Distribution Switching Devices Application Guide

How to Specify a Distribution Automation Switch

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ABSTRACT

The deployment of distribution automation on overhead circuits has been accomplished with several distinct types of switching devices, including; reclosers, sectionalizers, and motor operated switches. The biggest difference is how the each switching device is able to isolate a fault and sectionalize the circuit in preparation for restoration. Utilities have successfully deployed distribution automation using switching devices. This report discusses the advantages and disadvantages of approaches to deploying DA switches.

Keywords

Distribution Automation Switch
Recloser
Sectionalizer
Switch

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1
INTRODUCTION

During the past 25 years, utilities have utilized many switching device types as Distribution Automation (DA) switches. DA switches for the purposes of this guide, are defined as an automated switching device that is located on a distribution feeder. A DA switch device is not used to interrupt fault current, though it may have that capability. A DA switch may be normally open or closed, depending on location and desired function. Reclosers, sectionalizers, enclosed switches, and motor-operated switches are few examples utilized today. The main differences between switching device types are the operations performed by the device to isolate faults and sectionalize the feeder prior to restoration.

Utilities have successfully implemented Distribution Automation using these switching devices. Each type has advantages and disadvantages when being used as DA switch. Table 1-1 helps inform decisions regarding the specification of a Distribution Automation (DA) switch, not only as a device that will be used as part of a DA scheme, but also factoring in asset life-cycle management. This application guide presents the possible switching device types and the advantages and disadvantages of using each type.

Table 1-1
DA Switch Comparison Table

	Recloser/PulseCloser	Sectionalizer/Enclosed Switch	Motorized Air Break
Prevent Momentaries for Upstream Customers	Yes	No	No
Visible Break	No / Yes	Yes	Yes
Fault Detection	Yes	Yes	No
Coordination Required	Yes	No	No
Automatically Sectionalize	Yes	Yes	No
Fault Interruption Fault Close Operations Circuit Reconfigurations	Yes	No	No
Manual Stick Operation	Cannot Close/Yes	Yes	Yes
Single Phase Operation	Capable	No	No
Embedded Voltage/Current Sensing	Yes	Yes	No
Control Power	External/Internal	Internal/External	External

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DA SWITCH SURVEY RESULTS

A survey focusing on utility practices regarding DA switches, was sent to members of the EPRI Distribution Systems Program 180 in 2017. All indication of the responding utility was removed from any survey comments. Figure 2-1 shows the percentage of utilities using each classification of DA devices. Over 90% of respondents used triple single solid dielectric reclosers. Less than 25 % of respondents used electronically controlled hydraulic recloser or motor operated air break switches as DA devices.

