DISTRIBUTION PROTECTION OVERVIEW

Kevin Damron & Dana Hildebrand
Avista Utilities

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System Overview - Distribution Protection

Objective:
Protect people (company personnel and the public) and equipment by the proper application of overcurrent protective devices.

Devices include:
Relays operating to trip (open) circuit breakers or circuit switchers, and/or fuses blowing for the occurrence of electrical faults on the distribution system.

Design tools used:
1 – Transformer and conductor damage curves,
2 - Time-current coordination curves (TCC’s), fuse curves, and relay overcurrent elements based on symmetrical components of fault current.

Documentation:
1 - One-line diagrams and Schematics with standardized device designations as defined by the IEEE (Institute of Electrical and Electronics Engineers) – keeps everyone on the same page in understanding how the system works.
2 - TCC’s
System Overview – Inside the Substation Fence

Transformer relays

Feeder relay
System Overview –
Each device has at least one curve plotted with current and time values on the Time Coordination Curve.
System Overview –

What are the types of curves?

Damage Curves:
- transformer
- conductor

Protective Curves:
- relay
- fuse

So, what curve goes where?
Damage curves are at the top and to the right of the TCC.

Protective curves lowest and to the left on the TCC correspond to those devices farther from the substation where the fault current is less.

Avista has Category III size (5-30MVA) Distribution Transformers in service per the above standard.

The main damage curve line shows only the thermal effect from transformer through-fault currents. It is graphed from data entered below (MVA, Base Amps, %Z):

The dog leg on the curve is added to allow for additional thermal and mechanical damage from (typically more than 5) through-faults over the life of a transformer serving overhead feeders.

Time at 50% of the maximum per-unit through fault current = 8 seconds.

Dog leg curve - 10 times base current at 2 seconds.

Main curve - 25 times base current at 2 seconds.
Conductor Damage Curves

Copper Conductor Damage Curves
(2/0 damage at 1500A @ 100sec.)

ACSR Conductor Damage Curves
(2/0 damage at 900A @ 100sec.)

TIME-CURRENT CURVES @ Voltage 13.8kV
By DLH
For Copper Conductor Damage Curves
Comment
Date 12/13/05

TIME-CURRENT CURVES @ Voltage 13.8kV
By DLH
For ACSR Conductor Damage Curves
Comment
No.
Date 12/13/05
Conductor Ampacities


<table>
<thead>
<tr>
<th>ACSR Ampacity Ratings</th>
<th>Copper Ampacity Ratings</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conductor</td>
<td>Rating</td>
</tr>
<tr>
<td>556</td>
<td>730</td>
</tr>
<tr>
<td>336.4</td>
<td>530</td>
</tr>
<tr>
<td>4/0</td>
<td>340</td>
</tr>
<tr>
<td>2/0</td>
<td>270</td>
</tr>
<tr>
<td>1/0</td>
<td>230</td>
</tr>
<tr>
<td>#2</td>
<td>180</td>
</tr>
<tr>
<td>#4</td>
<td>140</td>
</tr>
</tbody>
</table>
Comparing a 140T fuse versus a #4 ACSR Damage curve. The 140T won’t protect the conductor below about 550 amps where the curves cross.
Transformer Protection using 115 kV Fuses
Transformer Protection using 115 kV Fuses

Used at smaller substations up to 7.5 MVA transformer due to low cost of protection. Other advantages are:
- Low maintenance
- Panel house & station battery not required

There are also several disadvantages to using fuses however which are:
- Low interrupting rating from 1,200A (for some older models) up to 10,000A at 115 kV. By contrast a circuit switcher can have a rating of 25KAIC and our breakers have normally 40KAIC.
- The fuses we generally use are rated to blow within 5 minutes at twice their nameplate rating. Thus, a 65 amp fuse will blow at 130 amps. This compromises the amount of overload we can carry in an emergency and still provide good sensitivity for faults.
Transformer Protection using 115 kV Fuses - continued

- The fuse time current characteristic (TCC) is fixed (although you can buy a standard, slow or very slow speed ratio which are different inverse curves).

- The sensitivity to detect lo-side SLG faults isn’t as good as using a relay on a circuit switcher or breaker. This is because we use DELTA/WYE connected transformers so the phase current on the 115 kV is reduced by the $\sqrt{3}$ as opposed to a three phase fault.

- Some fuses can be damaged and then blow later at some high load point.

- When only one 115 kV fuse blows, it subjects the customer to low distribution voltages. For example the phase to neutral distribution voltages on two phases on the 13.8 kV become 50% of normal.

- No indication of faulted zone (transformer, bus or feeder).
Transformer Protection using a Circuit Switcher
Showing Avista’s present standard using Microprocessor relays.
Transformer Protection using a Circuit Switcher
Showing Avista’s old standard using Electromechanical relays.
Transformer Protection using a Circuit Switcher

Some advantages to this over fuses are:

- Higher interrupting.
- Relays can be set to operate faster and with better sensitivity than fuses.
- Three phase operation.
- Provide better coordination with downstream devices.

