Auto-Circuit Reclosers: Features, Application and Coordination

Timothy Day
Sr. Application Engineer
Eaton Corp.
RMEL 2017 Distribution Engineers Workshop

Considering Reclosers

Timothy Day, Sr. Applications Engineer, EATON
Coordinating RECLOSERS with RECLOSERS
Recloser Characteristics

Response Curve: base

Min. Trip Current

#133 CURVE
Recloser Characteristics

Response Curve: with Time Multiplier
Recloser Characteristics

Response Curve: with Time Adder
Recloser Characteristics

Response Curve: with Time Multiplier and Time Adder
Recloser Characteristics

Response Curve: with Min. Response Time
Recloser Characteristics

Response Curve: FAST and DELAYED
Recloser Characteristics

Response Curve: GROUND and PHASE
Recloser Characteristics

Control Response vs. Total Clear
Recloser Characteristics - Hydraulic

- All plotted curves are CLEAR
- No response curves
- No curve modifiers
- If single phase, no ground curves

L, 50 Amp
2A, 2C
Recloser / Recloser Coordination: the goal.....

- Restrict any permanent outage, or any momentary interruption, to the smallest possible section of line.
Two Levels of Coordination

1. LOCKOUT Coordination
   • Must-have requirement!
   • Permanent fault assumed
   • Upline recloser stays closed
   • Downline recloser locks open
   • Slow-curve coordination
Two Levels of Coordination

2. TRIP Coordination
   - Difficult to achieve!
     - Hydraulics: tough!
     - Electronics: requires care in setup
   - Temporary fault assumed
   - Upline recloser stays closed
   - Downline recloser trips open
   - Fast-curve coordination
Coordination Methods – Hydraulic Control

- Use different minimum trip values (coils) for reclosers in series.
  - The "standard" way of obtaining coordination.
  - Allows for simplest coordination schemes.
  - Use of the same TCCs and sequence minimizes inventory.
  - Skipping a coil size extends range of coordinating currents.
Coordination Methods – Hydraulic Control

• Variation 1:
  • Same coil sizes.
  • Different TCCs.
Coordination Methods – Hydraulic Control

• Variation 2:
  • Different sequence.

Use of different TCCs and sequences complicates recloser inventory.
1-Phase Recloser Coordination

- Compare recloser curves.
- Determine curve separation in cycles
  - 2 cycles or less: no coordination; both reclosers will trip.
  - 2 – 12* cycles: coordination indeterminate; Recloser age, maintenance, manuf. tolerance, and ambient temperature can influence.
  - More than 12* cycles: coordination assured.

* 8 cycles for 3 phase hydraulic reclosers, less plunger follow-through
Compare TCCs

SOURCE

L, 100 Amp
2A, 2C

L, 50 Amp
2A, 2C

Current in Amperes

Time in Seconds

L, 50A, C curve

L, 50A, A curve

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Compare TCCs

SOURCE

L, 100 Amp
2A, 2C

L, 50 Amp
2A, 2C

Current in Amperes

Time in Seconds

L, 50A, C curve
L, 50A, A curve
L, 100A, A curve
Compare TCCs

SOURCE

L, 100 Amp
2A, 2C

L, 50 Amp
2A, 2C

Is Trip-Coordination assured?
Compare TCCs

SOURCE

L, 100 Amp
2A, 2C

L, 50 Amp
2A, 2C

Current in Amperes

Time in Seconds

L, 100A, C curve

L, 50A, C curve

L, 50A, A curve

L, 100A, A curve

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Compare TCCs

Is Lockout-Coordination assured?

L, 100 Amp, 2A, 2C
L, 50 Amp, 2A, 2C

Current in Amperes

Time in Seconds

L, 100A, C curve
L, 50A, C curve
L, 50A, A curve
L, 100A, A curve

minus 12 cycles

Cooper Power Systems
Coordination – Electronic / Hydraulic Control

- RULE: with different recloser types in series, e.g.,
  - 3Ø hydraulic to 1Ø hydraulic
  - Electronic control to hydraulic control

Characteristics of the source side device determine coordination
Coordination with Electronic Controls

• No "coasting" of internal plungers and solenoids.
• Well-defined, repeatable response time.
• Wide range of curve shapes and modifiers.
• Total-clear time = control response + INTERRUPTING TIME.
• Sequence Coordination feature helps ensure “Trip Coordination”
Coord. via TCCs

SOURCE

PHS: 340A, #105, #119

L, 70Amp 2A, 2C

1800 190

Current in Amperes

Time in Seconds

L: 70A, C curve

L: 70A, A curve

Max Fault
Coord. via TCCs

SOURCE

PHS: 340A, #105, #119

L, 70Amp
2A, 2C

1800
190

L: 70A, C curve

P: 340A, #105 Response, base

P: 340A, #105 Response
TM=0.3, TA=0.02

Max Fault

Current in Amperes

Time in Seconds
Coord. via TCCs

SOURCE

PHS: 340A, #105, #119

L, 70Amp

2A, 2C

1800
190

Is Trip-Coordination assured?

All variations negative

L: 70A, C curve

L: 70A, A curve

P: 340A, #105 Response

TN=0.3, TA=0.02

minus tolerance

Max Fault

Cooper Power Systems

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Coord. via TCCs

SOURCE

PHS: 340A, #105, #119

L, 70Amp

2A, 2C

1800

190

L, 70A, C curve

P, 340A, #119 Response

L, 70A, A curve

P, 340A, #105 Response

TN=0.3; TA=0.02 minus tolerance

Max Fault

Current in Amperes

Time in Seconds

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Cooper Power Systems
Coord. via TCCs

PHS: 340A, #105, #119

SOURCE

L, 70Amp
2A, 2C

1800
190

Is Lockout-Coordination assured?
Ground Fault Tripping on Source Recloser

- Scenario 1; downline device has only phase trip
  a) Source-side phase coordinates with load-side phase
  b) Source-side ground coordinates with load-side phase.
Ground Fault Tripping on Source Recloser

- Scenario 2; downline device has both phase and ground trip
  - Source-side phase coordinates with load-side phase
  a) Source-side ground coordinates with load-side ground.
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

L, 70Amp
2A, 2C

190

1800

L: 70A, C curve
plus tolerance

P: 340A, #119, Response

P: 340A, #105 Response
TM=0.3, TA=0.02

Max Fault

Current in Amperes

Time in Seconds

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Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

L, 70Amp
2A, 2C

190

1800

Cooper Power Systems
by Eaton

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Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

L, 70Amp
2A, 2C

1800

190

L: 70A, C curve
plus tolerance

P: 340A, #119, Response

G: 160A, #145 Response
TA = 0.02
minus tolerance

P: 340A, #105 Response
TN = 0.3; TA = 0.02

Max Fault
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

L, 70Amp
2A, 2C

Cooper Power Systems
by EATON

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Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

L, 70Amp
2A, 2C

Current in Amperes

Time in Seconds

Max Fault

G: minus tolerance
G 160A, #133 Response
G 160A, #104 Response
P 340A, #113 Response
P 340A, #105 Response
L 70A, C curve
L 70A, A curve
plus tolerance

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Coordination Electronic with Electronic

a) Coordinate PHASE curves one with the other
b) Coordinate GROUND curves one with the other
c) Use various curve shapes and modifiers to optimize
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112