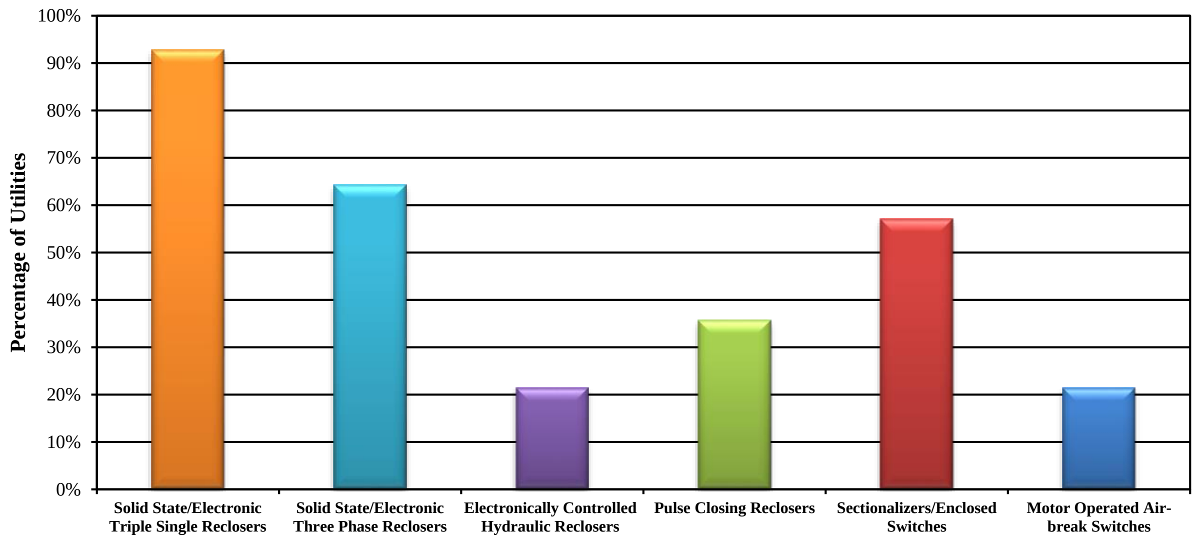

Figure 2-1
What types of DA devices are deployed on your system?

Figure 2-2 illustrates responses to the survey question, asking utilities to rate the factors they considered when choosing a DA device that will operate as a switch. Each utility either responded as very important, somewhat important, or not a factor. The factor deemed as very important by most utilities are system integration and the capability to make / break load currents.

