 3 (grid support only). While the vehicle remains plugged in, the entire rated power of the charger is available to offset rapid changes in PV output power.

\[17\] The inverter may also limit rapid increases in PV power by operating away from the maximum power point, as described in [32].
Figure 5.5: Demonstration of the charger’s three operating modes: (top) charging-only mode 1, used solely to charge the battery without grid support, (mid) charging and grid-support mode 2, used to simultaneously charge the battery and provide grid support, and (low) grid-support only mode 3, used to provide grid support without charging the battery.
5.3 Extension of MatDyn PV generator model to include integrated energy storage

In order to simulate the effect of a PV generator with integrated energy storage on power system frequency, the MatDyn model of a PV generator described in Section 3.2 was extended to include the battery charger system described in Section 5.2. Figure 5.6 shows a block diagram of the high level control for the PV generator with energy storage. The current reference for the battery charger $i_{chg,ref}$ is produced by high-pass filtering the current from the PV array $i_{pv}$, which is proportional to the PV output power $P_{pv}$ assuming the DC-link voltage is held constant by the PV inverter. Assuming the charger is able to follow its reference with high bandwidth, $P_{pv}$ will be separated into high-frequency content $P_{batt}$ flowing through the charger to the battery and low-frequency content $P_{inv}$ flowing through the inverter to the grid. Although $H_{hpf}(s)$ could be any high-pass filter transfer function, for the remainder of this dissertation it will be considered either as a 1st-order or critically damped 2nd-order filter with time constant $\tau_{hpf}$, as described by (5.1) and (5.2).

$$H_{hpf}(s) = \frac{s}{s + \frac{1}{\tau_{hpf}}} \quad (5.1)$$

$$H_{hpf}(s) = \frac{s^2}{s^2 + \frac{2s}{\tau_{hpf}} + \frac{1}{\tau_{hpf}^2}} \quad (5.2)$$
Figure 5.6: Block diagram of high level controller for battery charger used to reduce the magnitude and speed of fluctuations in PV generator output power.

The system shown in Figure 5.6 was replicated in MatDyn by creating a second user-defined generator model which will subsequently be called “PV with Energy Storage” (PVES). To speed up simulations it was assumed that the bandwidth of the battery charger was sufficiently high that $i_{chg}$ could be assumed equal to $i_{chg,ref}$ for the time frame of interest. For this analysis it is also assumed that the energy storage system has sufficient capacity and the battery charger has sufficient power rating to accommodate $i_{chg}$. $H_{hpf}(s)$ was chosen to be a 1st-order filter, as described by (5.1). With these assumptions the PVES model is identical to the original PV generator model with the following exceptions:

1. $P_{pv}$ is used as the input to the high-pass filter $H_{hpf}(s)$. In MatDyn only strictly proper transfer functions can be implemented, so $H_{hpf}(s)$ is represented with the state-space canonical controllable form $A=-1/\tau_{hpf}$, $B=1$, $C=-1/\tau_{hpf}$, $D=1$. This results in equations (5.3) and (5.4).

2. $i_{chg}$ is subtracted from the current flowing into the DC-link capacitor, resulting in equation (5.5).
\[ \dot{x}_{hpf} = \frac{P_{pv}}{v_{dc}} - \frac{x_{hpf}}{\tau_{hpf}} \quad (5.3) \]

\[ \dot{i}_{chg} = \frac{P_{pv}}{v_{dc}} - \frac{x_{hpf}}{\tau_{hpf}} \quad (5.4) \]

\[ \dot{v}_{dc} = \frac{1}{C_{dc}} \left( \frac{P_{pv} - P_{gen}}{v_{dc}} - i_{chg} \right) \quad (5.5) \]

For preliminary confirmation of the PVES model, simulations were run using the IEEE 9-bus test system and the results were compared with the results from Section 3.3. All parameters are identical to those in Section 3.3 and \( \tau_{hpf} \) was set to 60 seconds. Figure 5.7 shows the speed of generator 1 and the DC bus voltage of the PV generator during a linear increase in \( P_{pv} \) from 0 to 0.5 pu from \( t=5 \) to \( t=10 \) seconds, followed by a linear decrease in \( P_{pv} \) from \( t=20 \) to \( t=25 \) seconds, for both the original PV generator model and the PVES model. As expected the energy storage system absorbs most of the ramps in PV power, resulting in a much slower rise in DC-link voltage. This in turn leads to a much slower change in PV output power which results in a lower magnitude change in generator 1 speed.
5.4 Experimental validation of the PV generator model with storage

To validate the PVES model, the battery charger described in Section 5.2 was connected to the grid emulator and PV generator described in Chapter 4. The charger was programmed with a 1st-order high pass filter with a corner frequency $\tau_{hpf} = 16$ seconds. PV power $P_{pv}$ and grid emulator power $P_{ge}$ were logged at 10 Hz by a data acquisition computer, although the sampling of these values occurs at 60 Hz in the microprocessor of the grid emulator and at 1 kHz in the central microprocessor of the charger. Inverter output power $P_{inv}$ was calculated by subtracting $P_{ge}$ from the constant load power $P_{load}$. Figure 5.8 shows $P_{pv}$ and $P_{inv}$ logged during partly cloudy conditions on July 25, 2013. As expected, $P_{inv}$ appears as a low-pass filtered version of $P_{pv}$ and is also shifted downwards due to the losses in the PV inverter. From empirical observations these losses were found to be
\[ P_{loss\,[\text{kw}]} = 0.068 \cdot P_{pv} + 0.0516 \text{ kW} \] (5.6)

Figure 5.8: Measured \( P_{pv} \) and \( P_{inv} \) with charger low-pass filter (\( \omega_c = 1/16 \) seconds) during partly cloudy conditions.

