Evaluating Admittance Relaying for Inverter-Interfaced Microgrid Protection

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Microgrid Protection Challenges

• Protection Difficulties
  • Low fault current provided by inverter-interfaced generation
  • Bidirectional flow of fault current
  • Meshed lines
  • Many taps compared to transmission
  • Connect and disconnect to the main electrical grid, changing the fault current
  • Must avoid disconnecting local generation in case islanding is necessary

• Current Best Practice
  • Overcurrent relaying with negative and zero sequence current, time-overcurrent backup
  • Cons: false tripping if load imbalance is high (> 20%), poor response time for balanced faults
Why Not Use Differential Protection Everywhere?

Too many taps for differential protection to be cost effective.

But available fault current can still be close to rated current if the load power on this bus is not small compared to total generation power.

Admittance relaying works with taps.
Some Fixes

- One possible solution is to provide fault current via rotating equipment, eg. Synchronous condensors or induction motors.
- Downsides: fault current really isn’t desirable as it can cause damage to equipment.
- Although fault current isn’t present, this is an easier problem than trying to detect high-impedance faults.
- More possible solutions: look at transmission system protection.
  - Traveling-wave protection
  - Distance protection
  - Differential protection
  - Pilot protection
Current State of the art in Microgrid Protection

• CERTS microgrid: use negative-sequence and zero-sequence directional overcurrent protection

• Problems:
  • Potential for load encroachment if load is unbalanced. This could occur if protection on a single-phase circuit trips, causing an upstream trip
  • Cannot detect bolted three-phase faults. While a small fraction of faults, these are not rare
How About Admittance Protection?

Distance protection with directional relaying
Microgrid Converter Design

Controller

Infinite-switching frequency model of Power Stage

Voltage Controllers
Current Limiters
Current Controllers
PWM Delay & Voltage limits
Sinusoidal Voltage sources
LCL output filter
Microgrid Converter Controller Design

- PR controllers offer better performance during unbalanced operation and in the presence of load harmonics compared with proportional-integral (PI) controllers in a rotating reference frame (e.g., DQ0).
- Static reference frames include the Clark ($\alpha\beta\gamma$) and ABC coordinates.
- ABC coordinates require 3 sets of controllers instead of 2 but avoid difficulties with voltage regulation on the healthy phase during unbalanced faults.

Latched current limiters as opposed to instantaneous saturation avoid harmonic injection during faults but introduce a current discontinuity when switching the current controller reference from the voltage controller output to the limited current signal.
Admittance Protection in More Detail

- **Ground Fault Protection**
  - Use estimate of $Z_1$ behind the relay (why not use $V_0/I_0$? We’ll get to that…)
  - Use current compensation
    \[
    Z_{1eq} = \frac{V_a}{I_a + KI_0}
    \]

- **Line Fault Protection**
  \[
  Z_{LL} = \frac{V_a - V_b}{I_a - I_b}
  \]
Case Study System Oneline


<table>
<thead>
<tr>
<th>Name</th>
<th>Symbol</th>
<th>Value</th>
<th>Unit</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inverter rated power</td>
<td>$P$</td>
<td>50</td>
<td>kW</td>
</tr>
<tr>
<td>DC-bus voltage</td>
<td>$V_{dc}$</td>
<td>1800</td>
<td>V</td>
</tr>
<tr>
<td>Output filter inductance</td>
<td>$L$</td>
<td>18</td>
<td>$\mu$F</td>
</tr>
<tr>
<td>Output filter capacitance</td>
<td>$C$</td>
<td>250</td>
<td>nF</td>
</tr>
<tr>
<td>Maximum rms output current</td>
<td>$I_{\text{max}}$</td>
<td>70</td>
<td>A</td>
</tr>
<tr>
<td>Cable resistance</td>
<td>$R_c$</td>
<td>39</td>
<td>mΩ</td>
</tr>
<tr>
<td>Cable inductance</td>
<td>$L_c$</td>
<td>70.8</td>
<td>$\mu$H</td>
</tr>
<tr>
<td>Load real power</td>
<td>$P_d$</td>
<td>25</td>
<td>kW</td>
</tr>
<tr>
<td>Load reactive power</td>
<td>$Q_d$</td>
<td>12.5</td>
<td>kW</td>
</tr>
</tbody>
</table>
Case Study System in Detail