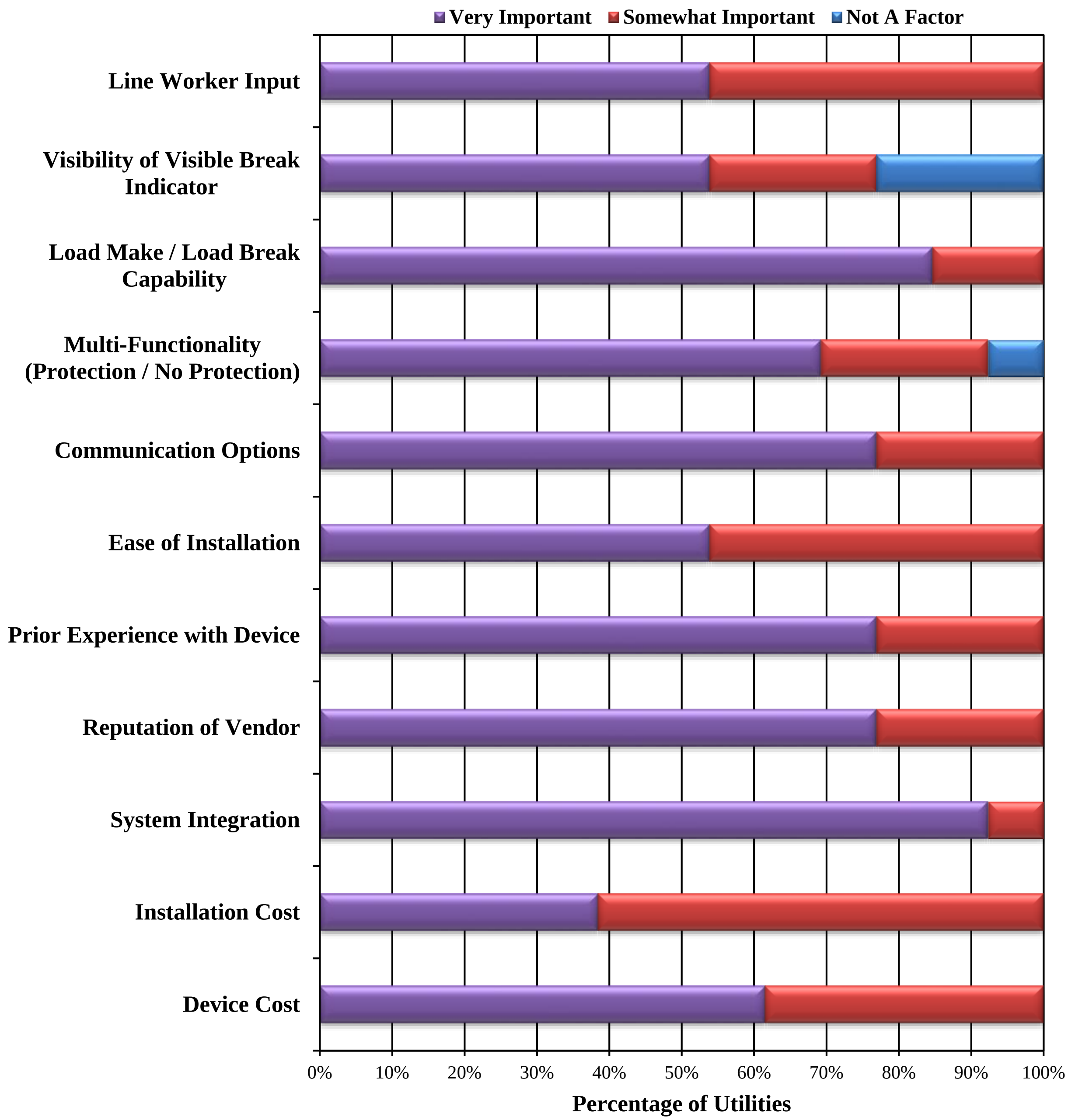

Figure 2-2
What would your utility consider very important when evaluating a DA switch?

A survey question asked utilities about the costs (hardware and labor) associated with deploying each type of DA device. Figure 2-3 and Figure 2-4 show the hardware and labor cost for each DA device type.