Some disadvantages would be:

- Higher cost.
- Higher maintenance.
- Requires a substation battery, panel house and relaying.
- Transformer requires CT’s.
Transformer Protection using a Breaker

This is very similar to using a circuit switcher with a couple of advantages such as:

- Higher interrupting – 40kAIC for the one shown below.
- Somewhat faster tripping than a circuit switcher (3 cycles vs. 6 – 8 cycles).
- Possibly less maintenance than a circuit switcher.
- The CT’s would be located on the breaker so it would interrupt faults on the bus section up to the transformer plus the transformer high side bushings.
SEL Various Relay Overcurrent Curves.
- Extremely Inverse – steepest
- Very Inverse
- Inverse
- Moderately Inverse
- Short Time Inverse – least steep

The five curves shown here have the same pickup settings, but different time dial settings.

These are basically the same as various E-M relays.

Avista uses mostly extremely inverse on feeders to match the fuse curves.
Relay Overcurrent Curves - Pickups & Time Dials

Pickup
- the current at which the relay will operate to trip the breaker.
- also known as “tap” from the electromechanical relay days
-expressed in terms of the ratio of the current transformer (CTR) that the relay is connected to,
- e.g., a relay with a CTR of 120 and a pickup (or tap) of 4 will operate to trip the breaker at 480 amps

Time dial
- at what time delay will the relay operate to trip the breaker
- the larger time dial means more time delay
- also known as “lever” from the electromechanical relay days
- Instantaneous elements have a “time dial” of 1 and operate at 0.05 seconds.
- Instantaneous curves are shown as a flat horizontal line starting at the left at the pickup value and plotted at 0.05 seconds.
Same Time Dial = 9
Right curve picks up at 960 Amps
Left curve picks up at 320Amps

Same Pickup = 960 Amps
Top curve Time Dial = 15
Bottom curve Time Dial = 2
Microprocessor relays have different types of curves based on the type of fault current being measured:

**Transformer relay curves**
- 51P – phase time overcurrent
- 51N or 51G – ground time overcurrent
- 51Q – negative sequence time overcurrent

**Feeder relay curves**
- 51P – phase time overcurrent
- 51N or 51G – ground time overcurrent
- 51Q – negative sequence time overcurrent

This brings us to a brief discussion of:
Symmetrical Components

The method of symmetrical components provides a practical technology for understanding and analyzing electric power system operation during unbalanced conditions. Typical unbalances are those caused by faults between the phases and/or ground (phase to phase, double phase to ground, phase to ground), open phases, unbalanced impedances, and combinations of these. Balanced three-phase faults are included. Also, many protective relays operate from symmetrical component quantities. For example, all ground relays operate from zero-sequence quantities, which are normally not present in the power system. Therefore, a good understanding of this subject is of great importance and is a very important “tool” in system protection.

Symmetrical Components for Power Systems Engineering, J. Lewis Blackburn,

There are three sets of independent components in a three-phase system: positive, negative and zero for both current and voltage. Positive sequence voltages (Figure 1) are supplied by generators within the system and are always present. A second set of balanced phasors are also equal in magnitude and displaced 120 degrees apart, but display a counter-clockwise rotation sequence of A-C-B (Figure 2), which represents a negative sequence. The final set of balanced phasors is equal in magnitude and in phase with each other, however since there is no rotation sequence (Figure 3) this is known as a zero sequence.
Symmetrical Components

Examples of three 13.8kV faults showing the current distribution through a Delta-Wye high-lead-low transformer bank:

Three phase (3LG) fault - Positive sequence currents – for setting phase elements in relays.
Phase -Phase (L-L) fault - Negative sequence currents – for setting negative sequence elements in relays.
Single phase (1LG or SLG) fault - Zero sequence currents – for setting ground elements in relays.

Symmetrical Components Notation:
Positive Sequence current $= I^+ = I_1$
Negative Sequence current $= I^- = I_2$
Zero Sequence current $= I^0 = I_0$

Phase Current notation:
IA – High side Amps
Ia – Low side Amps

8.33 = $115/13.8$ = transformer Voltage (turns) ratio

Phasor diagram from Fault-study Software.
Symmetrical Components – Positive Sequence, 3LG 13.8 kV Fault

You have only positive sequence voltage and current since the system is balanced.

IA = 619° -88°  Ia = 5158° -118°
IB = 619° 152°  Ib = 5158° 122°
IC = 619° 32°  Ic = 5158° 2°

Phase current = Sequence current

That is; Ia = I+.

