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The Incidence of Inverter Incidents: Understanding and Quantifying Contributions to Risk in Systems with Large Amounts of Inverter-Based Resources

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The Incidence of Inverter Incidents: Understanding and Quantifying Contributions to Risk in Systems with Large Amounts of Inverter-Based Resources

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Abstract

Renewable energy is an important and growing percentage of the total power supply. Additionally, non-wires alternatives, which are meant to substitute for the construction of more transmission lines, are increasing in quantity as the demand for electrical power increases. Many non-wires alternatives take the form of renewable energy resources and batteries, and are distributed over short distances through neighborhoods and communities. Inverters are used to connect these DC resources to the AC grid.

However, there is growing industry concern that the disconnect function that is inherent to interconnection standards for inverter-based resources has the potential to result in a cascading failure if voltages deviate significantly from nominal.

This thesis studies the conditions under which a cascading inverter collapse of this sort could occur. More specifically, it identifies engineering design parameters, such as time constants, that influence the speed and nature of these cascades, using a new model called Time-Dependant Inverters Model (TiDIM). While this model is preliminary, the results suggest that risk increases with a number of factors including large transmission or distribution line impedances, a large variance in inverter voltage setpoints, and an inappropriate number of inverter-based resources that can contribute to supplying too much or not enough power. Next, the thesis characterizes the risk at which one may expect this sort of event to occur as a function of line impedance and the resultant voltage magnitude. It is found that a greater proportion of inverter-connected power in the grid is associated with a higher probability of collapse, and a greater variance in inverter behavior is associated with a wider transition band, which is defined in this thesis as the range of impedances/voltages where the probability of collapse is an uncertain. Lastly, the thesis identifies cost-effective strategies to reduce the likelihood of such an event.

This thesis is dedicated to my fiancé and number one source of emotional support,
Eduardo Valdez

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Abbreviations

AC	Alternating current
ACR	Automatic circuit recloser
DC	Direct Current
DER	Distributed energy resource
DG	Distributed generation
IBR	Inverter-based resource
IEEE	Institute of Electrical and Electronics Engineers
NERC	North American Electric Reliability Corporation
NWA	Non-wire alternative
PMU	Phasor Measurement Unit
PV	Photovoltaic
TiDIM	Time-Dependant Inverters Model

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Chapter 1

Introduction

1.1 Introduction

The bulk power grid is an amazing system that supplies electricity with over 99.9% reliability.. However, the ever-evolving structure introduces risks that may make it difficult to maintain this level of reliability looking forward. The mission of a power systems electrical engineer is to ensure that power systems operate with a very high level of reliability at a reasonable cost.

Due to declining costs of renewable energy, coal plants are retiring rapidly in many states. Now, a diverse set of generation exists: solar, wind, hydro, biomass, geothermal, and small-scale generation such as roof-top solar, in addition to traditional generation. This portfolio has many advantages, but is also more difficult to manage. These resources vary in availability, and, for the first time on a large scale, the flow of electricity is not necessarily one-way from generation to consumer. With the rise of behind-the-meter generation like roof-top solar, this flow can become bidirectional depending on the number of solar panels, the load, the time of day, and other factors. The grid's infrastructure was not built to handle this two-way flow.

Another way the state of the grid has changed is overall volume. As population, infrastructure, services, and economic activity grows, so does the need for electricity. Additionally, energy-consuming machines like vehicles are increasingly becoming more electrified. However, building new transmission or distribution lines or updating substations can be expensive and it can be unclear who is responsible for the investment capital. It appears to be much more cost-effective to encourage behind-the-meter photovoltaics (PV), Tesla battery walls, and other consumer-side distributed energy resources (DERs). The generation and consumption of electrical power stays close to the source and does not require the long-distance line upgrades that may otherwise be necessary. These options to meet the growing demand are called non-wires alternatives (NWAs) because the addition of new wires such as transmission lines are not required.

One of the technologies that makes all of this possible is a power electronic device called an inverter. Inverters convert DC electricity from PV, wind, and batteries to AC electricity, which is what the grid uses. Resources that are connected to the grid via an inverter are known as inverter-based resources (IBRs). If any irregular voltage is detected, they will disconnect and interrupt the electrical connection between the grid and the DC equipment in order to protect workers, who must know where live power lines are and need the guarantee that when the power is shut off, there is no additional power injection. This essential feature, which is dictated by the IEEE 1547 standard (discussed in further detail below), has the potential to also make that irregularity into a bigger problem, which is discussed in detail below.

The goal of this work is to to understand and identify risk factors for IBR-influenced cascading events, to quantify the likelihood of such an event occurring, and to identify cost-effective risk strategies.

1.1.1 Non-Wire Alternatives and Distributed Energy Resources

As previously mentioned, DERs such as IBRs can be another option to building more infrastructure, serving as NWAs. DERs are especially useful for meeting peak loads [1], which require a lot of energy but do not occur often. It has already been shown that distributed generation (DG), of which DERs are a subset, can defer the investment costs from planning new network additions [2], [3]. And over the last 10 years, the cost of PV has dropped by more than 65% [4]; the prices in wind power have dropped by about 40% [5]. These factors, along with renewability, sustainablility, and other benefits, are large contributors to why there is an increase in NWAs.

1.2 Features of IEEE-1547 Compliant Inverters

Inverters are responsible for converting DC to AC; without them, using PV and batteries in an AC-dominated grid would not be possible. This makes environmentally-friendly PV and energy-storing batteries feasible options for individual consumers as well as large-scale PV farms or battery banks.

Inverters also have a safety feature to protect humans from dangerous live power lines if an abnormal voltage magnitude or frequency is detected and the grid needs to be serviced. If the voltage strays too far from nominal, the inverter will disconnect after a certain amount of time, called voltage ridethrough time. If the voltage is relatively close to nominal, the inverter waits longer before disconnecting, which is to say that the ridethrough time is large; if the voltage is significantly far off from nominal, then the inverter will disconnect more quickly [6].

Once the inverter disconnects, or ‘trips,’ it will stay disconnected for a certain amount of time, such as five minutes or indefinitely. Once this happens, there is no power flow to or from the bulk grid, so the grid’s load is not receiving power from the disconnected IBR. In an isolated case, this loss of power can be negligible. If the system contains a large amount of IBRs, then the loss of power can significantly upset the power balance of supply and load. This can cause the voltage anomaly to become worse, resulting in the disconnection of even more inverters. This chain of events has the potential to cause an IBR-based cascading failure event. The type of event that results is called a voltage collapse, which occurs when physical limits are violated and system equilibrium is lost, thereby causing power outages [7].

Inverters have another mode called momentary cessation. The inverter is still electrically connected, but pauses in injecting current to the grid if the voltage magnitude becomes too large or small; this pause is generally one second or less [8]. In either case - disconnection or momentary cessation - once the inverter resumes, it injects power with a ramp rate from zero power to pre-disconnection power levels.

1.3 Current State of IBR Events

The threat of an IBR-based cascading failure event is not a figment of science fiction, but one that has already occurred in reality. One of the most well-documented examples is the Blue Cut Fire Outage in southern California from 2016. A wildfire started near the Blue Cut hiking trail, and, more importantly, near an important transmission corridor with five high voltage transmission lines. There were thirteen line faults that day, resulting in loss of PV generation, the largest of which was a 1200MW loss. What is significant is that the loss in generation resulted not directly from the fire burning PV modules, but from the faults that the electricity-conducting plasma fire caused. The inverters that connected the PV disconnected in some cases when they perceived an abnormally low voltage frequency, and in other cases when the voltage magnitude was too low [8]. In 2017, two faults resulted from the Canyon 2 Fire Disturbance, also in southern California. 1600MW of power was lost [9].

There are also two documented events that took place in Australia. One is called the South Australian Blackout, which also took place in 2016. Tornado damage to three high voltage lines caused six faults resulting in a loss of 900MW from inverter-connected wind farms. The other is known as the South Australia System Event, where a damaged bus caused three faults, with losses including 400MW thermal and 150MW rooftop PV [9].

It is expected that these types of events will continue to occur and may increase in frequency as PV and other DERs become more popular. As of June 2019, 67GW of PV capacity had been installed in the U.S., and the capacity installed per year is predicted to double over the next 5 years [10].

There is a growing and valuable literature on the impact of PV generation on power systems reliability and stability. Some have found that inverter output voltage is sensitive to sudden change [11]. Others argue that remote monitoring and fault detection of PV systems is necessary because in some cases faulty components will not accurately sense the conditions and disconnect [12], which is related to to the lifetime of PV-to grid inverters [13] and the components that make up inverters [14]. Another factor that is important to PV inverter performance under voltage fluctuations is influence from grid-fault controllers and control strategies based on using continuous values for control parameters [15]. To increase stability of systems with a significant amount of distributed energy resources (DERS), solar power output can be adjusted to respond to changes in voltage [16]. Additionally, fault response analysis of such systems can be conducted by updating conventional analytical network analysis techniques [17]. Though PV systems can seem fragile, there are indications that PV systems can withstand natural disasters and function after the event [18].

1.4 Power Losses During Fault

This section introduces the concept of why line faults create dramatic changes in voltage. In the chapters that follow, a low-voltage situation will be created by forcing a transmission line to fault, so it's important to understand the physical processes that occur.

The guiding equation for this problem can be derived from the circuit diagram shown in Figure 1.1. S_{net} is the difference in power between the load, S_d, and the power supplied by the IBRs, S_s. The load and IBRs are located at the same bus as V_2. Z_{eq} is the equivalent impedance, or $\frac{1}{2}Z$.

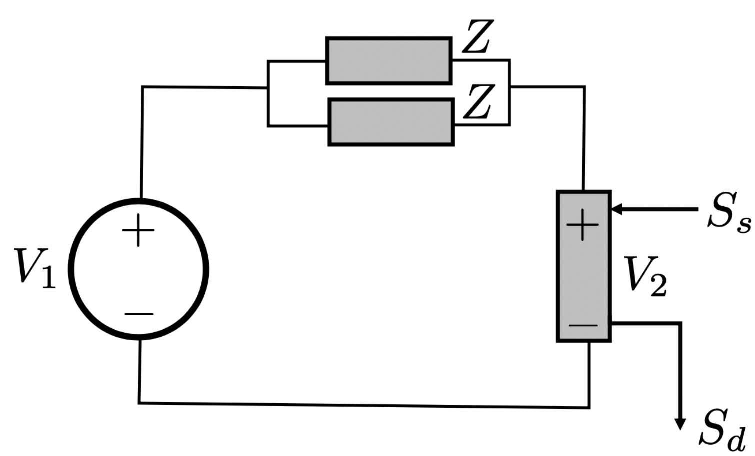

Figure 1.1: Circuit representation of two-line transmission system

A simple $V = IZ$ gives us

$$V_1 - V_2 = IZ_{eq} \longrightarrow I = \frac{V_1 - V_2}{Z_{eq}} \tag{1.2}$$

Also,

$$I = \frac{S_d^* - S_s^*}{V_2^*} \tag{1.3}$$

which can be substituted into the previous equation. Then,

$$V_2^*(V_1 - V_2) = Z_{eq}(S_d^* - S_s^*) \tag{1.4}$$

and

$$V_1^* V_2 - |V_2|^2 = Z_{eq} S_{net}^* \tag{1.5}$$

V_1 is a constant 1.0 pu, so V_2 is the only voltage left in the equation. To solve, V_2 can be broken down into its real and imaginary parts:

$$\mathrm{Im}\{V_2\} = \mathrm{Im}\{Z_{eq} S_{net}^*\} \tag{1.6}$$

and

$$\mathrm{Re}\{V_2\} - \mathrm{Re}\{|V_2|^2\} = \mathrm{Re}\{Z_{eq} S_{net}^*\} \tag{1.7}$$

or

$$\mathrm{Re}\{V_2\} - (\mathrm{Re}\{V_2\}^2 + \mathrm{Im}\{V_2\}^2) - \mathrm{Re}\{Z_{eq}S_{net}^*\} = 0 \tag{1.8}$$

$\mathrm{Re}\{V_2\}$ can be solved using the quadratic equation. Then, $V_2 = \mathrm{Re}\{V_2\} + j\mathrm{Im}\{V_2\}$. V_2 is solved for at every time step using the updated S_{net}.