\( P_{pv} \) was then used as the input to a MatDyn simulation using the PVES model, and the simulated \( P_{inv} \) and system frequency were compared to the measured values. Figure 5.9 shows the match between simulated and measured inverter output power \( P_{inv} \), indicating that the PVES model is accurately capturing the behavior of the real PV inverter with integrated energy storage. Figure 5.10 shows the measured vs. simulated AC frequency for the PV inverter power fluctuations of Figure 5.9. As shown, the frequencies match well during faster transients but deviate slightly during slower transients. This is a result of limited resolution in the grid emulator DSP which allows for only an approximation of the power-to-frequency transfer function \( H_{fp}(s) \).
Figure 5.9: Simulated, measured, and expected inverter output power ($P_{inv}$) based on measured PV power ($P_{pv}$) during partly cloudy conditions.

Figure 5.10: Simulated vs. measured frequency for the PV inverter output power shown in Figure 5.9.

5.5 Discussion

The validated PV and PVES models can be used to predict the improvements made to power system frequency regulation by integrating energy storage in PV generators. As mentioned in the introduction, the impact of PV generators on a power system, and thus the improvement made by incorporating energy storage, depends on many factors including the
topology of the power system network, the location and flexibility of other generators, the penetration and variability of the PV generators, and the quantity of integrated energy storage. The advantage of creating PV and PVES models is that, once validated, these models can be used in simulations of any power system with any penetration of PV generators and energy storage. Continuing with the IEEE 9-bus power system as an example, Figure 5.11 compares a MatDyn simulation of system frequency with a PV generator vs. a PVES generator for the same variations in $P_{pv}$ shown in Section 5.4. As shown, incorporating energy storage in this case reduces the peak deviation in frequency $\Delta f_{max}$ from 1.2 Hz to 0.8 Hz, an improvement of 33%. As discussed in [30], increasing the time constant of the high-pass filter used by the battery charger further reduces PV output power fluctuations at the expense of increased energy storage requirements. Chapter 6 explores the relationship between PV penetration, available energy storage, and frequency deviation.

![Figure 5.11: Comparison of simulated frequency deviations during partly cloudy conditions for the IEEE 9-bus system with a standard PV generator vs. a PV generator with integrated energy storage.](image-url)
Chapter 6

Effects of integrated energy storage on frequency control

The PVES model described and validated in Chapter 5 can be used to predict the amount of energy storage required to reduce worst-case PV variability enough to meet a maximum power system frequency deviation limit. Such an analysis is made possible by the linearity of the power-to-frequency transfer function for the power system being studied, which can be identified from simulations as described in Section 4.2. Thus the analysis is only valid under the following assumptions: (1) that the PV variability being studied occurs on a time scale of seconds to minutes, when power output from synchronous generators is controlled by automatic, linear systems and (2) that PV variability is not so large as to introduce non-linearities such as ramp-rate or minimum/maximum power limitations of the synchronous generators in the system.

The analysis presented below is similar to that conducted in [100], with the following differences. First, [100] examines the effects of wind turbine variability on power system frequency, while this analysis examines the effects of PV variability. Second, [100] derives the transfer function $H_{fp}(s)$ (denoted $G(f_W)$ in [100]) by combining individual synchronous generator transfer functions, whereas the analysis below identifies $H_{fp}(s)$ from power system simulations. Utilizing power system simulations accounts for transmission line impedances and load damping coefficients and allows pre-existing power system models to be used in-situ, rather than requiring extraction of parameters. The authors of [100] modified their analysis to use a power system model in [101]. Third, no analysis is provided in [100] or [101] to prove that the wind turbine power output data utilized represents a “worst-case” scenario of frequency deviation. This
dissertation provides such an analysis for PV output power. Fourth, [100] does not consider the use of energy storage to reduce frequency deviations, although the wind turbine-specific output power smoothing strategies presented in [102] are considered.

6.1 Defining “worst case” variability

When attempting to quantify the effects of PV variability on power system frequency it is useful to extract the “worst case” events from a particular set of power production data and then evaluate these events under different power system operating conditions. Typically the identification of worst case events is accomplished by finding the largest change in the magnitude of output power ($\Delta P_{\text{max}}$) over one or more time scales of interest. For example, [40] evaluates $\Delta P_{\text{max}}$ at 1-minute, 5-minute, and 10-minute time scales, and then uses the 10-minute $\Delta P_{\text{max}}$ to simulate the impact of variability on system frequency. However, most analyses, including that presented in [40], make no attempt to justify the selection of the time-frames of interest, and may therefore be neglecting faster or slower variations that may have greater effects on system frequency.

For example, consider the simulation data in Figure 6.1, which was copied from pages 162 and 163 of [40]. The 10-minute period between 600 seconds and 1200 seconds was selected by the authors of [40] as an example of worst-case wind and solar variability. During this period, wind power dropped from approximately 290 MW to approximately 210 MW and combined wind and solar power dropped from approximately 365 MW to approximately 250 MW, indicating that solar power dropped from 75 MW to 40 MW. $\Delta P_{\text{max}}$ for wind power was thus 80 MW over the 10-minute period and $\Delta P_{\text{max}}$ for solar power was 35 MW. However, closer examination of the data in Figure 6.1 reveals that during the 5-minute period from approximately 700 seconds to 1000 seconds, wind power dropped from approximately 285 MW to
approximately 235 MW and combined wind and solar power dropped from approximately 360 MW to 270 MW, indicating that solar power dropped from 75 MW to 35 MW. \( \Delta P_{\text{max}} \) for wind power was thus 50 MW over the 5-minute period and \( \Delta P_{\text{max}} \) for solar power was 40 MW. \( \Delta P_{\text{max}} \) for solar is therefore greater over the 5-minute period than it is over the 10-minute period, and accounts for a greater percentage of the total drop in wind and solar power. Furthermore, the frequency deviation resulting from the combined drop in wind and solar power does not occur at the end of the 10-minute period (1200 seconds) but rather at the end of the 5-minute period (1000 seconds). It is conceivable that a similar or even greater 5-minute drop in wind and solar power could exist in the dataset but was not drawn to the authors’ attention because the average 10-minute \( \Delta P_{\text{max}} \) of which the 5-minute drop was a part was not as severe as that shown in Figure 6.1. Nevertheless, this hypothetical 5-minute drop could cause a similar or even greater frequency excursion than that shown in Figure 6.1, and thus should definitely be considered.

