PNNL-28482

Advanced Reconfiguration and Protection of Distribution Systems

Four Areas of Supporting Research

December 2018

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U.S. DEPARTMENT OF ENERGY

Prepared for the U.S. Department of Energy
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Abstract

Historically, distribution systems have been very susceptible to transmission- and distribution-level events, such as line trips and faults within substations, because local sources of energy, if available at all, were only designed to operate in the context of a fully functional grid. However, the increasing deployment of advanced measuring devices, distributed energy resources (DERs), and energy storage provide the opportunity to improve reliability at the distribution level using advanced measurement-based reconfiguration and protection methods. This report discusses research regarding 1) a transmission equivalent model, 2) an algorithm for distinguishing between transmission- and distribution-level events, 3) a spreadsheet to help site new measurement devices, and 4) network theory to enable smart reconfiguration of distribution systems. Each of these areas of research support the development and study of advanced reconfiguration and protection methods.

Acknowledgments

The authors gratefully acknowledge Rob Hovsapian and Mayank Panwar of Idaho National Laboratory for their leadership on the *Smart Reconfiguration of the Idaho Falls Network* project and their thoughtful discussion.

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1.0 Introduction

Historically, distribution systems have been very susceptible to transmission- and distribution-level events, such as line trips and faults within substations, because local sources of energy, if available at all, were only designed to operate in the context of a fully functional grid. However, the increasing deployment of advanced measuring devices, distributed energy resources (DERs), and energy storage provide the opportunity to improve reliability at the distribution level. With these devices, the impact of transmission- and distribution-level events can be mitigated using advanced measurement-based reconfiguration and protection methods. The research efforts reported here supported a project aimed at developing and studying such methods for the Idaho Falls Power (IFP) grid, which has experienced outages that could have been mitigated if strategies for utilizing local hydro power had been available.

The interplay between transmission- and distribution-systems was a major focus of the research. To support simulation of the IFP grid during system events, an equivalent model for the transmission system surrounding the distribution system was required. The development of this model is detailed in Section 2.0. The interaction between transmission- and distribution-systems was also examined using synchrophasor measurements from both levels of the grid. A novel method for distinguishing between events occurring at each level is discussed in Section 3.0.

The research described in Sections 4.0 and 5.0 focus on the future of distribution systems. The synchrophasor measurements widely used in transmission systems are beginning to be collected from distribution systems as well. In Section 4.0, a spreadsheet developed to help utilities site new phasor measurement units (PMUs) is described. Finally, Section 5.0 details initial results in using network theory to reconfigure a distribution network into sustainable islands.

Though largely independent from each other, the tasks reported here all serve to support the development of advanced measurement-based reconfiguration and protection methods. These methods have the potential to improve the resilience and reliability of distribution systems as the prevalence of measurement devices, DERs, energy storage increases.

2.0 Transmission Equivalent System for the Idaho Falls Power Model

To fully examine the impacts of the new technologies on the Idaho Falls power grid, several simulation studies were conducted. Most of the improvements to the Idaho Falls system were deployed at the distribution level. However, many of the events that would cause these improved devices to act come from the transmission grid connection to the Western Electricity Coordinating Council (WECC) reliability region. Incorporating the full WECC model into the Real-Time Digital Simulation (RTDS) was not realistic, so a lower-order, equivalent model was needed.

The RTDS model of the Idaho Falls grid stops at two interface points to the transmission grid: the Westside substation and the Sugar Mill substation. The equivalent WECC model would need to interface with these two points to represent the transmission-level impacts.

Using the two substation interface points as a guide, the 2018 Heavy Summer planning case was used as a starting point. Once the two interface points were found on the transmission model, the overall connecting topology was evaluated. While it was possible to create two independent transmission-equivalent models, one for each substation, this would fail to capture the proper interactions between the Idaho Falls grid and the WECC; the WECC is much bigger, so even with significant distribution-level load and operational changes on the Sugar Mill versus Westside substation, the influence on the overall WECC would be greatly reduced.

Figure 2.1 shows the final equivalent topology selected for the transmission equivalent. This model captures major lines that feed into Idaho Falls, includes larger transmission lines that connect the two sides, and creates equivalent load representations for any small lines or communities in the study region. These smaller power components are not part of the Idaho Falls project and are not expected to have any significant load changes or impacts on the simulation. The names in the figure represent the WECC planning model bus names, which are often truncated from the actual location name.

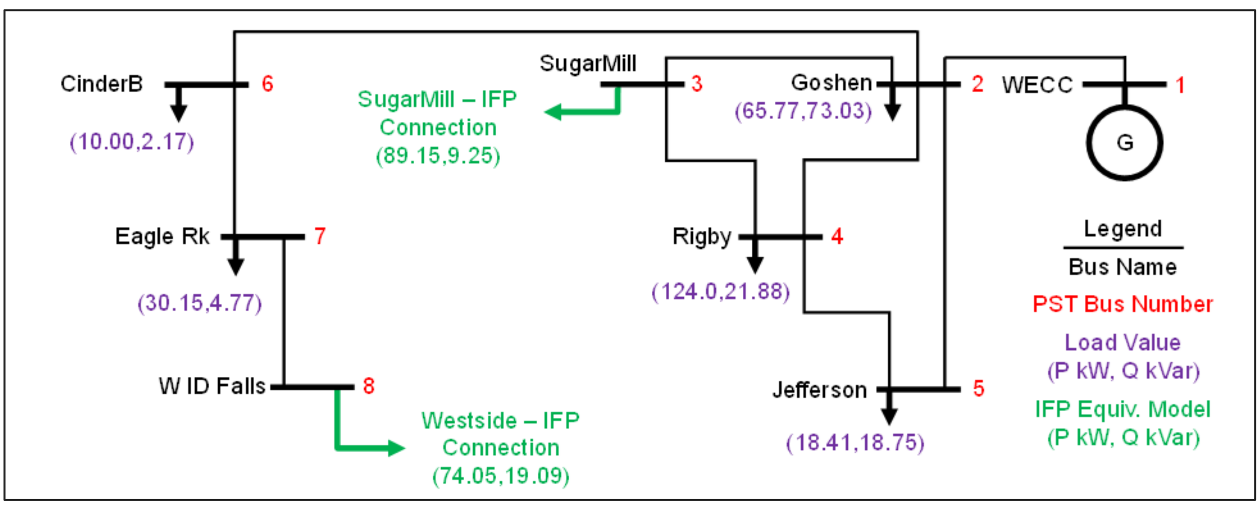

Figure 2.1. One-line diagram of equivalent transmission model for Idaho Falls grid. Green text and arrows represent the ties to the Idaho Falls distribution model.

With the topology selected, the Thevenin equivalent impedance associated with the line between Bus 1 (WECC) and Bus 2 (Goshen), as well as the WECC-representative generator, needed to be computed. This was accomplished by varying the load levels for the Idaho Falls system on the full WECC model and recording the line flows and voltages for Bus 2 (Goshen). The Idaho Falls load were set to 95%, 100%, and 105% of the base values from the 2018 Heavy Summer transmission planning case. The WECC generator was assumed to be an infinite source fixed at 161 kV, which matches the main voltage level of the Goshen transmission connection. Using an over-determined least squares approach, the three flow sets and voltage values at Bus 2 (Goshen), the impedance of the line between Bus 1 and Bus 2 and source voltage were solved. For the equivalent transmission topology model, the impedance of the Bus 1 to Bus 2 connection ("WECC to Goshen" line) is the only parameter of interest for the Thevenin equivalent of the WECC system, with the Bus 1 voltage being the ideal voltage source at 161 kV. The final impedance parameters of the model are shown in Table 2.1. Aside from the Bus 1 to Bus 2 impedance, all other impedance values were extracted from the existing planning model.

Table 2.1. Line parameters for the equivalent transformer model

From #	To #	From Name	To Name	R (pu)	X (pu)	B (pu)
1	2	WECC	Goshen	0.00015707	0.019632	0.0
2	3	Goshen	SugarMill	0.0166	0.0479	0.0242
3	4	SugarMill	Rigby	0.0168	0.0486	0.0243
2	4	Goshen	Rigby	0.0311	0.0937	0.0433
4	5	Rigby	Jefferson	0.0178	0.0522	0.0249
2	5	Goshen	Jefferson	0.0287	0.0880	0.0411
2	6	Goshen	CinderB	0.00285	0.02680	0.01459
6	7	CinderB	EagleRk	0.00065	0.00538	0.00327
7	8	EagleRk	WIDFalls	0.00130	0.00820	0.00480

Once the static powerflow parameters had been selected, it was necessary to capture the dynamic characteristics of the transmission interaction in the equivalent model. For simplicity, the WECC connection was modeled by the transient characteristics of a simple machine, with a turbine governor, and simple exciter model (Kundur, 1994; Rogers, 2000). Given the large size and reduced representation of the generator representing the WECC system, many default parameters were selected for the machine, turbine governor, and exciter parameters. Items such as the inertia and size of the generator were estimated through an iterative process to get a response from the simplified model similar to the full transmission simulation.

With all of the simulations and comparisons complete, the parameters for the dynamic aspects of the simulation are provided in Table 2.2, Table 2.3, and Table 2.4. Table 2.2 represents the explicit transient machine parameters, and Table 2.3 has the characteristics of the turbine governor. Table 2.4 shows the selected parameters for the simple exciter model.

Table 2.2. Transient machine parameters for equivalent transmission model

Name	Variable	Value	Unit
Base MVA		14500	MVA
Resistance	r_a	3.63	p.u.
d-axis synchronous reactance	x_d	1.6	p.u.
d-axis transient reactance	x'_d	0.42	p.u.
d-axis open-circuit time constant	T'_{d0}	4.34	seconds
q-axis synchronous reactance	x_q	0.963	p.u.
q-axis transient reactance	x'_q	0.42	p.u.

q-axis open-circuit time constant	T'_{q0}	1.0	seconds
Inertia	H	1.0	seconds
Local damping coefficient	d_0	6.0	p.u.

Table 2.3. Turbine governor parameters for equivalent transmission model

Name	Variable	Value	Unit
Speed set point	w_r	1.0	p.u.
Steady state gain	$1/r$	20.0	p.u.
Max power order	T_{max}	1.0	p.u.
Servo time constant	T_s	0.01	seconds
HP turbine time constant	T_C	0.04	seconds
Transient gain time constant	T_3	0.0	seconds
Time constant to set HP ratio	T_4	0.0	seconds
Reheater time constant	T_5	0.1	seconds

Table 2.4. Simple exciter parameters for equivalent transmission model

Name	Variable	Value	Unit
Exciter gain	K_A	200.0	p.u.
Exciter time constant	T_A	0.05	seconds
Transient gain reduction time constant	T_B	0.0	seconds
Transient gain reduction time constant	T_C	0.0	seconds

The final transmission-equivalent model for the Idaho Falls system was provided to Idaho National Laboratory (INL) for use in their Real-Time Digital Simulator (RTDS) system. INL rebuilt the topology of Figure 2.1 inside the RTDS, using the parameters of Table 2.1 to Table 2.4. Final validation of the equivalent model, as well as its use in the evaluation of technologies on the Idaho Falls distribution system, were beyond the scope of the PNNL work and are not included in this report.

3.0 Classifying Transmission and Distribution Level Events

With increasing penetrations of distributed energy resources (DERs) in power systems, the potential exists to improve reliability by reconfiguring distribution systems following an event such as a line trip or loss of generation. When severe events occur on the transmission system, it may even be beneficial to operate a distribution system as an island. To properly respond to an event, it is crucial to know which level of the system was directly impacted by the event. For example, it would be undesirable to disconnect from the transmission system in response to an event within the distribution system. Similarly, system reconfiguration schemes may require the feeder on which the event occurred to be identified. It is hown here that a combination of measurement devices within the transmission and distribution systems can be leveraged to make these distinctions.

Some work for determining the level at which events occurred is reported in (A. L. Liao, 2016). Synchronized measurements taken from different distribution feeders were analyzed to distinguish the transmission level events from the distribution level events.Bbased on the impact of an event in different distribution feeders, the feeder on which the event occurred was identified.

The work reported here extends these methods by analyzing synchronized measurements from both the transmission and distribution systems. Because the interplay between these levels of power system was a primary focus of the present project, it is reasonable to expect that access to transmission-level measurements will improve reliability of the algorithms. The work reported here focused on the development of the methods, and direct testing is left to future work.