Today we’ll just look at behavior under line-ground faults
Sequence Analysis: Equivalent Sequence Networks & Sources

Note that $I_{af}^0 = I_{af}^1 = I_{af}^2 = \frac{I_f}{3}$

\[
\begin{bmatrix}
I_{af}^0 \\
I_{af}^1 \\
I_{af}^2
\end{bmatrix} = \frac{1}{3} \begin{bmatrix}
1 & 1 & 1 \\
1 & \alpha & \alpha^2 \\
1 & \alpha^2 & \alpha
\end{bmatrix} \begin{bmatrix}
I_a \\
0 \\
0
\end{bmatrix} = \frac{1}{3} \begin{bmatrix}
I_a \\
I_a \\
I_a
\end{bmatrix}
\]
Sequence Analysis: Join the Sequence Networks Together

Because $I_{af}^0 = I_{af}^1 = I_{af}^2$, this justifies a series interconnection of the networks.
Sequence Analysis: Simplify the Network

$Z_{20} = Z_{eq2} + Z_{eq0} + 3Z_f$

Relay location
Sequence Analysis: Unbalanced Case

- Limiting the current on the faulted phase of the inverter can be approximated as reducing the voltage.
- This results in nonzero zero- & negative-sequence voltages at the source.

\[
\begin{bmatrix}
V_{a_g}^0 \\
V_{a_g}^1 \\
V_{a_g}^2
\end{bmatrix}
= \frac{1}{3}
\begin{bmatrix}
1 & 1 & 1 \\
1 & \alpha & \alpha^2 \\
1 & \alpha^2 & \alpha
\end{bmatrix}
\begin{bmatrix}
V_f \\
\alpha^2 V_s \\
\alpha V_s
\end{bmatrix}
\]

\[
= \frac{1}{3}
\begin{bmatrix}
V_f + \alpha^2 V_s + \alpha V_s \\
V_f + \alpha^3 V_s + \alpha^3 V_s \\
V_f + \alpha^4 V_s + \alpha^2 V_s
\end{bmatrix}
\]

\[
= \frac{1}{3}
\begin{bmatrix}
V_f + (\alpha^2 + \alpha)V_s \\
V_f + 2V_s \\
V_f + (\alpha^2 + \alpha)V_s
\end{bmatrix}
\]
Sequence Analysis: Simplify the Network for the Unbalanced Case

\[ Z_1 = \frac{z^1_{1M}}{Z_{1M}} \]

\[ Z_2 = z_{eq2} + z_{eq0} + 3z_f \]

\[ V_1 = \frac{v^1_S}{v_S} \]

\[ V_2 = v_{eq2} + v_{eq0} \]
Measured & Simulated Impedance for Downstream Line-Ground Fault
Conclusions

• Admittance protection with current compensation is viable for inverter-interfaced microgrids

• A downside is that pilot relaying is likely required given short line lengths & change in system configuration from switching – operating area will be large compared to the line impedance

• If a communications channel is required, there are more sophisticated methods such as state-estimation based protection that can operate with the failure of one or more sensors
Distribution Voltage Regulation using DER Grid-Support Functions

New Mexico Established Program to Stimulate Competitive Research (NM EPSCoR) Webinar
22 Nov, 2019

Jay Johnson
Renewable and Distributed Systems Integration
Sandia National Laboratories
Background

• Context
  ▪ Total installed capacity of PV is growing fast
  ▪ Large growth expected in distribution systems

• Problem
  ▪ Grid is slow to evolve, we encounter technical challenges with voltage/frequency regulation, protection, etc.
  ▪ Unless mitigated, these challenges will make it increasingly difficult and costly to continue integrating renewable energy

• Solution: advanced inverters
  ▪ Actively support voltage and frequency by modulating output
  ▪ Have high tolerance to grid disturbances
  ▪ Interact with the system via communications

• Research questions
  ▪ What is the best technique for providing voltage regulation?
  ▪ How can the methods be evaluated with physical devices prior to field implementation?
Distribution Voltage Regulation

Voltage regulation on a feeder without distributed generation.

Solution: Use DER grid-support functions with reactive power capabilities.
- Cost-effective: no additional equipment required
- Logical: employs devices which are causing voltage rise to mitigate the problem

**ENERGISE ProDROMOS Project**

**Programmable Distribution Resource Open Management Optimization System (ProDROMOS)**

The project created an Advanced Distribution Management System (ADMS) that captures distribution circuit telemetry, performed state estimation, and issued optimal DER setpoints based on PV production forecasts.