Before any fault or disturbance occurs, $Z_{eq} = \frac{1}{2}Z$. After the fault, one branch goes off-line, so $Z_{eq} = Z$ and therefore line losses double and the voltage drop increases. Because less power is being supplied to the bus with V_2, the voltage will decrease.

Chapter 2

Understanding factors that influence the risk of a cascade of outages due to inverter disconnection

This chapter has previously been published as a conference paper: C. Popiel and P. D. H. Hines, "Understanding factors that influence the risk of a cascade of outages due to inverter disconnection" 2019 North American Power Symposium (NAPS), Wichita, KS, USA, 2019, pp. 1-6.

2.1 Abstract

Because of the rapid growth in distributed solar generation, there is growing concern that inverter-connected generators, which are designed to automatically disconnect under abnormal voltage conditions, could disconnect in a manner that would lead to a cascade of outages and ultimately instability or voltage collapse. This paper studies the conditions under which a cascading inverter collapse of this sort could occur. More specifically, we identify engineering design parameters, such as time constants, that influence the speed and nature of these cascades. While this model is preliminary, the results suggest that risk increases with a number of factors including: large transmission or distribution line impedances, a large variance in inverter voltage set-points, and an inappropriate number of inverter-based resources that can contribute to supplying too much or not enough power.

2.2 Notation

Name	Symbol	Unit
Number of inverters	N	-
Load	P_d	MW
Line resistance	R	p.u.
Line reactance	X	p.u.
Nominal Voltage	V_0	p.u.
Acc. voltage, low	V_L	p.u.
Acc. voltage, high	V_H	p.u.
New voltage	$V_{i,t}$	p.u.
New area	A_n	voltseconds
Maximum area	$A_{\max}$	voltseconds
σ on max area	A_σ	voltseconds
Time step	dt	seconds
Simulation time	t_s	sec
Time of fault	t_f	sec

2.3 Introduction

Inverters are an integral part of all solar photovoltaic generation systems. As distributed PV generation forms an increasingly large fraction of the power supply portfolio, the discrete and continuous dynamics of inverters become increasingly critical to power system reliability, security and resilience.

Renewable energy has a number of important benefits in terms of mitigating air emissions from fossil fuel power plants; thus, removing barriers or challenges to incorporating renewable distributed energy resources is important. One potential barrier to PV adoption is the growing concern among industry professionals about the potential for cascading grid failures due to unexpected inverter disconnections. As specified in IEEE Standard 1547 [6], inverters are typically designed to disconnect when exposed to abnormal voltage or frequency conditions. While these rules are important to protect equipment and to ensure safety, inverter disconnection rules change the discrete dynamics of a power system and have the potential to trigger cascading failures.

Cascading failures and the blackouts that can result are not new to the electricity industry. One of the most infamous examples is the August 2003 blackout in the Northeast United States and Southern Canada, which was triggered by a number of events, including power lines contacting overgrown trees [19]. Many steps have been taken to protect against cascading blackouts [20, 21], such as improved reliability standards and additional oversight by NERC. Given that inverter-connected power plants make up an increasingly large fraction of the power supply portfolio there is need for tools that help us to better understand the potential cascading failure risk associated with this new generation.

There is substantial industry concern about the potential for cascading inverter failures. Analyses of a number of previous power system disturbances suggest that inverter disconnections can lead to loss of generation.

In this chapter, we will focus specifically on identifying parameters that could increase the risk of inverter-caused cascading failure, and more specifically determine the range of values that could impact blackout risk. We will do this using a new simulation model called the Time-Dependant Inverters Model (TiDIM), which is able to identify factors that contribute to voltage collapse.

2.4 Methods

Inverter disconnections change power system dynamics because each inverter is supplying a certain amount of power to the system, and when an inverter disconnects, it is no longer contributes to the total (active or reactive) power generated. As a result, generation and load are no longer balanced, leading to changes in both voltage frequency and magnitude.

IEEE 1547 makes recommendations for when an inverter should disconnect due to off-nominal voltage conditions. Per IEEE 1547, there is a non-zero time delay between when an abnormality is detected and when the disconnection occurs, which is known as fault ride through time. The time delays specified in 1547-2003 are summarized in Table 2.1.[1] This thesis uses these time delays to represent the fact that most existing inverters were designed to meet the 2003 standard. The default settings specified in 1547-2018 are similar, but the inverter settings can be adjusted to allowable ride through times upwards of 20 seconds for some abnormal voltages [22]. Therefore, it may be necessary to consider a wider variety of time delays in future work. Regardless, it is necessary to take this time delay into account when building a model, rather than having an inverter disconnect the instant the abnormality occurs.

[1] This table is taken from IEEE 1547's table 1. [6]

Table 2.1: Interconnection system response to abnormal voltages

Voltage range (% of base voltage[a])	Clearing time(s)[b]
V< 50	0.16
50 ≤ V< 88	2.00
110 < V < 120	1.00
V ≥ 120	0.16

[a]Base voltages are the nominal system voltages stated in ANSI C84.1-1995, Table 1.
[b]DR ≤ 30 kW, maximum clearing times; DR > 30kW, default clearing times.

In order to accurately simulate these time delays, we need a measure of the likelihood that a particular inverter will disconnect given its prior history of voltage or frequency (note that the results in this thesis come from a quasi-steady-state model and thus do not include frequency). In order to accurately capture this time-delay in simulations, we introduce the idea of 'under-voltage area' (UVA), or just area, in which each inverter will disconnect when the accumulated under- or over-voltages area exceeds a pre-specified limit. The area is a function of difference between acceptable voltage and actual voltage, and the time that is allowed at that voltage. There is an upper voltage limit to the safe voltage range, V_H, as well as a lower limit, V_L, thus two functions were derived in order to account for the two situations.

At the beginning of each simulation in TiDIM, a maximum threshold area is calculated based on using both V_H and V_L which are then averaged together. The formulae to find these thresholds take the form:

$$A_{max} = a_1V^6 + a_2V^5 + a_3V^4 + a_4V^3 + a_5V^2 + a_6V + a_7, \tag{2.2}$$

where the coefficients, as derived from parameters in IEEE 1547, are listed in Ta-

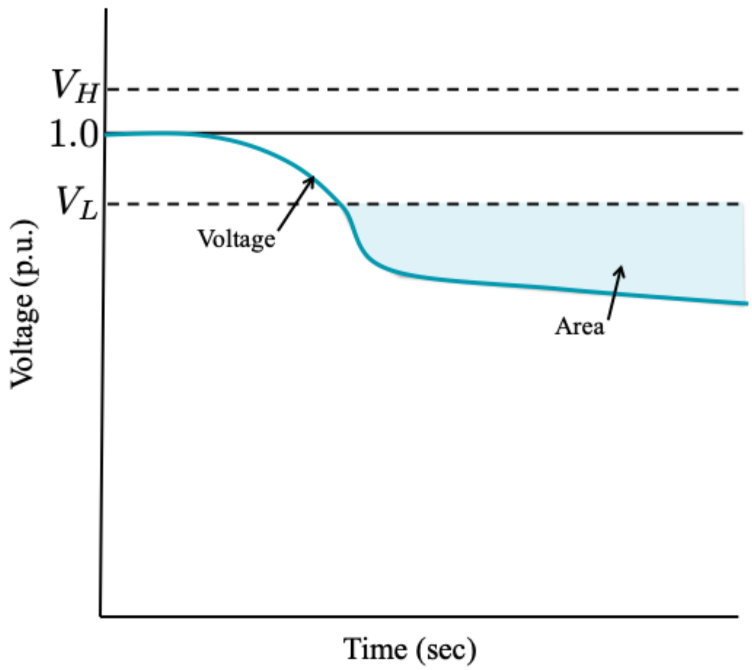

Figure 2.1: Voltage and Area Accumulation

ble 2.2. A different set of coefficients was calculated for both cases: $V = V_H$ and $V = V_L$. There is a very small number representing uncertainty, σ, around V_H and V_L, which is why this quantity is calculated every time the simulation is run rather than being a stagnant number. Once $A_{\max}$ is calculated, it is then constant for the rest of the simulation. Next, we need a way of deciding whether the accumulated area has exceeded the threshold $A_{\max}$ at each time step. To do so, at each time step t TiDIM uses the following difference equation:

$$A[t+1] = A[t] + A_n[t] \tag{2.3}$$

where $A[t]$ is the current amount of area accumulated and $A_n[t]$ is the new area accumulated at time step t. When voltages are within limits, $A_n[t] = 0$. When voltages our outside of the limits $A_n[t]$ has the form:

$$A_n[t] = 100(b_1V^6 + b_2V^5 + b_3V^4 + b_4V^3 \\ +b_5V^2 + b_6V + b_7)\Delta t, \tag{2.4}$$

Table 2.2: Coefficients for $A_{\max}$

coeff.	V_L	V_H
a_1	0	-49.408
a_2	-25.273	400.4
a_3	48.633	-1289.6
a_4	- 26.339	2062.3
a_5	5.2588	-1637.6
a_6	- 0.2528	515.38
a_7	0	1.1

with the coefficients listed in Table 2.3. 100 is the normalization factor. Because the equations for A_n are nonlinear, area accumulates faster when voltage strays further outside of the nominal voltage range.

Table 2.3: Coefficients for A_n

coeff.	$V_{L,t}$	$V_{H,t}$
b_1	0	34.197
b_2	20.887	-252.19
b_3	-51.95	738.75
b_4	41.438	-1074.9
b_5	-6.8146	778
b_6	- 5.2201	-225.27
b_7	1.76	1.1

When a simulation is initiated, each inverter is given a custom value of $A_{\max,i}$, which deviates from the original $A_{\max}$ using a Gaussian random variable with mean 0 and standard deviation σ_A. When $A_i[t]$ exceeds $A_{\max,i}$, inverter i disconnects from the system. Because each $A_{\max,i}$ is slightly different, the inverters disconnect at a different time points during the simulation.

TiDIM also comes insured with accident forgiveness. If the voltage returns to the acceptable range, the accumulated area is set back to zero. If the voltage begins to stray again, the area accumulates from zero with no previous memory of past area.