The work reported here does not capture every type of event that can be observed in power systems. Though several weeks of data were examined for events, some types that occur only rarely were not observed. Further work to include a wider variety of events could lead to adjustment and expansion of the proposed algorithm.

3.1 Methodology

The algorithm for classifying events was developed based on observations made while analyzing transmission- and distribution-level measurements containing events. with the availability of synchronized measurements from both levels of the system made very clear the type of event . Following is a list of observations that can be utilized in an algorithm to automate the decision process:

1. Most distribution events do not have a measureable impact on the bulk power system's synchronous frequency. Thus, any significant change in the system frequency will be caused by a transmission-level event, assuming the distribution system is not being operated in islanded mode.

2. The effects of transmission-level events are apparent in distribution-level measurements and result in similar per-unit (p.u.) drops in voltage magnitude at both levels.

3. Distribution-level events are often unobservable in transmission-level measurements. When they are visible in transmission-level voltage magnitude measurements, they are relatively small and likely to be relatively local.

4. When a distribution-level short-circuit causes a drop in voltage magnitude in distribution-level measurements, it is accompanied by a significant increase in current magnitude on the distribution feeder.

5. When a transmission-level event causes a drop in voltage magnitude in distribution-level measurements, the current magnitude on the distribution feeder is unaffected.

6. As observed in (A. L. Liao, 2016), events on one distribution feeder do not have significant impacts on measurements from other distribution feeders.

Before proceeding, another observation from distribution measurements warrants discussion. As mentioned previously, most distribution-events are far too small to impact the bulk power system's synchronous frequency. However, this does not mean that distribution-level events do not impact the frequency measurements provided by distribution-level measurement devices. The frequency "measurements" produced by PMUs are actually calculated based on voltage measurements. Thus, distortions to local voltages can result in significant changes to frequency measurements for short periods, even though the system's synchronous frequency is unaffected. The impact on frequency measurements is determined in part by the PMUs settings. For the settings of distribution PMUs in this study, the impact was significant. This observation provides a good reminder that measurements should be interpreted appropriately. Otherwise, a relatively small event on the distribution system could be misinterpreted as a significant event on the transmission system.

The algorithm for distinguishing between distribution- and transmission-level events is represented as a flowchart in Figure 3.1. The abbreviations F, V, and I denote frequency, voltage magnitude, and current magnitude, respectively. Subscripts T and D denote transmission- and distribution-level measurements, respectively. Finally, the Δ symbol indicates a calculated change in the measurement due to the event and the μ symbol indicates calculation of the signal's average value. The threshold presented in the flowchart were selected based on the particular set of signals available for the study and would likely need to be adjusted for a different system. An explanation of the algorithm follows.

Step 1:
The change in the frequency of the system is analyzed. The event is classified as a transmission-level event if it caused a significant change in the frequency as measured by the transmission-level PMUs. See observation 1 above.

Step 2:
The impacts of the event on transmission-level voltages are analyzed. Significant drops in transmission voltage lead to classification as transmission-level events. In this case, observation 3 above is used to rule out a distribution-level event.

Step 3:
If the event is not classified in Step 2, the impact on voltages at the transmission- and distribution-levels are compared. If the per-unit drop is larger on the transmission side, then the event is classified as a transmission-level event. This step uses observation 3 to rule out a distribution-level event.

Step 4:

At this point, the frequency and voltage checks have ruled out a transmission-level event. Before classifying the event as a distribution-level event two final checks are made. In Step 4a, the drop in distribution voltage magnitude must be large enough to support its classification as a distribution-level event. In Step 4b, a check is made to ensure that the voltage drop was associated with a sudden increase in feeder current. If either check fails, the event remains unclassified. In the real-world experiments described in the following section, no unclassified events were observed. Note that an unclassified event would result only if (1) a relatively small change in voltage or (2) a relatively small change in current were observed on the distribution side.

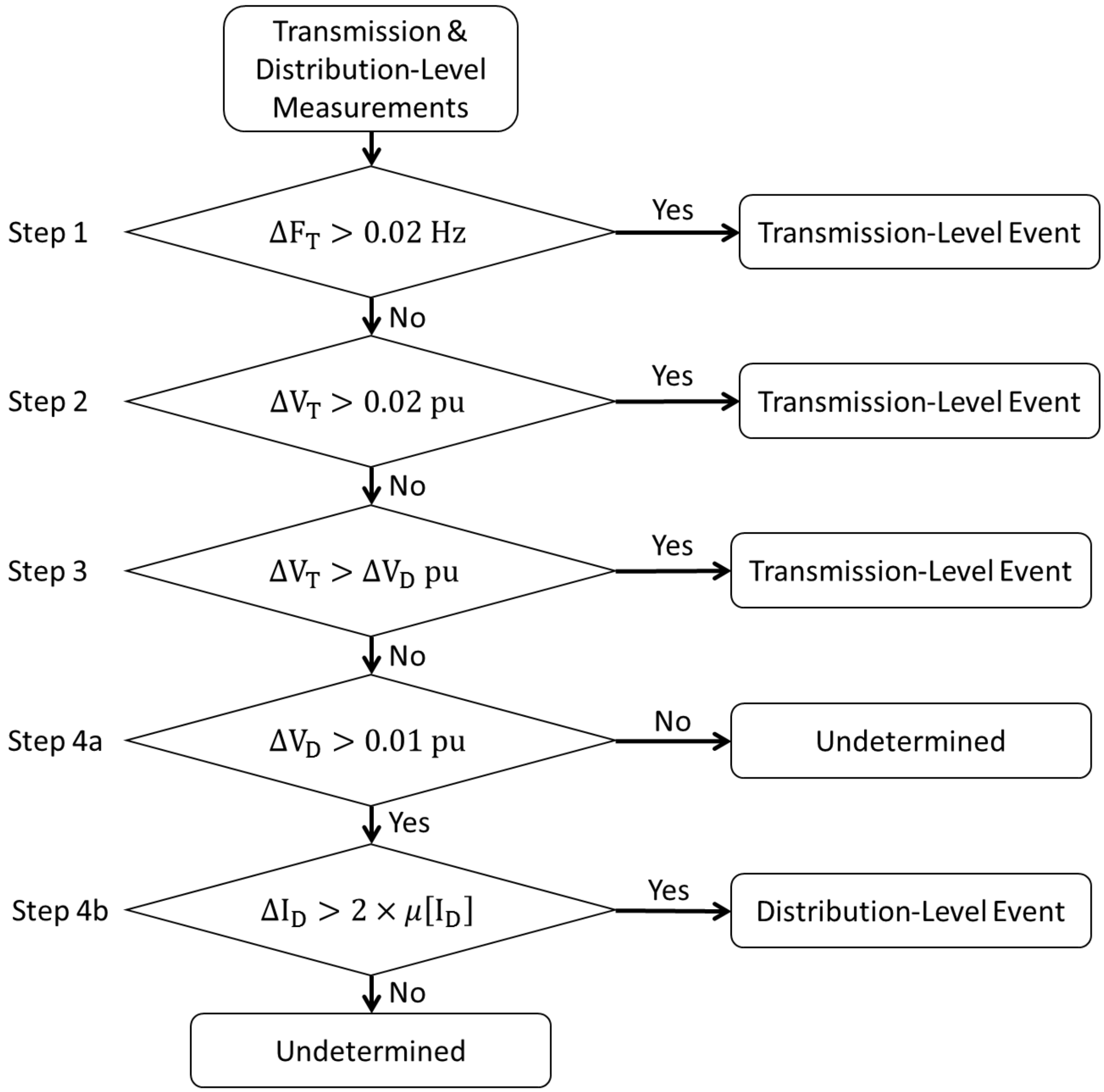

Figure 3.1. Flowchart describing the algorithm to distinguish between transmission- and distribution-level events

3.2 Results and Discussion

The algorithm was implemented using real-world measurements taken from four transmission lines and two closely-placed distribution feeders. The four transmission lines were selected due to their proximity to the analyzed distribution system. Due to the confidentiality requirement, further information on these measurements is omitted from this report. Data obtained over two months was analyzed using ArchiveWalker, a tool for identifying periods of interest in synchronized measurements (Setting Up and Reviewing Analyses with the Archive Walker GUI, 2018). The measurements for these events were then further analyzed to distinguish between distribution- and transmission-level events.

In this section of the report, results obtained for some of the events detected by Archive Walker are presented. They illustrate that the algorithm presented in the flowchart can effectively distinguish the transmission level event from the distribution level.We give results showing:

a. Frequency deviation figures, with values obtained by subtracting the median of the frequency measurements calculated over the analysis window from the actual measurement values.

b. Change in per-unit voltage obtained by subtracting the median of the voltage measurements calculated over the analysis window from the actual measurent values.

c. Current measurements, unadjusted.

Plots of transmission voltages include positive sequence measurements for all four lines. Distribution voltage and current plots include the three phases for the specified line. Vertical axes are scaled for direct comparison between distribution- and transmission-level measurements.

3.2.1 Transmission-Level Event

Here, an event is classified as occuring at the transmission level using the algorithm described earlier. In the first step, the frequency measurements were analyzed. As seen in Figure 3.2, the event did not cause much impact in the frequency measurements. Also, comparing Figure 3.2 and Figure 3.3, it can be seen that the frequency measurements in the distribution level were highly affected by the voltage measurements as described earlier.

In Step 2, the voltage measurements at the transmission line were analyzed. As the voltage drop at the transmission level was more than 0.02 p.u. as shown in Figure 3.4, the event was classified as a transmission level event without requiring further analysis.