Team used PHIL experiments to gain confidence in control algorithms, verify communication interfaces, and predict performance prior to deploying the ADMS on a live feeder in Massachusetts.

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1Prodromos is Greek for "forerunner" and the prodromoi were a light cavalry army unit in ancient Greece used for scouting missions.
Options for Voltage Regulation using Grid-Support Functions

**Distributed Autonomous Control**
- Function: volt-var or volt-watt
- Pros: simple, requires little or no communications, DER locations not needed
- Cons: does not reach global optimum

**Extremum Seeking Control (ESC)**
- Function: power factor or a new grid-support function
- Pros: can achieve global optimum
- Cons: requires fitness function broadcast or PF calculation by central entity

**Optimal Power Factor Control**
- Function: power factor or reactive power commands
- Pros: direct influence over DER equipment to achieve objective
- Cons: requires telemetry, knowledge of DER locations, and state estimator/feeder model
Extremum Seeking Control (ESC) was used as a comparison to the PF optimization technique.

Steps in ESC:

A. Centralized control center collects data from the power system.
B. Control center calculates the objective function, e.g., \( J = \frac{1}{n} \sum \left( \frac{V_i - V_n}{V_n} \right)^2 \)
C. Control center broadcasts objective function to all inverters.
D. Individual inverters extract their frequency-specific effect on the objective function and adjust output to trend toward the global optimum.

- Code: [https://github.com/sunspec/prodromos/blob/master/optimization/extemum_seeking_control.py](https://github.com/sunspec/prodromos/blob/master/optimization/extemum_seeking_control.py)
Particle Swarm Optimization (PSO) Optimal Power Flow (OPF)

In the PSO OPF method, time-series OpenDSS simulations were wrapped in an optimization to calculate the PF values for each PV inverter.

- RT power data for each of the buses and the PV forecasts were used to generate a time-series simulation by setting the active and reactive power levels of dynamic loads in the OpenDSS model.
- The OpenDSS load data was populated by Georgia Tech’s Integrated Grounding System Analysis program for Windows (WinIGS) state estimation solution.
  - Active and reactive loads were assumed static.
  - Future PV production estimations were populated by PV persistence forecasts.

Objective Function:

\[
\min_{PF} w_0 \delta_{\text{violation}}(V) + w_1 \sigma(V - V_{\text{base}}) + w_2 C(PF)
\]

\[
\delta_{\text{violation}}(V) = 1 \text{ if any } |V| > V_{\text{lim}}
\]

\[
\sigma(V - V_{\text{base}}) \text{ is standard deviation of } V - V_{\text{base}}
\]

\[
C(PF) = \sum 1 - |PF|
\]

Cost minimized when voltage = \(V_{\text{nom}}\) and PF=1
Creating Realistic Power Simulations

- Feeder models, based on existing distribution systems were reduced to smaller equivalent distribution systems using the OpenDSS.

- These models were migrated into MATLAB/Simulink and simulated in RT with a simulated PV inverter.

- The OPAL-RT platform was used to demonstrate the capabilities of RT-PHIL.

<table>
<thead>
<tr>
<th>Before Reduction</th>
<th>After Reduction</th>
</tr>
</thead>
<tbody>
<tr>
<td>Line</td>
<td>Xfmr</td>
</tr>
<tr>
<td>9393</td>
<td>840</td>
</tr>
<tr>
<td>Line</td>
<td>Xfmr</td>
</tr>
<tr>
<td>32</td>
<td>5</td>
</tr>
</tbody>
</table>

Simulated PV systems were used in the RT and RT-PHIL simulations.