Is Trip-Coordination assured?
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112

Current in Amperes

Time in Seconds

P: 280A, #113, Response
P: 340A, #119, Response

plus tolerance + interpt time

minus tolerance

Max Fault

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Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112

Is Lockout-Coordination assured?
Ground Fault Tripping on Both Reclosers

- Coordinate GND curves of both reclosers
  - Fast with Fast
  - Delayed with Delayed
- Adjust Fast curves to optimize Trip-Coordination
- Verify Delayed curves provide Lockout-Coordination
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112

G: 160A, #104 Response
TIA=0.4, TA=0.06 with minus tolerance

G: 140A, #101 includes plus tolerance and interrupt time

Max Fault
Coord. via TCCs
Enable Ground Trip Protection

SOURCE

PHS: 340A, #105, #119
GND: 160A, #104, #133

PHS: 280A, #101, #113
GND: 140A, #101, #112

G. 160A, #133 Response with minus tolerance

G. 140A, #112 includes plus tolerance and inttrpt. time
Electronic Control: Sequence Coordination

- **Application:**
  - Up-line recloser must be electronically-controlled.
  - Fuse-saving (fast and delayed curves) are active in both reclosers.

- **Theory:**
  - Reduce / eliminate blinks of Zone1 recloser for permanent faults in Zone2.
  - Logic in up-line control increments its sequence counter when faults are cleared by the action of other devices.
Sequence Coordination

• Minimal coordination not achieved.
• Both devices trip on fast curves.
• Sequence Coord. Logic cannot fix this
Sequence Coordination

• Better curve selection coordinates fast curves.
• Set Form6 Sequence Coordination to two operations.
Fault Directionality: Introduction

- Application: Feeder with Distributed Generation
- Feeder is no longer radial
- Fault current may flow in either direction through recloser
- Recloser’s response to the fault may depend upon the fault’s direction (programmable)
Fault Directionality: Introduction

- 3-Phase Voltage sensing required
- Phase angles of current AND voltage determine fault direction
Fault Directionality: Introduction

Positive Sequence Network

Negative Sequence Network

Zero Sequence Network
3-Phase Fault Directionality: Introduction

- \( V_1 = \frac{1}{3}(V_A + aV_B + a^2V_C) \)
- \( I_1 = \frac{1}{3}(I_A + aI_B + a^2I_C) \)

- \( a \) is the unit vector operator
- \( 1 \angle 120^\circ = -0.5 + j0.866 \)

- \( V_1 \) and MTA define the complex current plane
- Fault direction depends on location of \( I_1 \) phasor

\[ \cos(\phi_{V_1} - \phi_{I_1} - \phi_{MTA}) < 0 \]

\[ \cos(\phi_{V_1} - \phi_{I_1} - \phi_{MTA}) > 0 \]
3-Phase Fault Directionality: Introduction

Non-zero torque creates no-man’s land
Prevents direction declaration on low-level noise signals.

$\cos(\phi_{V1} - \phi_{i1} - \phi_{MTA}) < -\text{Torque Value}$

$\cos(\phi_{V1} - \phi_{i1} - \phi_{MTA}) > \text{Torque Value}$
Fault Directionality: Other Fault Types

- Different phasors are used for different fault types
  - 3Phase: \( V_1, I_1 \)
  - Line-Line, Line-Ground, Line-Line-Ground: \( V_2, I_2 \)
  - Line-Ground (3-wire systems): \( V_0, I_0 \)
- Algorithms determine fault type and select correct phasors
Fault Directionality: Basic Logic

- If Fault Directionality is selected, correct fault direction must be declared for tripping.
• **LOOP SCHEME**

  - If SOURCE-N fails, FEEDER-N recloser senses loss of voltage and opens after delay-X
  - TIE recloser senses loss of voltage and closes after delay-Y if other source is active
  - Delay-Y > Delay-X
Distribution Automation: Self-Healing

- Radio, Leased Line, Fiber
- Radio Backbone System
- Distribution Line
- Cell Modems
- Substation
- SCADA System

Photo courtesy of PG&E
Voltage Regulator Controls

Jon Grooters
Western Regional Sales/Applications Manager
Beckwith Electric
- Types of Voltage Regulation Devices:
  - NLTC (No-Load TC) or DETC (De-Energized TC)
  - OLTC or LTC (On-load TC)
    - Taps changed to raise or lower voltage while under load
    - No interruption in load current
    - Never dead or short on any part of the transformer winding
    - Can be manual or automatic (preferred type in North America)
    - Considerably more expensive than NLTC’s
    - Sensing a single phase but operates all three phases in ganged operation
- Single Phase Voltage Regulators
  - Taps changed to raise or lower voltage while under load
  - No interruption in load current
  - Each phase is sensing and operating independently of each other
Voltage Regulator Controls

Voltage Profile

Volts (Secondary)

126V

114V

Voltage Profile
Voltage Profile

Volts (Secondary)

126V

114V
Voltage Regulator Controls

Volts (Secondary)

126V

114V

Voltage Profile
Examples of Load Tap Changers
Load tap changers
Basic types

<table>
<thead>
<tr>
<th>In-tank</th>
<th>On-tank</th>
<th>On-tank</th>
</tr>
</thead>
<tbody>
<tr>
<td>vacuum/resistance</td>
<td>vacuum/reactance</td>
<td>resistance</td>
</tr>
<tr>
<td>Example: type VUCG</td>
<td>Example: type VRLTC</td>
<td>Example: type UZ</td>
</tr>
<tr>
<td>Application: HV winding</td>
<td>Application: LV winding</td>
<td>Application: LV &amp; HV winding</td>
</tr>
</tbody>
</table>

Voltage Regulator Controls
Examples of Single Phase Voltage Regulators
Pole Mounted
Voltage Regulator Controls

Pole Mounted
Pole Mounted
Substation
Configurations of Single Phase Voltage Regulators
Wye Configuration
Open Delta Configuration
Closed Delta Configuration
Typical LTC/Regulator arrangement in North America

- Voltage Range: +- 10% of Low Voltage
- Tap Steps: 32 Tap Steps + Neutral. Approximately 5/8% steps, with 16 steps above and 16 steps below rated voltage
- Capacity:
  - Deliver rated KVA power at rated low voltage at all positions above rated voltage (+1 ~ +16)
  - Deliver current corresponding to rated low voltage at all positions below rated low voltage (-1 ~ -16). This is also known as reduced capacity
How do we get the 32 Tap Steps + Neutral?
- An LTC control (aka “90” device) or regulator control is in charge of sensing and commanding the LTC/Regulator to raise or lower taps if voltage is out of band.

- LTC controls sense 120V therefore when we say that they regulate +/-10% they are in effect changing voltage in secondary units by +/-12V.