IA = Ia / 8.33 = 5158A / 8.33
IA = 619A

Phase currents and voltages for the 115kV side.
Symmetrical Components – Negative Sequence, L-L 13.8 kV Fault

115kV side sequence currents and voltages

3LG 13.8kV fault = 5158A,
Ib=Ic=4467 A, 4467/5158 = 86.6% = √3/2
IB_{3LG} = IB_{LL} = 619A
IA & IC = IB or Ia & Ic = Ib
I_2 = the phase current/√3 = 4467/√3 = 2579

Digital relays 50Q/51Q elements set using 3I2.
3I2 = Ib x √3 = 4467 x 1.732 = 7737,
Symmetrical Components – Zero Sequence, 1LG 13.8 kV Fault

3I₀ is the sum of the 3 phase currents and since Ib & Ic = 0, then 3I₀ = Ia. This means the phase and ground overcurrent relays on the feeder breaker see the same amount of current.

5346/(8.33*√3) = 370 amps. So the high side phase current is the √3 less as compared to the 3Ø fault.

Digital relays ground elements set using 3I₀.
Symmetrical Components - Summary of 13.8 kV Faults

If you have a Delta-Wye transformer bank, and you know the voltage ratio and secondary phase current values for 13.8kV 3LG (5158) and SLG (5346) faults, you can find the rest:

3LG – positive sequence current

IA = 619  Ia = 5158  \( \frac{5158}{8.33} = 619 \)  \( Ia = 5158 = I1 \)
IB = 619  Ib = 5158
IC = 619  Ic = 5158

L-L – negative sequence current

IA = 309  Ia = 0  \( 5158 \times \sqrt{3}/2 = 4467 \)  \( Ib \times \sqrt{3} = 7737 = 3I2 \)
IB = 619  Ib = 4467  \( 4467/(8.33 \times \sqrt{3}) = 309 \)
IC = 309  Ic = 4467  \( 309 \times 2 = 619 \)

SLG – zero sequence current

IA = 370  Ia=5346  \( \frac{5346}{(8.33 \times \sqrt{3})} = 370 \)  \( Ia = 5346 = 3I0 \)
IB = 0  Ib = 0
IC = 370  Ic = 0
Symmetrical Components - Summary of 13.8 kV Faults

You’ve heard of a Line-to-Line fault, how about an “Antler-to-Antler” fault?
Electromechanical Relays used on Distribution Feeders

Avista’s standard distribution relay package (until the mid-1990’s) included the following:

3 phase 50/51 CO-11 relays,

1 reclosing relay

1 ground 50/51 CO-11 relay
Electromechanical Relays used on Distribution Feeders

Objectives:
- Protect the feeder conductor
- Detect as low a fault current as possible (PU = 50% EOL fault amps)
- Other than 51P, set pickup and time dial as low as possible and still have minimum Coordinating Time Interval (CTI) to next device. CTI is minimum time between operation of adjacent devices.
- Carry normal maximum load (phase overcurrent only).
- Pickup the feeder in a cold load condition (≥ 2 times maximum normal load) or pickup ½ of the next feeder load.
Electromechanical Relays
used on Distribution Feeders

Pickup setting criteria of 2/1 ratio of “end of line” fault duty / pickup
- ensures that the relay will “see” the fault and operate when needed.
Electromechanical Relays
used on Distribution Feeders

FEEDER SETTINGS
51P = 2000 / 2 = 1000 A
51N = 1000 / 2 = 500 A

MIDLINE SETTINGS
51P = 1000 / 2 = 500 A
51N = 500 / 2 = 250 A

FAULT at MIDLINE
3LG = 2000 A
1LG = 1000 A

MIN FAULT at END OF LINE
3LG = 1000 A
1LG = 500 A
Electromechanical Relays
used on Distribution Feeders

500A FEEDER SETTINGS
51P = 960 A
51N = 480 A

13 kV BUS

SECTION
LOAD = 500 A
Electromechanical Relays
used on Distribution Feeders

13 kV BUS

500A FEEDER SETTINGS
51P = 960 A
51N = 480 A

SECTION
LOAD = 500 A

SECTION
LOAD = 500 A

SECTION
LOAD = 250 A

SECTION
LOAD = 250 A

SECTION
LOAD = 250 A

N.O.
Electromechanical Relays
used on Distribution Feeders

Reclosing

- Most overhead feeders also use reclosing capability to automatically re-energize the feeder for temporary faults. Most distribution reclosing relays have the capability of providing up to three or four recloses.
  -- Avista uses either one fast or one fast and one time delayed reclose to lockout.

- The reclosing relay also provides a reset time generally adjustable from about 10 seconds to three minutes. This means if we run through the reclosing sequence and trip again within the reset time, the reclosing relay will lockout and the breaker will have to be closed by manual means. The time to reset from the lockout position is 3 to 6 seconds for EM reclosing relays.
  -- Avista uses reset times ranging from 90 to 180 seconds.

- Lockout only for faults within the protected zone. That is; won’t lockout for faults beyond fuses, line reclosers etc.