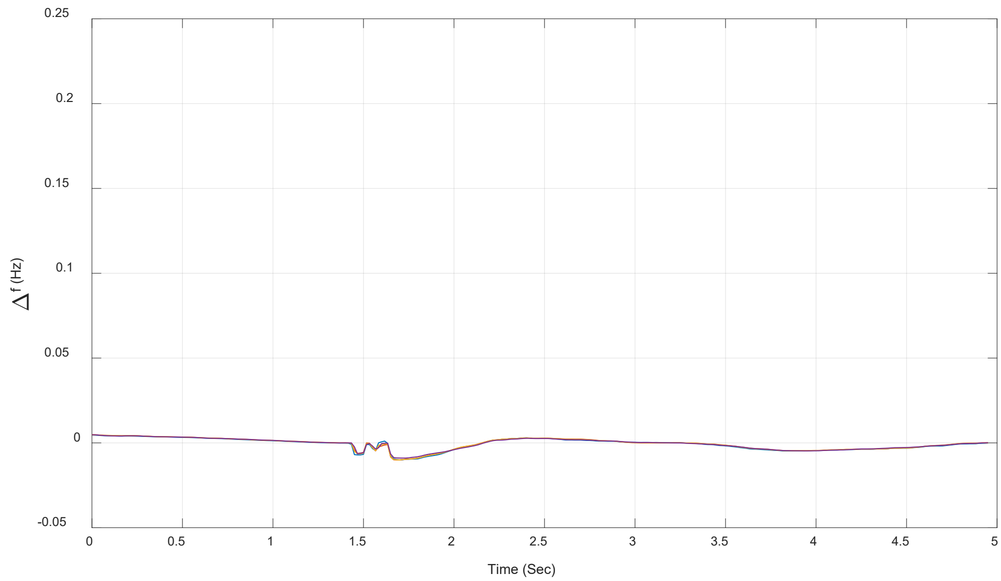

Figure 3.2. Frequency deviation measurements at transmission level

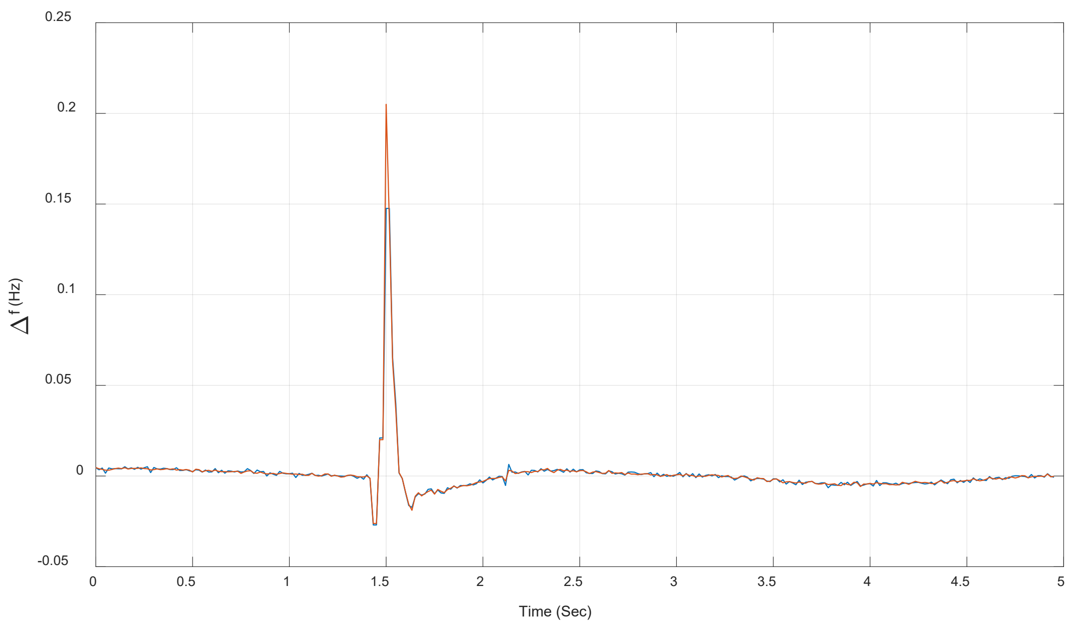

Figure 3.3. Frequency deviation measurements in distribution feeders

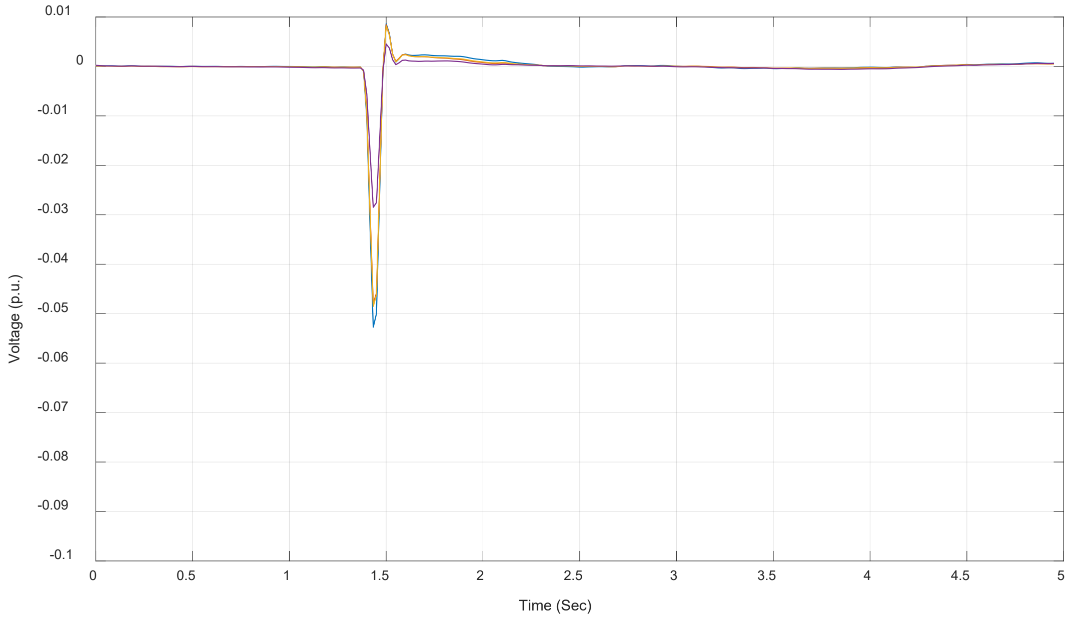

Figure 3.4. Change in voltage measurements in four transmission lines

The voltage measurements at two distribution feeders are shown in Figure 3.5 and Figure 3.6, and as expected, the impact of voltage drop in the transmission level is seen in the distribution level. The p.u. impact is more significant at the distribution level, but this is likely due to a differencebetween the transmission and distribution PMUs in the filter settings used to trade off between precision and fast response (for further details, see the Performance Classes section of (IEEE Standard for Synchrophasor Measurements for Power Systems, 2011)).

Figure 3.7 and Figure 3.8 show the current measured at the two distribution feeders. there is slight increase in the current, which is much lower than the threshold selected for classifying an event as a distribution level event, this increase can be attributed to the change in the voltage drop caused by the event in the transmission level. Therefore, analyzing voltage and current measurements at distribution feeders also lead to the same conclusion that the event occurred at the transmission level.