- So if we are raising +12V or lowering -12V over 16 taps then each tap will move voltage by 12/16 or 3/4V (0.75V).
Minimum settings for an LTC control (basic setpoints)

- Band Center
  - 100~135Vac in 0.1V increments, 120Vac is the default

- Band Width
  - 1~10Vac in 0.1V increments, 2.0Vac is the default

- Time Delay
  - 1~120s in 1s increments, 30s is the default

![Diagram showing voltage levels and settings](attachment:image.png)

V=Voltage Setpoint of tapchanger control

121V  Upper Band Width
120V  Band Center
119V  Lower Band Width
- Basic Settings
Time Delay/Coordination

- A typical setting for an LTC control in a substation is 30 seconds.
- If there are line regulators in the feeders a common practice is to add 15 seconds to each stage moving out of the substation.
- For proper time coordination it is important that the shortest time delay is set at the substation and longer times in the feeder.
- **Cascaded LTC & Regulators**
  - If not properly coordinated (shortest time in substation, longer time farther out in the feeder) LTC controls and Regulator controls may force taking unnecessary taps for large system voltage variations.
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- Coordination with Capacitor Banks
  - Capacitor banks on the distribution grid also need to be coordinated with LTC and regulator controls
  - Known commonly as Volt-Var Optimization or VVO
Time Delays

- Two types of Time Delays
  - Definite Time Delay – Time delay fixed (1~120s @1s)
  - Inverse Time Delay – Time delay varies with the amount of voltage difference. The greater the difference, the less time delay
- **Definite Time Delay**

  - No matter how far out of band the voltage is, the control will wait the entire time delay before it operates.

  ![Graph showing time delay with voltage bands](image)
- **Inverse Time Delay**

- Time delay varies based on how far out of band the voltage is

**Inverse Time Example**

Band Center: 120V  
Band Width: 3V  
Inverse Time Delay Setting: 60s  
\[ \Delta V = \frac{\text{Band Width}}{2} = 1.5V \]  
\[ V_{in} = 124 \text{ V} \]  

**Voltage deviation in multiples of \( \Delta V \)**  
\[ = \frac{V_{in} - \text{Band Center}}{\Delta V} \]  
\[ = \frac{(124 - 120)}{1.5} \]  
\[ = 2.67 \]  

**Time delay from Figure**  
\[ = 38\% \text{ of Inverse Time Delay setting} \]  
\[ = 23 \text{ sec} \]
- Inverse Time Delay

  - Time delay varies based on how far out of band the voltage is
Two type of timers (resets)
- When a limit bandwidth is exceeded and then returns to normal, there are two ways to reset the timer
  - Integrating – Increments timer 1 count every second voltage is out of range and decrements counter 1 count towards zero when voltage is within range
  - Instantaneously – Increments timer 1 count every second voltage is out of range and resets count to zero immediately when voltage is within range
- Instant Reset Timer

![Graph](image.png)

Timer instantly resets when voltage goes back in band.
- Integrating Timer

Timer starts counting backwards when voltage goes back in band

11..10..9..

12s

8s

4..5..6..7..
Line Drop Compensation (LDC)

- LDC allows the user to regulate the voltage at a point closer to the load as voltage drops due to loss in the line because of line impedance.
- Two types of LDC are provided:
  - R/X
  - Z
LDC – R,X

- Where individual line information is known, R & X values (volts) can be implemented
  - R,X values can come from software modeling
  - R,X values can be calculated:

\[
\begin{align*}
R_{\text{set}} &= (\frac{I_{\text{CT}}}{N_{\text{PTR}}}) \times R_{L} \\
X_{\text{set}} &= (\frac{I_{\text{CT}}}{N_{\text{PTR}}}) \times X_{L}
\end{align*}
\]

- $I_{\text{CT}}$ is the primary CT rating of the regulator
- $N_{\text{PTR}}$ is the primary transformer ratio
- $R_{L}$ is the primary line resistance from the regulator to the load center
- $X_{L}$ is the primary line reactance from the regulator to the load center
- LDC allows the user to regulate the voltage at a point closer to the load as voltage drops due to loss in the line because of line impedance.

Without LDC at full Load:
- 120V
- 118V
- 115V

With LDC at full Load and unity power factor (R=5):
- 125V
- 123V
- 120V
LDC - Z (General Compensation)

- **Application:** Distribution bus regulation

- **Concept:** Increase bus voltage as the load level increases
- **No individual line information**
- **Uses current magnitude ONLY**
LTC Area of Responsibility

- VD=3V
- VD=5V
- VD=7V
- VD=2V
Notice there is no cap on the compensation.
Notice that if the current is in reverse mode, the voltage is dropped instead of raised.
Voltage Regulator Controls

**Metering with LDC**

- Local voltage is the measured & regulated voltage
- Source Voltage is the calculated source voltage on the primary side using the tap position
- Compensated Voltage is the calculated voltage seen at load center after applying LDC
Undervoltage Block

Block – Block Lower

- Used to keep voltage from dropping to low which could cause motors to stall.
- If voltage falls below this level, voltage reduction is blocked and all Lower commands are blocked.
- Can be configured from 95.0 – 135.0 Vac in 0.1 Vac increments.
Overvoltage Block

Block Raise (First House Protection)

- Used to keep voltage from going too high.
- If voltage goes above this level, all Raise commands are blocked.
- Can be configured from 95.0 – 135.0 Vac in 0.1 Vac increments
Overvoltage Runback

Overvoltage Runback (OR) – Block Raise

- If voltage exceeds the OR level (Block Raise + Deadband), Raise commands are blocked and Lower commands are issued until voltage goes below the OR level.

![Diagram showing voltage levels and block points for overvoltage runback](image)
Overvoltage Runback

Deadband

Volts (Secondary)

121.5V

120V

118.5V

Time (Seconds)

0 10 20 30
Tap Position Block

- Requires the tap position to be monitored using either
  - Keep Track
  - Positive Knowledge
- Control allows different settings for the block on the lower and the block on the raise
- Incorrect tap position will cause undesirable blocking
Low Current Block

- LTC control only see magnetizing current of LTC (<4mA)
- LTC control could tap and run away
- When returning to normal configuration, may be several taps off
LDC with Distributed Energy Resources (DER)

- Line Drop Compensation has worked well for many years but with the proliferation of DER on the distribution grid it has met some challenges
LDC with Distributed Energy Resources (DER)

- Band Center: 120
- Band Width: 3
- R/X: 4/0
- Full Load Current: 800A
- Load Current: 600A
- Current Seen at LTC: 600A

- Resultant Band Center at LTC: $(\frac{600}{800})*4 = 3V = 123V$
LDC with Distributed Energy Resources (DER)

- Band Center: 120
- Band Width: 3
- R/X: 4/0
- Full Load Current: 800A
- Load Current: 600A
- Current Seen at LTC: 200A

- Resultant Band Center at LTC: \((200/800)*4 = 1V = 121V\)
Voltage Regulator Controls

- Band Center: 120
- Band Width: 3
- R/X: 4/0
- Full Load Current: 800A
- Load Current: 600A
- Current Seen at LTC: -200A

Resultant Band Center at LTC: \((-200/800) \times 4 = -1V = 119V\)
- Load Center (LC) is polled via SCADA and found to be 117V
- With a Band Center of 120, 3V (120V-117V) will be added for compensation
- Resultant Band Center at LTC = 123V
Reverse Power

- With increased Distribution Automation (DA) and proliferation of DER, Reverse Power is becoming a major challenge for utilities
  - It is important to know why you are going in to reverse power and set the control to handle accordingly
Reverse Power Modes

- Block
- Regulate Forward (Ignore) or Lock Forward
- Regulate Reverse or Bi-Directional
- Return to Neutral or Neutral Idle
- Regulate Reverse (Measured) or Bi-Directional Measured
- Distributed Generation or Cogeneration
- Automatic Determination

