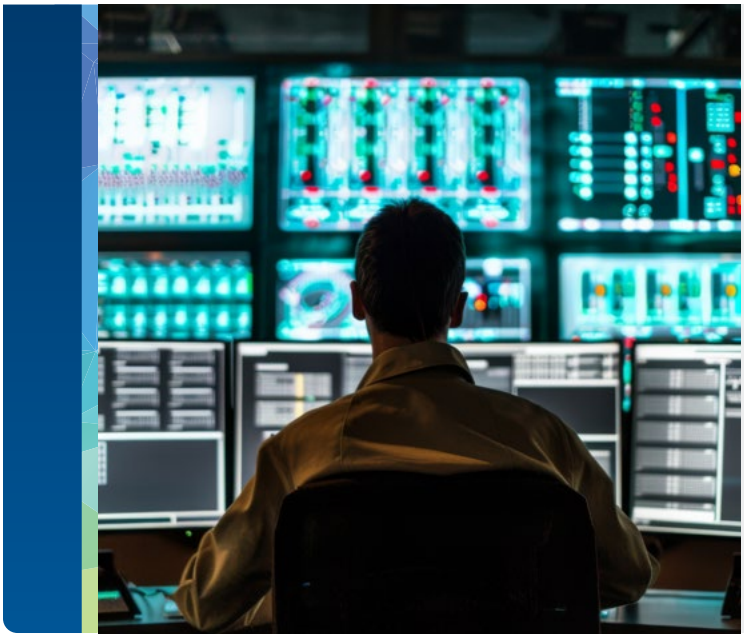
TETRA TECH

Distribution Automation Savings Calculator



Prioritizing reliability investments and restoration improvements

Two failures of the same type of equipment may take the same time to repair, but each can produce very different customer outages. One may interrupt a small group of customers until repairs are complete. Another may disrupt a large part of a feeder with a momentary outage, but customer service may be restored through available switching and alternate supply before repairs are complete. For a distribution utility, knowing where those differences in outages occur is essential to directing reliability spending.

Tetra Tech's Distribution Automation Savings Calculator (DASC) evaluates the reliability impact of modeled equipment faults and compares restoration under different levels of network automation. It connects feeder topology, customer counts, the utility's outage restoration philosophy, and typical repair times to estimate the number of customers affected and customer minutes of interruption. Those results can support consistent comparisons across feeders and identify high-risk assets according to their potential contributions to the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI).

Developed for a utility client, DASC addresses a practical planning problem: how to compare the value of existing distribution automation initiatives, proposed modernization investments, and changes in outage response on a common reliability basis. Its principal value is the ability to examine potential outages before they occur.

At the asset level, DASC helps identify fault locations with the greatest modeled customer impact. At the program level, it helps utilities compare manual response, fault information with manual switching, and automated isolation and restoration. In operations, comparisons with historical events can reveal where actual restoration diverges from the assumed practices and repair times and where further investigation is worthwhile.

By simulating the entire sequence of switching steps and restoration steps for each outage, DASC does not simply assume that the reliability impact of an asset type is identical in all installations. Instead, it supplements a utility's operational experience and asset health indexing for the likelihood of failure, letting utilities compare the SAIDI and SAIFI impact per device system-wide. This additional insight helps prioritize investments into distribution automation, maximizing impact per dollar spent.



Define the network and restoration practices

Compare manual response, fault information and full automation

Estimate customer interruptions and potential reliability savings

Guide asset priorities, automation investments and restoration improvements

Reliability savings

The term “customer minutes of interruption” expresses the accumulated time customers spend without service. A single customer interrupted for 60 minutes contributes 60 customer minutes, while 100 customers interrupted for that duration contribute 6,000 customer minutes. Because restoration can occur in stages, each affected customer group contributes according to its own interruption duration.

Faster restoration and fewer sustained interruptions

Customers restored within a utility’s momentary-interruption threshold qualify as “momentary outages” and help to reduce the reportable customer and customer minutes, which improves (lowers) the utility’s SAIDI and SAIFI. Automation can lower SAIDI by shortening qualifying outages. Performance depends on the placement of distribution automation and fault circuit indicators throughout a feeder, as well as on the utility’s outage restoration and patrol policies.

Fault location assistance can improve SAIDI by narrowing the patrol area and distance travelled by the responding field crew. But sustained outages, with restoration exceeding the threshold, contribute to affected customer counts and SAIFI all the same, regardless of whether fault location helps crews find and restore a fault faster.