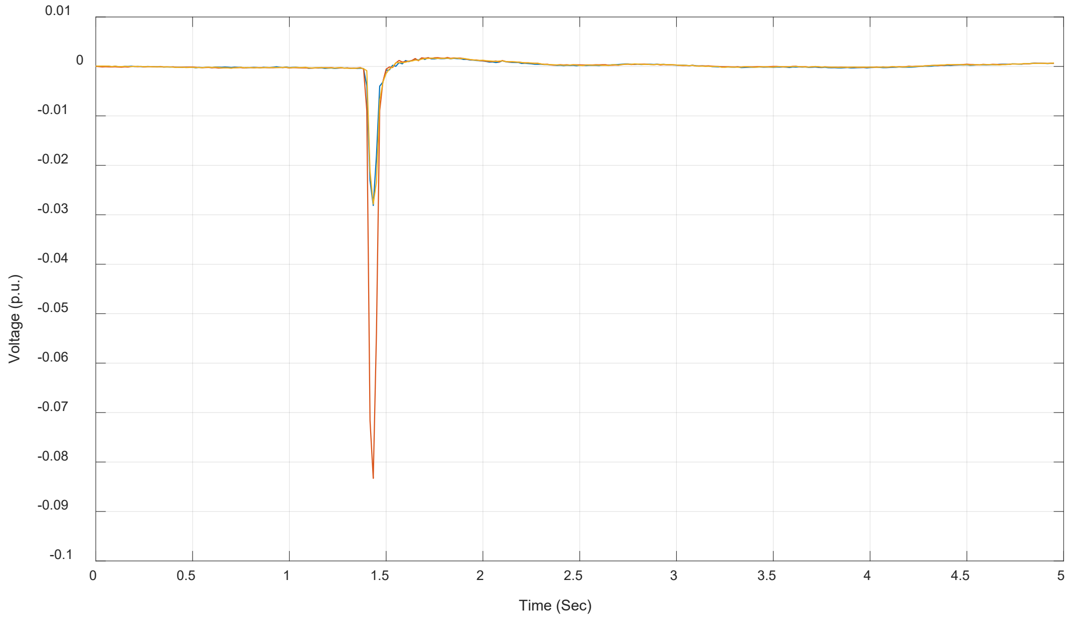

Figure 3.5. Per-phase change in voltage measurements in distribution feeder 1

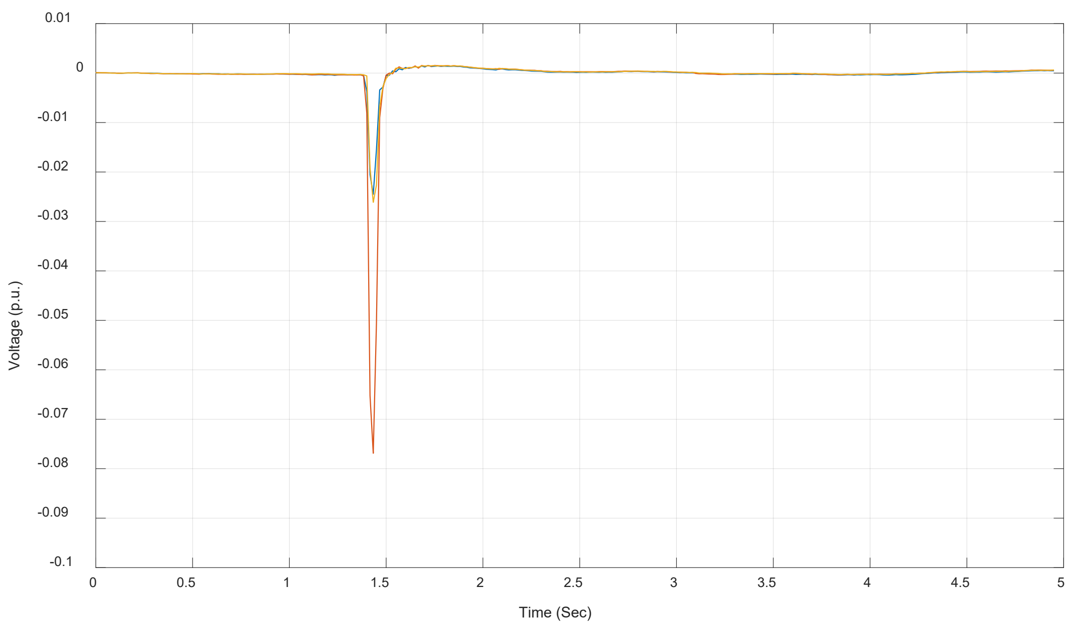

Figure 3.6. Per-phase change in voltage measurements in distribution feeder 2

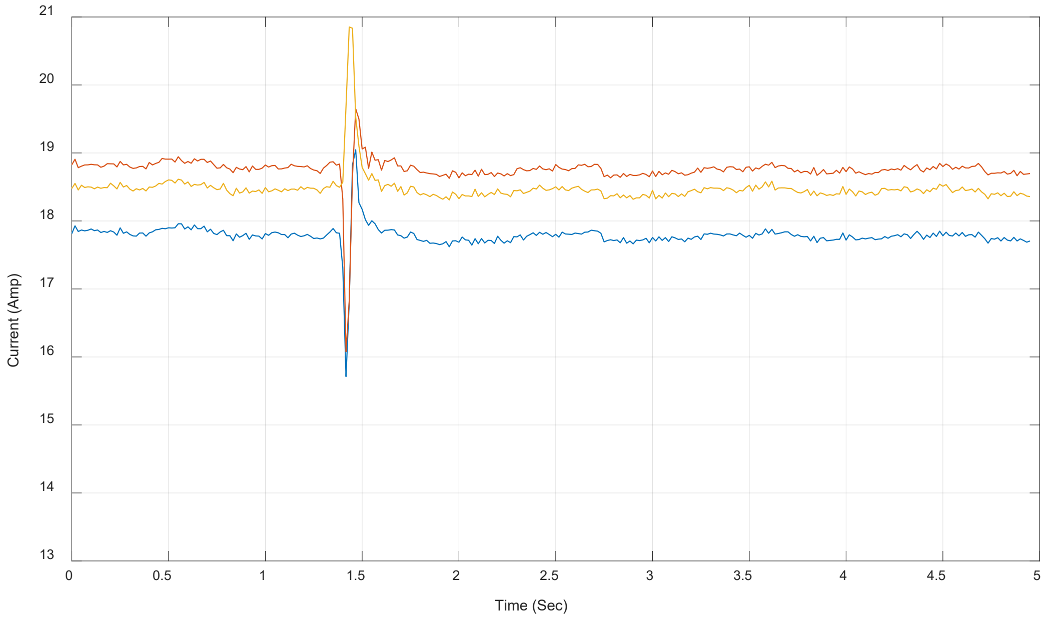

Figure 3.7. Per-phase current measurements in distribution-feeder 1

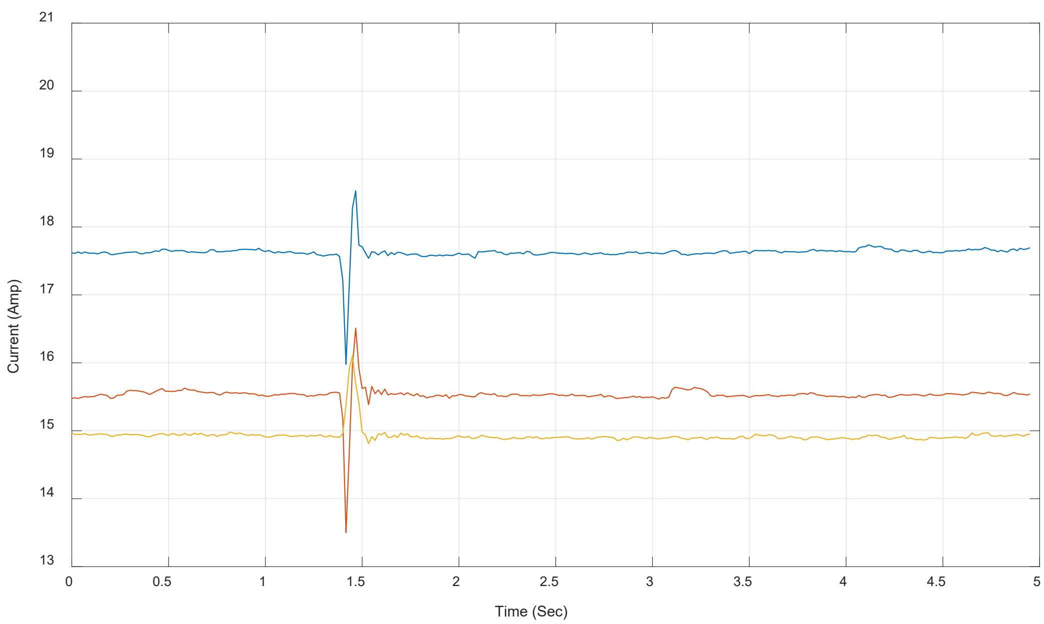

Figure 3.8. Per-phase current measurements in distribution feeder 2

3.2.2 Distribution-Level Event

Here, an event that occurred in the distribution level is analyzed. As seen in Figure 3.9, no impact was observed in the transmission-level frequency measurement during Step 1. In Step 2, the voltage measurement at the transmission level was analyzed. As seen in Figure 3.11, the event had essentially no voltage impact. In Step 4, the voltage and current measurements at the distribution level were analyzed. There was not any significant change observed in the current and voltage measurements from the first distribution feeder as shown in Figure 3.12 and Figure 3.14. As shown in Figure 3.13 and Figure 3.15 for feeder 2, however, the voltage dropped by approximately 0.06 p.u. in one of the phases and the current increased by more than twice its steady-state value. Thus, the event was classified as a distribution-level event occurring on distribution feeder 2.