- Most distribution reclosing relays also have the capability of blocking instantaneous tripping.
  -- Avista normally blocks the INST tripping after the first trip to provide for a Fuse Protecting Scheme.
Electromechanical Relays used on Distribution Feeders

Reclosing – Sequence shown for a permanent fault

RECLOSING SEQUENCE

Closed  0.5"  12"  LOCKOUT
Open

RESET = 120"
(INST Blocked during Reset Time)
Fault on fused lateral on an overhead feeder:
- Station or midline 51 element back up fuse.
- Station or midline 50 element protects fuse.

During fault:
- Trip and clear the fault at the station (or line recloser) by the instantaneous trip before the fuse is damaged for a lateral fault.
- Reclose the breaker. That way if the fault were temporary the feeder is completely re-energized and back to normal.
- During the reclose the reclosing relay has to block the instantaneous trip from tripping again. That way, if the fault still exists you force the time delay trip and the fuse will blow before you trip the feeder again thus isolating the fault and re-energizing most of the customers.
- Of course if the fault were on the main trunk the breaker will trip to lockout.
Shows the maximum fault current for which S&C type T fuses can still be protected by a recloser/breaker instantaneous trip for temporary faults (minimum melt curve at 0.1 seconds):

- 6T – 120 amps
- 8T – 160 amps
- 10T – 225 amps
- 12T – 300 amps
- 15T – 390 amps
- 20T – 500 amps
- 25T – 640 amps
- 30T – 800 amps
- 40T – 1040 amps
- 50T – 1300 amps
- 65T – 1650 amps
- 80T – 2050 amps
- 100T – 2650 amps
- 140T – 3500 amps
- 200T – 5500 amps
Distribution Fusing – Fuse to Fuse Coordination

NOTE: These values were taken from the S&C data bulletin 350-170 of March 28, 1988 based on **no preloading and then preloading** of the source side fuse link. Preloading is defined as the source side fuse carrying load amps equal to it’s rating prior to the fault. This means there was **prior heating of that fuse** so it doesn’t take as long to blow for a given fault.

<table>
<thead>
<tr>
<th>Source Side</th>
<th>Load Side</th>
<th>Maximum Coordinating</th>
<th>Maximum Coordinating</th>
</tr>
</thead>
<tbody>
<tr>
<td>200T</td>
<td>140T</td>
<td>8,300</td>
<td>4,650</td>
</tr>
<tr>
<td>140T</td>
<td>100T</td>
<td>5,800</td>
<td>3,800</td>
</tr>
<tr>
<td>100T</td>
<td>80T</td>
<td>3,600</td>
<td>1,900</td>
</tr>
<tr>
<td>80T</td>
<td>65T</td>
<td>2,700</td>
<td>1,400</td>
</tr>
<tr>
<td>65T</td>
<td>50T</td>
<td>2,200</td>
<td>Too close</td>
</tr>
<tr>
<td>50T</td>
<td>40T</td>
<td>1,550</td>
<td>640</td>
</tr>
<tr>
<td>40T</td>
<td>30T</td>
<td>1,400</td>
<td>820</td>
</tr>
<tr>
<td>30T</td>
<td>25T</td>
<td>1,100</td>
<td>570</td>
</tr>
<tr>
<td>25T</td>
<td>20T</td>
<td>840</td>
<td>360</td>
</tr>
<tr>
<td>20T</td>
<td>15T</td>
<td>630</td>
<td>315</td>
</tr>
<tr>
<td>15T</td>
<td>12T</td>
<td>540</td>
<td>295</td>
</tr>
<tr>
<td>12T</td>
<td>10T</td>
<td>410</td>
<td>210</td>
</tr>
<tr>
<td>10T</td>
<td>8T</td>
<td>320</td>
<td>175</td>
</tr>
<tr>
<td>8T</td>
<td>6T</td>
<td>235</td>
<td>145</td>
</tr>
</tbody>
</table>

**Distribution Fusing – Fuse to Fuse Coordination**

**NOTE:** These values were taken from the S&C data bulletin 350-170 of March 28, 1988 based on **no preloading and then preloading** of the source side fuse link. Preloading is defined as the source side fuse carrying load amps equal to it’s rating prior to the fault. This means there was **prior heating of that fuse** so it doesn’t take as long to blow for a given fault.
Distribution Fusing – S&C T-Fuse Current Ratings

Typical continuous and 8 hour emergency rating of the S&C T rated silver fuse links plus the 140T and 200T.