- Controller uses bias to determine/delay change in direction
  - No Bias
  - Forward Bias
  - Reverse Bias
Reverse Power Modes: Block

- **Block**
  - Inhibits automatic tapchanger operation
  - Locks the tapchanger on the tap position in use at the time reverse power flow is detected
  - Recommended setting for independent power producers or in situations when reverse power flow is not expected
  - The control will revert to normal operation when forward power flow resumes
Reverse Power Modes: Regulate Forward or Lock Forward

- **Regulate Forward (Ignore)**
  - Control will take no different action than in the forward direction
  - Essentially does not use the power direction in the control decisions
  - Same as a control which does not have power direction knowledge
Reverse Power Modes: Regulate Reverse or Bi-Directional

- **Regulate Reverse**
  - Control will detect reverse power flow and regulate according to reverse power settings as selected in the Setpoint Menu.
  - With tap position knowledge, the control calculates the source-side potential without the use of a source side VT.
  - Designed for use with feeder voltage regulators which continue to operate in a radial mode after system switching causes the power flow reversal.
Reverse Power Modes: Regulate Reverse or Bi-Directional

1. Regulator sees reverse load current
2. Regulate Reverse is initiated
3. Voltage is calculated on source side (need accurate tap position)
Reverse Power Modes: Regulate Reverse or Bi-Directional (Measured)

- **Regulate Reverse (Measured)**
  - When reverse power is detected the control will energize an internal contact that will switch the input to the VT from Load side to source side
  - After a 4 cycle delay, the source side voltage will be measured, the load voltage at this instant will be displayed as zero
  - In forward power direction, the control will switch the input back to the load side voltage
Reverse Power Modes: Regulate Reverse or Bi-Directional (Measured)

1. Regulator sees reverse load current
2. Regulate Reverse is initiated
3. Voltage is measured on source side (need source side PT)
Reverse Power Modes: Return to Neutral or Neutral Idle

- **Return to Neutral**
  - Driven to neutral when reverse power is detected
  - Tap position will be driven to neutral regardless of the voltage or currents present at the control
  - Normal operation will resume when forward power is detected.
  - Intended as a safe response to a power reversal on a system which can have conflicting situations
Reverse Power Modes: Distributed Generation or Cogeneration

- **Distributed Generation**
  - Driven to neutral when reverse power is detected
  - Tap position will be driven to neutral regardless of the voltage or currents present at the control
  - Normal operation will resume when forward power is detected.
  - Intended as a safe response to a power reversal on a system which can have conflicting situations
Reverse Power Modes: Distributed Generation or Cogeneration

1. Regulator sees reverse current
2. DG mode is initiated
3. Voltage regulation still needs to be in forward direction but may want to eliminate or modify LDC
Reverse Power Modes: Automatic Determination

- **Auto Determination**
  - Distributed Generation Mode will be applied initially
  - On the next tap operation, Load Voltage will be measured before and one second after the tap
    - If Tap Delta Voltage > 0.4Vac, controls stays in Distributed Generation Mode
    - If Tap Delta Voltage < 0.4Vac (two consecutive measurements) control changes to Regulate Reverse
1. Regulator sees reverse current
2. DG mode is initiated
3. Regulator does not see voltage change on load side
4. Regulator control switches to Regulate Reverse mode
Reverse Power Modes: Automatic Determination

1. Regulator sees reverse current
2. DG mode is initiated
3. Regulator continues to see voltage change on load side
4. Regulator control stays in DG mode
电压调节器控制

- 调节器检测到正向电流
- 调节向前模式被启动
- 调节器在负载侧看不到电压变化
- 调节器控制开关切换到调节反向模式

反向功率模式：自动确定

1. 调节器检测到正向电流
2. 调节向前模式被启动
3. 调节器在负载侧看不到电压变化
4. 调节器控制开关切换到调节反向模式
Voltage Reduction

- Why Voltage Reduction?
  - Purpose of voltage reduction is to reduce load
    - $V = I \times R$ for resistive load
    - Therefore the lower the $V$ the lower the $I$
    - The lower the $I$ the lower the Watts
  
  - Can be deployed at all times for energy savings
  - During system emergencies or shortages (load shed)
  - For peak avoidance

- Often referred to as Conservation Voltage Reduction (CVR)
Voltage Reduction: History

- In the past Voltage Reduction was typically part of load management software.
- The Load Management software would issue commands to close in relays that would add voltage to the sense input of the control.
- The control would not know that it was in reduction but would simply react to the voltage input change.

Disadvantages:
- The time delay to tap is still in play.
- The percentage of reduction is fixed due to the taps on the summing transformer.
- Each percentage reduction point required an auxiliary relay.
- If the communications failed while in reduction, the LTC or Regulator would remain in voltage reduction.
Voltage Reduction: Modern Controls and Systems

- Can be initiated by DMS with VVO/CVR
  - DMS can initiate control to go in to one of the programmable voltage reduction steps
  - DMS can write a new band center to control
    - Disadvantage: Control does not know it is in CVR
- Can be initiated locally/remotely using software
- Can be initiated by HMI
- Can be initiated by hardwired contacts
Voltage Reduction: Modern Controls and Systems

- Voltage Reduction changes the band center to induce controls to lower voltage instead of increasing sensed voltage.

- Time delay skipped on initial voltage reduction command.

- Because band center is being altered, entering reduction does not always reduce voltage, or reduce near amount of requested reduction.
Voltage Reduction: Modern Controls and Systems

- **Standard Voltage Reduction**
  - Apply a **2%** reduction
  - \( 122 - 122 \times 0.98 = 119.56 \) or **119.6**
    - Upper rail = **119.6 + (3/2) = 121.1**
    - Lower rail = **119.6 - (3/2) = 118.1**

- Assume 0.75V/tap (10V/16 taps = 0.75V/tap)
- 120.7V before reduction, after reduction that value is still in-band
- Results in no voltage reduction, **0%**
Voltage Reduction: Modern Controls and Systems

- **Standard Voltage Reduction**
  - Apply a **3%** reduction
  - \[ 122 - 122 \times 0.97 = 118.34 \text{ or } 118.3 \]
    - Upper rail = \( 119.6 + \frac{3}{2} = 119.8 \)
    - Lower rail = \( 119.6 - \frac{3}{2} = 116.8 \)

Assume 0.75V/tap (10V/16 taps = 0.75V/tap)
- 120.7V before reduction, 2 Taps Down Taken
- Tap 1 = 119.95, Tap 2 = 119.2
- \[ \% = \left( \frac{|V1 - V2|}{(V1 + V2)/2} \right) \times 100 \]
  - \[ = \left( \frac{|120.7 - 119.2|}{((120.7 + 119.2)/2)} \right) \times 100 = 1.25\% \text{ reduction} \]
Voltage Reduction: Modern Controls and Systems

- Smarter approach to Voltage Reduction
  - Apply a 3% reduction
  - \( 122 \times 0.97 = 118.34 \) or 118.3
    - Upper rail = 119.6 + (3/2) = 119.8
    - Lower rail = 119.6 – (3/2) = 116.8

- Assume 0.75V/tap (10V/16 taps = 0.75V/tap)
- 120.7V before reduction, 4 Taps Down Taken
- Tap 1 = 119.95, Tap 2 = 119.2, Tap 3 = 118.4, Tap 4 = 117.7
- \[ \% = \left( \frac{|V_1 - V_2|}{(V_1 + V_2)/2} \right) \times 100 \]
- \[ = \left( \frac{|120.7 - 119.2|}{((120.7 + 117.7)/2)} \right) \times 100 = 2.52\% \text{ reduction} \]
Voltage Reduction: Modern Controls and Systems

- Smarter approach to leaving Voltage Reduction

The lower band is temporarily disabled to force the voltage to finish between the band center and the high band edge.