These observations suggest the following conclusions: (1) that solar variability is faster than wind variability and (2) that frequency deviations are affected by the speed of variability as well as its magnitude. Rather than arbitrarily choosing the time-frame over which \( \Delta P_{\text{max}} \) is evaluated, an analysis should therefore be performed to determine the time-frame that results in the maximum frequency deviation.
Figure 6.1: Example from [40] of the effects of wind & solar variability on power system frequency.

Representing the relationship between variability $\Delta P$ and $\Delta f$ with the transfer function $H_{fp}(s)$ makes it possible to analytically determine the time frame of $\Delta P_{\text{max}}$ that causes the greatest deviations in system frequency. This is accomplished by finding the time $t_{\text{max}}$ at which the frequency deviation $\Delta f(t)$ is maximized for a given $H_{fp}(s)$. Section 6.1.1 presents a methodology for finding the worst case time frame for $\Delta P_{\text{max}}$ caused by PV generator variability, assuming that $H_{fp}(s)$ is of the band-pass form shown in (4.4). Section 6.1.2 applies this methodology to find the worst case frequency deviation that would be caused by a 1.2 MW PV array on a 5 MW
power system, based on 380 days of 3-second resolution insolation data from Kalealoa, Oahu, Hawaii [54] and the $H_{fp}(s)$ parameters given in Table 4.2.

6.1.1 Worst case variability for PV generators without energy storage

For PV generators, variability is caused by clouds passing over the PV array, and thus the time frame of $\Delta P_{\text{max}}$ depends on the speed of the clouds and the size of the array. These two effects can both be captured by passing high-resolution measured insolation data through a low pass filter with cutoff frequency defined by the size of the PV array, as described in Section 2.2.2. Typically the rate of change of insolation is significantly faster than the rate of change of PV output power, and therefore the worst case change in insolation $\Delta G(t)$ can be approximated as the step function

$$\Delta G(t)_{[kW/m^2]} = \Delta G \cdot u(t) \quad (6.1)$$

Taking the Laplace transform of (6.1) and passing through the PV array size filter of Figure 2.8 yields

$$\Delta P_{\text{pv}}(s)_{[MW]} = \frac{\eta_{\text{inv}} P_{\text{rat}} \Delta G}{s(\tau_{\text{pv}}s + 1)} \quad (6.2)$$

where $\eta_{\text{inv}}$ is the efficiency of the PV inverter, $P_{\text{rat}}$ is the rated power of the PV array in MW, and $\tau_{\text{pv}}$ is the time constant of the PV array size filter shown in Figure 2.8. Passing $\Delta P_{\text{pv}}(s)$ through $H_{fp}(s)$ yields
\[
\Delta f(s)_{[Hz]} = \frac{\eta_{inv} P_{rat} A_{fp} \Delta G / P_{base}}{\left(1 + \frac{s}{\omega_{p1}}\right) \left(1 + \frac{s}{\omega_{p2}}\right)(\tau_{pv}s + 1)}
\] (6.3)

where \( P_{base} \) is the base power of the system in MW, \( A_{fp} \) is the gain of \( H_{fp}(s) \), \( \omega_{p1} \) is the low-frequency pole, and \( \omega_{p2} \) is the high-frequency pole. Assuming \( \omega_{p2} \gg 1/\tau_{pv} \), \( \omega_{p2} \) will have very little effect on the maximum frequency deviation and can therefore be neglected, resulting in the time domain representation of

\[
\Delta f(t)_{[Hz]} = A\left(e^{-t\tau_{pv}} - e^{-\omega_{p1}t}\right)
\] (6.4)

where \( A = \frac{\eta_{inv} P_{rat} A_{fp} \Delta G \omega_{p1}}{P_{base} \tau_{pv} \left(\omega_{p1} - 1/\tau_{pv}\right)} \). Solving for the maximum of (6.4) via differentiation yields

\[
t_{max}[sec] = \frac{\ln\left(\omega_{p1} \tau_{pv}\right)}{\omega_{p1} - 1/\tau_{pv}}
\] (6.5)

where \( t_{max} \) is the time at which \( \Delta f(t) \) is maximized, and therefore should be the time frame used when finding the worst case variability \( \Delta P_{max} \).

### 6.1.2 Example of worst case variability without energy storage

The process described in Section 6.1.1 was applied to find the worst case variability for a 1.2 MW PV generator, using 3-second resolution insolation data collected between March 17, 2010 and March 31, 2011 at Kalaeloa, Oahu, Hawaii [54]. The parameters used for \( H_{fp}(s) \) were those listed in Table 4.2, identified from simulations of the IEEE 9-bus test power system. The inverter efficiency \( \eta_{inv} \) was assumed to be 95% and the system base power \( P_{base} \) was 5 MW. To find the worst case variability \( \Delta P_{max} \), for each day, the insolation data was first passed through a low-pass filter with DC gain = \( \eta_{inv} P_{rat} = 1.14 \) and time constant \( \tau_{pv} = 18.7 \) seconds to produce
The average change $\Delta P_{pv}$ over time $t_{\text{max}} = 33$ seconds was then computed for every 11 samples of $P_{pv}(t)^{18}$. Taking the maximum of all $|\Delta P_{pv}|$ yields $\Delta P_{\text{max}}$, and filtering the samples of $P_{pv}(t)$ that yielded $\Delta P_{\text{max}}$ through $H_{fp}(s)$ yields the frequency deviation $\Delta f(t)$, $0 < t < t_{\text{max}}$ with maximum frequency deviation $\Delta f_{\text{max}} = \Delta f(t_{\text{max}})$. This process assumes that $\Delta f(0) = 0$, and that the power system behaves linearly as defined by $H_{fp}(s)$.