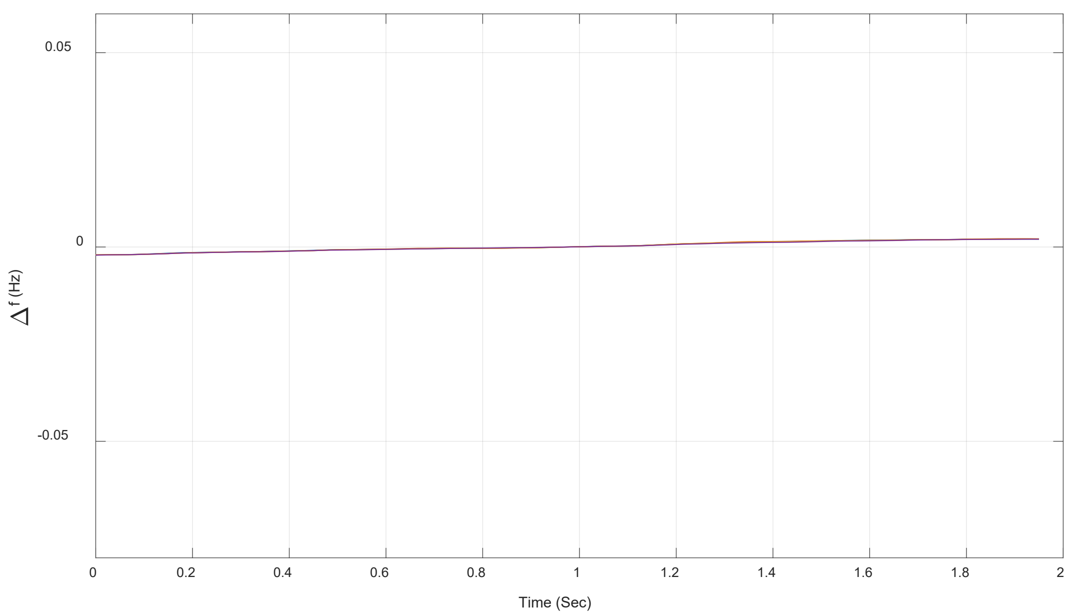

Figure 3.9. Frequency measurements at transmission level

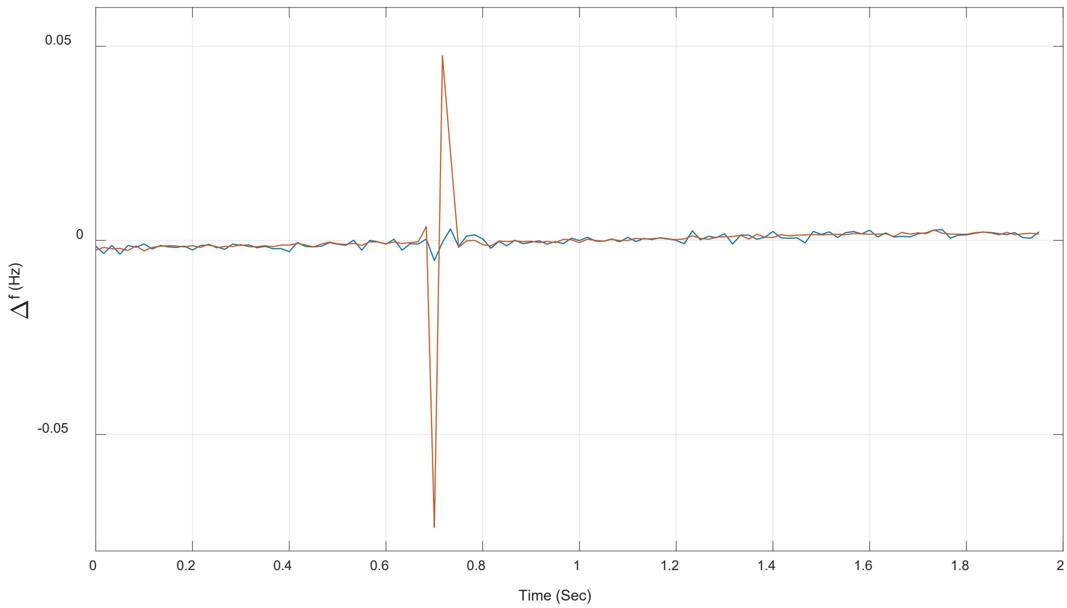

Figure 3.10. Frequency measurements in distribution feeders

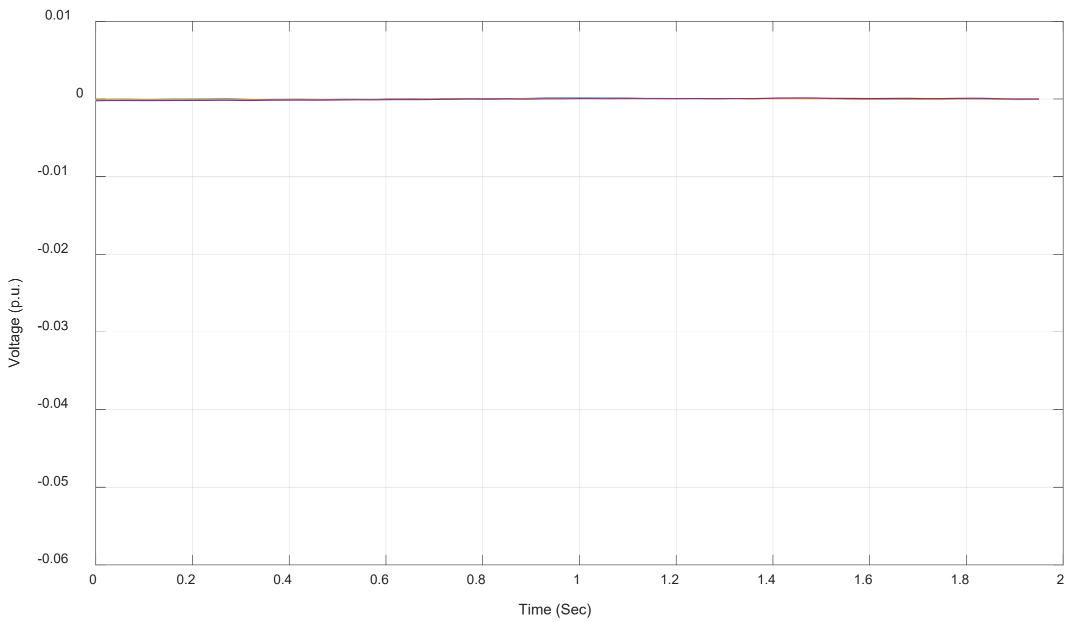

Figure 3.11. Change in voltage measurements in four transmission lines

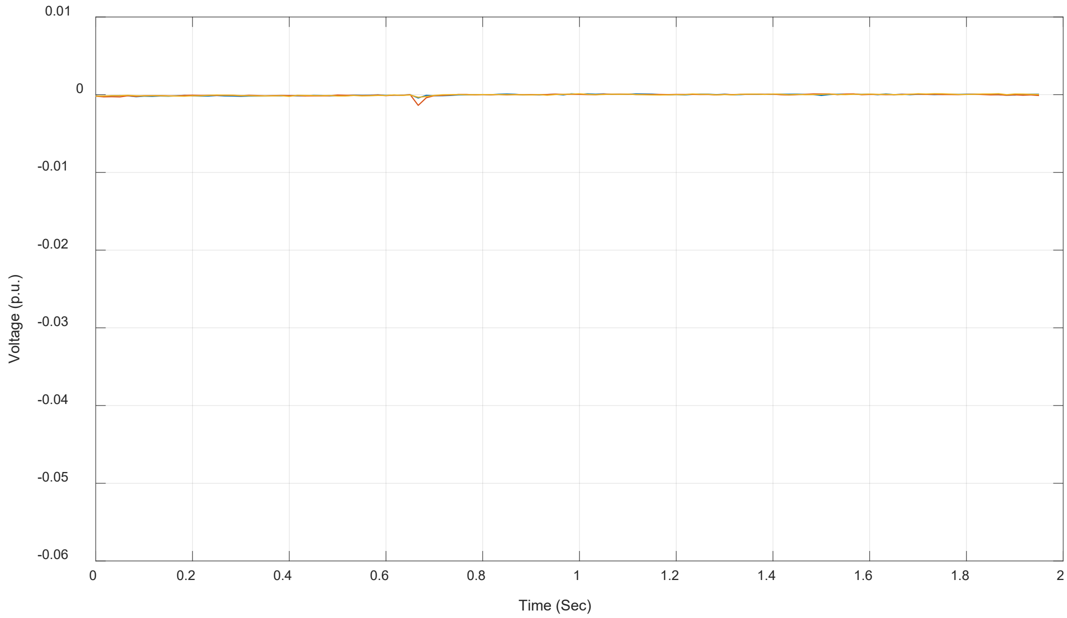

Figure 3.12. Per-phase change in voltage measurements in distribution feeder 1

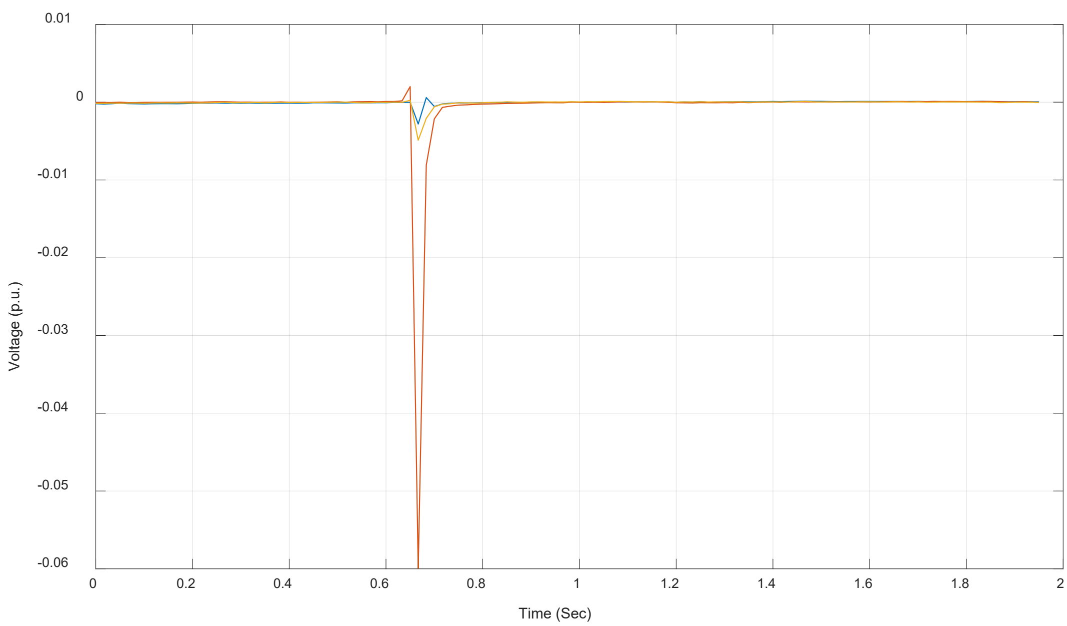

Figure 3.13. Per-phase change in voltage measurements in distribution feeder 2

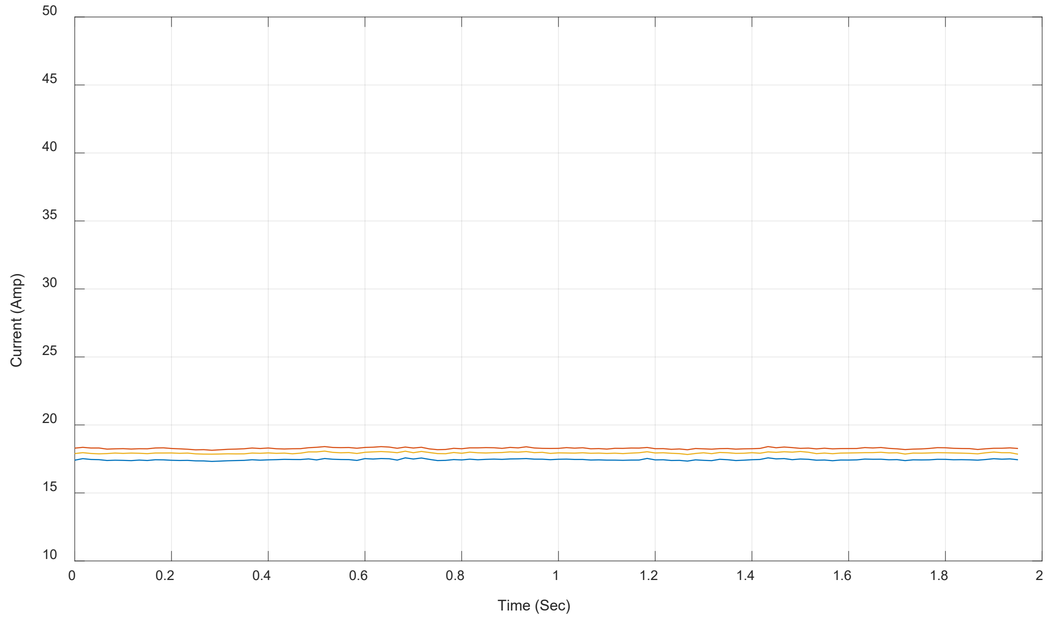

Figure 3.14. Per-phase current measurements in distribution-feeder 1

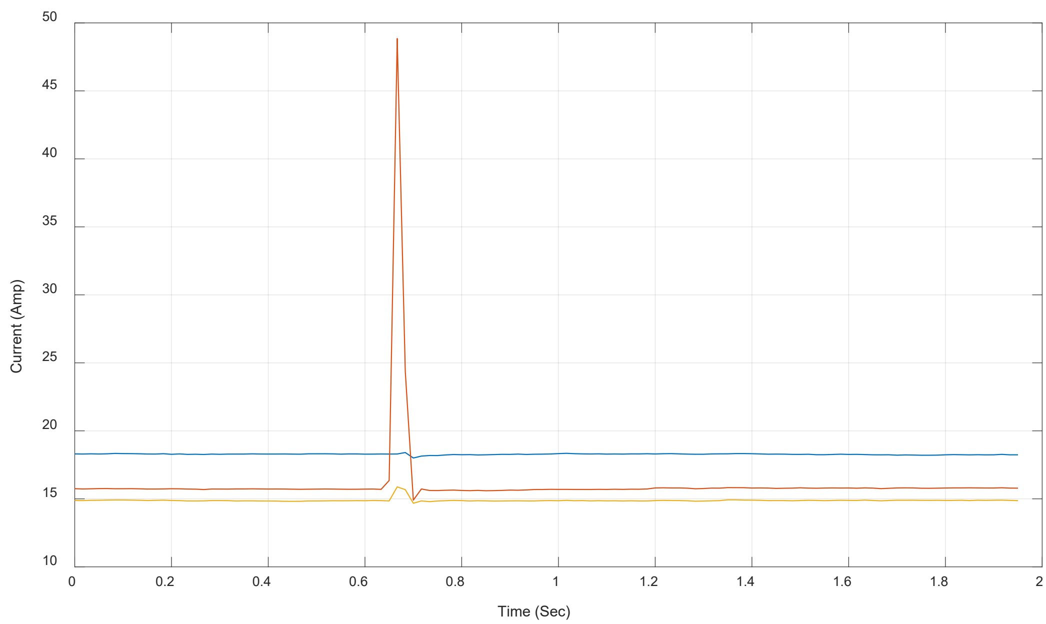

Figure 3.15. Per-phase current measurements in distribution feeder 2

3.2.3 Transmission-Level Event with Significant Frequency Drop

In this example, a transmission-level event characterized by a significant frequency drop was analyzed. As seen in Figure 3.16, the frequency dropped from its steady-state value by more than 0.02 Hz, indicating that it was a transmission-level event without further analysis. This can also be verified looking at the drop in the transmission-level voltage measurements in Figure 3.18, which was significant, and the current increase in the distribution level shown in Figure 3.21 and Figure 3.22, which was small.