Full fault location, isolation and service restoration (FLISR) implementation automatically narrows the patrol area and distance travelled by crews and may automatically restore customers outside of the isolated region if safe to do so. This level of automation can substantially reduce a utility’s SAIDI and SAIFI.

That said, distribution automation does not inherently reduce the frequency of physical equipment failures. It may significantly reduce the reliability impact of outages, but preventing equipment failures benefits reliability and customer experience the most.

Utilities, with numerous competing budget priorities, must determine the value of each additional investment in automation. DASC can help decide where it makes sense to invest more in automated restoration devices and where less-expensive fault identification is sufficient. This supports more focused decisions on communications, controls, switching devices, maintenance, and operating practices.

The reliability prioritization challenge

Distribution utilities must choose between asset renewal, additional switching, automation upgrades, and operational improvements while working within capital and workforce limits. Each option addresses a different part of the reliability problem. Replacing deteriorated equipment can reduce the likelihood of failure. Automation can reduce the number of customers left without supply and the time they remain interrupted. Better fault information and restoration practices can shorten response without changing the failed equipment.

Asset condition and outage consequence

Condition assessments help to identify equipment that may fail. They do not, by themselves, show how much customer disruption a failure would cause. Network position, customer distribution, available isolation points, and restoration options can make otherwise similar assets very different reliability priorities.

DASC adds a view into the consequences of an outage at each modeled fault location. What interruption impact would result under defined operating assumptions? Combining that view with condition, failure history, and asset exposure supports a more complete risk assessment.

Historical performance and unobserved exposure

Outage history records what happened under the conditions that occurred. It can expose recurring problems and slow restoration, but it is an incomplete picture of future exposure. An asset in a consequential location in the network may have little recent outage history, making it appear lower-risk. Conversely, a feeder with a poor recent result may have experienced an unusual event that is not representative of normal operating conditions.

DASC scenario analysis complements that history by applying a consistent set of assumptions across the modeled network. It makes potential consequences visible even where there is no directly comparable recorded event. Historical data then help test the plausibility of the assumptions and explain where model results differ from operational experience.

The value of installed automation capability

A utility may already own automated switches and fault indicators but use only part of their capability. Information that narrows fault location has value even where switching remains manual. Enabling automated isolation and restoration can offer additional value, subject to communications, controls, and network constraints. Evaluating these operating states separately helps explain which portion of the benefit comes from faster diagnosis and which comes from faster restoration.

This distinction also matters when renewing an aging automation system. The business case may include retaining a reliability benefit that customers already receive. A comparison with manual operation can make that retained value visible, while a separate comparison with the existing operating state isolates the incremental benefit of an upgrade.

How DASC supports value comparison

DASC uses distribution feeder models, the inventory of participating automation devices, and adjustable restoration assumptions to evaluate permanent-fault scenarios. When developing the calculator, Tetra Tech used the client's existing CYME model to implement it. However, other modeling software formats or GIS data are suitable inputs as well. At a high level, the model supplies network connectivity and customer information. Devices are identified throughout the distribution network, including overhead conductors, underground cables, switches, reclosers, fuses, and transformers.

Three operating scenarios

Scenario modeled	Type of response	Client benefit
Manual response	Fault location and switching depend on crews.	Establishes a reference for the value of automation.
Fault information with manual switching	Automation devices assist fault location and switching remains manual.	Separates the value of better information from automated restoration.
Full fault location, isolation, and service restoration (FLISR)	Eligible isolation and restoration actions are fully automated.	Estimates the additional value of automated response.

For each scenario, the calculator evaluates customer interruption and restoration over time at each eligible fault location. Customers may have their service restored at different stages, while those dependent on repair remain interrupted longer. DASC outputs summarize the resulting customer impact and retain supporting records of the modeled response. Because outage data may be recorded differently across utilities or jurisdictions, detailed switching steps and restoration steps are recorded to better understand the calculated outage response and to compare against historical outages.

Inputs that shape the result

The analysis depends on the quality of data on network connectivity, customer allocation, and device status. It also depends on operational assumptions such as dispatch, fault location, switching, and repair times. A scenario should represent a credible way the utility operates or intends to operate. If several assumptions change together, the resulting benefit belongs to the combined change and should not automatically be attributed to a single device.