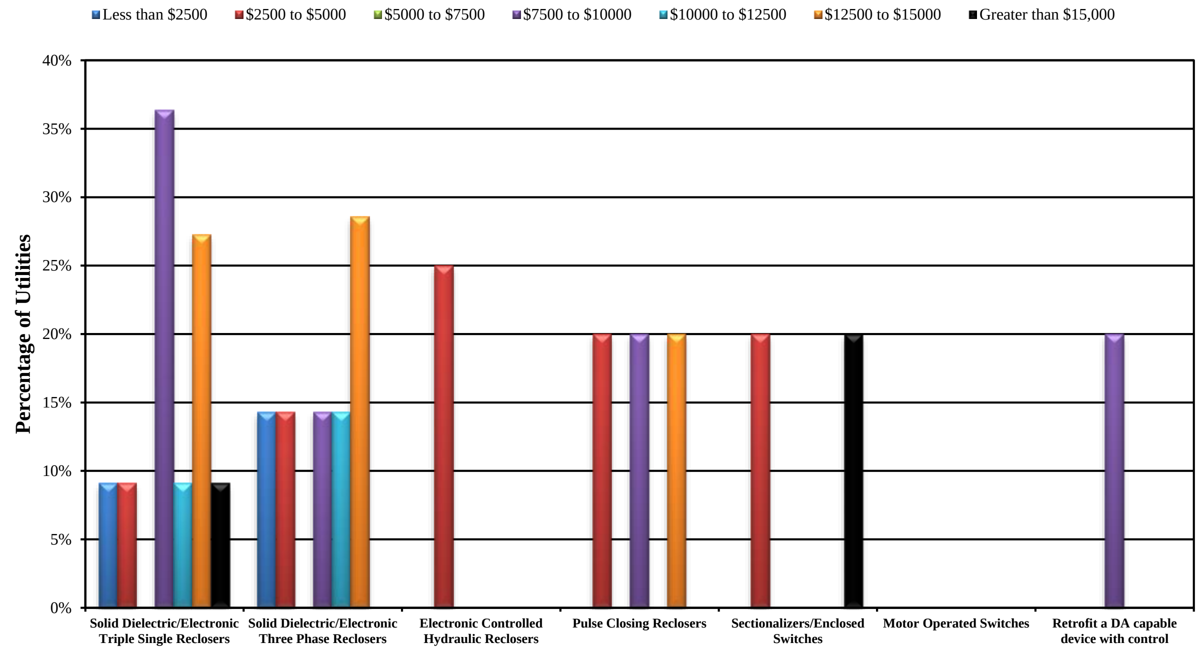

Figure 2-3
Installation Labor Costs

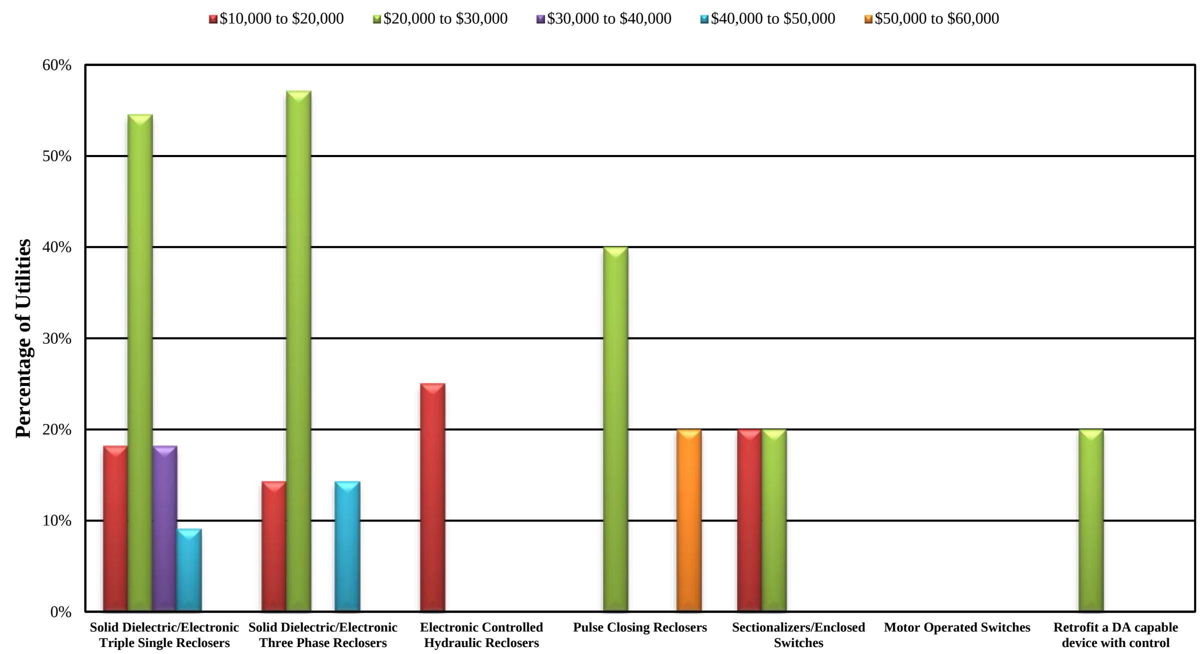

Figure 2-4
Hardware Costs

A survey question asked respondents to provide information about their decision to purchase a DA devices, based on associated costs (including installation), device reliability and system reliability impact. The following responses were received:

- Early DA schemes used switches. Recently, older schemes have been replaced with our recloser standard. We feel reclosers are more reliable to operate, while providing system protection features and field worker safety functions, while only costing a fraction more than motor operated switches.
- Costs - material costs should be less than fault interrupting devices.
- Unitized construction is preferred to simplify installation, thus reducing installation costs.
- Device reliability - should be reliable with few moving parts and components to reduce potential failure points.
- System Reliability – must perform load break, SCADA ready and provide visible break.
- It is critical for the switch to be functionally flexible, such that it could be used for a variety of roles; recloser, automated switch, and sectionalizer as required.
- Our current standard recloser is programmable and able to be used as a switch. Our standard is very costly solution, due to the limited operational functionality compared to using the device in recloser mode. We are currently considering a switch device from the same manufacturer that will provide similar reliability, while providing a better balance between cost and function.
- Primarily, we use electronic reclosers (Today's Standard - Vipers & Elastimold with SEL-651R2) to serve as remote switches through programming (recloser, switch, sectionalizer, etc). These are used as sectionalizing reclosers and tie reclosers in our loop schemes. They also act as sectionalizers. The average cost that includes installation, transportation and material is roughly $70k.
- We currently only have one DA installation, with two more under construction in 2017. Today, the Cooper NOVA reclosers are used as switches/sectionalizers but will not be utilized the same way for future installations.
- Standardized on Viper reclosers programmed as a switch. Motor-Operated are unreliable without regular maintenance. A majority of solid dielectric reclosers / controllers carry the same cost, compared to a Viper so we only use Viper.
- Switch contacts must be fully enclosed. Nulec-RL and Cooper DAS switches are used.

A survey question asked utilities how many of their DA devices communicate status to a centralized control center. The following responses were received.