Figure 6.2 shows a histogram of $\Delta P_{\text{max}}$ for the 380 days of insolation data analyzed. A total of 84 days (22% of the days studied) had a $\Delta P_{\text{max}}$ of approximately 0.8 MW in 33 seconds. Most of these days occurred between the months of April and September, 2010. The largest $\Delta P_{\text{max}}$ was 0.922 MW, which occurred on May 20, 2010 at approximately 12:45pm. Figure 6.3 shows $P_{pv}(t)$ and $\Delta f(t)$ for the minute when this $\Delta P_{\text{max}}$ occurred. As shown, the 33-second ramp of 0.922 MW causes an increase in frequency of 0.45 Hz, and although the ramp continues beyond 33 seconds, no further increase in $\Delta f(t)$ is observed. This example therefore verifies that $t_{\text{max}} = 33$ seconds is the appropriate time frame for computing $\Delta P_{\text{max}}$, which validates the analysis performed in Section 6.1.1.

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$^{18}$ According to (6.5), the calculated value of $t_{\text{max}}$ is actually 33.95 seconds, but 33 seconds was chosen because it is an even multiple of the sample time of 3 seconds.
Figure 6.2: Histogram of daily $\Delta P_{\text{max}}$ for a 1.2 MW PV generator, based on 380 days of insolation data.

Figure 6.3: Worst case $\Delta P_{\text{max}}$ of all 380 days, for May 20, 2010 at approximately 12:45pm.
6.1.3 Worst case variability for PV generators with energy storage

The analysis presented in Section 6.1.1 can be extended to PV generators with integrated energy storage of the type discussed in Chapter 5. Recall that the power flowing to the battery $P_{\text{batt}}(t)$ is the output from a high-pass filter $H_{\text{hpf}}(s)$ with time constant $\tau_{\text{hpf}}$ acting on the PV power $P_{\text{pv}}(t)$, and power flowing through the inverter to the grid is equal to $\eta_{\text{inv}}(P_{\text{pv}}(t) - P_{\text{batt}}(t))$. If $H_{\text{hpf}}(s)$ is first-order and $\tau_{\text{hpf}} \gg \tau_{\text{pv}}$, then $t_{\text{max}}$ can be found by simply replacing $\tau_{\text{pv}}$ with $\tau_{\text{hpf}}$ in (6.5).

If $H_{\text{hpf}}(s)$ is of higher order, finding $t_{\text{max}}$ becomes more complicated. For a 2nd order critically damped $H_{\text{hpf}}(s)$ with time constant $\tau_{\text{hpf}}$, following the procedure from Section 6.1.1 yields

$$\Delta f(t)_{[\text{Hz}]} = B \left[ e^{-t/\tau_{\text{hpf}}} \left( 1 - \frac{t}{\tau_{\text{hpf}}} (2\tau_{\text{hpf}}\omega_p - 1) (\tau_{\text{hpf}}\omega_p - 1) - e^{\omega_p t} \right) \right]$$

(6.6)

where

$$B = \frac{\eta_{\text{inv}} P_{\text{rad}} A_p \Delta G \omega_p}{P_{\text{base}}} \left( \frac{2\tau_{\text{hpf}}\omega_p - 1}{(\tau_{\text{hpf}}\omega_p - 1)^2} \right)$$

Finding $t_{\text{max}}$ that maximizes (6.6) cannot be accomplished analytically due to the $t \cdot e^{-t/\tau_{\text{hpf}}}$ term. However, a solution can be found if numerical values are substituted for $\omega_p$ and $\tau_{\text{hpf}}$.

As an example, consider a 2nd order, critically damped $H_{\text{hpf}}(s)$ with time constant $\tau_{\text{hpf}} = 300$ seconds. Solving $\frac{d}{dt} \Delta f(t) = 0$ for $t$ with $\omega_p = 0.014$ rad/s yields $t_{\text{max}} = 112$ seconds. This value of $t_{\text{max}}$ was used to find the daily $\Delta P_{\text{max}}$ for a 1.2 MW PV generator with integrated energy storage, based on the same 380 days of insolation data considered in Section 6.1.2. A histogram of the results is shown in Figure 6.4. Here $\Delta P_{\text{max}}$ is a measure of the maximum change in the
absolute value of PV inverter power over a time period $t_{\text{max}}$, where the PV inverter power $P_{\text{inv}} = \eta_{\text{inv}} P_{\text{pv}} \cdot (1 - H_{\text{hpf}})$. The largest $\Delta P_{\text{max}}$ was 0.58 MW, which occurred on April 24, 2010 at approximately 1:01 pm. Figure 6.5 shows $P_{\text{inv}}(t)$ and $\Delta f(t)$ for the minute when this $\Delta P_{\text{max}}$ occurred. As shown, the 112-second ramp of 0.58 MW causes an increase in frequency of 0.16 Hz, and although the ramp continues beyond 112 seconds, no further increase in $\Delta f(t)$ is observed. $t_{\text{max}} = 112$ seconds is therefore the appropriate time frame for computing $\Delta P$ for this example, which validates the analysis performed above to determine $t_{\text{max}}$ for PV generators with integrated energy storage employing 2nd order, critically-damped high-pass filters. Furthermore, the decrease in $\Delta f_{\text{max}}$ from 0.45 Hz without energy storage to 0.16 Hz represents an improvement of 65% due to the addition of integrated energy storage.