EPRI Simulator
Distributed Energy Technology Laboratory at SNL

- The Distributed Energy Technologies Laboratory (DETL), located at Sandia National Laboratories in Albuquerque, NM, provides power systems and power electronics testing capabilities.
- DETL includes a 480 V, 3-phase microgrid, with interconnections to the utility grid and several DER devices (PV inverters, microturbines, fuel cells, reciprocating engine-generators, and energy storage systems).
- The laboratory also has an OPAL-RT real-time simulator used to perform RT-PHIL tests with 1φ or 3φ PV inverters, a 100 microinverter testbed, and other DER.
- DETL researchers have extensive expertise in DER grid-integration.
PSO OPF Real-Time Power Hardware-in-the-Loop Setup

OPAL-RT Communication Interfaces
- PMU C37.118 to state estimator
- OPAL-RT DataBus Interface receives P/Q values for EPRI DER simulators and transmits bus voltages and frequency

Information Flow
- The State Estimator ingests PMU data to produce current/voltage estimates for the distribution system
- State estimation data and PV generation forecasts populate an OpenDSS model.
- PSO wraps the OpenDSS model to calculate the optimal PF setpoints for each of the DER devices.
- DER PF settings were issued through Modbus and IEEE 1815 (DNP3) commands.

RT-PHIL allows for an affordable and repeatable alternative to testing physical devices under real operating conditions before they are connected to an actual system.
PNM RT Simulation Results

There is only a small improvement in bus voltage when implementing Volt-Var with a relatively passive curve. ESC and PSO improve voltage regulation at the PCC of PV inverter 2 and globally.

- The average bus voltage is close to nominal (good)
- The maximum voltage is reduced substantially (good)
- The minimum voltage is reduced (bad)

\[
\text{score} = \frac{1}{T} \int_{t=0}^{t_{\text{end}}} \sum_{n=1}^{N} (|v_{\text{bl},n} - v_{\text{nom},n}| - |v_{\text{reg},n} - v_{\text{nom},n}|) dt
\]

where:
- \(v_{\text{bl}}\) Baseline Voltage
- \(v_{\text{nom}}\) Target Voltage
- \(v_{\text{reg}}\) Voltage with control applied
- \(T\) Time Period
- \(n\) bus
- \(t\) time

<table>
<thead>
<tr>
<th>PNM Feeder Score</th>
<th>Phase A</th>
<th>Phase B</th>
<th>Phase C</th>
<th>Average</th>
<th>Improvement (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VV</td>
<td>0.024</td>
<td>0.024</td>
<td>0.024</td>
<td>0.071</td>
<td>12.9%</td>
</tr>
<tr>
<td>ESC</td>
<td>0.140</td>
<td>0.140</td>
<td>0.132</td>
<td>0.412</td>
<td>74.5%</td>
</tr>
<tr>
<td>PSO</td>
<td>0.139</td>
<td>0.139</td>
<td>0.130</td>
<td>0.408</td>
<td>73.7%</td>
</tr>
<tr>
<td>Best Score</td>
<td>0.186</td>
<td>0.188</td>
<td>0.179</td>
<td>0.553</td>
<td></td>
</tr>
</tbody>
</table>

High irradiance variability produced voltage deviations.
NG Simulations with $3\phi$ inverters at Old Upton Road

- The National Grid system was highly unbalanced.
- None of the voltage regulation techniques were capable of correcting the voltage deviations using the $3\phi$ inverters at Old Upton Rd.

Question: if all the PV systems on this feeder were used for voltage regulation (not just Old Upton Rd) would there be a big improvement?
NG Simulations with All Inverters

- PV size, location, and rating of the PV inverters are important for the control.
- Controlling all PV generated larger excursions, but in general kept the voltages closer to nominal.
  - The improvement is clear in the feeder scoring results.

\[
score = \frac{1}{T} \int_{t=0}^{t_{\text{end}}} \sum_{n=1}^{N} \left( |v_{bt,n} - v_{\text{nom},n}| - |v_{\text{reg},n} - v_{\text{nom},n}| \right) dt
\]