Once the voltage crosses the band center, the lower band edge becomes active again.
2017 RMEL Distribution Workshop
Voltage Regulator Controls

Questions?
Distribution Capacitor Banks and a Process for Independence Power & Light

Brent Gerling
Distribution Engineer
Independence Power & Light
Distribution Capacitor Banks

A Cap Bank Program For Independence

Project Manager:
J. Brent Gerling. P.E.
Independence, MO & IPL

- Independence, MO
  - 4th Largest City in Missouri
  - Outlier of Kansas City
  - Hometown of President Harry S Truman
- Independence Power & Light (IPL)
  - Created by Charter in 1901
    - Municipal Electric Utility for the City
  - 56,000 + Customers
  - Generation, Transmission & Distribution
Power & Why We Use Capacitors?

- Power is the amount of energy produced or consumed during work.
- Three types of Power:
  - Real Power (P) – performs work, Watts (kW)
  - Reactive Power (Q) – does not perform work (kVAR)
  - Apparent Power (S) – magnitude of the difference (kVA)
Power & Why We Use Capacitors?

- Power Factor (PF) is the measure of electrical efficiency.
  - Ratio of True Power (kW) to Apparent Power (kVA)
  \[
  PF = \frac{kW}{kVA} \quad PF = \cos \Theta
  \]

Power Factor = \[
\frac{\text{Beer (kW)}}{\text{Mug Capacity (KVA)}}
\]
Power & Why We Use Capacitors?

- Why do we have reactive power (Q)?
  - Inductive (L) and Capacitive (C) Loads
    - Examples of Inductive Loads:
      - Induction motors
      - Fluorescent & LED lighting
      - Transformers
      - Overhead conductors
    - Capacitive Loads?
  - Inductive loads cause a lagging and Capacitive loads cause a leading Power Factor on the system.
Power & Why We Use Capacitors?

- In the absence of another source, the generator must supply non-working power. This is **cost** money!
- Capacitors can provide nearly all of this non-working power, increase the Power Factor, support voltage downline and reduce line current. They **save** money!
Power & Why We Use Capacitors?

- What are capacitors and how are they used?
  - The basics:
Power & Why We Use Capacitors?

- How are Capacitors installed in the Electric Distribution System?
  - Single or Multi Phase; Overhead or Underground
  - What are the Benefits for each case
Power & Why We Use Capacitors?

- Electric Utilities install capacitor banks to save money although, other factors can drive their use.
- Several of the aspects to consider in developing a lasting Distribution Capacitor Bank Program are:
IPL and Cap Banks

- Independence Power & Light is completing an extensive program to update their facilities. Some items that were considered:
  - Safety; Field Personnel and Instruction
  - Existing Inventory; Inspect, Test & Rebuild
  - Feeder Evaluation; What’s Needed and Where
  - Controller evaluation; What do we want it to do
  - Construction standards; Two Types of Installation, New Material
  - Equipment Installation & Software Programming/Hosting
  - Cost; Material/Labor Expenses Based on Initial Pilot Project
  - Payback; Returns Based on Initial Pilot Project
  - Construction Schedule
IPL and Cap Banks

- Inspecting the existing inventory....what did we really have working?
IPL and Cap Banks

- What did we find:
  - Many of the existing facilities weren’t working.
  - More used banks sitting idle with no direction.
  - Old controllers can’t be set safely.
- What should we do with them?
- Are these things safe?
- Can we use any of this stuff?
- What does IPL need or want?
IPL and Cap Banks

- Inspect, Test & Rebuild components of old banks; Why?
  - Usable parts
  - Disposal cost
  - Cost of new bank
    - $8,139.46
  - Cost of Refurbished bank
    - $4,162.04
  - Difference (money saved)
    - $4,127.42
IPL and Cap Banks

- Feeder Analysis on 66 Distribution Feeders
  - Historical SCADA Data
  - Feeder Layout
  - Large Customers
  - Peak Days
  - Trending VAR needs
  - Bank Location(s)
  - Future Load Growth
  - Any Additional Benefits
IPL and Cap Banks

- Can we do a Pilot Project on several feeders or an entire Sub?
  - Sub H with 7 Feeders, 3-working cap banks.
  - Upgraded with 10 (Switched & Fixed) cap banks and IED’s (Controller) operating on VAR needs.
    - Pre study Bus Totals: 25.6 MW / 7.0 MVAR; PF=96%
    - Post study Bus Totals: 27.5 MW / 2.6 MVAR; PF=99%
  - Results: 65% reduction of distribution VARs, improved PF to near Unity and supported voltage to downline customers.
IPL and Cap Banks

- What did we learn from this?
  - What value(s) do we get with each type of bank?
  - Should we monitor Fixed Banks?
  - IED’s need regular checking unless installed with Communication; should we use Com’s?
    - Are there other IED’s that may work better?
  - Can this process be used system wide?
  - Is this better than using Substation level VAR recovery?
IPL and Cap Banks

- Communication for IED’s...
  - Cellular, Radio or Fiber
    - Monitor Fixed Banks
- What about a different Controller?
  - What do we need & want? Let’s evaluate...
    - Four Controllers: Fischer Pierce, S&C, Cooper & GE
      - Programmable
      - Safety
      - Communication
      - Installation
IPL and Cap Banks

**Simplifying Bank Sizes**
- We had eight sizes of banks; reduced to 3: 450, 900 & 1350 kVAR

<table>
<thead>
<tr>
<th>Pro’s</th>
<th>Con’s</th>
</tr>
</thead>
<tbody>
<tr>
<td>Better sizing for Feeders</td>
<td>More Costly Material</td>
</tr>
<tr>
<td>Better Power Factor</td>
<td>Confusing for Personnel</td>
</tr>
<tr>
<td>Optimal Use</td>
<td>Maintenance Cost</td>
</tr>
<tr>
<td>Easier on Switches</td>
<td>Standards &amp; Records trouble</td>
</tr>
</tbody>
</table>

More Dynamic, but Loosing Gains

More Rigid, but Still Adequate
IPL and Cap Banks

- We need to build a Standard Junction Box for control
- Put the arrestors up top to protect the whole bank
- Maximize grounding

Standard Material & Construction Standards
- Two Bushing Capacitors: 150 & 300 kVAR
- Vacuum Switches vs. Oil Switches
- Have a Primary Sensor, and a Neutral Sensor

New Programmable Controller with Cellular Communication

We'll maintain the 6-pin Meter Socket base for controllers

Put the arrestors up top to protect the whole bank

Maximize grounding
IPL and Cap Banks

- Assembling the Banks
  - Create Fixed Banks
  - Turn On & Stay On
  - Use Older Racks
  - Use Older Caps
  - Use Oil Switches
  - Use Older Controller
  - Time Delay
  - Monitor Voltage
  - Maintain VAR Needs
IPL and Cap Banks

- Assembling the Banks
  - Create Switched Banks
    - Use Vacuum Switches
    - Regular switching
    - Low Maintenance
  - New Sensors for Control
    - Primary Sensor
    - Neutral Sensor (Alarm)
  - New Controller w/Comm.
  - Two-Way Operation
IPL and Cap Banks

- Assembling the Banks
  - Introduce new Components & Operation Practices on each type; who needs to know?
IPL and Cap Banks

- Construction Process
  - Work Management Flow
    - Work orders, material, line crews, manufacturer(s), etc.