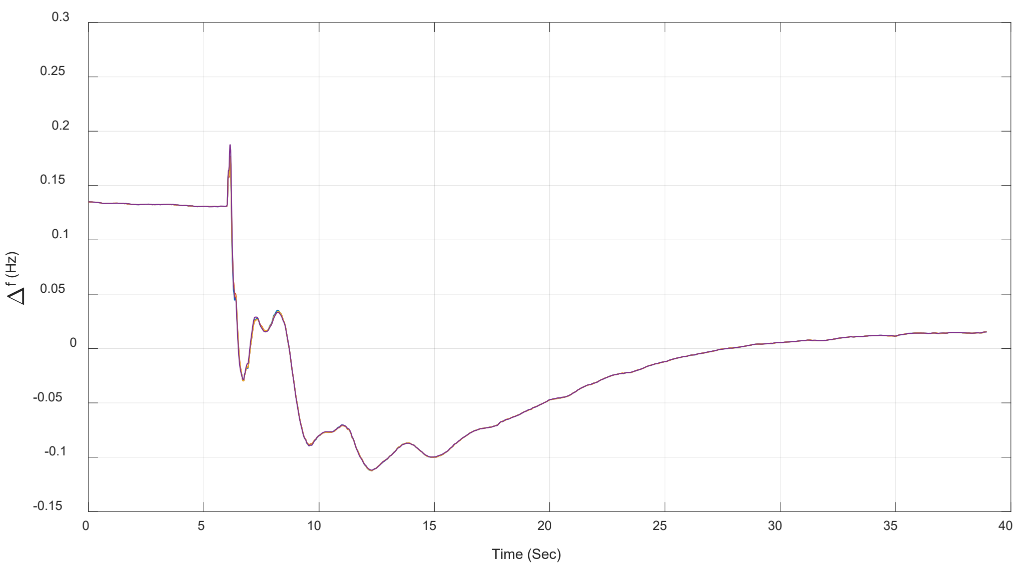

Figure 3.16. Frequency measurements at transmission level

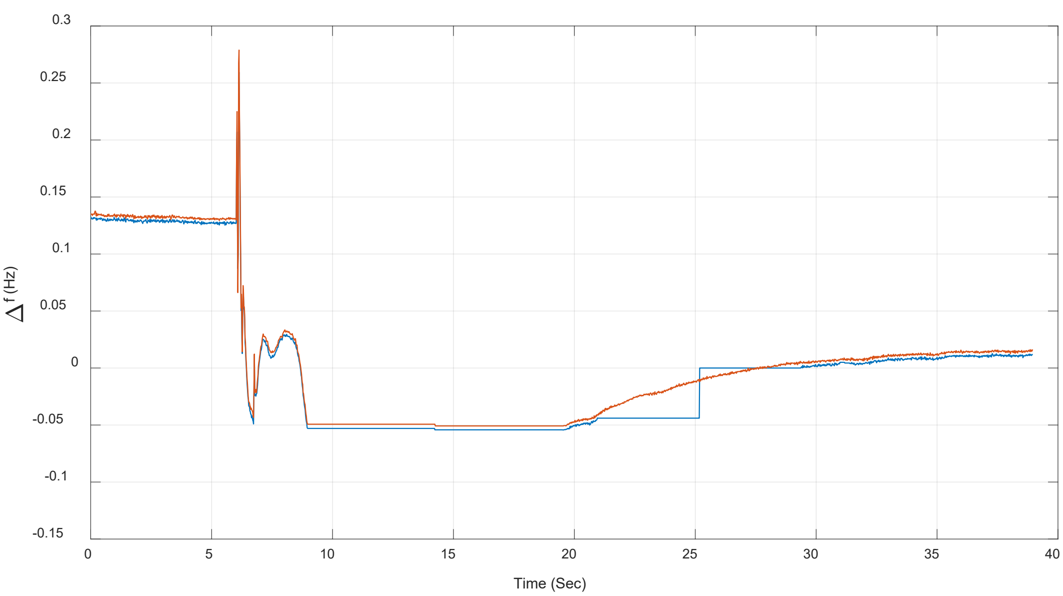

Figure 3.17. Frequency measurements in distribution feeders

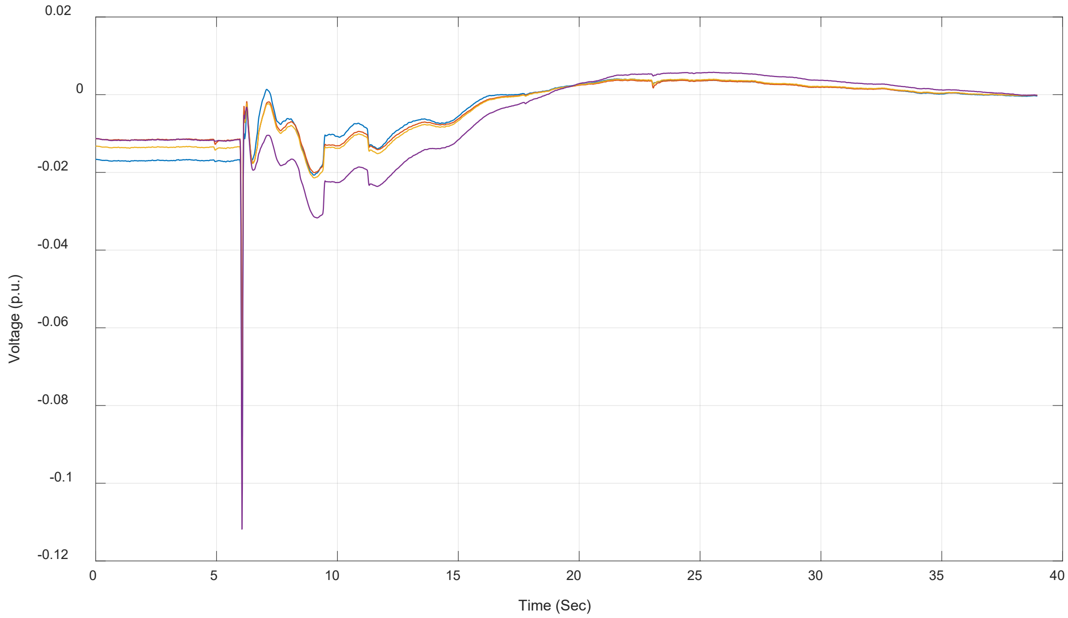

Figure 3.18. Change in voltage measurements in four transmission lines

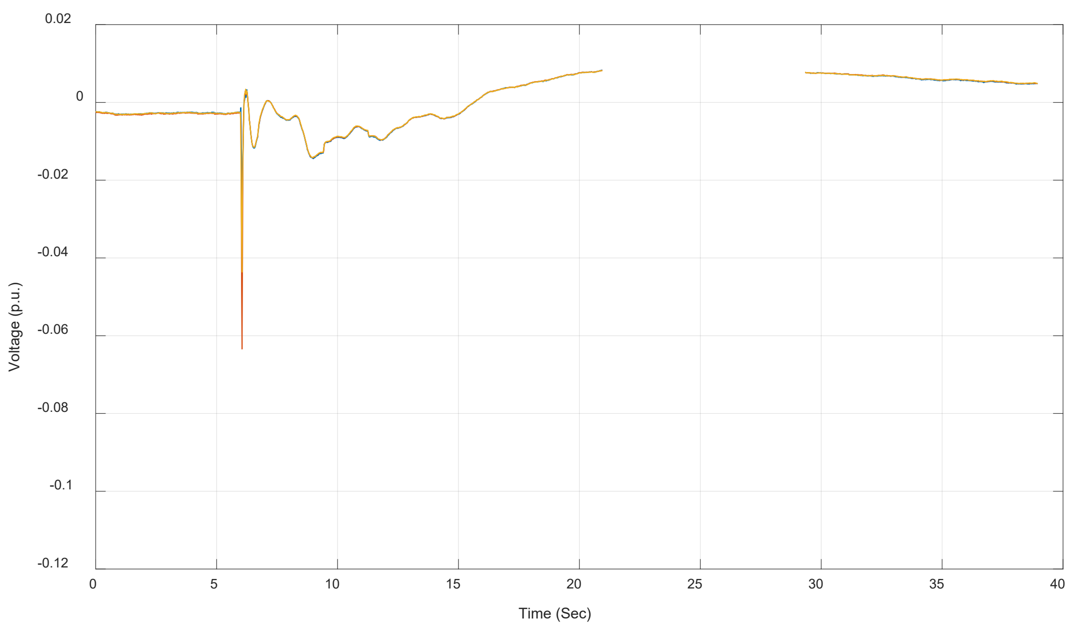

Figure 3.19. Per-phase change in voltage measurements in distribution feeder 1

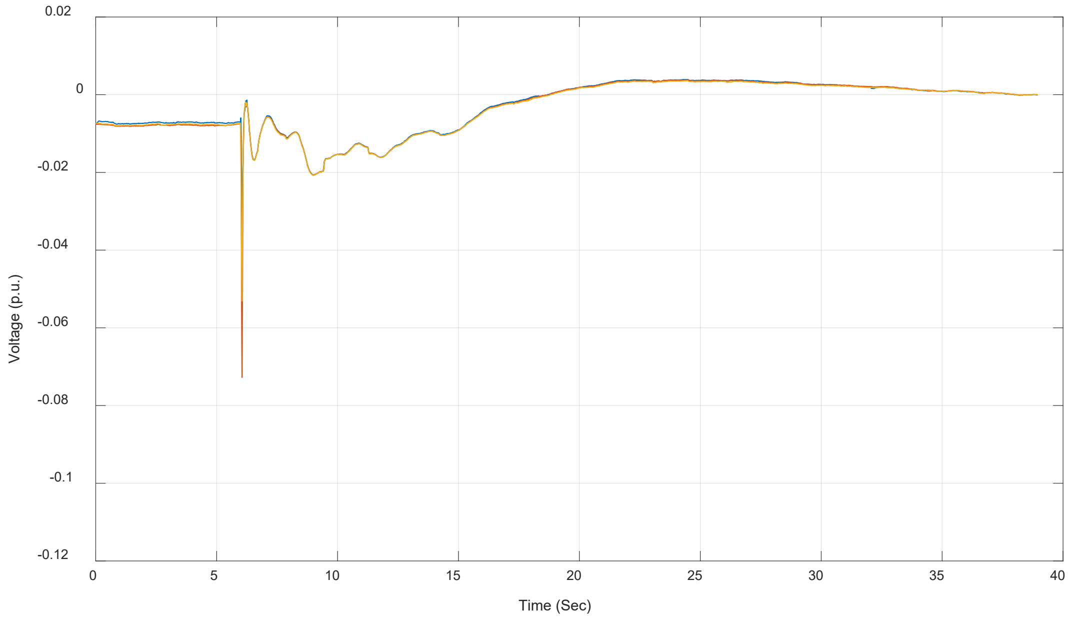

Figure 3.20. Per-phase change in voltage measurements in distribution feeder 2

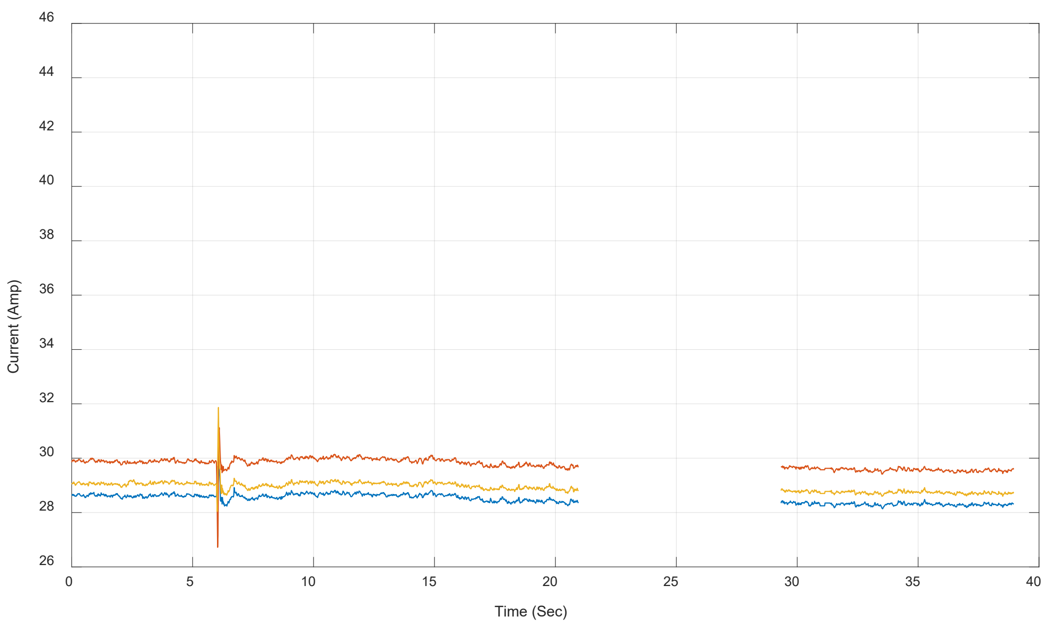

Figure 3.21. Per-phase current measurements in distribution-feeder 1

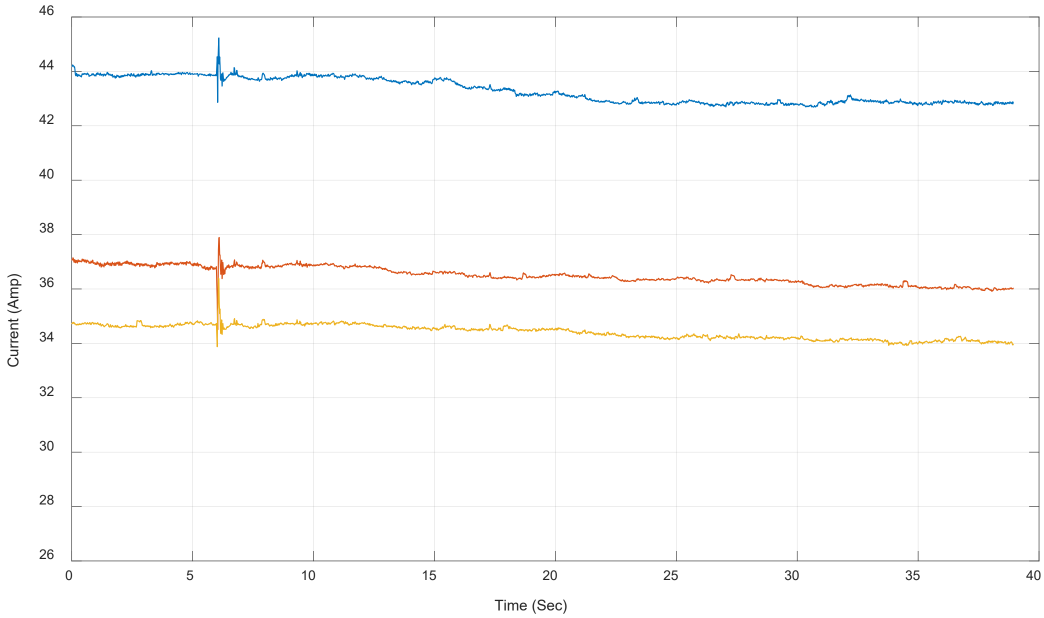

Figure 3.22. Per-phase current measurements in distribution feeder 2

3.3 Conclusion

In this report, an algorithm has been presented that distinguishes between transmission- and distribution-level events. It is based on the analysis of synchronized measurements obtained from both transmission and distribution levels of the system. The results obtained so far, using real-world measurements from locations in the Pacific Northwest, indicate that the proposed algorithm accurately distinguishes events on transmission from events on distribution. Since the observations made so far do not include very many possiblities for events on either the transmission or the distribution side of the system, further work is planned. It may be that some refinement of the algorithm is needed to maintain high accuracy for all possible events.

4.0 Substation Selection Spreadsheet

A substation-selection algorithm was implemented in a spreadsheet to simplify the choice of a substation to be the first (or second) location for a PMU. The idea behind the spreadsheet is to allow the user to express various preferences numerically in several categories, and have those preferences result in a score that allows the substation selection to reflect those preferences. Once the calculation is done, the spreadsheet sorts the results and presents them in descending order of the total score.

4.1 Categories for Scoring

The spreadsheet considers all the substations in the assumed power system, and takes into account four aspects of the problem of choosing one substation. The categories were

- Is there a high-voltage infeed?
- Is there a DER?
- Is there an “essential load”?
- Are adequate communications available?

The assumed distribution system was that of Idaho Falls Power.

The first three of these factors were included in the calculation of a total score for each of the IFP substations. Each factor was addressed on a separate sheet, and the results from each sheet wereintegrated into a Top Level sheet. (A fifth “spare” sheet was included for adaptation by the user.)

The decision could be made at “run time” to include of not include any of these categories.

4.2 Example: Essential Loads

The calculations on each sheet are similar, and only one will be described here: the Essential Load sheet. Consider the screen dump shown in Figure 4.1.

	A	B	C	D	E	F	G	H	I	J	K	L	M	N	O
1					Sub 1 Rack	Sub 3 Milligan	Sub 4 Templeview	Sub 6 Sugarmill	Sub 9 15th St	Sub 12 Boulevard	Sub 13 City	Sub 14 York	Sub 16 Harrison	Sub 17 Hatch	Sub 18 Westside
2	number on one-line	Essential load name	score												
3	1	Hospital (EIRMC)	5						1				2	1	
4	2	Hospital (Mtn View)	5						1				2	1	
5	3	Idaho Falls Power	5			1					2				
6	4	911 Dispatch	3				2				1				
7	5	Airport (East)	3			1	2			1					
8	6	Airport (West)	3				2				1				
9	7	Jail	3					1		1				2	
10	8	IFPD	3						1		2				
11	9	IFFD and Fire Stn 1	2						1		2				
12	10	Fire Stn 3	2			1	2			1					
13	11	Fire Stn 4	2												
14	12	ISP	2			1	2			1					
15	13	WWTP Feed 1	2		2							1			
16	14	WWTP Feed 2	2		1							2			
17	15	Urgent Care	2						1				2	1	
18	16	Community Care	2			2					1				
19															
20															
21		weighted matrix			0	0	0	0	5	0	0	0	10	5	0
22					0	0	0	0	5	0	0	0	10	5	0
23					0	5	0	0	0	0	10	0	0	0	0
24					0	0	6	0	0	0	3	0	0	0	0
25					0	3	6	0	0	3	0	0	0	0	0
26					0	0	6	0	0	0	3	0	0	0	0
27					0	0	0	3	0	3	0	0	0	6	0
28					0	0	0	0	3	0	6	0	0	0	0
29					0	0	0	0	2	0	4	0	0	0	0
30					0	2	4	0	0	2	0	0	0	0	0
31					0	0	0	0	0	0	0	0	0	0	0
32					0	2	4	0	0	2	0	0	0	0	0
33					4	0	0	0	0	0	0	2	0	0	0
34					2	0	0	0	0	0	0	4	0	0	0
35					0	0	0	0	2	0	0	0	4	2	0
36					0	4	0	0	0	0	2	0	0	0	0
37															
38		totals by sub			6	16	26	3	17	10	28	6	24	18	none

Figure 4.1. Screen dump of substation parameters

Loads designated as Essential by IFP are listed in column B. The corresponding numbers listed in column A are identifiers used on the one-line diagram provided by IFP. The user assigns each essential load a score in column C to reflect his or her assessment of the load's criticality.