<table>
<thead>
<tr>
<th>Fuse Rating</th>
<th>Continuous</th>
<th>8 Hour emergency</th>
</tr>
</thead>
<tbody>
<tr>
<td>6T</td>
<td>7.8</td>
<td>8.8</td>
</tr>
<tr>
<td>8T</td>
<td>10</td>
<td>12</td>
</tr>
<tr>
<td>10T</td>
<td>13</td>
<td>15</td>
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<tr>
<td>15T</td>
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<td>25T</td>
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<td>100T</td>
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<td>135</td>
</tr>
<tr>
<td>140T</td>
<td>210</td>
<td>225</td>
</tr>
<tr>
<td>200T</td>
<td>295</td>
<td>320</td>
</tr>
</tbody>
</table>

General Rule: Fuse Blows at 2X Rating in 5 Minutes
Coordinating Time Intervals

Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices.
Other utilities may use different times.

DEVICES:  

<table>
<thead>
<tr>
<th>CTI (Sec.)</th>
<th>Devices</th>
</tr>
</thead>
<tbody>
<tr>
<td>0.2</td>
<td>Relay – Fuse Total Clear</td>
</tr>
<tr>
<td>0.4</td>
<td>Relay – Series Trip Recloser</td>
</tr>
<tr>
<td>0.3</td>
<td>Relay – Relayed Line Recloser</td>
</tr>
<tr>
<td>0.4</td>
<td>Lo Side Xfmr Relay – Feeder Relay</td>
</tr>
<tr>
<td>0.4</td>
<td>Hi Side Xfmr Relay – Feeder Relay</td>
</tr>
<tr>
<td>0.4</td>
<td>Xfmr Fuse Min Melt – Feeder Relay</td>
</tr>
</tbody>
</table>
Coordinating Time Intervals

Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices. Other utilities may use different times.

**DEVICES:**

- Relay – Fuse Total Clear: 0.2 Sec.
- Relay – Series Trip Recloser: 0.4 Sec.
- Relay – Relayed Line Recloser: 0.3 Sec.
- Lo Side Xfmr Relay – Feeder Relay: 0.4 Sec.
- Hi Side Xfmr Relay – Feeder Relay: 0.4 Sec.
- Xfmr Fuse Min Melt – Feeder Relay: 0.4 Sec.
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Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices.
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**DEVICES:**

<table>
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<tr>
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</tr>
<tr>
<td>Hi Side Xfmr Relay – Feeder Relay</td>
<td>0.4</td>
</tr>
<tr>
<td>Xfmr Fuse Min Melt – Feeder Relay</td>
<td>0.4</td>
</tr>
</tbody>
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Coordinating Time Intervals

Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices. Other utilities may use different times.

**DEVICES:**  
CTI (Sec.)

- Relay – Fuse Total Clear 0.2
- Relay – Series Trip Recloser 0.4
- Relay – Relayed Line Recloser 0.3
- Lo Side Xfmr Relay – Feeder Relay 0.4
- Hi Side Xfmr Relay – Feeder Relay 0.4
- Xfmr Fuse Min Melt – Feeder Relay 0.4
Coordinating Time Intervals

Typical Coordinating Time Intervals (CTI) that Avista generally uses between protective devices. Other utilities may use different times.

**DEVICES:**

- Relay – Fuse Total Clear: 0.2
- Relay – Series Trip Recloser: 0.4
- Relay – Relayed Line Recloser: 0.3
- Lo Side Xfmr Relay – Feeder Relay: 0.4
- Hi Side Xfmr Relay – Feeder Relay: 0.4
- Xfmr Fuse Min Melt – Feeder Relay: 0.4
Coordinating Time Intervals

3LG Fault Coordination Example:

Top – Ckt Swr w/ Phase E-M relay

----- 0.4 sec. ------

Middle - E-M Phase relay for a 500 Amp Feeder

----- 0.2 sec. ------

Bottom – 140T Feeder Fuse (Total Clear)
Coordinating Time Intervals

SLG Fault Coordination Example:

Top – Ckt Swr w/ E-M Phase relay

----- 0.4 sec. ------

Middle - E-M relays (Phase & Ground) for a 500 Amp Feeder

----- 0.2 sec. ------

Bottom – 140T Feeder Fuse (Total Clear)
Coordinating Time Intervals

L-L Fault Coordination Example:

Top – Ckt Swr w/ E-M relay

----- 0.4 sec. ------

Middle - E-M (Phase) relay for a 500 Amp Feeder

----- 0.2 sec. ------

Bottom – 140T Feeder Fuse (Total Clear)
The Final Product

An example of a completed 13.8kV Feeder Coordination Study with 20 Time-Current Curves representing:

Instantaneous & Time-Delay Curves for the:
- Transformer high side protection,
- Transformer low side protection,
- Station feeder breaker protection,
- Midline feeder breaker protection.

Two Fuses

Transformer Damage Curve

Three Conductor Damage Curves
IEEE Device Designations commonly used in Distribution Protection

Avista sometimes adds letters to these such as F for feeders, T for transformers, B for bus and BF for breaker failure.