2.5 Results

This section provides a set of results that illustrate the application of TiDIM to a two-bus test case.

2.5.1 Test Case

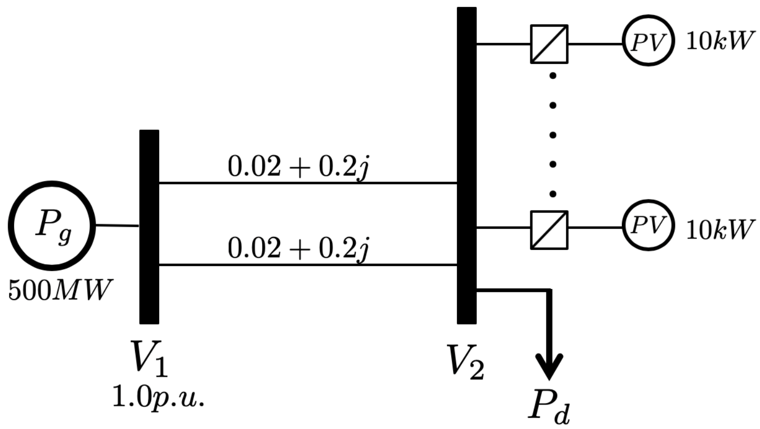

Figure 2.2: Illustration of the two-bus test case used for simulations in this thesis.

The test case used in this thesis, shown in Figure 2.2, is a two bus model with a voltage-controlled generator at bus 1 and a large number of PV systems and a load at bus 2. In the pre-fault scenario, there are two identical transmission lines between the two buses. A simulation begins at $t = 0$. At $t = 0.1$ sec, one of two parallel transmission lines faults and is immediately removed from service to introduce an initial disturbance. The parameters for the base case can be found in Table 2.4.

Applying TiDIM to the test case and varying the various parameters allows one to understand the impact of these parameters on a power system. In Figure 2.3 and each of the subsequent plots, the broad, shaded region shows the 5th and 95th percentile of possible outcomes from one set of initial conditions. The range is due to small sources of uncertainty within the initial conditions. The darkened line is the mean of the results for that set of conditions. The high voltage at the far left of the plot shows the pre-fault voltage. This plot shows that even with the same initial conditions, a wide range of results are possible. As previously mentioned, there is a σ_A for $A_{\max}$.

The following parameters also have a small σ to represent variability in the value due to conditions or uncertainty of the exact value: V_L, V_H, and V_0.

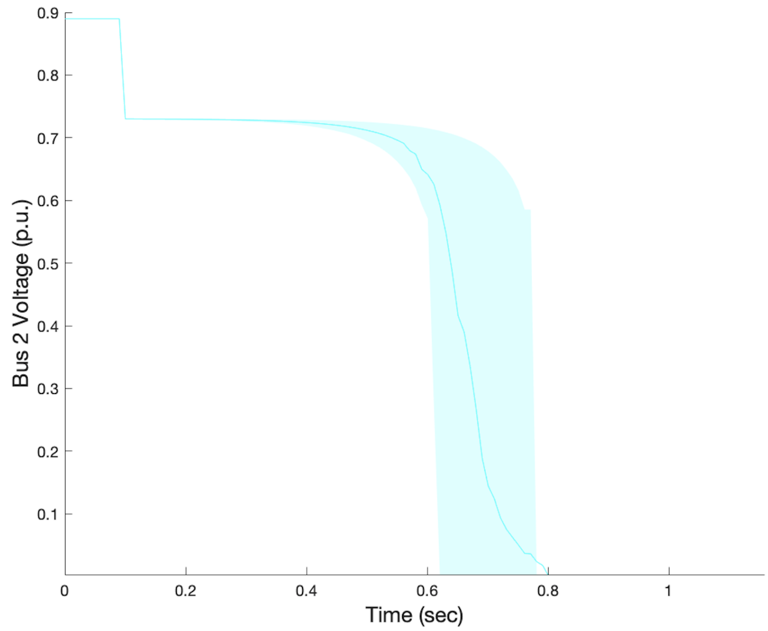

Figure 2.3: Voltage at bus 2 in the base case simulation. Note that the shaded region in this and each of the plots represents the 5% to 95% percentile results.

Table 2.4: Parameters for Test Case

Parameter	Value
$P_{d,0}$	500 MW
σ_A	0.4
X	0.2 p.u.
R	0.02 p.u.
N	50×10^3
kW/module	10

2.5.2 Initial Load, $P_{d,0}$

Voltage collapse occurs when the net load at bus two exceeds the total transfer capability of the transmission path from bus 1 to bus 2. Hence, there is a critical point around $P_d = 480$MW where the system is able to survive for a fairly long period of time without inverter outages that could lead to cascading failures. Due to the inverter parameter variability in TiDIM, there is no precise single value for the critical point. (If all σs representing variability in TiDIM are set to zero, then this inflection point is $P_d = 485$MW.) Before and after this point of precarious balance, the time to failure increases with the load and then decreases again once the load becomes too large (Figure 2.4).

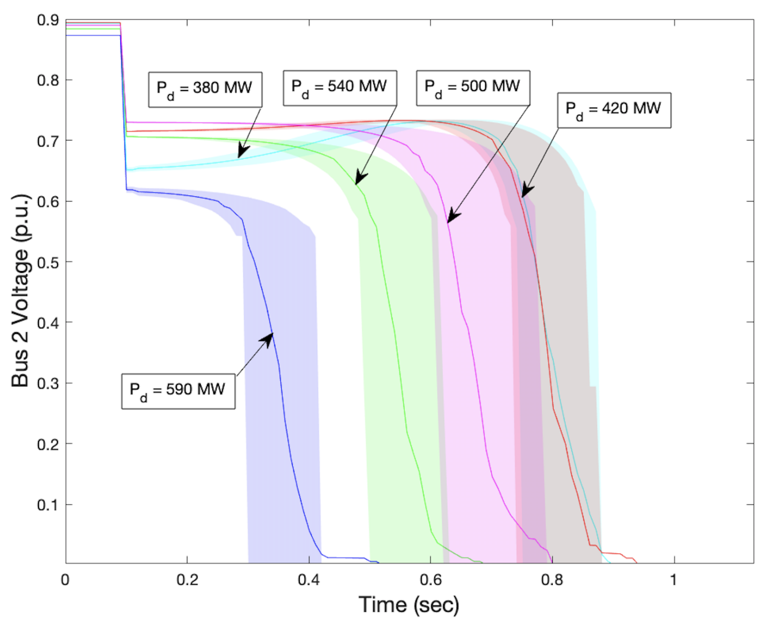

Figure 2.4: Bus 2 Voltage over time with varying initial loads, $P_{d,0}$

2.5.3 Area limit variation, σ_A

The effect that σ_A has is two-fold, which can be seen in Figure 2.5. First of all, σ_A determines how long the system will persist before collapsing: a small σ_A leads to prolonged persistence, while a large σ_A leads to more imminent failure. When σ_A is small, this indicates that many of the inverters in the system are of the same demographic, and when σ_A is large, it indicates that there is a wide range of inverter type, brand, age, and so on. Secondly, σ_A changes the shape of the collapse curve. When σ_A is small, many of the inverters disconnect at the same time, which leads to a sudden voltage collapse. When σ_A is larger, the voltage collapses more gradually; although the collapse occurs relatively quickly because of some inverters having a low area limit, it is still not a sudden drop in voltage and may be easier to detect before it is too late to react.

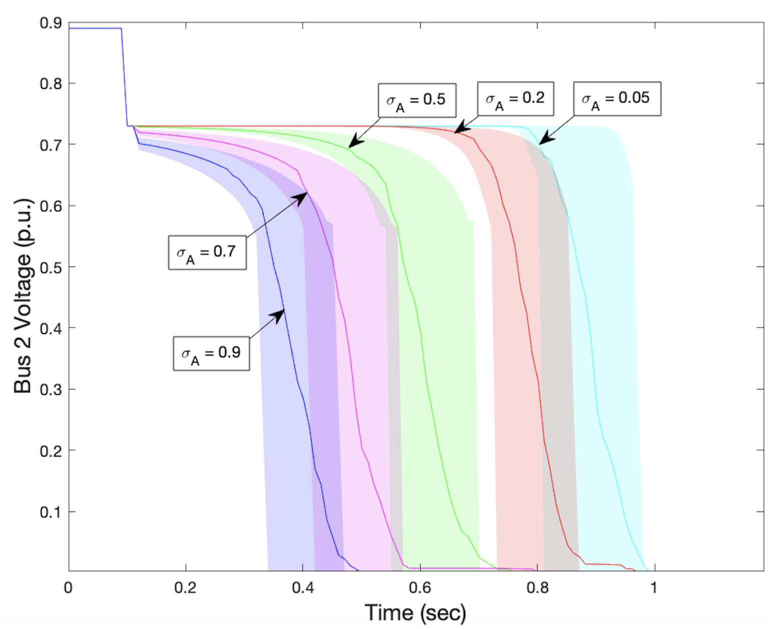

Figure 2.5: Bus 2 Voltage over time with varying σ_A on area limits

2.5.4 Number of Inverters, N

The number of inverters is directly proportional to the power supplied by the PV sources, and additionally, we assume that all PV modules supply the same amount of power to the system, 10kW per installation.

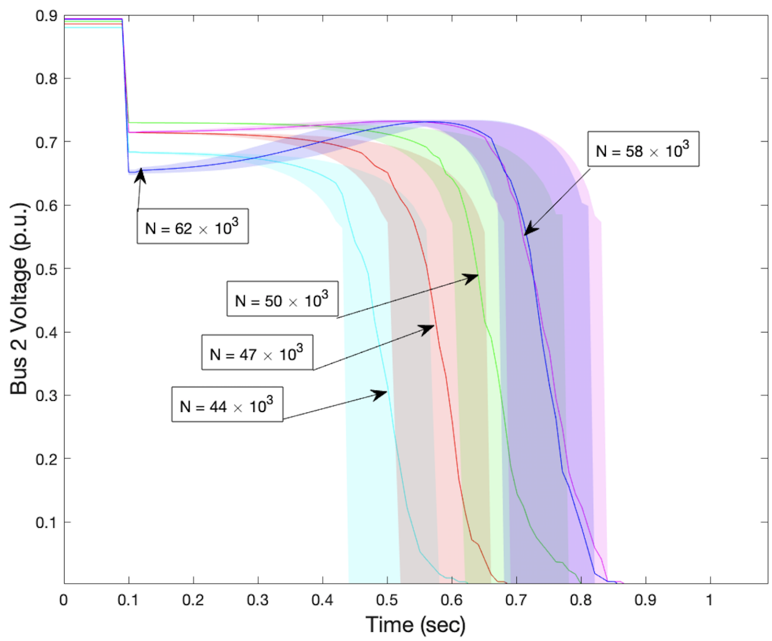

Figure 2.6: Bus 2 Voltage over time with varying numbers of inverters, N

As with load, increasing or decreasing the number of inverters beyond the less-risky region led to a quicker voltage collapse in Figure 2.6.