Column D is left blank. In the future, a sheet weighting factor could be put here to adjust the relative importance of (say) essential loads compared to DER.

Each substation in the IFP system is identified across the first row, starting in column E and ending in column O. They are in numerical order.

The block of colored cells links the essential load column (column B) to the calculations of the weighting in the rows underneath the colored block, on a column-by-column basis. If a particular substation has no possibility of connection to a given load, the colored cell is left empty. If there is a possible connection, a score of one is shown in this example. A score of two also is used, indicating this is the most likely way this load would be fed.The products of the scores in column C and the numbers entered (by the user) into the colored cells in columns E through O are calculated in rows 21 through 36 and summed in row 38. Thus, if a given substation feeds more than one essential substation (though the degree of "essentialness" may not be the same), it will gain a higher score in this category.

A similar calculation is done for each category of the other categories. A Top-Level sheet brings all the information together.

4.3 Top-Level Sheet

The totals in row 38 are used as part of the "top-level" calculation, as in the screen-dump in Figure 4.2.

	A	B	C	D	E	F	G	H	I	J	K	L	M
1	Concerns	include (Y/N)?	Sub 16 Harriso	Sub 13 City	Sub 14 York	Sub 4 Temple	Sub 18 Westsi	Sub 6 Sugarmill	Sub 17 Hatch	Sub 9 15th St	Sub 3 Milliga	Sub 12 Boulev	Sub 1 Rack
2	DER management;	n	0	0	0	0	0	0	0	0	0	0	0
3	Essential load	y	24	28	6	26	0	3	18	17	16	10	6
4	HV infeed	y	12	0	20	0	24	16	0	0	0	0	0
5	Spare	n	0	0	0	0	0	0	0	0	0	0	0
8	additional considerations												
9	Multiple bus?												
12	total		36	28	26	26	24	19	18	17	16	10	6
14	Communication status		no	OK	OK	no	not known	no	OK	OK	no	no	no
18	Ctrl-q to run macro												

Top Level | HV infeed | DER locations | Essential Loads | Communications | Spare sheet

Figure 4.2. Screen dump of top-level calculation

The Top-Level evaluation allows the user to see *why* one particular substation has emerged as the "winner" to receive a PMU. At this point, the user may decide the result is unexpected, and wish to review the scoring each substation received.

An additional factor must be considered before a final choice is made, and that is the question of communications. Some utilities have high-quality communication channels from their control room to all the substations, but this situation is not yet universal. Based on an assessment of the communication needs for the substation (in turn based on the estimates in the IEEE Std C37.118.2™-2011, IEEE Standard for Synchrophasor Data Transfer for Power Systems) the need for additional communicatins capability can be considered. This is, at least, something a utility can reasonably contemplate compared (say) to moving an essential load to another source.

4.4 Excel Macro

The Excel macro that executes the sorting is shown in Figure 4.3. The comments (in green) clarify what the macro does.

```
Sub sort()
'
' sort Macro
' sorts substations by score, highlights top scorer
' September 2017, Kirkham, PNNL
'
'clear protection
    Sheets("Top Level").Select
    ActiveSheet.Unprotect
'clear color from previously highlighted cell
    Range("c1").Select
    Selection.Style = "Normal"
'select and set up sort range
    Range("b1:m14").Select
    ActiveWorkbook.Worksheets("Top Level").sort.SortFields.Clear
    ActiveWorkbook.Worksheets("Top Level").sort.SortFields.Add Key:=Range("c12:m12") _
        , SortOn:=xlSortOnValues, Order:=xlDescending, DataOption:=xlSortNormal
    With ActiveWorkbook.Worksheets("Top Level").sort
        .SetRange Range("c1:m14")
        .Header = xlGuess
        .MatchCase = False
        .Orientation = xlLeftToRight
        .SortMethod = xlPinYin
        .Apply
    End With
'   lock the top row of cells (fixing bug in Excel?)
    Range("A1:m4").Select
    Selection.Locked = True
'set yellow highlight in name cell of winner
    Range("B1").Select
    Selection.Style = "Note"
'restore protection
'    ActiveSheet.Protect DrawingObjects:=False, Contents:=True, Scenarios:=True
End Sub
```

Figure 4.3. Excel sort macro

4.5 Conclusion

A simple support tool has been developed to allow the user to weigh the effect of his own preferences in selecting a location for an early PMU addition. The spreadsheet includes the factors that were thought relevant at the time of writing, including the practical matter of available communications Other factors can be added to account for different interests, and one blank page has been included in the spreadsheet to allow for that.

5.0 Distribution System Management Based on Fault Containment Regions

In the distribution system, power has traditionally been moved from a bulk supply system, through substations and into customer loads in a one-directional way. The level of penetration of distributed energy resources (DER) has now reached the point, however, that two-way power flow is possible. There exists the possibility of operating a section of the distribution system as an island or a microgrid based on DER.

To do that, there must exist a system that identifies an island when it forms, and balances the load and generation.

The section has three parts.

- We will define a fault containment region in a power system. We will show that the concept allows a relatively simple algorithm to identify islands of operation.
- We will show that power-balance in such islands can be aided by a book-keeping method based on the fault containment regions.
- We will examine what the concept offers.

5.1 Fault Containment

Distribution system topology has typically been radial, with power flowing out from a substation on overhead or underground lines. For cost reasons, fault isolation in the distribution system has been rather simpler than in the transmission system, and one-time devices like fuses and drop-out isolators have been the rule. However, the increasing deployment of generation in distribution systems provides strong motivation for the development of more advanced protection systems. Further, there will be the possibility of operating an isolated island as a microgrid. To do that, it is proposed here to identify the existence of an island by means of what are known as Fault Containment Regions.

Surprisingly, although the term "fault containment region" is heard quite frequently in space power circles, it seems not to be used in terrestrial power applications. Therefore, the following definition is made:

> Fault Containment Region: A closed region of a power system that will be affected by a fault anywhere inside it. Its boundaries are defined by the locations of circuit interruption devices. A fault containment region (FCR) that contains within it no other fault containment regions can be called a *minimum* fault containment region (mFCR).

As we shall see, this definition will turn out to be very useful[1].

[1] It would be convenient if there were a straightforward correspondence between the minimum fault containment regions and the blocks of a Reliability Block Diagram (RBD) or the zones of a protection system, but that is not the case.

5.2 Example of mFCR

The diagram of Figure 5.1 represents part of a distribution system. Two substations are shown (Main Street and Station Street), and express feeders from these two are tapped to serve the loads along all the side-streets. There are fuses and disconnects (or sectionalizers) at various places.

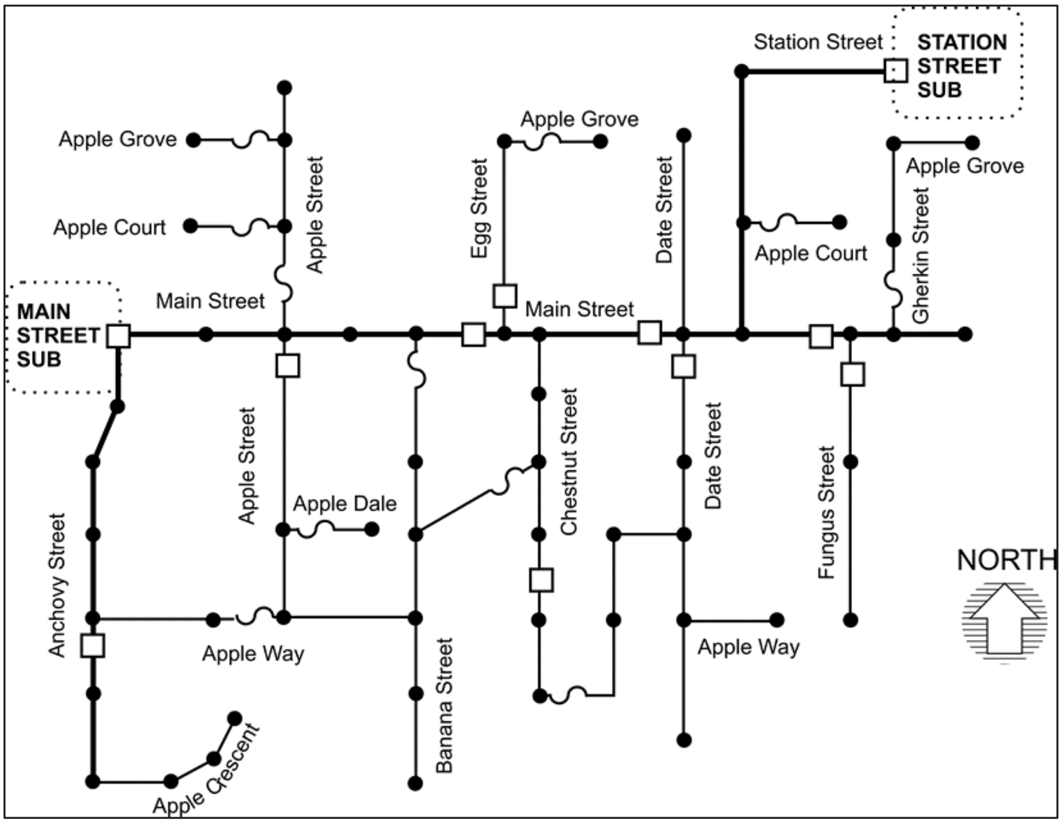

Figure 5.1. Representative distribution system

In Figure 5.2 the various mFCRs are identified, and highlighted with hatching so they can more easily be seen and distinguished. They are drawn based on the definition that an mFCR is bounded by circuit interruption devices and contains no such devices within itself.

For simplicity, the Main Street substation has been assigned mFCR number 0, and in what follows, it will remain connected. The Station Street substation has been assigned mFCR number 16.