2 – Time delay relay.
27 – Undervoltage relay.
43 – Manual transfer or selective device.
   We use these for cutting in and out instantaneous overcurrent relays, reclosing relays etc.
50 (or 50P) – Instantaneous overcurrent phase relay.
50N (or 50G) – Instantaneous overcurrent ground (or neutral) relay.
50Q – Instantaneous Negative Sequence overcurrent relay.
51 (or 51P) – Time delay overcurrent phase relay.
51N (or 51G) – Time delay overcurrent ground (or neutral) relay.
51Q – Time delay Negative Sequence overcurrent relay.
52 – AC circuit breaker.

52/a – Circuit breaker auxiliary switch closed when the breaker is closed.
52/b – Circuit breaker auxiliary switch closed when the breaker is open.
59 – Overvoltage relay.
62 – Time Delay relay
63 – Sudden pressure relay.
79 – AC Reclosing relay.
81 – Frequency relay.
86 – Lock out relay which has several contacts.
   Avista uses 86T for a transformer lockout, 86B for a bus lockout etc.
87 – Differential relay.
94 – Auxiliary tripping relay.
Dana’s Turn
Distribution Transformer
Electromechanical Relays

Criteria (for outdoor bus arrangement, not switchgear)

- Protect the Transformer from thermal damage
  - Refer to Damage Curves

- Backup feeder protection (as much as possible)
  - Sensitivity is limited because load is higher

- Coordinate with downstream devices (feeder relays)

- Carry normal maximum load (phase only)

- Pick up Cold Load after outages
Distribution Transformer
Electromechanical Relays - Setting Criteria

Relays:
- 3 High Side Phase Overcurrent (with time and instantaneous elements)
- 1 Low Side Ground Overcurrent (with time and instantaneous elements)
- Sudden Pressure Relay
Phase Overcurrent Settings – Current measured on 115kV side

- **51P Pickup (time overcurrent)**
  - Don’t trip for load or cold load pickup (use 2.4 * highest MVA rating)
  - Ends up being higher than the feeder phase element pickup
  - Example: 12/16/20 MVA unit would use 2.4*20*5 = 240 amps (1940A low side)

- **51P Time Lever (time dial)**
  - Coordinate with feeder relays for maximum fault (close in feeder fault)
  - CTI is 0.4 seconds
  - Worst coordination case: Ø-Ø on low side (discrepancy due to delta/wye conn.)
  - Multiple feeder load can make the transformer relay operate faster

- **50P Pickup (instantaneous overcurrent)**
  - Must not trip for feeder faults → set at 170% of low side bus fault
  - Accounts for DC offset
Ground Overcurrent Settings – Current measured on 13.8 kV side

- 51N Pickup (time overcurrent)
  - Set to same sensitivity as feeder phase relay (in case the feeder ground relay is failed)
  - This setting is higher than the feeder ground, so we lose some sensitivity for backup

- 51N Time Lever (time dial)
  - Coordinate with feeder relays for ground faults
  - CTI is 0.4 seconds

- 50N Pickup (instantaneous overcurrent)
  - DO NOT USE!!!!
Distribution Transformer & Feeder Protection with Microprocessor Relays

Advantages:

- More precise TAP settings
- More Relay Elements
- Programmable Logic / Buttons
- Lower burden to CT
- Event Reports!!!!!!!!
- Communications
- Coordinate with like elements (faster)
- More Settings
Distribution Transformer & Feeder Protection with Microprocessor Relays

Elements We Set:
- 51P
- 50P
- 50P2 (FTB)
- 51G
- 50G (115kV)
- 51N (13.8kV)
- 50N1 (FTB)

FTB = Fast Trip Block (feeder relays must be Microprocessor)
Transformer Phase Overcurrent Settings - Current measured on 115kV Side

- 51P - Phase Time Overcurrent Pickup
  - Set to 240% of nameplate (same as EM relay)
- 51P Time Dial
  - Set to coordinate with feeder’s fastest element for each fault
  - CTI is still 0.4 seconds

- 50P1 – Phase instantaneous #1 Pickup
  - Direct Trip
  - Set to 130% of max 13.8 kV fault (vs. 170% with EM relay)

- 50P2 – Phase instantaneous pickup for Fast Trip Block scheme
  - Set above transformer inrush
  - 4 Cycle time delay
  - Blocked if any feeder overcurrent elements are picked up
Distribution Transformer & Feeder Protection with Microprocessor Relays

Transformer Ground Overcurrent Settings - Current calculated from 115kV CTs

- 51G - Ground Time Overcurrent Pickup
  - Set very low (will not see low side ground faults due to transformer connection). Usually 120 Amps.

- 51G Time Dial
  - Set very low

- 50G1 – Ground Instantaneous #1 Pickup
  - Set very low. Usually 120 Amps.

Symmetrical Components!
Transformer Neutral Overcurrent Settings - Current measured by neutral CT or calculated from 13.8kV CTs.