Figure 6.4: Histogram of daily $\Delta P_{\text{max}}$ for a 1.2 MW PV generator with integrated energy storage, based on 380 days of insolation data.
6.2 Relationship between storage time constant, required battery capacity, required charger power, and worst-case frequency deviation

The analysis presented in Section 6.1.3 shows that the time period $t_{\text{max}}$ used to find the worst-case variability $\Delta P_{\text{max}}$ is a function of the time constant $\tau_{\text{hpf}}$ used in the high-pass filter that is employed by the integrated energy storage system, and is also a function of the order of said filter. Higher order filters will result in a lower $t_{\text{max}}$ than lower order filters with the same $\tau_{\text{hpf}}$. This is because while all orders of filter absorb all of the high frequency content of $P_{\text{pv}}(t)$, lower order filters absorb more of the low-frequency content than do higher-order filters. Absorbing more low-frequency content also results in lower frequency fluctuations, but at the expense of increased energy storage and increased charger power requirements.

The following analysis can be performed to find a relationship between $\tau_{\text{hpf}}$, the order of $H_{\text{hpf}}(s)$, required energy storage, required charger power, and frequency deviation. As a worst-case, suppose that the change in insolation $\Delta G = 1 \text{ kW/m}^2$. For first-order $H_{\text{hpf}}(s)$, the power to the battery $P_{\text{batt}}(s)$ is
\[ P_{\text{batt}}(s)_{[\text{MW}]} = H_{\text{hpf}}(s)P_{\text{pv}}(s) = \frac{P_{\text{rat}}\tau_{\text{hpf}}}{(\tau_{\text{pv}}s + 1)(\tau_{\text{hpf}}s + 1)} \] (6.7)

and the change in energy stored in the battery \( \Delta E_{\text{batt}}(s) \) is

\[ \Delta E_{\text{batt}}(s)_{[\text{MW} \cdot \text{s}]} = \frac{1}{s}P_{\text{batt}}(s) = H_{\text{hpf}}(s)P_{\text{pv}}(s) = \frac{P_{\text{rat}}\tau_{\text{hpf}}}{s(\tau_{\text{pv}}s + 1)(\tau_{\text{hpf}}s + 1)} \] (6.8)

After taking the inverse Laplace transform of (6.7) and (6.8) and maximizing via differentiation, the maximum battery power \( P_{\text{batt, max}} \) and maximum change in stored energy \( \Delta E_{\text{batt}} \) will be

\[ P_{\text{batt, max}}_{[\text{MW}]} = \max \left( P_{\text{batt}}(t) \right) = \frac{P_{\text{rat}}\tau_{\text{hpf}}}{\tau_{\text{pv}} - \tau_{\text{hpf}}} \cdot \left( \frac{1}{\tau_{\text{pv}}/\tau_{\text{hpf}} - \tau_{\text{hpf}}} - \frac{1}{\tau_{\text{pv}}/\tau_{\text{hpf}} - \tau_{\text{hpf}}} \right) \] (6.9)

\[ \Delta E_{\text{max}}_{[\text{MW} \cdot \text{s}]} = \max \left( \Delta E_{\text{batt}}(t) \right) = \lim_{t \to \infty} \Delta E_{\text{batt}}(t) = P_{\text{rat}}\tau_{\text{hpf}} \] (6.10)

Thus for first order filters, the maximum change in energy stored is proportional to the rating of the PV array and the time constant of the high-pass filter. Substituting \( \tau_{\text{hpf}} \) for \( \tau_{\text{pv}} \) in (6.4) and (6.5), the maximum frequency deviation \( \Delta f_{\text{max}} \) can be written

\[ \Delta f_{\text{max}}_{[\text{Hz}]} = A \left( e^{-t_{\text{max}}/\tau_{\text{hpf}}} - e^{-\omega_{\text{p1}}t_{\text{max}}} \right) \] (6.11)

where \( A = \frac{\eta_{\text{inv}}P_{\text{rat}}A_{fp}\omega_{\text{p1}}}{P_{\text{base}}\tau_{\text{hpf}}\left(\omega_{\text{p1}} - 1/\tau_{\text{hpf}}\right)} \) and \( t_{\text{max}} = \frac{\ln\left(\omega_{\text{p1}}\tau_{\text{hpf}}\right)}{\omega_{\text{p1}} - 1/\tau_{\text{hpf}}} \).

For 2nd order \( H_{\text{hpf}}(s) \), \( P_{\text{batt, max}} \), \( \Delta E_{\text{max}} \), and \( \Delta f_{\text{max}} \) cannot be found analytically because of the \( te^{-t/\tau} \) terms; however, numerical solutions can be found by substituting values for all constants.
Figure 6.6 shows $\Delta E_{\text{max}}$ and $\Delta f_{\text{max}}$ as a function of $\tau_{\text{hpf}}$ for $P_{\text{rat}} = 1.2$ MW, $P_{\text{base}} = 5$ MW, $\eta_{\text{inv}} = 0.95$, $A_{fp} = 223.77$, $\omega_{p1} = .014$ rad/s, and $\tau_{pv} = 18.7$ seconds, for both 1$^{\text{st}}$ and 2$^{\text{nd}}$ order filters. In order to keep $\tau_{\text{hpf}} \gg \tau_{pv}$, the analysis was limited to $\tau_{\text{hpf}} > 100$ seconds. As shown, maximum frequency deviation for 1$^{\text{st}}$ order filters is approximately 40% lower than for 2$^{\text{nd}}$ order filters for the same $\tau_{\text{hpf}}$. However, 1$^{\text{st}}$ order filters require approximately 2.7 times more energy storage than 2$^{\text{nd}}$ order filters for the same $\tau_{\text{hpf}}$. The combination of these two trends means that for the same energy storage requirement $\Delta E_{\text{max}}$, 1$^{\text{st}}$ order filters result in slightly higher maximum frequency deviation than 2$^{\text{nd}}$ order filters.