- 100% – 6 respondents
- 95% – 3 respondents
- Most DA devices communicate to a centralized DMS (Distribution Management System). Many devices provide status information and allow remote control. Most sectionalizing devices are telemetered but legacy equipment, that does not send device information back to the centralized DMS.

Out of 3005 electronic "recloser" and AT switchgear locations, only 46 do not have communications (approx. 550 landline and remaining cellular). Unsolicited reporting is not implemented in our DMS but we have status and control. With that said, we also utilize "recloser" loop schemes for automated restoration purposes. The "recloser" can also function as a switch or sectionalizer within the scheme.A survey question asked utilities how they identified multiple uses for the same DA device on their GIS or their as operated electric models (i.e. a three-phase electronic recloser could be programmed as switch). The following responses were received:

- All DA devices are reclosers and operate as such. Additional notation at each location on our GIS indicates the device is part of DA scheme rather than a plain recloser.
- Device function is identified on the SCADA screen used by the Control Center operators.
- The device uses a 5-digit number. As a switch, the device always operates in alternate profile #3. As a protective device, it operates in normal profile. Our GIS and operate drawings display the devices with different symbols.
- Distribution Planning and Protection groups would likely coordinate these efforts, as far as identifying where DA devices should be placed in the system. Our current standard calls for a recloser and programmable recloser control that will allow for the device to be configured as a recloser, sectionalizer, or switch. All hardware is the same, with the flexibility in function using different programs loaded onto the device.
- The function of DA devices are identified within the naming configuration and by providing additional notes on the circuit one lines.
  - For instance, as loop scheme recloser will have "LS" at the end of the name ("309T364LS" is a tie recloser between the 309 and 364 circuits). One-line notes may reference that the device is a switch mode recloser and is not programmed to operate for faults. When programmed as a sectionalizer it gets a "X" designation in device number. This allows our operators to understand the specifics of the device. The operator screen also provides status of what mode is "enabled" when the device has capability of multiple protection modes (e.g., recloser mode changes to switch mode for certain event types).
- Normal equipment classification is identified in GIS. The automation software (housed in the SCC), shows the real-time equipment classification.
- Different symbol based on function and attributes.
- Not a GIS issue just a SCADA issue. Our deployment is not large enough to warrant the difference.
- Every normally closed switch is programmed as a sectionalizer and represented that way. We do not use reclosers as normal opens.

A survey question asked the respondents how their utility measures the cost benefit for DA device deployment. The following responses were received:

- DA loop proposals include the number of devices, plus any required system improvement work. That total cost estimate is divided by the number of customer outages seen in recent outage history (3 years) to produce a "Cost/Benefit Ratio". All proposals are ranked by this ratio and the most cost-effective ones are chosen to build first.
- Cost benefit is based on reliability improvement. Costs are used to compare options.
- We calculate the customer interruption per recloser per year (it was 600). Measure the cumulative CI benefits average per year and then decide where CI returns begin to level off. In our system this leveled off around 1500 devices.
- Each circuit targeted by the Reliability Program is on the annual worst performing circuit list and all have much worse performance than our utility averages for reliability. These investments are expected to improve customer interruptions and in customer hours lost on the affected circuits and contribute to slowing the degradation of overall utility reliability measures – SAIFI, CAIDI, and CEMI-4. Improving circuit reliability also contributes to improved customer satisfaction.
- All distribution circuits are reviewed annually to determine performance compared to both corporate targets and customer expectations at the circuit level. Performance levels are analyzed to develop an annual worst performing circuit list. This list uses various circuit performance indicators over the last 5 years such as:
  - Frequency of outages.
  - Duration of outages.
  - Number of customers impacted.
  - Customer expectations for reliability.
  - Overall circuit impact on system level reliability indices - SAIFI and CAIDI.
- Circuits with the highest contribution to system SAIFI and CAIDI are prioritized on the improvement list and will provide the highest value to improving those metrics.
- One of the greatest cost benefit solutions to our reliability improvement is strategic installation of automated reclosers and switches.
- Detailed data is used to prioritize circuits that will be included in the OH automation program. Data considered are; circuit logistics, number of ties and switches, 3-year customer interruptions and customer hours lost with causes. Listings of the priority circuits to be included in a 3 or 5-year program is summarized. The list of circuits will be updated annually to re-prioritize circuits as performance changes on the entire list of circuits.
- Customer reliability, CAIDI and customer outages avoided.
- The largest benefit is the ability for our FISR program to manipulate DA devices. The speed with which the program acts minimizes customer outages. Also, devices are remotely accessible and operable, therefore changing ones state does not require a crew to be deployed to affected locations.
- Non-asset failure risk reduction.