2.5.5 Transmission Line Reactance, X

As one would expect, the effect of the reactance in the voltage collapse is quite significant, as seen in Figure 2.7. Over a relatively small range of reactance values, varying X can lead to anything from near immediate collapse ($X = 0.26$ p.u., not shown on plot) to no collapse at all. In fact, a mere 0.01 p.u. is enough to swing the outcome from near certain safety to near certain failure. This result suggests that reactance (i.e., proximity to voltage collapse) strongly influences the likelihood of an inverter cascade.

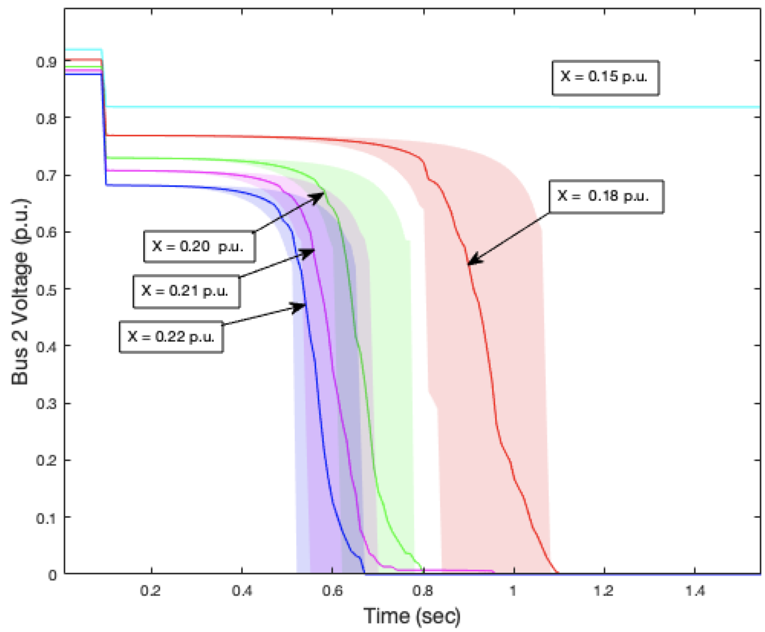

Figure 2.7: Bus 2 Voltage over time with varying X

2.5.6 Transmission Line Resistance, R

While minute changes in X had a substantial impact on the likelihood of a cascade, changes in the resistance did not have such a drastic effect. Reducing R by an entire magnitude resulted in very little change (Figure 2.8). Increasing R resulted in some change (a quicker voltage collapse), but it is necessary to increase R by an order of magnitude from the test case resistance in order to get a significant change in the results. As would be expected from standard models of voltage collapse, changing R

has a much smaller impact on cascading risk, relative to changing X.

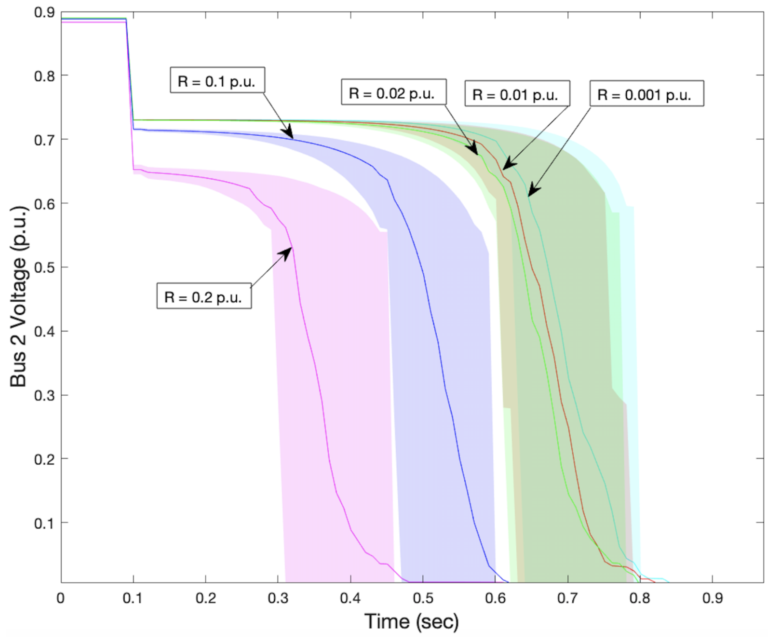

Figure 2.8: Bus 2 Voltage over time with varying R

2.5.7 Non-significant parameters

Additional experiments were performed to understand the impact of varying σs on V_L, V_H, and V_0. The results suggest that these parameters have very little impact on the likelihood of a cascade.

2.6 Conclusions

The results of the experiments run in this chapter are summarized in Table 2.5. From these results it is clear that a large reactance, a large resistance, and a larger σ_A can contribute to a higher risk of or an increased speed of cascading inverter failures.

Among the reactance and resistance, the results confirm conventional power systems results, which would suggest that changes in reactance can dramatically change the risk of voltage collapse. Additionally, a large mismatch between load and power supplied by inverter-based sources can also contribute to a higher risk of failure.

It is our intention that as this model matures, TiDIM will enable engineers to better understand the conditions that lead to dangerous inverter failure cascades and use the insights that results to design systems that are more resilient to wide scale collapses. While the results from the two-bus test case used in this chapter provide insight into the general problem of inverter cascades, we acknowledge that it is difficult to draw broad conclusions from a single, small test case. Future work will provide deeper insight into this problem through the use of more detailed dynamical models and larger test cases. Although the results from this early work are tentative, they provide useful insight into an important and timely power systems problem. Future work, in part discussed below, will expand on these results and provide more actionable engineering conclusions.

Table 2.5: Results Summary

Parameter	Region of Increased Risk
σ_A	larger is riskier
N	dependant on typical demand
X	> 0.16 p.u.
R	> 0.03 p.u.

Chapter 3

Characterizing the Risk of Cascading Inverter Disconnection in Power Systems with Large Amounts of Solar PV

3.1 Abstract

Renewable resources are an important and growing percentage of the total power supply, and inverters are used to connect these resources (as well as batteries) to the grid. However, there is growing industry concern that the disconnect function that is inherent to the design of inverter-based resources has the potential to result in a cascading failure if voltages deviate significantly from nominal. In this paper, we aim to characterize the risk at which one may expect this sort of event to occur as a function of line impedance and the resultant voltage magnitude. We find that a greater proportion of inverter-connected power in the grid is associated with a higher probability of collapse, and a greater variance in inverter behavior is associated with a wider transition band, which we define in this paper as the range of voltages where the probability of collapse is an uncertain.

In a world where renewable generation is necessary to secure a fossil-fuel free future, inverters are equally necessary, as they connect the dc electricity generated from renewables such as PV into the ac electricity that the grid uses. However, a large penetration of inverter-based resources (IBRs) is also associated with a threat to voltage stability [23] especially since many of the older inverters currently in the field may not have reactive power functionality.

Inverter-influenced cascading failure is not a theoretical concept but one which has already occurred multiple times. One example of this is the previously discussed Blue Cut Fire disturbance, an event where a fire in southern California caused faults to important transmission lines that resulted in PV generation loss, the greatest of which was a 1,200MW loss [8]. Other examples include the Canyon 2 Fire disturbance in

California in 2017, the South Australian Blackout in 2016, and the South Australian System Event in 2017 [9]. Among these four examples, three are suffered from loss of generation and widespread tripping of inverters, and the South Australian Blackout is classified as a cascading failure event.

We have identified these questions as important concerns to investigate because of the growing number of non-wires alternatives (NWAs), discussed in Chapter 1. Demand for electrical power is increasing as infrastructure and electrification increase, and instead of building more transmission lines, NWAs such as PV are installed instead. This localized, renewable energy is a good thing, but NWAs are not without consequences, which we hope to identify and quantify in this chapter.

The goal of this chapter is to characterize the risk of cascading inverter disconnection under different power systems conditions and IBR characteristics. Because we know that these events are possible in the future, it is imperative that risks associated with a cascade of inverter disconnections be identified so that we can be prepared for them and ideally avoid them all together. Specifically, we will vary percentage of power supplied by the inverters and variability in inverter behavior, and increase the base load. Doing this will help address the question of the risk of an inverter-influenced cascading event based on a given situation (time of day, load, inverter variability). This will be done using our simulation model, TiDIM, which is able to show changes in voltage magnitude after an event by disconnecting inverters in the model to reflect the voltage ridethrough time.

3.2 Methods

Inverter disconnections change power system dynamics because each inverter supplies a certain amount of power to the system, and when an inverter disconnects, it no longer contributes to the total (active or reactive) power generated, effectively increasing net load. As a result, sudden changes in net load lead to changes in voltage frequency and magnitude. This chapter focuses on voltage magnitude but it is important to note that frequency can also be affected and will be included in future work.

IEEE 1547 makes recommendations for when an inverter should disconnect due to off-nominal voltage conditions, as previously discussed. The time delays specified in 1547-2003 are summarized in Table 2.1. This chapter also uses these time delays to represent the fact that most existing inverters were designed to meet the 2003 standard. Additionally, regulatory agencies have only recently begun enforcing the interconnection standards in the updated 2018 rules.

In order to accurately simulate these time delays, we need a measure of the likelihood that a particular inverter will disconnect given its prior history of voltage or frequency. In order to accurately capture this time delay in simulations, we introduced the idea of under-voltage area (UVA) in the previous chapter. To summarize, UVA provides a way to integrate the amount of under (or over) voltage over time. When UVA exceeds a certain limit (calibrated to align with the timings set by IEEE 1547, called $A_{\max}$ in the previous chapter), the inverter will disconnect. $A_{\max}$ is varied by some amount σ_A in each simulation, to represent the variability that may exist in inverter behavior in the field. There is a very small number representing uncertainty,

V_σ, around the upper voltage limit, V_L, given by IEEE-1547, which was found in the previous chapter to have little impact om results.

Given that inverters are designed to disconnect under certain voltage conditions, it is useful to define the term 'transition band' as it pertains to our work. In every case we examine, there is a voltage above which a fault will almost never lead to voltage collapse, and a voltage below which a fault will almost always lead to collapse. Between these two voltages, where the outcome is not certain, is the transition band, where either collapse or stabilization is possible. As we will see below, the transition band varies in width and location based on amount of inverter-supplied power and inverter behavior.

To study the probability of failure, we used a Monte-Carlo technique to vary the load and percent of power supplied by inverters in order to change the post-disturbance voltage of each simulation. Then, we separated the results into bins and assigned a probability based on the number of fails over total runs for each bin. For computational simplicity, we assume that voltage collapse occurs whenever voltage magnitude is at or below 0.8 p.u.

Figure 3.1 shows the parameters that were varied to achieve our range our results. The base load (100MW), line impedance (0.022+0.11i p.u.), time step size (0.01s), and power supplied by each inverter module (10kW) were kept constant. The percentage of load supplied by IBR power and σ_A were changed by the user, and the changes to these parameters, in conjunction with the growth factors and A_{max}s drawn from gaussian distributions, resulted in the variations to the load, amount of IBR power, and A_{max} actually used in the simulation. A total of 200,000 simulations were run in order to produce the figures below.