Figure 6.6: Example of $\Delta E_{\text{max}}$ and $\Delta f_{\text{max}}$ vs. $\tau_{\text{hpf}}$ and filter order

Figure 6.7 shows $P_{\text{batt,max}}$ as a function of $\tau_{\text{hpf}}$ and filter order for the same conditions as in Figure 6.6. As shown, 1$^{\text{st}}$ order filters require approximately 0.1 MW more charger power than second order filters for the same $\tau_{\text{hpf}}$. Due to the effects shown in Figure 6.6 and Figure 6.7, it can be concluded that 2$^{\text{nd}}$ order filters result in better utilization of energy storage and charger power to reduce frequency deviations than do 1$^{\text{st}}$ order filters.
Lastly, Figure 6.8 shows the worst-case frequency deviation $\Delta f_{\text{max}}$ as a function of energy storage available $\Delta E_{\text{max}}$ for the example system with a 2$^\text{nd}$ order filter. As shown, small amounts of energy storage can lead to significant reductions in maximum frequency deviation, although the returns diminish as more energy storage is added to the system.

![Graph showing $P_{\text{batt, max}}$ vs. $\tau_{\text{hp}}$ and filter order](image1)

![Graph showing $\Delta f_{\text{max}}$ vs. $\Delta E_{\text{max}}$](image2)
6.3 Discussion

The analysis presented above shows how identifying a linear relationship between power and frequency for a particular bus of a particular power system can be utilized to predict worst-case frequency deviations on small power systems with high penetrations of PV generators. In addition, the analysis quantifies the effectiveness of integrated energy storage at reducing frequency deviations on such power systems under worst-case conditions. In the example system, the worst-case frequency deviation was reduced from 0.45 Hz to 0.16 Hz, a 65% improvement requiring only 36.7 kWh of energy storage for a 1.2 MW PV array. Given an accurate model of a real power system such as that on Lanai, this methodology could inform decisions on how much energy storage should be added to the system to reduce frequency fluctuations to a desired level, based on how much PV must be added to reach renewable energy targets. With this information, system planners can compare energy storage to other methods of mitigating the effects of PV variability on power system frequency, in order to choose a method that meets renewable energy targets and maintains system reliability at minimum cost.
Chapter 7
Conclusions

As the amount of variable renewable generation on power systems increases, new control techniques will be required to maintain good power quality and reliability. Specifically, on small, isolated power systems with high penetrations of photovoltaic (PV) generators, traditional frequency control techniques may be inadequate to maintain system frequency within prescribed limits on partly-cloudy days when PV output power is highly variable. The solution to this problem is not to limit PV penetration, but rather to implement control techniques that reduce frequency variations despite high PV penetration.

One such technique is to incorporate energy storage into PV generators to reduce variability. However, because energy storage is expensive it is desirable to have methods of accurately estimating how much storage is required to ensure adequate frequency control. This dissertation presents three methods of analyzing, modeling, and experimentally observing the effects of PV variability on power system frequency, both with and without energy storage. As an example, each method is quantitively applied to the IEEE 9-bus test power system.

In Chapter 6 it is shown that worst-case frequency deviations on a 5 MW power system with a 1.2 MW PV array can be reduced 65% by integrating only 36.7 kWh of energy storage into the PV generator. This example is meant to represent the PV penetration and system load on the island of Lanai, Hawaii. However, the dynamic characteristics of the power system are derived from simulations of the IEEE 9-bus test power system, as parameters for the Lanai
system were not publically available. Given knowledge of these dynamic parameters, the techniques presented in this dissertation could be applied to the Lanai system to predict the frequency deviations caused by PV variability and inform decisions on the amount of required energy storage. It is the author’s opinion that the results of such an analysis would indicate a significantly lower energy storage requirement than the 500 kWh system that was installed on Lanai in 2011, resulting in significant cost savings.

It is the author’s hope that the methods presented in this dissertation will be applied to real power systems in order to intelligently mitigate the impacts of PV variability, instead of establishing an arbitrary limit on PV penetration or an arbitrary amount of required energy storage. High PV penetrations have already affected voltage control on distribution systems, and unfortunately the industry response was to place an arbitrarily limit of 15% capacity penetration, beyond which an expensive, often cost-prohibitive integration study is required [103]. Although retroactive efforts to develop a simple, inexpensive methodology to predict the impacts of high PV penetrations on distribution system voltage are underway, the 15% limit has already prevented numerous PV installations, resulting in greater than necessary electric costs and fossil fuel emissions. It would be heartening if we could learn from this mistake and apply more intelligent techniques when it comes to limiting the impacts of PV variability on power system frequency.

7.1 Summary of contributions

1) Development of an integrated energy storage system to reduce variability of PV generator output power

One method of reducing the impact of PV generators on power system frequency is by filtering out some of the variability caused by passing clouds. Energy storage is
required to accomplish this while still maximizing the amount of power delivered from the PV array to the grid. Chapter 5 of this dissertation presents the development of a 98% efficient battery charger that enables the battery of an electric vehicle to be connected to the internal DC bus of a PV generator and used to reduce PV variability. The PV generator with integrated energy storage is then used in conjunction with the grid emulator described in Chapter 4 to assess the improvements made to the frequency control of the IEEE 9-bus test system.

2) Development of a PV generator dynamic model for use with the open-source power system dynamic simulator MatDyn

Dynamics simulators provide an efficient way to examine the response of large, interconnected power systems to disturbances such as faults or losses of load or generation. Simulators can also be used to examine the response of power systems to PV variability if an accurate dynamic model of a PV generator is available. PV generator models have recently been created for many commercial simulators but they generally do not include integrated energy storage or other controls used to reduce PV variability. In this dissertation a PV model with integrated energy storage is created for the open-source power systems dynamic simulator MatDyn. The model is then used to compare frequency deviations on the IEEE 9-bus test system resulting from variability of PV generators both with and without integrated energy storage.