<table>
<thead>
<tr>
<th>NG Feeder Score Controlling a Single PV Site</th>
<th>Phase A</th>
<th>Phase B</th>
<th>Phase C</th>
<th>Average</th>
<th>Improvement (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VV</td>
<td>0.000</td>
<td>0.000</td>
<td>0.000</td>
<td>-0.001</td>
<td>0.0%</td>
</tr>
<tr>
<td>ESC</td>
<td>0.012</td>
<td>0.000</td>
<td>0.031</td>
<td>0.043</td>
<td>3.2%</td>
</tr>
<tr>
<td>PSO</td>
<td>-0.001</td>
<td>0.000</td>
<td>0.004</td>
<td>0.002</td>
<td>0.2%</td>
</tr>
<tr>
<td>Best Score</td>
<td>0.194</td>
<td>0.635</td>
<td>0.507</td>
<td>1.336</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NG Feeder Score Controlling All PV System (including 1f devices)</th>
<th>Phase A</th>
<th>Phase B</th>
<th>Phase C</th>
<th>Average</th>
<th>Improvement (%)</th>
</tr>
</thead>
<tbody>
<tr>
<td>VV</td>
<td>-0.004</td>
<td>0.122</td>
<td>0.085</td>
<td>0.203</td>
<td>15.2%</td>
</tr>
<tr>
<td>ESC</td>
<td>-0.023</td>
<td>0.328</td>
<td>0.202</td>
<td>0.508</td>
<td>38.0%</td>
</tr>
<tr>
<td>PSO</td>
<td>-0.023</td>
<td>0.124</td>
<td>0.137</td>
<td>0.238</td>
<td>17.8%</td>
</tr>
<tr>
<td>Best Score</td>
<td>0.194</td>
<td>0.635</td>
<td>0.507</td>
<td>1.336</td>
<td></td>
</tr>
</tbody>
</table>
National Grid PV System

The team ran Volt-Var, ESC, and PSO OPF control techniques on the live National Grid feeder in Grafton, MA.

- 28 PV inverters were controlled at the 672 kVA PV site
- A feeder monitor located at a separate location on the feeder was be used to collect feeder voltages
- Data was collected for multiple days for each control technique to compare the techniques

684 kW_{dc}/672 kW_{ac} Old Upton Rd PV Installation
Digital Twin Concept for PSO

**Problem**

- Not enough Intelligent Electronic Devices (IEDs, i.e., PMUs, DERs, meters, etc.) to make state estimation observable for the field demonstration feeder
- Short-term load forecasts or historical data is often used as “pseudo-measurements” to get a solution, but the team didn’t have access to this data

**Implementation**

- Use a real-time digital twin of the feeder to estimate the system operations
  - If general behavior of digital twin is similar to the physical feeder, the “optimal” PF settings should support feeder voltages
- PV power was mapped from physical system to simulated DER device using the curtailment function
- PV PF setpoints are sent to the physical and virtual PV system
- This does not account for the current load (only pre-recorded versions)
PSO on NG Feeder

- Forecast matched PV production
- Line drop compensation should be disabled so that voltage regulation is completed with a single controller
- PSO operated near unity and could do little to help the voltage imbalance of the feeder—just like the other methods.
- Since Old Upton Rd only included three-phase inverters it was not possible to help the phase imbalance but did attempt to move the feeder voltages toward nominal.
- Digital twin method appears to work well!

When PV output is high, there is low voltage because there is a voltage regulator with line drop compensation on this feeder.
NG Field Demonstration

- All the voltage regulation methods were deployed on the live feeder by programming the volt-var or power factor setpoints in the 28 PV inverters at Old Upton Rd.

- Difficult (impossible?) to compare voltage regulation methods in the field because of different irradiance profiles and voltage regulation equipment on the feeder.

- Average PCC voltage close to nominal for all methods.
Project Conclusions and Accomplishments

• **Demonstrated incremental development approach was effective** (simulation to real time to PHIL to field)
  ▪ Communications between measurement equipment, ADMS controllers, and DER devices was verified.
  ▪ Built confidence in controls before field deployment.

• **Digital twin was necessary during development** to overcome sparse measurements for state estimation

• **Observations about control options**
  ▪ **Volt-var** functionality provides some DER voltage regulation without communications.
  ▪ In low communication environments, **extremum seeking control** is a viable means to control a fleet of DER devices to track toward optimal PF setpoints, but it is relatively slow and the system must be tolerant of probing signal ripple.
  ▪ State estimation-fed, model-based **DER optimization** is a viable control strategy with sufficient telemetry.
  ▪ None of the methods were capable of solving the phase imbalance issue with three-phase inverters.

• **Open question and observations:**
  ▪ How well could negative and zero sequence current from inverters regulate voltage on unbalanced feeders?
  ▪ Available telemetry and communications will rarely supply what is assumed during ADMS development.
  ▪ Software interoperability continues to be challenging.

ProDROMOS GitHub Repository: [https://github.com/sunspec/prodromos/](https://github.com/sunspec/prodromos/)
Thank You

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