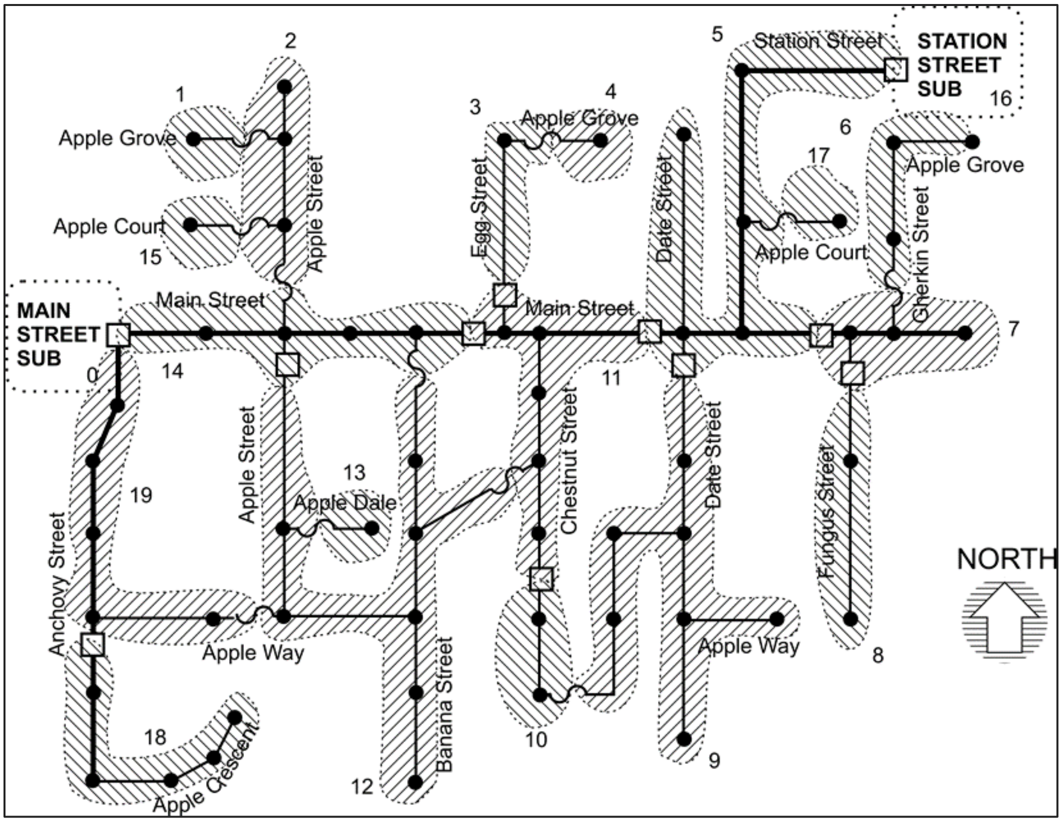

Figure 5.2. Distribution system with mFCRs identified

It is possible to show how the mFCRs are connected by writing a connectivity matrix, as in Figure 5.3. Here, the diagonal is obscured because all the numbers on the diagonal are always 1, and the locations at which mFCRs join are shown as a “1” with a green background. mFCRs that are not connected are shown as blank entries for clarity. The matrix is symmetrical.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0															1					1	0
1			1																		1
2															1	1					2
3					1							1									3
4																					4
5								1		1		1					1	1			5
6								1													6
7									1												7
8																					8
9											1										9
10												1									10
11													1		1						11
12														1	1					1	12
13																					13
14																					14
15																					15
16																					16
17																					17
18																				1	18
19																					19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.3. Connectivity matrix for the system of Figure 5.2

Suppose the connectivity matrix is multiplied by itself 20 (the number of mFCRs) or more times. It transpires that there will be an entry in a cell at the interconnection of two mFCRs if one is connected (though not necessarily directly) to the other. In fact, the calculation can be done with fewer steps by multiplying the matrix by itself (squaring it) and then multiplying that matrix, and so on until the matrix is raised to a number greater than 20. Figure 5.4 shows the result for the configuration shown in Figure 5.2, and assuming that all the disconnecting devices are closed.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
1		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2			1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	2
3				1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	3
4					1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	4
5						1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	5
6							1	1	1	1	1	1	1	1	1	1	1	1	1	1	6
7								1	1	1	1	1	1	1	1	1	1	1	1	1	7
8									1	1	1	1	1	1	1	1	1	1	1	1	8
9										1	1	1	1	1	1	1	1	1	1	1	9
10											1	1	1	1	1	1	1	1	1	1	10
11												1	1	1	1	1	1	1	1	1	11
12													1	1	1	1	1	1	1	1	12
13														1	1	1	1	1	1	1	13
14															1	1	1	1	1	1	14
15																1	1	1	1	1	15
16																	1	1	1	1	16
17																		1	1	1	17
18																			1	1	18
19																				1	19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.4. Connectivity matrix raised to the power of 256

In this image, the numerical value of the cell content is not important, and all non-zero numbers have been replaced by 1. The diagonal is now highlighted.

Now, suppose the connection between mFCR 5 and mFCR 7 is broken. The connectivity matrix is now as seen in Figure 5.5. The spreadsheet has changed the color of the cell at (7,5) to red because the entry has been changed to a letter "O" representing an open connection.

After the requisite number of multiplications, the final matrix is as shown in Figure 5.6. It is straightforward for the reader to see that the three mFCRs numbered 6, 7 and 8 are connected to one-another, and all the rest are connected, but the three form an island. They are the three mFCRs on the right side of the one-line diagram.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0															1					1	0
1			1																		1
2															1	1					2
3					1							1									3
4																					4
5								0		1		1					1	1			5
6								1													6
7									1												7
8																					8
9											1										9
10												1									10
11													1		1						11
12														1	1					1	12
13																					13
14																					14
15																					15
16																					16
17																					17
18																				1	18
19																					19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.5. Connectivity matrix with mFCR5 and mFCR7 disconnected

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0	1	1	1	1	1	1				1	1	1	1	1	1	1	1	1	1	1	0
1		1	1	1	1	1				1	1	1	1	1	1	1	1	1	1	1	1
2			1	1	1	1				1	1	1	1	1	1	1	1	1	1	1	2
3				1	1	1				1	1	1	1	1	1	1	1	1	1	1	3
4					1	1				1	1	1	1	1	1	1	1	1	1	1	4
5						1				1	1	1	1	1	1	1	1	1	1	1	5
6							1	1	1												6
7								1	1												7
8									1												8
9										1	1	1	1	1	1	1	1	1	1	1	9
10											1	1	1	1	1	1	1	1	1	1	10
11												1	1	1	1	1	1	1	1	1	11
12													1	1	1	1	1	1	1	1	12
13														1	1	1	1	1	1	1	13
14															1	1	1	1	1	1	14
15																1	1	1	1	1	15
16																	1	1	1	1	16
17																		1	1	1	17
18																			1	1	18
19																				1	19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.6. Final connectivity matrix with mFCR5 and mFCR7 disconnected

Suppose that for some reason the fuse blows that connects mFCR 14 to mFCR 2. We can show this on the connection matrix, as in Figure 5.7. The result is, of course, the formation of another island. This can be seen in the final connection matrix, Figure 5.8. An island is now formed by mFCR 1, 2 and 15.

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0															1					1	0
1			1																		1
2															O	1					2
3					1							1									3
4																					4
5								O		1		1					1	1			5
6								1													6
7									1												7
8																					8
9											1										9
10												1									10
11													1		1						11
12														1	1					1	12
13																					13
14																					14
15																					15
16																					16
17																					17
18																				1	18
19																					19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.7. Connectivity matrix with mFCRs 5 and 7 disconnected and mFCRs 2 and 14 disconnected

	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	
0	1			1	1	1				1	1	1	1	1	1		1	1	1	1	0
1		1	1													1					1
2			1													1					2
3				1	1	1				1	1	1	1	1	1		1	1	1	1	3
4					1	1				1	1	1	1	1	1		1	1	1	1	4
5						1				1	1	1	1	1	1		1	1	1	1	5
6							1	1	1												6
7								1	1												7
8									1												8
9										1	1	1	1	1	1		1	1	1	1	9
10											1	1	1	1	1		1	1	1	1	10
11												1	1	1	1		1	1	1	1	11
12													1	1	1		1	1	1	1	12
13														1	1		1	1	1	1	13
14															1		1	1	1	1	14
15																1					15
16																	1	1	1	1	16
17																		1	1	1	17
18																			1	1	18
19																				1	19
	0	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	

Figure 5.8. Final Connectivity matrix with mFCRs 5 and 7 disconnected and mFCRs 2 and 14 disconnected

5.3 Power Balance

We have so far assumed that power is entering the system at mFCR 0 and mFCR 16, so that only the groups that include one of these mFCRs are powered up. By scanning along row 0 in Figure 5.8, the reader can see that mFCRs 3-5, 9-14, and 16-19 are energized, and by scanning along row 16 it is seen that mFCRs 17-19 are powered.

The mFCRs in the small island on the right of the one-line diagram are nominally without power. However, in the day of the smart grid, it may be that there is local generation, connected to the distribution system. If there is, a logical question to ask would be: “Can it be operated as an island?”

To answer that question, we must do a power-balance calculation. It is a simple matter to allocate power generation and load to an mFCR. At least, it is simple on paper. (In the real world, a level of communication would be required that is not presently common.)

Rather than attempt the balance calculation in Excel, we performed the calculations in Python, and added a color scheme to the connectivity matrix. An example is given in Figure 5.9. For this situation, and using some arbitrary assumptions about the availability of generation and load in the system of Figure

5.1, we generated the representation of balance shown in Figure 5.10. The numbers we assigned were arbitrarily chosen to show differences. The red color signifies that there is adequate power available, and the purple signifies that there is not, by a significant percentage.

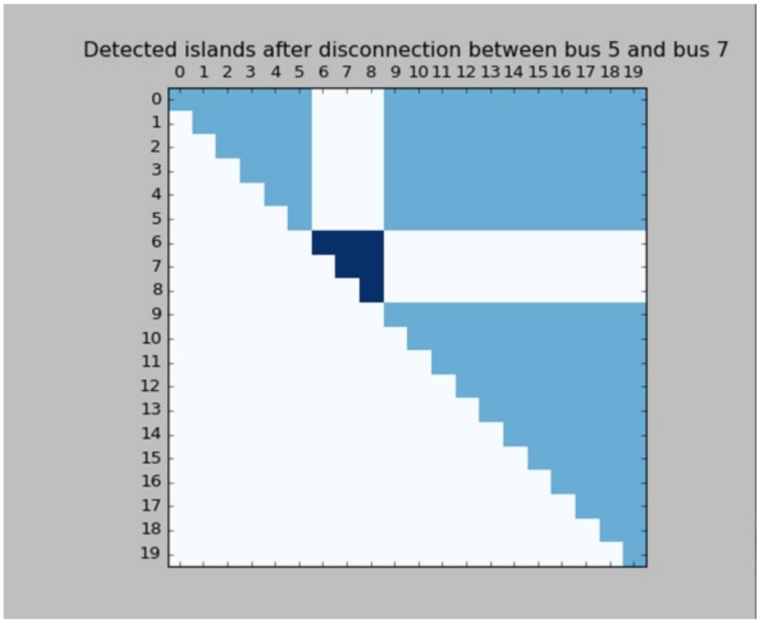

Figure 5.9. Matrix showing islands caused by disconnecting bus 5 and bus 7

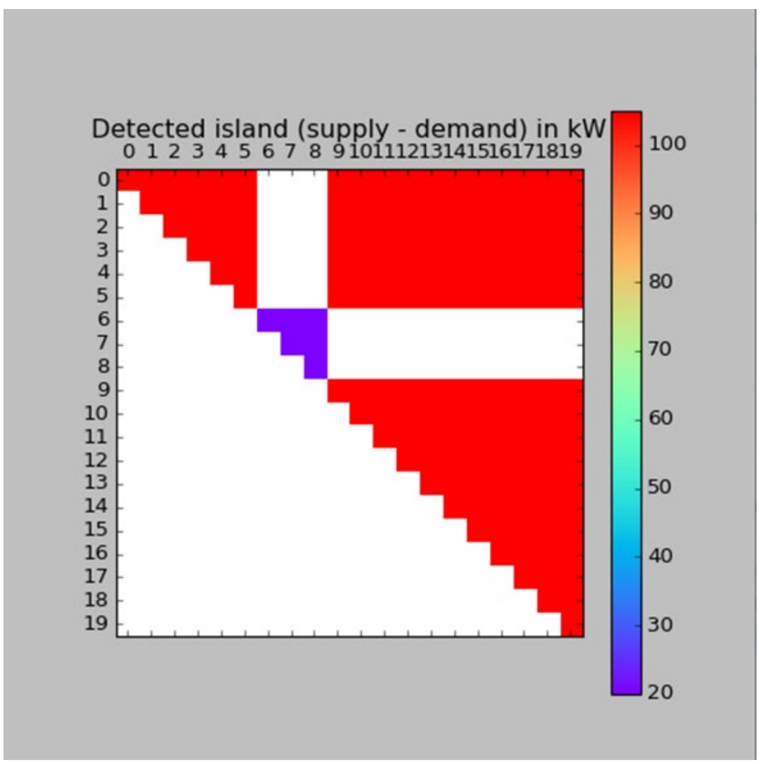

Figure 5.10. Matrix showing power balance in each island

5.4 Conclusion

This is to be regarded as early work, demonstrating a possibility. In further development we would hope to allow the creation of balanced islands by selectively removing mFCRs from the identified islands.

The method shows promise as a fast and simple way to calculate power balance in an ad-hoc islanding situation.

6.0 References

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