- Be the resource for answering questions & concerns
IPL and Cap Banks

- Program Costs & Returns
  - New Material + Disposal Costs = Total Equipment Costs
    - $640,661.00
  - Labor (Removal, Rebuild, Records, Programming, Etc.)
    - $171,345.00
  - Saved Funds by Testing, Inspecting & Rebuild
    - -$104,346.00
  - Saved Funds in MVAR Recovery per year
    - -$84,974.00
  - Payback period = 8 Years
Capacitor Bank Worksheet

LINE CONDITIONS

- Step 1: Distance to Substation: 3 Miles
- Step 2: Conductor Size and Type: 559 AAAC
- Step 3: Line Voltage: 13.2 kV
- Step 4: Bank Size: 1200 kVAR
- Step 5: Load Current: 300 A, l_LINE 0.94 PF

VALUES FOR COMPUTATION

- Step 6: Cost of energy: $0.0435 $/kWh
- Step 7: Single-Phase Line Resistance: (Step 1)Miles x (Conductor value)Ω/res/mile = 0.19 Ω_LINE
- Step 8: Single-Phase Line Inductance: (Step 1)Miles x (Conductor value)Ω/res/mile = 0.44 Ω_IND
- Step 9: Single-Phase Capacitor Current: (Step 4)kVAR_CAP / ((Step 3)kV_LINE x V3) = 52.49 A, Σ_CAP
- Step 10: Single-Phase Inductive Load Current: V^2/((Step 5)I_LINE^2 - ((Step 5)I_LINE x (Step 5)PF)^2) = 102.35 A, Σ_IND
- Step 11a: Estimated hours per year cap bank is on: 10_h/yr x 7_day/wk x 35_wk/yr = 2450 hr/yr
- Step 11b: Calculated hours per year fixed bank is on: 8760 hr/yr
- Step 12: Calculated three-phase line loss reduction: 3 x (Step 7)(2 x (Step 10) x (Step 9) - (Step 9)^3)/1000 = 4.56 kW_SAVE
- Step 13: Calculated Yearly Energy Cost Savings: (Step 12)kW_SAVE x (Step 11a)hr/yr x (Step 6)$/kWh = $485.59 $SAVE/YR switched bank
- Step 14: Calculated Increase in Line Voltage (120V ref): (Step 9)I_CAP x (Step 8)Ω_IND x 1.120 x 1.73 / (Step 3)kV = 0.36 V, ΔE_SEC
- Step 15: Calculated Reduction in kVA Demand: ((Step 5)I_LINE x (Step 5)PF)^2 = 79524.00 A^2, I_RESIS^2
- Step 16: Line Current with Cap Bank ON: V^2/((Step 15)I_RESIS^2 + ((Step 10)I_IND - (Step 9)I_CAP)^2) = 286.37 I_LINE/CAP
- Step 17: Reduction In Line Current: (Step 5)I_LINE - (Step 16)I_LINE/CAP = 13.63 A, ΔI
- Step 18: Reduction in Demand: [3 x (Step 17)ΔI x (Step 3)kV / 1.73] = 311.88 ΔkVA
IPL and Cap Banks

• Current Results
  • Installation & Removal – 95% Complete *
    • 31 – Removed Banks
    • 33 – Installed Fixed Banks
    • 57 – Installed Switched Banks
  • Installed 74 MVAR of Capacitance
  • 4400 Man-hours Worked (in-house)*
  • Remote Operation/Monitoring on Switched Banks is Success; Fixed Banks....
  • Programming is Commencing
IPL and Cap Banks

• Any Questions?

J. Brent Gerling, P.E.
Distribution Engineer
City of Independence - Power & Light
17221 E 23rd St S
Independence, MO 64057
O: 816-325-7444
M: 816-261-2038
bgerling@indepmo.org
Distribution Automation Schemes – Proven Solutions to Reduce the Duration of Power Outages and Improve System Reliability

Daniel Wycklendt
Business Development Manager, Distribution Automation
G&W Electric Company
Distribution Automation Schemes – Proven solutions to reduce the duration of power outages and improve system reliability!

Daniel Wycklendt – G&W Electric
• Vision and Objectives
• Introduction of Automated Solutions (Script Based)
  • Open Loop - Communicating
  • Closed Loop - Communicating
  • Open Loop – Non-Communicating
  • Distributed Generation/Microgrid
• Factory Acceptance Testing
• Questions
What to Consider When Choosing an Automation Solution?

1. What do you have Now? *History! Challenge!*
2. What do you want in the Future? *Vision!*
3. System Wide or Area Specific
4. Criticality or Sensitivity of the Application
5. Targets for Improvement
6. Costs Internal and External
• Rubicon Technology – fed by the City of Batavia
• Manufacturing facility for synthetic sapphire substrates (LCD Displays)
• Two separate 35 kV feeders
• Requirement to provide ultra reliable power
Rubicon Technology — Solution

- (4) SF6 Switches and (2) Viper Reclosers
- Automatic Reconfiguration on loss of voltage or fault
- Central Controller Based
- Voltage sensing and faulted circuit indication
- Fast Response and flexible solution
Electrical System Layout

Source 1 - 35 kV

Recloser 1

Switch 1

1 2
L1

Fault indicators at locations 1 and 2 on each switch

Source 2 - 35 kV

Recloser 2

Switch 2

1 2
L2

Switch 3

1 2
L3

Switch 4

1 2
L4

L5
Communication and Control Layout

Recloser control 1

Recloser control 2

Fiber optic cable

DNP over Ethernet to SCADA

S1
S2
S3
S4
Fault between Switch 1 and 2
Fault detected by recloser. Recloser opens to interrupt fault.
Controller determines fault location and opens closest switches to isolate fault.
Controller commands recloser and switch way to close into reconfigured circuit to restore power
Electrical System Layout

Source 1 - 35 kV

Recloser 1

Switch 1

Switch 2

L1

L2

L3

Source 2 - 35 kV

Recloser 2

Switch 3

Switch 4

L4

L5

50% of Loop Experiences an Outage ($\approx 1.5$ seconds)
Manufacturer of raw material used for making LCD chips is impressed with reconfiguration time of 1.6 seconds!
Alternate Electrical Layout

Source 1 - 35 kV

Recloser 1

Switch 1

Open Point

Switch 2

Open Point 1

Switch 3

Switch 4

Source 2 - 35 kV

Recloser 2

25% of Loop Experiences an Outage (less than 20 cycles)
St. Lawrence Seaway Management Corporation Flight Locks 4-Way Medium Voltage Switchgear

With Closed Loop FDIR/LOV Protection and Transfer Trip Scheme LaZer Automation
Closed Loop FLISR and Loss of Voltage Application using PNI40s