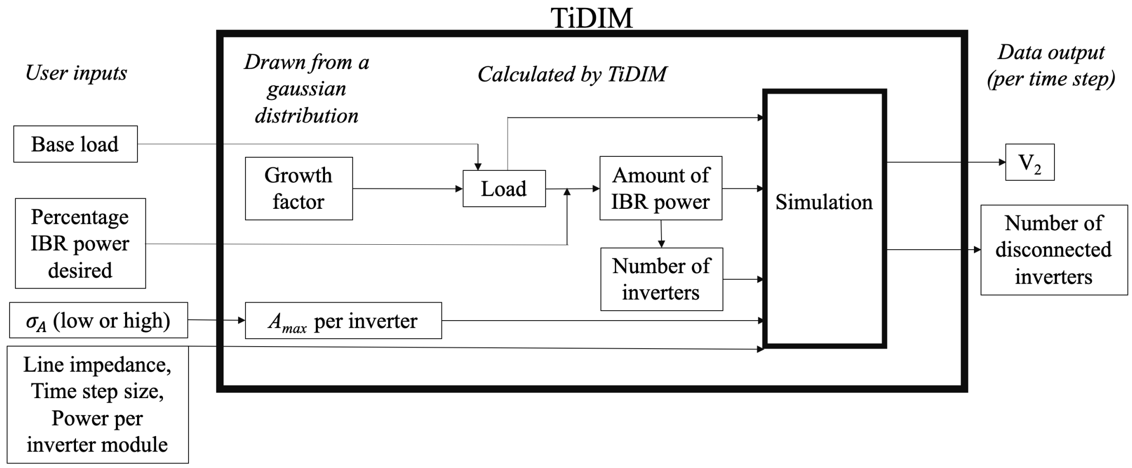

Figure 3.1: This figure illustrates the inputs to and outputs from TiDIM for this chapter.

3.3 Results

This section provides a set of results that illustrate the application of TiDIM to a two-bus test case. First, we present a test case and the rate of inverter disconnection in order to orient ourselves with what a voltage collapse curve tends to look like in the scenario we have created. Next, we move onto probability of voltage collapse, or risk, given a certain set of circumstances. The validation test is created by looking at the post-fault voltage and calculating the probability of collapse at that voltage. The probability of collapse as a function of amount of IBR-based power will show how risk changes throughout the day (different amounts of sunlight) and as more and more people adopt rooftop PV and other IBRs. Lastly, the probability of collapse due to a simultaneous increase in load and increase in IBR power is examined to determine how big of an impact these factors cause as NWAs rise.

3.3.1 Test Case

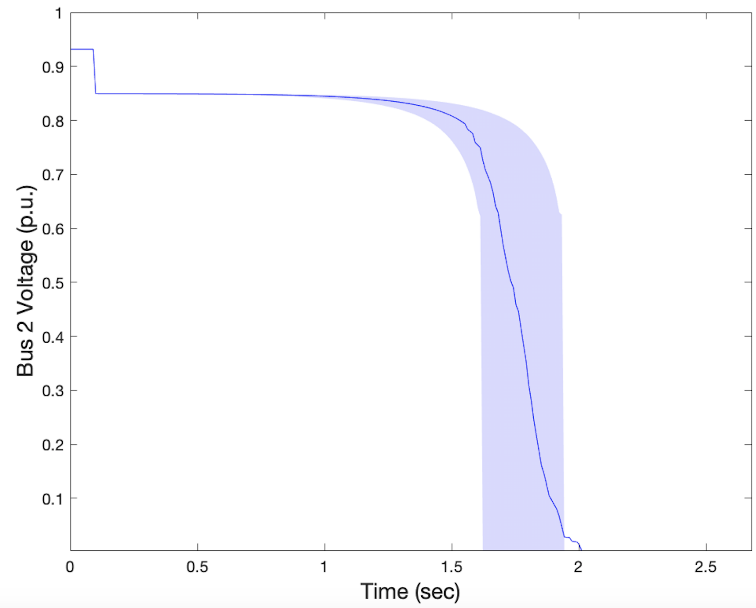

Figure 3.2: Voltage at bus 2 in the base case simulation. Note that the shaded region in this and each of the plots represents the 5% to 95% percentile results. The parameters here are 100% inverter-supplied power, 0.13 p.u. line impedance, and medium variance.

The test case used in this thesis, shown in Figure 2.2, is a two bus model with a voltage-controlled generator at bus 1 and a large number of PV systems and a load at bus 2. In the pre-fault scenario, there are two identical transmission lines between the two buses. A simulation begins at $t = 0$. At $t = 0.1$sec, one of two parallel transmission lines faults and is immediately removed from service to introduce an initial disturbance. This is the same scenario as introduced in Chapter 2.

Applying TiDIM to the test case and varying the various parameters allows one to understand the impact of these parameters on a power system. In Figure 3.2 and each of the subsequent plots, the broad, shaded region shows the 5th through 95th percentile of possible outcomes from one set of initial conditions. The range is due to small sources of uncertainty within the initial conditions. The darkened line is the mean of the results for that set of conditions, and the initial voltage at the far left of the plot shows the pre-fault voltage. This plot shows that even with the same initial conditions, a wide range of results are possible due to the σs discussed above. Figure 3.2 does not represent all scenarios but most voltage collapses tend to follow the shape of this curve.

3.3.2 Validation Test with Probability of Failure as a Function of Post-Event Voltage

As we can expect, the lower the immediate post-event voltage is, the greater the probability of failure is. When the voltage begins low, area accumulates faster, inverters disconnect sooner, and this increases the chance of a collapse. Figure 3.3 demonstrates this trend. The transition band is between 0.80 and 0.90 p.u., with certain failure below the lower limit and certain safety above.

Interestingly, the transition band is not monotonically decreasing with the increase in voltage. These spikes in the middle of the bands represent phase transitions, which are discussed in part below.

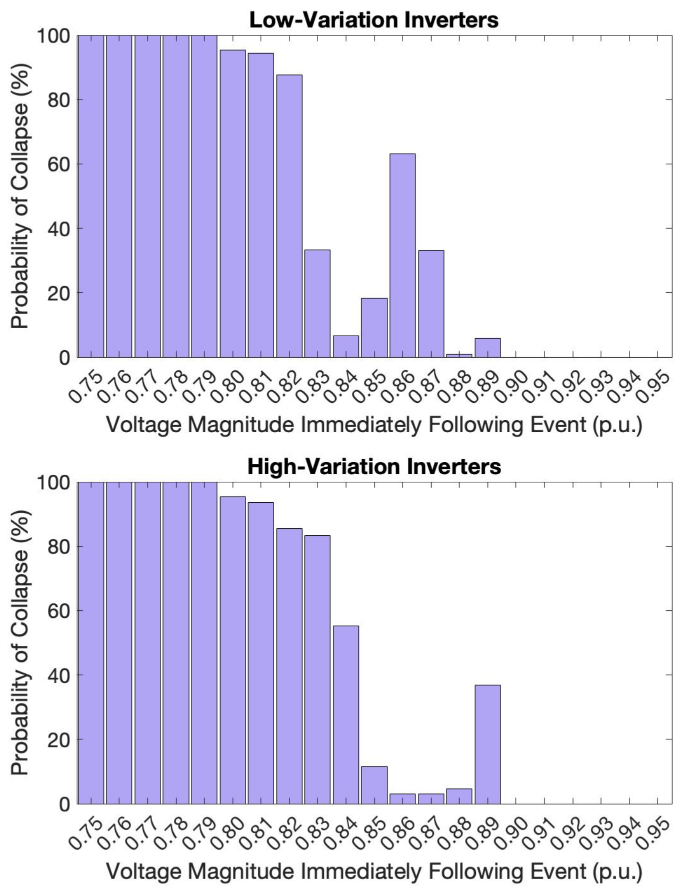

Figure 3.3: Probability of failure as a function of voltage at the first time step post-fault

3.3.3 Probability of Failure due to Amount of IBR Power

One factor of the probability of failure is the percentage of the load that is supplied with power from inverter-connected sources. A range of examples are shown here, from approximately 10% of load met by IBRs, representing morning, evening, or a cloudy day to approximately 100%, representing a sunny midday. These conditions

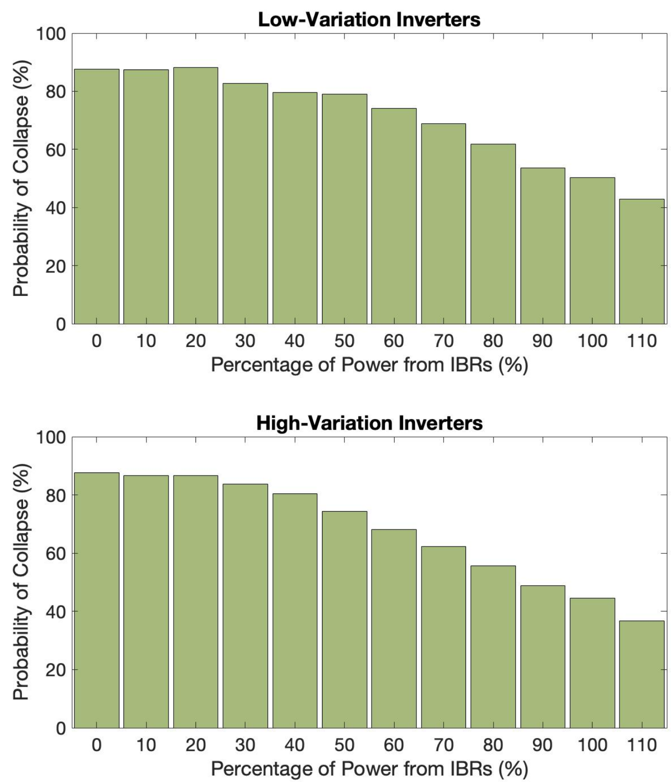

Figure 3.4: Probability of Failure vs. Post-Event Voltage, based on inverter percentage and variability. Note that the colored bars represent collapse and lack of color represents stabilization, so the goal is to reduce the colored area by as much as possible.

can also represent non-PV sourced IBR power, such as a windy or calm day on a wind farm. It is also possible to have 0% (no IBRs) and over 100%, on a day that is especially sunny or windy and load is not too high.

When there are no IBRs in the system, the probability of collapse is about 80%. This is, of course, not how any power engineer would design their system. Our pre-fault conditions have been engineered so that the pre-fault voltage is lower than what a system would normally operate at, which represents some weakness in the system that makes it more susceptible to total failure if some fault then occurs. To put it simply, there would be very few results to be drawn about inverters from a perfect system.