- **51N** - Ground Time Overcurrent Pickup
  - Set slightly higher than feeder ground pickup (about 1.3 times)

- **51N Time Dial**
  - Set to coordinate with feeder ground
  - CTI is 0.4 seconds

- **50N1** – Ground Instantaneous for Fast Trip Block
  - Set slightly above the feeder ground instantaneous pickup
  - Time Delay by 4 cycles
  - Blocked if Feeder overcurrent elements are picked up
Inrush – The current seen when energizing a transformer.

- Need to account for inrush when using instantaneous elements (regular or FTB).
- Inrush can be approximately 8 times the nameplate of a transformer.

Note that the microprocessor relay only responds to the 60 HZ fundamental and that this fundamental portion of inrush current is $\approx 60\%$ of the total. So to calculate a setting, we could use the 8 times rule of thumb along with the 60% value. For a 12/16/20 MVA transformer, the expected inrush would be $8 \times 12 \times 5 \times 0.6 = 288$ amps. We set a little above this number (360 Amps).
Transformer inrush **UNFILTERED** current. The peak current is about 1800 amps.

Transformer inrush **FILTERED** current (filtered by digital filters to show basically only 60 HZ). Peak is about 700 amps.
Distribution Transformer & Feeder Protection with Microprocessor Relays

**Microprocessor Feeder Relay**
- Overcurrent
- Reclosing
- Fast Trip Block Output
- Breaker Failure Output

**Elements We Set:**
- 51P
- 50P
- 51G
- 50G
- 51Q
Distribution Transformer & Feeder Protection with Microprocessor Relays

Feeder Phase Overcurrent Settings

- 51P - Phase Time Overcurrent Pickup
  - Set above load and cold load (960 Amps for 500 Amp feeder)
  - Same as EM pickup

- 51P Time Dial
  - Same as EM relay (coordinate with downstream protection with CTI)
  - Select a curve

- 50P – Phase instantaneous Pickup
  - Set the same as the 51P pickup (960 Amps)
Feeder Ground Overcurrent Settings

- 51G - Phase Time Overcurrent Pickup
  - Same as EM pickup which is 480 Amps

- 51G Time Dial
  - Same as EM relay (coordinate with downstream protection)
  - Select a curve

- 50G – Phase instantaneous Pickup
  - Set the same as the 51G pickup
Feeder Negative Sequence Overcurrent Settings

- 51Q - Negative Sequence Time Overcurrent Pickup
  - Set with equivalent sensitivity as the ground element (not affected by load)
  - Coordinate with downstream protection

- 51Q Time Dial
  - Same as EM relay (coordinate with downstream protection)
  - Select a curve

- 50Q – Negative Sequence instantaneous Pickup
  - DON’T USE!!!!!
  - Contributions from motors during external faults could trip this
Transformer Differential Protection – External Fault

Current flow through an E/M 87 differential relay for an internal and external fault.

External fault: The secondary currents flow through both restraint coils in the same direction and then circulate back through the CT’s. They do not flow through the operate coil.
Transformer Differential Protection – Internal Fault

INTERNAL FAULT
THE SECONDARY CURRENTS FLOW THROUGH BOTH RESTRAINT COILS IN OPPOSITE DIRECTIONS, ADD AND THEN FLOW THROUGH THE OPERATE COIL AND BACK TO THE RESPECTIVE CT'S
Transformer Differential Protection

- The differential relay is connected to both the high and low side transformer BCT’s.

- EM Differential Relay
  Since the distribution transformer is connected delta – wye the transformer CT’s have to be set wye – delta to compensate for the phase shift.
GRAB YOUR HANDOUT!

MOSCOW FEEDER 515 PROTECTION EXAMPLE
The Scenario

- A hydraulic midline recloser on a 13.8kV feeder in Moscow, ID is being replaced by a newer relayed recloser. The recloser is P584 on feeder 515.

- The field engineer would like to replace the recloser in the existing location.

- Protection engineer must review the feeder protection and report back to the field engineer.

- NOTE: Avista designs for a “fuse saving” scheme with one instantaneous trip. The field engineers decide if they want to enable or disable the instantaneous tripping.
Where do we start the protection design?

1) Gather Information:
   - Feeder Rating (expected load)
   - Protective devices (Breakers, line reclosers, fuses)
   - Fault Duty (at each protective device)
   - Conductors to be protected
   - Project deadline (tomorrow?)
How do we proceed?