- The six PNI Switchgear (PMS) connected to form a closed substation loop protection scheme.
  - Loss of Voltage (Utility)
    - ATS
  - Line, Tap, and Bus Faults
    - POTT and DCB
  - Loss of Communication
    - Time Based LOV
Alternate Electrical Closed Loop Layout

Source 1 - 35 kV

Recloser 1

Switch 1

Switch 2

Switch 3

Switch 4

Source 2 - 35 kV

Recloser 2

0% of Loop Experiences an Outage
**Non-Communicating Loop Scheme**

<table>
<thead>
<tr>
<th>Designation</th>
<th>Description</th>
<th>Automatic Operation</th>
</tr>
</thead>
<tbody>
<tr>
<td>ALLR</td>
<td>Automatic Line Reconfiguring Recloser</td>
<td>Opens on overcurrent timing or loss of voltage</td>
</tr>
<tr>
<td></td>
<td>Normal closed-loop scheme recloser</td>
<td></td>
</tr>
<tr>
<td>ASRR</td>
<td>Automatic Sectionalizing Reconfiguring Recloser</td>
<td>Opens on two counts of overcurrent or loss of voltage</td>
</tr>
<tr>
<td></td>
<td>Sectionalizing Recloser</td>
<td></td>
</tr>
<tr>
<td>ATRR-2</td>
<td>Automatic Tie Reconfiguring Recloser</td>
<td>Closes for loss of voltage on one side</td>
</tr>
<tr>
<td></td>
<td>Half-Loop Tie Recloser</td>
<td></td>
</tr>
<tr>
<td>ATRR-3</td>
<td>Automatic Tie Reconfiguring Recloser</td>
<td>Closes for loss of voltage on either side</td>
</tr>
<tr>
<td></td>
<td>Half-Loop Tie Recloser</td>
<td></td>
</tr>
</tbody>
</table>
**LOSS OF VOLTAGE S1**
R1 and R2 sense loss of voltage and open
R3 and R5 sense loss of voltage and closes
R3 closes to provide power to the section of line between R2 and R3 from source S2
R5 closes to provide power to the section of line between R1 and R2 from source S3
Reconfiguration is complete in about a minute (coordination dependent)
FLISR Scenarios

FAULT BETWEEN R1 AND R2
R1 recloses to attempt to clear the fault and then locks open to isolate fault if unsuccessful - R2 senses loss of voltage and opens
R3 and R5 sense loss of voltage and close
R3 closes to provide power to the section of line between R2 and R3 from source S2
R5 closes into a fault and locks out
Reconfiguration is complete in about a minute (coordination dependent)

S1
R1
ALRR
R2
ASRR
R5
ATRR-2
R3
ATRR-3
S3
R4
ALRR
S2
**FLISR Scenarios**

**FAULT BETWEEN R2 AND R3**
- R1 recloses to attempt to clear the fault
- R2 locks open to isolate fault after 1 or more recloses by R1
- R3 senses loss of voltage
- R3 closes into a fault and locks out

Isolation is complete in less than a minute (coordination dependent)
After Installing their loop scheme there were fewer and shorter outages

- More than 500,000 customer interruptions were avoided in 2012–2013.
- ComEd’s SAIFI indices saw a 15% reduction in outage frequency from 2012 (metric is 20%).
- ComEd’s CAIDI indices saw a 27% reduction in outage duration from 2012 (metric is 15%).
Havasupai Community – Micro Grid

- 9 new switches, and 1 existing
  - Padmount Switchgear Style
  - SEL Relays
  - Existing switch was retrofitted with new control
- Centralized Control
  - FDIR
  - LOV Transfer
  - HMI
  - Load Management
- Diesel Generator Backup (300 kW)
- PV Grid Connected Distributed Generation (490 kW)
Havasupai Communication
Havasupai Operation

Double Click on Switch to Control
Energized Lines Indicated by Graphical Flow
Factory Acceptance Testing
Factory Acceptance Testing (FAT)

What is Factory Acceptance Testing?

– Factory acceptance testing is a comprehensive analysis of your solution comprised of switchgear, controls, and communication equipment. The testing is performed on your actual equipment and communication devices, operating on a live communication network that replicates your solution.

What Tests can be performed:

– 3 Ph and 1Ph Fault Response
– Fault Response thru Multiple Switches/Reclosers
– Loss of Voltage
– Loss of Communication or Telemetry
– Customer Specific Tests

The Solution Test.

– The controls used in the test are yours and will verify the control logic used in the field. Operation of the installed Solution is validated, using actual device configurations. Live messages are exchanged by the controls and in turn also verifies operation of the communication system.
Austin Energy Retrofit Presentation

Danny McReynolds
Power System Engineer Sr., Distribution Design
Austin Energy
• 8th largest community-owned electric utility serving 435,000 meters and a population of approximately one million

• 437 square miles of service area covering City of Austin, Travis County and portions of Williamson County.

• Owns and operates generation, transmission, and distribution

• System peak load - 2714 MW

• Annual budget - $1.51 billion

• First public power utility in Texas to earn Diamond Level recognition (2011) as a Reliable Public Power Provider (RP3) by the American Public Power Association (APPA); again in 2013 (eligible every 2 years)

• ISO Certified T&D Organization since 2007
Definitions

**Emergency Power** - “an independent reserve source of electric energy that, upon failure or outage of the normal source, automatically provides reliable electric power within a specified time to critical devices and equipment whose failure to operate satisfactorily would jeopardize the health and safety of personnel or result in damage to property.” - IEEE Std. 446-1995

**Optional Standby Systems** – ”Those systems intended to supply power to public or private facilities or property where life safety does not depend on the performance of the system. These systems are intended to supply on-site generated power to selected loads either automatically or manually.“ – NEC, NFPA 70-2014
Definitions

**Automatic Throw Over (ATO) / Automatic Transfer Switch (ATS)** – a device which allows for the transfer of electric power from a preferred source to an alternate source if the preferred source loses power.

**Open Transition** – break before make

**Close Transition** – make before break

**Transfer Time** – time required to switch from the preferred to the alternate source OR the alternate source back to the preferred source

**Retransfer** – automatically switching back to the preferred source from the alternate source when the preferred source is restored
How does an ATO work?

CM - 456

ATO

Normally Open

FV - 123

Fault

CM - 456

ATO

FV - 123
Types of Customers

- Schools
- Hospitals and Nursing Homes
- Data Centers
- Corporations & Technology Companies
- Water Treatment Plants
- Government
Customer requests have ranged from 1-100 MVA with most services falling between 2-12 MVA.

AE reviews request with the customer and recommends the best type of service (dedicated feeds, direct feeds, multiple ATOs, single ATOs, standard service, etc.)

Planning reviews existing system loads to determine sources, recommends a preliminary feeder routing, and provides customer with an order of magnitude estimate.

Design & System Engineering design both the on-site and off-site services, requisition equipment and collect payment.