3.3.4 Effect of Growth on Probability of Failure

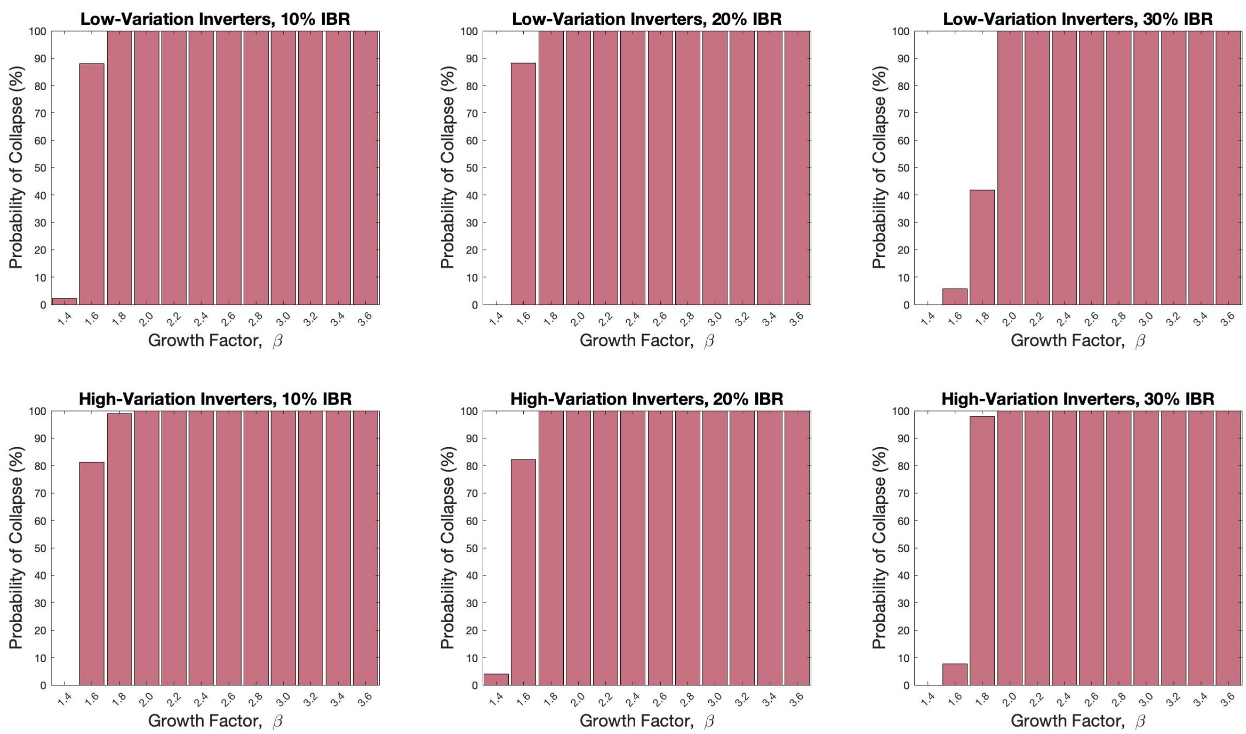

Figure 3.5: Probability of collapse as a function of growth factor, β, for 10%-30% IBR-sourced power

One of our research questions is how the growth of electrical load effects the probability of failure, while large amounts of IBRs as NWAs are simultaneously implemented. Figures 3.5 through 3.7 show the probability of collapse as a function of the amount of load at bus 2 in our test system. The growth factor, α, is the multiple of the base load, P_d, which we define in this section to be 100MW. When $\alpha > 1$, the load has been increased to greater than 100MW. Therefore, the net load is

$$S_{net} = \alpha(P_{d,base} - P_{IBR}) \tag{3.2}$$

The top rows show low-variation inverters ($\sigma_A = 0.2$), and the bottom shows high-variation inverters ($\sigma_A = 0.8$). The subplots are further broken down into amount of IBR power. For example, if the amount of IBR power is 10%, then 10% of the base load for any of the base loads in that subplot comes from IBRs. And then in the next one, 20%, and so on; the percentage (as well as σ_A) is what is constant for that particular subplot.

What is unique about increasing the load is that the percent of IBR power supplying that load greatly shapes the probability of collapse profile. For low amounts of IBR power (Figure 3.5, 10%-30%), there is a very small transition band; below $\beta = 1.4$, probability of collapse is low and above $\beta = 1.8$, collapse is almost certain.

For $\beta \geq 40\%$, there is a region of apparent stability in the transition band, or an unexpected "spike." This region of stability shifts from about $\beta = 1.4$ to about $\beta = 3.0$ as the percent of load met by IBR power increases from 40% to 90%. Interestingly, the region of stability only appears in the case where inverter variation is low.

For high-variation inverters, there is a transition band with no initial spike in probability of collapse. This transition band shifts to higher βs as IBR power increases. This makes sense because a large load (large β) is balanced by a large amount of IBR power and a small load is better balanced by a small amount of IBR power. Therefore, as the load increases, it is better to have a matching amount of IBR power,

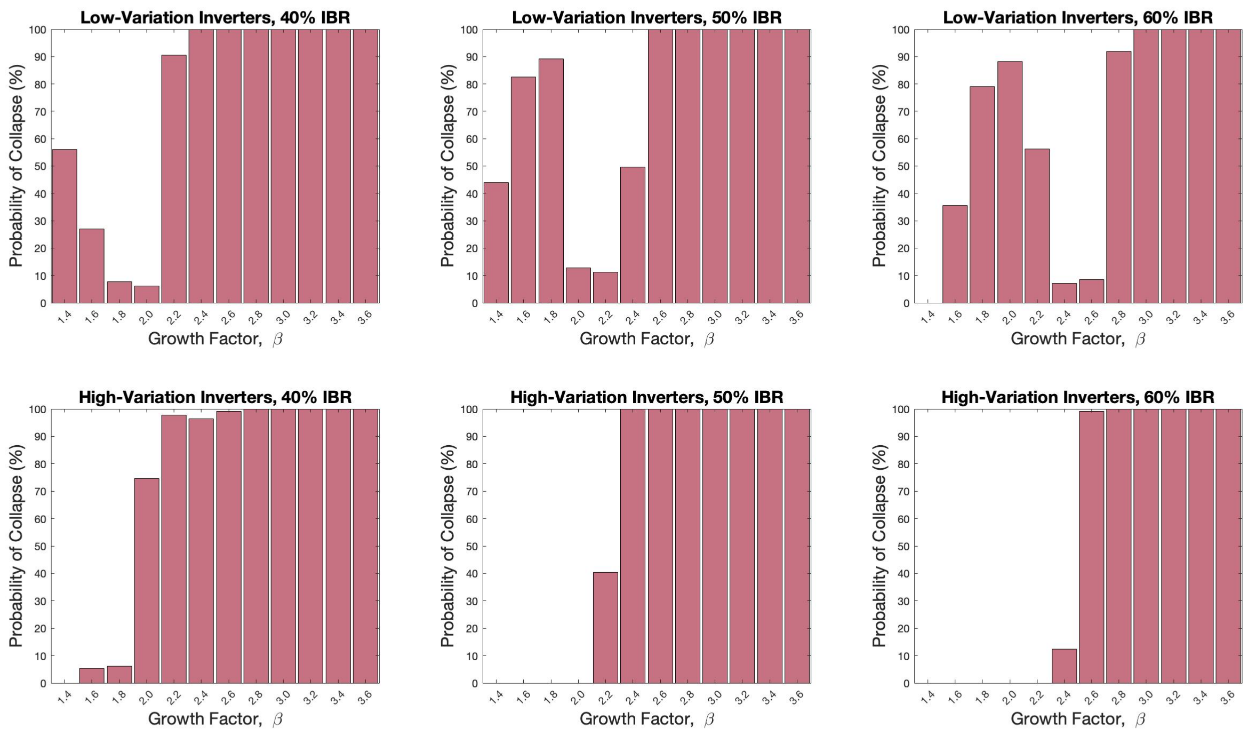

Figure 3.6: Probability of collapse as a function of growth factor, β, for 40%-60% IBR-sourced power

and the greater number of inverters that are used as a result appear to not increase the chances of a voltage collapse. High-variation inverters also decrease or eliminate the transition band's spike, allowing for a wide range of βs that do not have a high probability of collapse.

The transition band spike in the low-variations cases, though, leaves some room for further investigation. For this further study, we will examine the low-variation, 70% IBR power case.

Figure 3.8 shows the voltage curves for three different loads: low (before the spike), medium (in the middle of the spike), and high (after the spike, but before the final

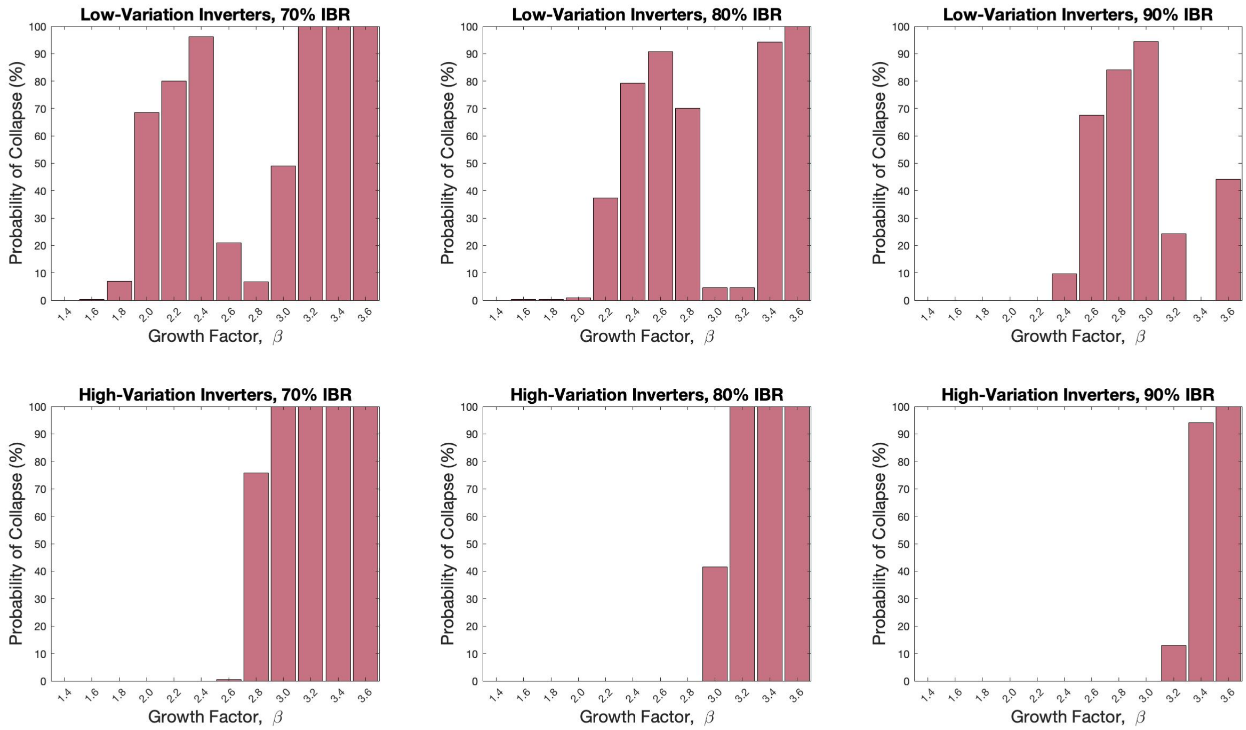

Figure 3.7: Probability of collapse as a function of growth factor, β, for 70%-90% IBR-sourced power

transition to guaranteed voltage collapse).