• At each coordination point
  – Loading
  – Coordination
    • What will coordinate with the downstream device
    • Are we above the fuse rating
  – Conductor Protection
    • minimum conductor that can be protected by the feeder settings or fuse
  – Fault Detection
    • Can we detect the fault by our 2:1 margin
  – Fuse Saving for Temporary faults
    • What can a fuse be protected up to?
• POINT 8: This is a customers load and we are using 3-250 KVA transformers to serve the load. The full load of this size of bank is 31.4 amps. The Avista transformer fusing standard says to use a 65T on this transformer so that’s what we’ll choose.
FUSE - POINT 6B:

What we know:
- 3Ø lateral feeding to a 65T at the end
- #4 ACSR conductor

Fuse Selection:
- Loading – Assume the load is all downstream of point 8, so a 65T or higher will still suffice.
- Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse
- Fault Detection - Under the Relay Setting Criteria we want to detect the minimum line end fault with a 2:1 margin. The SLG is 463 so we calculate the max fuse as follows:
  - $463/2$ (2:1 margin) = 231 amps. “T” fuses blow at twice their rating so divide by 2 again, with a result of 115. Fuse must be 100T or less.
- Coordination – From Table 2, we see that we need an 80T or larger to coordinate with the downstream 65T fuse (at fault duties ≤ 1400A w/preload)
- Fuse Saving - From Table 1 we see that an 80T fuse can be protected up to 2,050 amps for temporary faults and the 3Ø fault is 1,907 amps so we could choose an 80T or higher from that standpoint
Point 6B - So what fuse size should we use?
POINT 5 – Midline Recloser

- What we know:
  - Conductor to protect: #4 ACSR (can carry 140A load)
  - Max fuse to coordinate with = 100T (FUTURE per distribution engineer)
  - Maximum load (per engineer) = 84A

- Settings Considerations:
  - Loading: Cold load would be $\approx 84 \times 2 = 168$ A, but the conductor can carry 140A max. Size for some load growth by setting at $\approx 2 \times \text{conductor rating}$. 300 Amp phase pickup setting. NOTE: we don’t design settings to protect for overload.
  - Conductor Protection: From the table, Avista’s 300A feeder settings can protect down to #2 ACSR, so 300A pickup is still acceptable. Review curves to confirm.
  - Fault Detection: detect the minimum fault with a 2:1 margin. Here the min fault is at point 6
    1. The Ø-Ø fault at point 6 is $0.866 \times 1907 = 1,651$ so our margin to detect that fault would be $1651/300 = 5.5:1$ so no problem with the 300 amps Ø PU from that standpoint (used Ø-Ø because it’s the minimum multi phase fault)
    2. The SLG at point 6 is 1,492 so we could set the ground up to $1492/2 = 745$ amps and still detect the fault. However, our criteria says to set as low as possible and still coordinate with the largest downstream device and from above we’re trying to use a 100T. Based on curves, this is 300 amps (same as phase, which is unusual).
  - Coordination: Based on fault study, set the time dial to coordinate with a 100T fuse with 0.2 second CTI.
  - Fuse Saving: The fault duty at the recloser is 3453 3PH and 2762 1LG. An instantaneous trip will protect the 80T fuse if the fault duty is less than 2050 Amps. Some fuse protection is compromised but there is nothing we can do about it.
TRUNK FUSE - POINT 3C:

What we know:

- #4 ACSR 3Ø trunk
- Load is 84 Amps
- Downstream protection is the midline recloser

Fuse Selection:

- Loading – Assume the load is the same as at the midline recloser. We set that at 300A, and a 200T can carry 295 A continuous.
- Conductor Protection - From Table 7 we see that #4 ACSR can be protected by a 100T or smaller fuse.
- Fault Detection - Under the Relay Setting Criteria we want to detect the minimum line end fault with a 2:1 margin.
  - SLG at midline is 2762 so even a 200T would provide enough sensitivity.
- Coordination – PROBLEM! We have coordinated the midline with a 100T, so the upstream fuse must coordinate with that.
- Fuse Saving: As before, some fuse saving is compromised due to higher fault duty.
TRUNK FUSE Point 3C - Solutions?
TRUNK FUSE Point 3C - Solutions?

- Move Recloser
- Re-conductor
FEEDER BREAKER - POINT 1:

What we know:

- This is a 500 amp feeder design. The load is 325 amps and cold load 650 per field engineer.
- Downstream protection is either the midline recloser or a 140T fuse.

Settings Considerations:

- Loading: A standard 500 amp feeder phase pickup setting of 960 A will carry all normal load and pick up cold load. The ground pickup does not consider load and will be set at 480A.
- Conductor Protection: The main trunk is 556 ACSR and from Table 7 a 500 amp feeder setting of 960 A can protect 1/0 ACSR or higher. Laterals with smaller conductor must be fused.
- Fault Detection:
  - The Ø-Ø fault at point 5 is 0.866*3453 = 2990 so our margin to detect that fault would be 2990/960 = 3.1:1
  - The SLG at point 5 is 2,762 so our margin to detect that fault is: 2762/480 = 5.7:1
- Coordination: Use fault study to calculate settings to achieve 0.2 second CTI to fuses and 0.3 second CTI to the recloser.
- Fuse Saving – We have decided that a 140T fuse is the maximum fuse we will use on the feeder even though it can’t be saved by an instantaneous trip at the maximum fault duties.
Questions?