Construction, System Engineering, Control Engineering set, install, and commission the service.
Single Tank Vista ATO

Source: S&C
Single Tank PME ATO

Example: PME – 9 Source Transfer

Source: S&C
PME ATO & Transformers

CKT A

PME-9 SOURCE TRANSFER (ATO)

2500 KVA

AE EQUIPMENT

2500 KVA

CUSTOMER EQUIPMENT

CKT B
Dual Tank ATO

Source: Powell
Ckt A - Direct or Non-Direct

Powell ATO (600 Amp)

Normal Open

S&C System VI Primary Metering Gears
Including - 900 Amp Switches
Outgoing - 600 Amp Interrupters

AE Equipment

Customer Equipment
1) Initial assessment fee - $4000 per site

2) Capacity reservation & maintenance Fee - $1,300/MVA per month

3) Facilities design and construction – cost* + 15% per fee schedule - approximately $250K to $1M+ per installation depending on distance to source and type of service requested

* Effective Oct 1st, 2014 AE line extension policy was changed to 100% of estimated cost for labor and material
Design & Operations

➢ Do you need redundant transmission feeders, power transformers, circuit routing, ATOs, distribution transformers, etc..?

➢ Will the customer have direct OR dedicated feeds?

➢ Should you add a bypass switch to your design for maintenance purposes?

➢ Should you coordinate your ATO transfers with your substation breakers to ride through the 1st reclose?

➢ Do you manually do a retransfer or do you allow the ATO do it automatically?
ATO Communications Retrofit

Parts includes:

- Antenna
- Solar Panel
- Communication Hoffman Enclosure
  - Radio
  - RTU
  - 12V Battery
  - Charge controller
  - Surge Arrester
  - Fuses
  - Fuse holder
  - Terminal blocks
ATO Communications Retrofit

- Coaxial cables
- Conduit pipe
- Split core CTs
- Powell Low Voltage Cabinet
  - CT shorting strip
  - Box receptacle connector
  - Remote indication card
- Ground clamp
- Connector, bushing, conduit 90 degree bend ....
Communication Hoffman enclosure layout

Index#       Parts List
1            LMR200 Coaxial Cable, 2ft
2            Surge Arrester
3            55AHr 12V Battery
4            Radio, Series 4 DA IWR
5            RTU
6            35mm Din Rail Channel
7            Charge Controller
8            5A Fuse
9            10A Fuse
10           Fuse Holder
11           Terminal Blocks
Wiring Schematic sheet

Solar Battery
Radio RTU

Charge Controller

ATO Preferred Source

ATO Alternate Source

ATO

RTU Status inputs

RTU Analog inputs

NOTES: UNLESS STATED OTHERWISE, ASSUME ALL WIRING SHOWN TO BE A CONDUCTOR SIZE #14 AWG

SOLAR PROJECT
Analog Input to RTU
Status Input to RTU
Testing Status point (SCADA Screen Shots)

Both sources closed
Both source closed again
Source 1 open
Both source open
Testing Analog point

Signal from source 2 pA
Signal from source 2 pB
Questions?

Daniel McReynolds, P.E.
daniel.mcreynolds@austinenergy.com
Office: 512.505.7868
Enhanced Power Service

Bryan Cooper
Operations Engineer
Colorado Springs Utilities
Enhanced Power Service

Bryan J. Cooper, PE
Electric Operations
Colorado Springs Utilities
Overview

- Background
- Definitions
- Becoming an EPS Customer
- Design
- Operations
- Events
Background

• Colorado Springs Utilities
  – 4 Service Municipal Utility
  – Electrical Peak Demand 908 MW (06/26/2012)
  – 10 Generation Plants (~1,050 MW)
    • 55% NG, 40% Coal, 3% Hydro, 2% Solar
  – Operating voltages: 230kV, 115kV, 34.5kV, 12.47kV
  – 51 Substations
  – Approximately 250,000 service points, and growing
Definitions

• Enhanced Power Service (EPS)
• Reserve Capacity Charge (RCC)
• Operations & Maintenance (O&M)
• Automatic Throw-Over (ATO)
• Customer Request
  – Require a higher availability of electrical power
  – Critical Infrastructure, Hospitals, Data Centers, and Manufacturing
Road to EPS

- EPS Contract
  - 5 year term
  - Load projections
  - RCC and O&M Charges

- Operating Agreement
  - Defines PCC
  - Formalizes relationship
Capacity: 8 MVA (12.5kV) / 24 MVA (34.5kV)
Design

LOADBREAK SWITCH (6X12 VAULT MOUNTED)

ATO TRANSFORMER (48"X48" PAD)

LOADBREAK SWITCH (6X12 VAULT MOUNTED)

SOURCE-A
1000AL

AUTO THROW-OVER (ATO) (6X12 VAULT MOUNTED)

ATO TRANSFORMER (48"X48" PAD)

AUTO THROW-OVER (ATO) (6X12 VAULT MOUNTED)

SOURCE-B
1000AL

TRANSFORMERS UP TO 2500 KVA EACH
(PAD SIZE DETERMINED BY KVA)
Design

- Static Transfer Switch
- Customer owned ATO
- Main-tie-main
Operation

• S&C Vista Switch
  – 5802 or 6802 Controller
  – 2 Motor Operators
  – 2 Fault Interrupters

• Communication
  – Radio or Fiber

• Programming
Event on 6/29/2017

- A 34.5kV power circuit breaker locked out at 0720 hrs. The cause was a failed underground cable. Restoration/switching time was 40 minutes.
- That particular circuit fed a 34.5kV to 12.47kV transformer.
- One EPS customer is fed from that transformer.
Event on 6/29/2017
Conclusion

• An EPS customer receives a higher level of power availability, not necessarily power quality.

• An EPS customer also receives a higher level of customer service. They have access to a standby engineer, 24x7x365, as well as an assigned Key Account Manager.
Questions?
Modeling Strategies for the Modern Grid

Ryan Lane
Project Analyst
Burns & McDonnell
Modeling Strategies for The Modern Grid
Grid Modernization

Preparing for tomorrow's energy customers

- Integrate distributed energy resources
- Deliver information and choice to customers
- Make the most of the existing grid
- Fuel tomorrow's technology
- Keep lights on with distribution automation
- Open gateways to smart appliances
Comprehensive Planning Methodology

- Be data-driven
- Target areas of greatest need
- Pursue sustained reliability
- Reduce failure risk
- Enable flexibility
Comprehensive Planning Process

Trigger #1: Recurring Planning Cycle

Trigger #2: Customer Complaint/Issue

Trigger #3: Low Performance Measured

Comprehensive Engineering Analysis Process, Tools & Automation

- Build Model
- Validate/Tune
- Identify Areas of Need
- Develop & Evaluate Projects

Asset Planning Database

Synergi Electric

Comprehensive Projects

Predict Future Concerns (long-term)
Circuit Characteristics & Performance

- Asset Health (age, material, etc.)
- Compliance (voltage, loading, etc)
- Performance (SAIDI)
- Vegetation Issues
Common Project Scenarios

1. Strategically upgrade backbone
2. Redesign/reroute to avoid vegetation
3. Add devices to SCADA/Expand DA
4. Split Circuits, New Transmission, etc.
Benefits over Traditional Distribution Planning

► Better use of construction budget
  • Consolidation of equipment specs and sourcing

► Outage time reduced
  • SCADA devices help locate true cause of outage quickly

► More issues caught in single review
  • A wide lens catches problems in the periphery

► One solution for many issues
  • Projects designed to address combination of issues (e.g. compliance, DER/EV growth, exposure, etc..)
Rebuilds and Asset Optimization
ALT Schemes
CREATE AMAZING.