- SAIDI, SAIFI, CMI savings.
- Presently don't equate above metrics to dollars but we have used the ICE tool for business case development.
- $ per customer outage avoided.

3

DISTRIBUTION AUTOMATION SWITCH TYPE COMPARISON

This section aims to provide an overview of each switching device type and discuss the advantages and disadvantages of using the device as a DA switch

Reclosers

Reclosers are switching devices that are designed to open and close during a fault. Reclosers are self-contained, small, lightweight circuit breakers, also capable of opening load currents. They are designed to either operate as a three-phase device or as three independent single-phase devices (triple-single). Figure 2-1 shows examples of a triple-single recloser and two three phase reclosers.

A B C

Figure 3-1
Examples of distribution reclosers: G&W Viper-ST (triple-single recloser) [A], Eaton (Cooper) NOVA (three-phase recloser) [B], and Tavrida OSM (three-phase recloser) [C].

Pulse-closing reclosers are similar to traditional reclosers, except that the device tests for a permanent fault and aborts the reclose operation prior to completely closing into the fault. S&C IntelliRupter PulseClosers as shown in Figure 3-2, are an example of this unique type of recloser. The recloser has its communication and control modules built-in and does not require external controls or control cabling.

Figure 3-2
Pulse-closing recloser: S&C's IntelliRupter PulseCloser Fault Interrupter

Advantages

Reclosers are protective, fault interrupting devices that can be programed to work as a DA switch. This ability is advantageous, allowing for additional operational flexibility. For example, if a circuit needs to be reconfigured or is in an abnormal state, the device can continue to run protection even if it is usually operated as a switch. A majority of reclosers have embedded three-phase voltage sensing on both sides, or options to add external voltage sensors on the recloser rack. Most reclosers have embedded three-phase current sensing capabilities, that provides a linear output over a current range from load to fault current. An additional advantage to recloser usage is that they do not cause a momentary for upstream customers when operated.

Disadvantages

Typically, reclosers may cost 20% more than an enclosed switch or sectionalizer. Reclosers are not able to be manually closed using a hot stick. The control must be operational to close the recloser. Most reclosers don't provide a visible break indication, requiring a bypass switch to be installed, to provide a visible break. There is some debate whether a recloser can operate as a load switch without premature degradation, but no evidence was found to support these claims during investigation.

Enclosed Switches/Sectionalizers

Enclosed switches and sectionalizers do not have the ability to interrupt fault current. But, some enclosed switches have the ability to interrupt load current. Enclosed switches are often used as open tie points in DA systems. Sectionalizers are typically used as normally open or closed point that are used to further isolate a circuit after protection devices have operated. A sectionalizer and enclosed switch are similar in that all contacts are enclosed within a housing.

Sectionalizers have similar appearance to a recloser and come with similar sensing and control mechanisms. Sectionalizers can open to interrupt load, but cannot interrupt fault current. Instead, they count the reclosing shots on the circuit from an upstream protective device, and after a configurable number of counts, they open while the circuit is de-energized. Downstream sectionalizers can be operated to open and isolate the fault between automated devices, putting the feeder in a position to enable remote restoration. Sectionalizers are often deployed where coordination is difficult to achieve between the breaker or recloser and downstream fusing.

When an enclosed switch is used as a DA switch, once it senses the fault current, it waits for the upstream circuit breaker or recloser to trip and clear the fault. The enclosed switch then uses a centralized control algorithm to manage fault isolation. Enclosed switches cannot be counted on to operate between reclosing, thus the switch remains closed until the feeder breaker locks out.