The medium load case is interesting because there are three distinct groups of voltage collapses. One group is steady and does not drop below the failure voltage of 0.8 p.u. One group drops in voltage very quickly and then remains constant, due to the fact that all possible inverters have disconnected and there is not a way for the voltage to drop any more. In between these two voltage collapse groups is a 'waterfall' voltage collapse group, which is characterized by two small drops in voltage that eventually lead to collapse. When the load is much bigger or smaller, as shown by the 180MW and 280MW subplots, the waterfall group does not exist. The waterfall

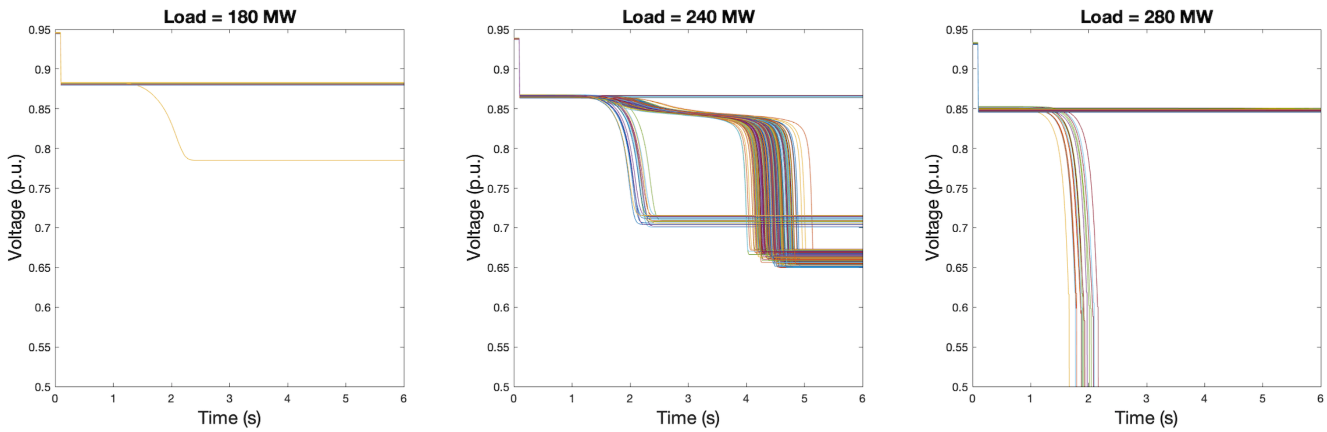

Figure 3.8: Voltage collapse curves for the low-variation, 70% IBR power case

group only appears in the loads that correspond to the transition band spike βs that represent the same loads. This indicates that when there are three voltage groups including a waterfall group, the risk of collapse is high.

The next figure, Figure 3.9, is a plot of the change in voltage magnitude that occurs when one inverter disconnects as a function of load. This change in voltage, dV, is shown for the 70% IBR case as well as the 50%, 60%, 80%, and 90% cases surrounding it. We can see that when the load is small, dV is relatively large to when the load is small. This makes sense because when there is a small amount of power, the loss of one inverter's power is big, and the change in voltage due to this one inverter is also big. When there's a large amount of power concerned, one inverter does not matter that much.

Ergo, there are two opposing forces that are captured in Figures 3.5 through 3.7. Normally, when the load, or β, is small, the risk of voltage collapse is small; however, in Figure 3.9, we showed that inverter disconnection makes a bigger difference in the voltage when the load is small. We hypothesize that these two trends interfere with each other to create the transition band spike.

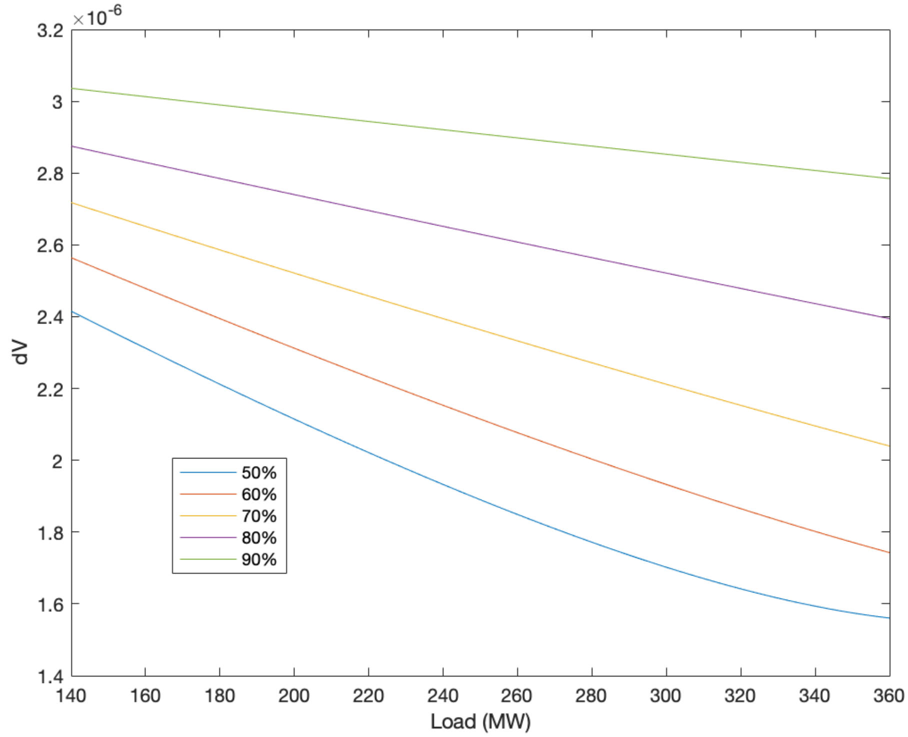

Figure 3.9: Change in voltage magnitude due to the loss of power from one disconnected inverter, which decreases as the load increases

When inverter variation is high, the waterfall group does not exist (figure not shown); this particular group of voltage collapse curves is unique to the low-variation inverters, as is the transition band spike at these same loads. Therefore, we hypothesize that the abrupt disconnection of inverters in the low-variation case may help influence the creation of the transition band spike and waterfall group.

3.4 Conclusions

A positive conclusion that we can tentatively draw based on our work is that in most events with a transmission line fault, the presence of inverters will *not* lead to a voltage collapse scenario; this is based on the assumption that most events do not fall below about 0.95 p.u. in voltage magnitude. However, based on recent historical data, we know that inverter-influenced cascading failure does occasionally occur, which is why it is important to consider the implications of the presence of a significant number of inverters.

We acknowledge that in most events, a system's voltage will usually not drop as low as shown here in the results from our simulations. However, this work demonstrates the predictability (or, rather, unpredictability) of the outcome from a given situation, which is not fully determined. This work also demonstrates the need for voltage control at the load bus, which is necessary if that bus is islanded, but also may be necessary for an event that limits the reactive power support to that bus.

In this chapter, we found that risk is:

- 0% if V_2 is above 0.89 p.u.,
- 100% if V_2 is below 0.82 p.u.,
- Lower when the inverter-supplied power matches the load, and
- Risk is different throughout the day and year.

Additionally, we can expect that as more renewable energy is integrated into the grid as NWAs, and as more inverters are added that follow the new IEEE 1547-2018 standard, it is likely that the percentage of inverter-connected power will increase and that the inverters in the system will become more varied based on the presence of new and old inverters.

Chapter 4

Risk Mitigation

The aim of this chapter is to identify modifications that may be made to existing inverter systems in order to minimize risk. An IBR-influenced cascading event can be classified as high impact/low probability, so although the existing risk is not very high, it is worth the effort to avoid the devastating impact that is possible.

4.1 Voltage Ridethrough

Based on the current literature, researchers tend to agree that a longer voltage ridethrough time would help the problem. In [9], the authors recommend that inverter manufacturers eliminate momentary cessation and increase ridethrough time; that is, inverters "react too quickly to waveform anomalies." The analysis of the Blue Cut Fire disturbance also recommended that momentary cessation be decreased and ridethrough increased [8]. However, there is some disagreement; [24] points out that European codes require 150ms of ridethrough at 0 volts, which can potentially lead to equipment damage and increased DC voltage in some types of systems.

On first glance, indeed, voltage ridethrough times appear arbitrary. One theory is that when inverters started to be used en masse, it made sense that they should respond quickly; power electronics like inverters can respond much more quickly than traditional generation. In the presence of a disturbance, fast response time seemed like it would be a good idea. But just like many other systems, power systems can oscillate out of control if disturbances get over-corrected [25]. Whatever the original intentions were, it is nevertheless time for a voltage ridethrough overhaul.

Depending on the situation, increasing the voltage ridethrough may or may not avoid a cascade. If, for example, a power line goes down and the voltage permanently drops, increasing the ridethrough time will only delay the inevitable by a couple of seconds.

However, if there is a fault that lasts only for a small duration of time, having an increased ridethrough time may help the system avoid voltage collapse because the power is still being injected.

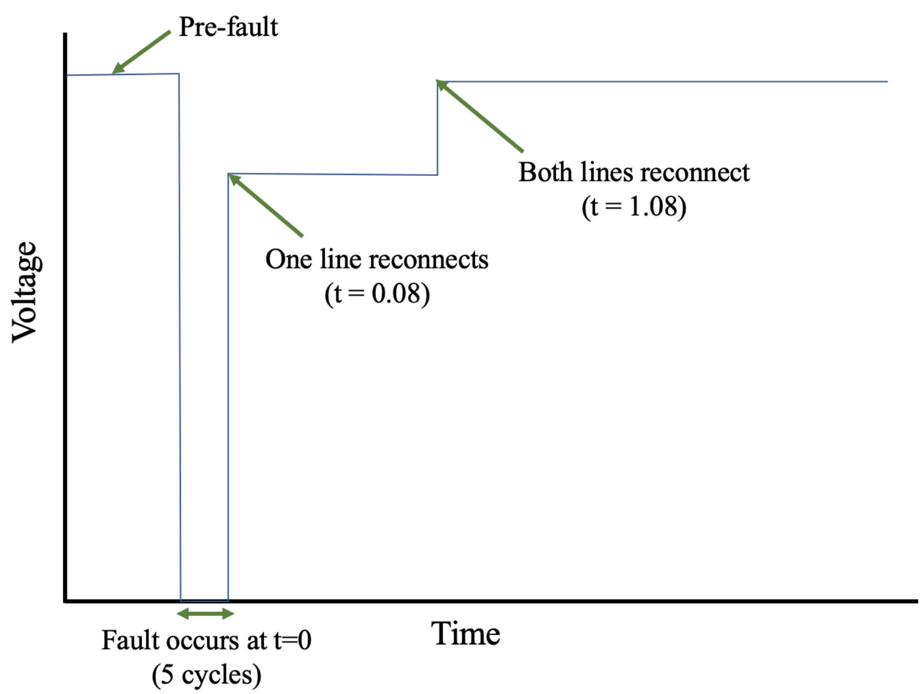

Figure 4.1: Situation that is suitable for testing increases in voltage ridethough

Consider the following case: There exists a two-line transmission system similar to that in Figure 2.2. Suppose there is a short outage and the voltage drops to 0 for 5 cycles (0.083 seconds). Then, one transmission line resumes transmitting power while the other trips an automatic circuit recloser (ACR). After one second, the ACR closes and both transmission lines transmit power. This case is represented by Figure 4.1.

With normal 1547-2003 ridethrough times[1], the probability of voltage collapse is about 18% for no IBRs, and about 20-25% with the addition of IBRs. Current voltage ridethrough means that the probability of collapse is increased.