3) Development of a method to experimentally replicate the frequency of a power system using a grid emulator

Modern PV inverters include various “grid support” features that are designed to decrease the impact of PV variability on power quality. In order to test the effects of
these features the PV inverter must be connected to a power system that is (a) small enough to be influenced by PV variability and (b) isolated from events other than the actions of the PV inverter. Because very few power systems meet these requirements, grid emulation has been developed as a method of emulating the response of a power system to the grid support actions of PV inverters for testing purposes. Typical grid emulators consist of a programmable AC power supply connected to a computer that is used to sense the actions of the PV inverter, determine the appropriate response of the power system, and program the AC power supply accordingly. These sensing, processing, and communication steps can result in a lag in the response of the grid emulator, which in turn can affect the PV inverter controller and produce an invalid test result. Chapter 4 of this dissertation presents the development of a grid emulator that is controlled completely at the microprocessor level, thereby eliminating the need to communicate with an external computer. The grid emulator is connected to a PV inverter with integrated energy storage and used to emulate the frequency of the IEEE 9-bus test system in the presence of PV variability caused by passing clouds.

4) **Evaluation of the effects of worst-case PV variability on frequency control for PV generators with integrated energy storage**

Worst-case PV variability is typically evaluated by finding the change in power over a pre-determined time period such as 10 minutes. The selection of this time period is fairly arbitrary, resulting in analyses that ignore frequency deviations resulting from faster or slower PV variability. Moreover, these ignored frequency deviations may be more severe than those highlighted by the analysis. This dissertation presents an analytical method for choosing the time period to evaluate worst-case PV variability
based on the power-to-frequency transfer function of a power system, the size of the PV array, and the order and time constant of an integrated energy storage system. Worst-case PV variability is then evaluated for a power system with a 5 MW load and 1.2 MW PV generator. A relationship between maximum frequency deviation and amount of energy storage is derived for the example system. Results indicate that incorporating just 37 kWh of energy storage can reduce maximum frequency deviation from 0.45 Hz to 0.16 Hz.

7.2 Future research directions

1) Use energy storage to experimentally mimic the effects of a larger PV array

As was described in Section 2.2.2, the variability of power output from PV arrays depends on the geographic area of the array – power output from larger arrays is smoother than power output from smaller arrays. However, in the experiments presented in Chapter 4 the 2 kW rooftop PV array was used to represent a 100 MW (1 pu) PV array on the IEEE 9-bus test system, resulting in much greater variability (and consequently larger frequency deviations) than would be observed from an actual 100 MW array. Although it is impractical to use larger arrays for laboratory experiments, the energy storage system described in Chapter 5 could be used to absorb some of the variability of a small PV array in order to produce a power output more similar to that of a large array. To accomplish this, the charger’s reference current would be produced by passing the sensed PV current through the transfer function of equation (7.1), where τ₁ is the time constant of the smaller array (based on Figure 2.8) and τ₂ is the time constant of the larger array. If desired, a high pass filter could be cascaded
with equation (7.1) in order to mimic the effects of a larger PV array with integrated energy storage and the control scheme described in Chapter 5.

\[ H(s) = \frac{1 + \tau_1 s}{1 + \tau_2 s} \]  \hspace{1cm} (7.1)

2) **Extend the grid emulator controller to include a Q-v control loop**

This dissertation focuses on how to improve power system frequency control in the presence of highly variable active power output from photovoltaic generators. However, PV variability can also affect power system voltage control at the transmission and distribution levels. Although the bulk power system simulations upon which the grid emulator is based do not include distribution-level dynamics, they do model transmission-level relationships between reactive power and voltage at every bus in the network. Just as frequency dynamics are influenced by synchronous generator governors and active power output of PV generators, voltage dynamics are influenced by synchronous generator exciters and the reactive power output of PV generators. Modern PV inverters offer a variety of ways to control the reactive power output of PV generators, but it is difficult to test the effects of these controls on the power system for the same reason it is difficult to test the effects of active power controls (see Chapter 4). The grid emulator could be extended to mimic the Q-v dynamics of a larger power system by implementing a transfer function between reactive power and the voltage reference of the low-level controller, similar to the transfer function between active power and frequency reference. It would then be possible to study the effects of PV inverters with reactive power control on power system voltage regulation.
3) **Expand the grid emulator and PV inverter to support 3-phase operation**

Both the grid emulator and PV inverter currently only support single phase operation. Although this is adequate to study the effects of PV variability on frequency control, three-phase operation would enable testing with more typical PV inverter control methods based on balanced three-phase operation. For example, the zero-crossing phase-locked-loop (PLL) implemented by the PV inverter could be improved to a more typical rotating reference frame PLL, as described in [49]. Furthermore, the current controller could be implemented in the rotating reference frame, which eliminates 60 Hz error because the dq current references are not sinusoidal. Finally, because three phase power is constant the DC buses of both the PV inverter and grid emulator would be less prone to 120 Hz ripple than they are for single-phased operation, and therefore they would be easier to control.

4) **Model and test different methods of active power control**

This dissertation only considered integrated energy storage as a way to control active power of PV generators. However, numerous other methods have been developed, including ramp limits, active power droop, and inertia emulation [28]–[37]. The effects of these active power controls on power system frequency could be modeled and tested using the MatDyn and grid emulator platforms.
Appendix A
Modeling PV generators with integrated energy storage in DIgSILENT PowerFactory

To maximize transparency and replicability, MatDyn was chosen as a power system dynamic simulator for this dissertation. However, to verify the MatDyn model of a PV generator with integrated energy storage, and to illustrate how such generators can be incorporated into power system simulations using commercial-grade software, the following procedure was performed in DIgSILENT PowerFactory. Note that following this procedure requires a fundamental understanding of how to use the PowerFactory software.

1. Open the “9 Bus Bar System” from the PowerFactory examples page.

2. Remove the fault location and extend line 2 to connect bus 5 and bus 7. Verify that line 2 has the correct impedance as shown in Table 2.2.