A B C

Figure 3-3
Examples of enclosed sectionalizer switches: S&C Scada-Mate [A], Schneider (Nulec) RL [B], and Eaton (Cooper) NOVA DAS [C].

Advantages

Sectionalizers can be deployed where coordination is difficult with upstream and downstream devices. Enclosed switches are typically less expensive than a recloser. Many of these device provide a visible break. Enclosed switches and sectionalizers have several advantages over motorized air break switches, particularly the presence of embedded sensing and the fact that the switch contacts are enclosed.

Disadvantages

The disadvantages of using enclosed switches and sectionalizers as a DA switch are that the device cannot be repurposed as a protective device. Also, many of the devices require a specialized control that may not be standardized like many recloser controls. The use of these devices requires utilities to stock spares for an additional device type.

Motorized-Air Break Switch

A motor operated air break (MOAB) switch with fault current measurement can be deployed as a DA switch as shown in Figure 3-4. When MOABs are used as a DA switch, upstream breakers and reclosers perform their operations until the feeder breaker locks out. A central control algorithm then manages fault isolation after lockout. MOABs have an external motor that is used to open and close the switches based on commands from a control placed on the pole. MOABs can have external sensors mounted to measure line current and voltage. MOABs have been used as a DA device for normally open tie points and normally closed line segments between protective devices.

Figure 3-4
Two examples of motor operated air break switches

Advantages

The advantage of using a MOAB is that they provide a visible air break without the need to open bypass switches, when using reclosers as DA switches.

Disadvantages

The disadvantages to using MOABs is the need to add external sensors for fault detection, the need for yearly maintenance, and the switch is exposed to environmental conditions. A MOAB cannot be counted on to operate between reclose cycles.

4

SUMMARY OF ASSET LIFE CYCLE CONSIDERATIONS

When specifying a DA switch type, considerations should be made, in terms of operation, technology and asset life cycle management.

Selection

Utilities usually have many different DA switch device types deployed on their system. This may be due to deployment years, as they come to market, or from a desire to create a pilot, using many different vendors to see which device works the best for them. Some utilities are attempting to standardize the selection, especially for a controls perspective, allowing standard configurations regardless of switching device purpose.

Installation and Commissioning

The ease of installation and device commissioning is an important consideration when installing a DA switch. Potential considerations when deciding on the device type and approach include:

- Installation of additional hardware on device and/or pole (bypass switches, arresters, control power transformers, communication equipment, etc.)
- Pole replacement or upgrade.
- Ease of access to the installation location.
- Replacement of existing manual switch / new location.
- Provisioning versus commissioning the DA switch control.
- How to test the DA scheme once devices are installed.

Operation

Varying DA device types require specialized training for field workers who interact with the devices. A major difference in devices type, is how a visible break is obtained and verified, from a safety perspective. When using reclosers as switches, a set of bypass switches must be installed to achieve a visible break. A MOAB on the other hand, does not require additional infrastructure to provide a visual break. Many enclosed switches and sectionalizers provide a visible break without additional hardware.

Future asset flexibility should also be considered when choosing a device to deploy. If there is a possibility in the future that a circuit where a DA switch is deployed may be reconfigured, it may be advantageous to deploy a recloser. That would allow for the switch to easily be reprogrammed to act as a protective device.

Inspection and Maintenance

The inspection and maintenance should be a consideration when choosing a DA switch type. Varying device types require different maintenance protocols, and long-term maintenance needs should be considered when choosing a device type. For example, MOABs should be operated at least once a year. Some utilities have come up with a method to perform this maintenance through their SCADA system. This utility closes their normally open device in a loop scheme, and then goes around the loop opening and closing each switch. This method exercises each switch without having to send field crews to each location. The ability to log device operations can also be helpful. By having a log of operations, this would allow the utility to know which devices need to be operated. The time to find out there is a problem is NOT when you are trying to perform an automated operation to restore customers.

There is also a need to inspect the control and device at regular intervals. A few utilities have reduced the amount of inspections they perform and have moved to alarm based maintenance, relying on the control to notify the utility when there is a problem. The ability to remotely monitor alarms has allowed utilities to know when a control battery failure in imminent and allows them to monitor the contact wear in vacuum interrupters.

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