	IBR (%)		
Increase in A_{max} (γ)	0	50	100
1	18.25	23.25	20.5
2.11	18.25	23.25	20.5
6.56	18.25	27	31
9.33	18.25	10	1
12.11	18.25	5	0

Table 4.1: Probability of collapse (%), where γ is the multiple of the 1547-2003 based A_{max}

With longer ridethrough times, created by making A_{max} about 10 times bigger, which is to say $\gamma = 10$, probability of collapse goes down to less than 10%. In the case of 100% IBRs, with $\gamma = 12$, this reduces the probability to zero. Ergo, a large amount of voltage ridethrough can actually help a system avoid collapse if there is a large amount of IBRs.

To achieve the desired 12-fold increase in A_{max}, both the voltage limits and the times spent at those limits will have to be changed. A future area of research would be finding the ideal balance of voltages and times that would limit the danger from live equipment. It is unknown if such a large increase in voltage ridethrough is possible without causing too much damage, but based on these preliminary results, even a $\gamma = 9$ increase could help reduce the risk of a voltage collapse.

Changing the ridethrough in existing inverters would, if it is possible, be an effective and very low-cost risk reduction method.

[1] This is represented by "$\gamma = 1$ multiplied by A_{max}" in Tables 4.1 and 4.2, meaning no ridethrough has been added on to the usual that has so far been used throughout this thesis.

Increase in A_{max} (γ)	IBR (%) 0	50	100
1	n/a	100	100
2.11	n/a	100	100
6.56	n/a	99.9	99.9
9.33	n/a	23.2	8.66
12.11	n/a	12.9	6.49

Table 4.2: Number of Disconnected Inverters (% of Total), where γ is the multiple of the 1547-2003 based A_{max}

4.2 Power Factor

One way to define a smart inverter verses a normal inverter is that a smart inverter has has the ability to generate reactive power, and thus regulate local voltages or perform power factor correction. Conventional inverters, which are modeled throughout this thesis, have a unity power factor of 1, meaning that all power is active and none is reactive. A smart inverter that has a non-unity power factor can inject both real and reactive power into the grid, and this reactive power helps stabilize the voltage.

In the model presented in this thesis, about 65 percent of the inverters must be smart inverters in order to have effective voltage control.[2] Although this suggestion motivates the replacement of inverters for smart inverters, it also means that 100% substitution is not necessary, so there is less pressure to find and replace old inverter hold-outs.

[2]This calculation assumes that the load is 300MW+98.61MVAR = 316MVA, the power factor is 0.9, and each inverter is capable of supplying 10kVA. Thus, each inverter contributes 9kW + 4.36kVAR. To meet this load, about 35,000 total inverters are needed to meet the active power demand, and about 23,000 inverters are needed to meet the reactive power demand. This means that about 65% of the inverters need to be smart inverters for voltage control. The percentage will vary based on load, power supplied by each IBR, and power factor, but 65% is a good estimate for planning purposes. The assumption is that all of the demand is met by the IBRs, so if there is any voltage control from an additional source that proportionately exceeds that from the inverters, less smart inverters will be needed.

A non-smart inverter may cost around $400 [26], where a smart inverter with adjustable power factor can cost upwards of $2,000 [27]. This difference in price cost is non-negligible, so an incentive program could encourage people to upgrade their inverters or buy a smart inverter from the start.

4.3 Ramp Rate

When an inverter disconnects or enters momentary cessation, there is a time delay before the inverter will reconnect and resume injecting power, described in Chapter 1. The maximum allowable ramp rate is generally between 1 to 10% per minute depending on the location [28], which means it would take between 10 minutes to nearly 2 hours to regain normal power levels. Typical ramps rates following momentary cessation are much faster, although in Blue Cut Fire analysis, it was found that very short ramp rates (less than 1 second total time) cause brief drops in frequency [8]. This thesis assumed that an inverter would immediately resume power injection if voltage rose to acceptable value, which did not occur in any case where typical 1547-2003 suggestions were used, and therefore delayed reconnection was not studied. However, future research will want to consider and adjust the maximum ramp rate and reconnection speed that can be used, because resuming power injection quickly is important, but sudden jumps in power or voltage are damaging to system dynamics, so the reconnection speed can not be infinite.

4.4 Long-Term Risk Mitigation

The above strategies will help reduce the risk of and IBR-influenced voltage collapse, but effective long-term risk mitigation will take some time to implement. Purchasers should opt for smart inverters that have a reasonably quick or programmable ramp rate.

Micro-phase measurement units, or μPMUs, are important grid monitoring devices that will help sense disturbances in the grid and thereby avoid situations such as voltage collapse. PMUs measure grid phasors, which include magnitude, frequency, angle, and timestamp, at a rate of 10-60Hz , which is much higher than SCADA's rate of one sample every 4 seconds. PMUs are typically used in transmission systems where dangerous changes in voltage tend to be quite large. For distribution systems, which operate at lower voltages and have impactful small changes in voltage, engineers propose that μPMUs be incorporated. μPMUs have very fine resolution, between 4-20 times better than normal PMUs, and are able to detect small changes in voltage. Then, action can be taken to ameliorate the problem before inverters are affected. Currently, μPMUs are not widely used in practice, but the price tends to be much lower than for normal PMUs, so hopefully research will continue and μPMUs will become a part of everyday grid monitoring [29]. Alternative voltage control will also be important, both as a function of inverters and in general. As more renewables and IBRs are utilized, there will be less spinning reserves available to support the voltage.

Chapter 5

Conclusions

5.1 Research Conclusions

From Chapter 2, we can conclude that a mismatch in supply and demand power, as well as a larger variance in inverters σ_A, influence a cascading failure to fail more quickly. More or less IBR power is not a universal solution, but is dependent on a system's typical load profile and other system characteristics.

From Chapter 3, we can conclude that risk of voltage collapse is high when the voltage drops below 0.82 p.u., low when the voltage is above 0.89 p.u., and uncertain in between these two numbers. The risk is lower when the inverter-supplied power matches the load, and importantly, risk is different throughout the day and year. It is very dependent on when the sun shines and when the wind blows, as well as the amount of installed capacity in a particular region.

In Chapter 4, we investigated how the risk of an inverter-influenced voltage collapse event can be mitigated without expensive overhauls to the power grid. We showed that under at least some circumstances, increasing voltage ridethrough time can reduce or eliminate the risk of collapse. We also found that about 65% of inverters need to be smart inverters in order to have meaningful voltage control.

5.2 Related Fields

This work provides good motivation for other fields of study.

5.2.1 Catastrophe theory

In Chapter 3, we define the transition band to be the range of conditions where either stabilization or collapse is possible, and in general, we define any voltage below 0.8 p.u. to be a failure, which is a hard cut-off. Both of these features make catastrophe theory an ideal way to further study and qualify IBR-influenced cascading failure events. Catastrophe theory is a "universal method for the study of all jump transitions, discontinuities, and sudden qualitative changes [30]." Where typical laws of nature and calculus fail, catastrophe theory can be used.

In Chapter 3, one of the conclusions made was that this work demonstrates the unpredictability of the outcome from a given situation, which is not fully determined. In catastrophe theory, one set of circumstances leads to one outcome while another set of circumstances leads to a different outcome. A mix of the two circumstances may lead to either outcome, and the transition from one outcome to the other is not fully delineated; there is an area of overlap where either outcome is possible [31]. This aptly describes the mix of results from Chapter 3, as well as the regions that were called transition bands. Additionally, applying catastrophe theory may help identify a 'point of no return' where voltage collapse is inevitable. This would likely be related to the circumstances that lead to a 100% failure rate.

5.2.2 Islanding and Alternative Voltage Control

In this context, an island is small grid that is electrically disconnected from the greater grid. In some cases, islands are necessary because of factors such as geographical location. In other cases, islands are created on an as-needed basis. If a fault occurs, it is better to isolate subsystems that have not been affected yet so that the fault is unable to cause any harm. IBRs will be, and are for existing islands, important suppliers of power. Additionally, with the presence of smart inverters, IBRs can act as a form of voltage control.

Without the presence of generators regulating the voltage, it is necessary for voltage control to stabilize the voltage, especially since we expect a system with balance load and supply to run successfully. However, inverters can not solely be relied on for voltage control in a majority-IBR or island scenario. Preliminary work in [32] found that the AC/DC ratios in inverters limit their voltage support ability, which means that inverters are not able to correct all of the voltage anomalies that they encounter.

5.3 Future Work

This thesis focused on the effects of cascading failure based of the changing magnitude of the voltage. Future models should include the frequency component of voltage as well, because in some cases the changing frequency may cause the inverters to trip before the magnitude does. And in order to accurately reflect frequency, future models should feature a dynamically responding generator. A generator will be able to respond to changes in frequency by adjusting the speed of rotation. It is yet to be seen if a generator can compensate quickly enough to keep the voltage within acceptable boundaries, or whether inverters would begin to disconnect before the voltage could be adjusted. This is likely to depend on how much spinning reserves there are in a given system; a system with a large amount of IBR would have a more difficult time with voltage regulation.

Most of the inverters that are out in nature right now follow the 1547-2003 standards, which is what the research in this thesis is based on. However, in the future, a greater percentage of inverters will follow the 1547-2018 standards, which recommend different ridethrough times and allow for more flexibility. Future research will need to take these times into account, and in general, σ_A will increase.

A future model should also be flexible in the number of busses it can accommodate, so that larger systems than a two-bus system can be analyzed. The two-bus system used in this paper illustrates concepts well but does not reflect the complexity found in real-world systems.

In addition to the future modeling and simulations, inverter parameters must be further investigated. The results clearly show that the variance in inverter characteristics is a significant influence on the risk of inverter cascades. However, the extent to which real inverters vary from one another is not clear. It will be useful to have a realistic variance, σ_A, around the inverter disconnect threshold. In order to be prepared for future contingencies, it is also necessary to study how σ_A will change with the addition of new, IEEE 1547-2018 inverters. Another important inverter parameter is the amount of power supplied by inverter-connected resources to the grid, and one will have to research that amount of power as a function of time of day and time of year, as well as the resources that are used by a particular utility.

The default settings specified in 1547-2018 are similar, but the inverter settings can be adjusted to allowable ride through times upwards of 20 seconds for some abnormal voltages [22]. Therefore, it will be necessary to consider a wider variety of time delays in future work.

Another future area of research would be adjusting voltage ridethrough time to find the ideal balance of voltages and times that would limit the danger from live equipment. Since the voltage/time relationship in IEEE-1547 is non-linear, and both voltage limits and time duration have the potential to be adjusted, there are a wide number of adjustment combinations that may increase ridethrough, so identifying times and limits that are both appropriate and implementable is a non-trivial task.

* * *

Voltage collapses that are caused by IBR-influenced cascading failures can and do happen, but generally should not be a major concern at the present. Problems will arise if 'dumb' inverters are still used to connect IBRs as IBRs continue to increase as popular NWAs. If the use of smart inverters increases over time, even with large loads and large amounts of DERs, evidence in this thesis suggests that IBR-influenced cascades should remain rare to non-existent. This thesis should motivate the use of smart inverters and careful planning of grid voltage management while tempering the industry concern about the prevalence of these cascading failure events.

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