3. Remove the DC1 exciters from the generator composite models.

4. Add an IEEET1A exciter to generator 3. To make the exciter model the same as the one implemented in MatDyn, replace the $S_e(E_{id})$ block with one that takes $A_{ex}$ and $B_{ex}$ as parameters and simply implements the function $y_a = A_{ex}e^{y_B}$. Then use the parameters in Table B.1 for the exciter model, which were taken from the default exciter parameters from MatDyn.
<table>
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<td>Controller Gain</td>
<td>pu</td>
<td>50</td>
</tr>
<tr>
<td>$T_a$</td>
<td>Controller Time Constant</td>
<td>s</td>
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</tr>
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<td>Exciter Time Constant</td>
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</tr>
<tr>
<td>$E_{fd,\max}$</td>
<td>Exciter Output Maximum</td>
<td>pu</td>
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</tr>
<tr>
<td>$E_{fd,\min}$</td>
<td>Exciter Output Minimum</td>
<td>pu</td>
<td>-5.5</td>
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<tr>
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<td>Stabilization Path Gain</td>
<td>pu</td>
<td>0.04</td>
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<td>Stabilization Path Time Constant</td>
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<td>Saturation Factor 2</td>
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<tr>
<td>$V_{r,\min}$</td>
<td>Controller Output Minimum</td>
<td>pu</td>
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<tr>
<td>$V_{r,\max}$</td>
<td>Controller Output Maximum</td>
<td>pu</td>
<td>1.7</td>
</tr>
</tbody>
</table>

Table B.1: Exciter parameters for generator 3

5. Add frequency dependence to the loads, in order to capture the relationship between load and frequency. To mimic the MatDyn 9-bus system, a 90% static, 10% dynamic load with dynamic load time constant = 2 seconds, $k_{pf} = 30$ and $t_{pf} = 40$ was used.

6. Add IEEEG2 governors to generators 1 and 3. This type of governor is most similar to the one implemented in MatDyn. The parameters for the governors, presented in Table B.2, are translated from those used in MatDyn (Table 4.1).

<table>
<thead>
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<th>Gen 3</th>
</tr>
</thead>
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<td>pu</td>
<td>3</td>
<td>4</td>
</tr>
<tr>
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<td>Governor Time Constant</td>
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<td>$T_2$</td>
<td>Governor Derivative Time Constant</td>
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<td>0</td>
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<td>$T_3$</td>
<td>Servo Time Constant</td>
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<td>0</td>
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<td>$T_4$</td>
<td>Water Starting Time</td>
<td>s</td>
<td>0.1</td>
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<td>$P_{\text{N}}$</td>
<td>Turbine Rated Power(=0 $\rightarrow$ $P_{\text{N}}=P_{\text{gnn}}$)</td>
<td>MW</td>
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<td>0</td>
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<tr>
<td>$P_{\text{min}}$</td>
<td>Minimum Gate Limit</td>
<td>pu</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
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<td>Maximum Gate Limit</td>
<td>pu</td>
<td>1</td>
<td>1</td>
</tr>
</tbody>
</table>

Table B.2: Governor parameters for generators 1 and 3

7. Modify the composite frame “SYM Frame no droop” to include an AGC slot with a frequency input (signal: fe_bus2) and a power adjustment output (signal: psco).
Connect the frequency input to the voltage measurement slot and the power adjustment output to the governor slot.

8. Create an AGC model to populate the AGC slot. The model can simply be a summation block followed by an integrator with gain. The summation block should compute the difference between the nominal frequency (1 pu) and the frequency input. The integrator gain should be a parameter of the model.

9. Populate the AGC slot of generators 1 and 3 with the AGC model. Tune the AGC gain to get the desired settling time after a load step. Figure B.1 shows a comparison of the generator powers and speeds after a load step of -0.5 pu at bus 8 in both the MatDyn model and the PowerFactory model with an AGC gain of 0.13. As shown, non-linear effects are more apparent in the PowerFactory model, but these will be greatly reduced by the addition of energy storage.
10. Add a PV generator model and LV-HV transformer to bus 8. The PowerFactory library template may be used, but the power rating should be increased to a more significant value in order to model the effects of high penetrations of PV. 50 MW was chosen as the size of the PV generator. The number of PV modules in series in the PV Array model and the nominal PV power in the DC busbar and capacitor model were increased accordingly.
11. To model the effects of PV on frequency without active power controls, the Active Power Reduction block should be disabled by increasing the $f_{up}$ parameter.

12. To model a ramp in irradiance the Ramp E block should be modified to integrate a constant change in irradiance ($W/m^2\cdot s$) from a minimum to a maximum value. Figure B.2 shows generator speeds and powers after a ramp in irradiance from 0 to 1000 W/m$^2$ in 1 second.

![Figure B.2: PowerFactory simulation of generator speeds and powers for system with PV generator on bus 8 during irradiance ramp from 0 to 1000 W/m$^2$](image)

13. Add an energy storage model next to the PV generator model on the low voltage side of bus 8. The default PowerFactory model for battery energy storage may be used, but the control needs to be changed from frequency control to the high-pass filter control described in Chapter 5. This can be accomplished by performing the following:

   a. Create a high-pass filter block reference that inputs PV power and passes it through a high-pass filter with parameterized corner frequency. Replace the Frequency Control model in the BESS-Control frame with the high pass filter model.
b. Add a second PQ measurement slot to the BESS-Control frame. The model for this slot should measure the power of the PV generator and pass it to the high-pass filter block. Figure B.3 shows a screenshot of the modified high-pass filter control block.

c. Account for the nominal power ratings of PV generator and battery energy storage when calculating per-unit power signals.

![Figure B.3: High-pass filter control frame for battery energy storage](image)

Figure B.4 shows generator speeds and powers for simulation of a PV generator with integrated energy storage in both MatDyn and PowerFactory. Both simulations used a 1\textsuperscript{st} order high pass filter with a time constant of 300 seconds. Battery energy storage reduces speed deviation to a point within the governor deadband, so only AGC response is present in the PowerFactory model. This results in almost identical responses between the two simulations.
Figure B.4: Generator speeds and powers for simulation of a PV generator with integrated energy storage in PowerFactory (top) and MatDyn (bottom).
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