Outputs for planning

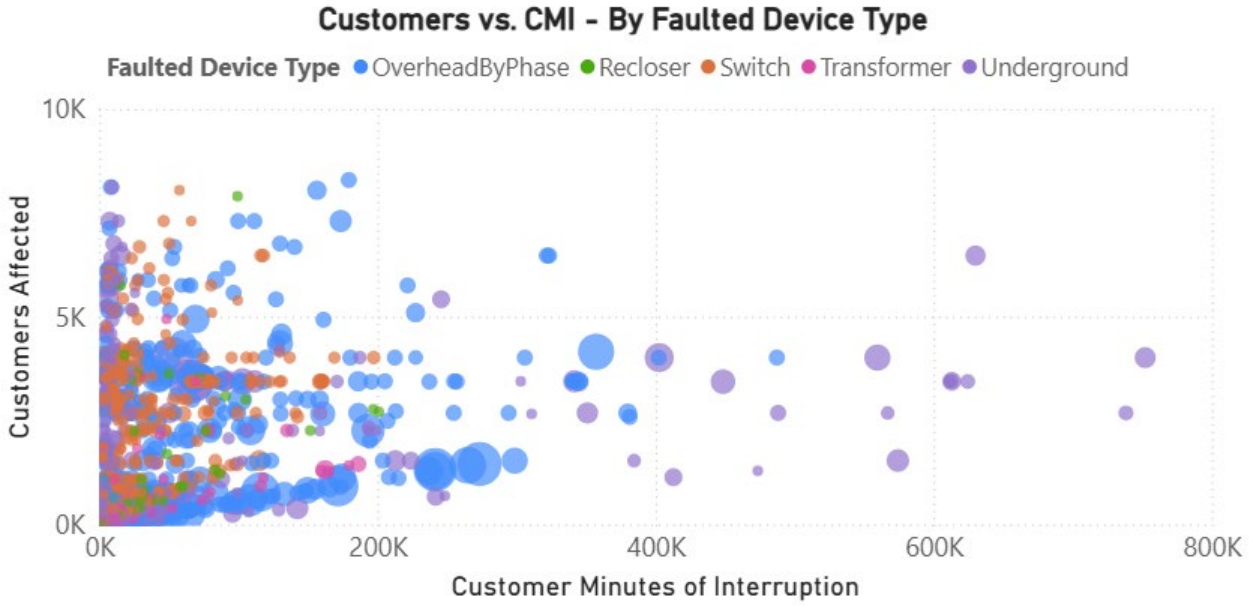
The documented outputs include customer interruption and restoration summaries, modeled switching records, and fault-location patrol information. They can be aggregated in a reporting environment to compare fault locations, feeders, and operating scenarios. The supporting records allow engineers to investigate why the consequences of a modeled outage are high and whether the assumed response is credible.

Using the results across the utility

System-wide asset prioritization

Applying the same scenario definitions across feeders lets a utility compare outage consequences throughout the system. Planners can rank eligible faulting devices by customer minutes of interruption and qualifying customer interruptions, then examine the largest contributors. Useful reporting also shows the affected feeder, the assumptions used, and how automation changes the impact.

The next question is what is causing these consequences. A large concentration of customers in a single outage may indicate the need to divide the grid into smaller distribution sections using either manual or automated switches. A long interruption may point to constrained restoration options or repair dependence. Where the likelihood of failure is high, asset renewal may deserve greater attention. Utilities can use this understanding of outage consequences, modeled according to their policies and procedures, to decide how to prioritize investments in maintenance and replacement.



The value of existing and proposed automation

Comparing manual response with a utility's current automation capability estimates the reliability value associated with that capability under the modeled faults. Comparing current operation with a proposed configuration estimates incremental improvement. When a utility already has some level of automation and wants to assess the value of adding more, keeping these baselines separate avoids attributing the entire benefit of distribution automation to the new investment.

The intermediate scenario helps evaluate whether fault information alone captures much of the available benefit or whether automated restoration offers a substantial further reduction. This can inform the sequencing of device, communications, and control upgrades.

The value of an existing automation system can often be overlooked, as the outage restoration improvements become normalized as the expected reliability performance. Insufficient system maintenance may negatively impact reliability over time in the form of failed controllers, radios, or batteries and miscoordination. With DASC, utilities don't have to wait for equipment failures to see whether their distribution automation systems are a good investment—they can assess the value of automation before problems occur.



Restoration practice improvements

Operational timing inputs also support sensitivity studies. A utility can examine shorter dispatch delays, faster fault location, or revised manual switching assumptions and compare their modeled customer benefit with a hardware option. Such studies can help target procedure reviews, training, or field-response improvements.

What DASC contributes

Tetra Tech's DASC gives utilities a common basis for asking where a fault would hurt customers most, how much automation could reduce that impact, and which response improvements deserve attention. It also makes the value of existing distribution automation capability visible, supporting renewal decisions as well as expansion.

Its strongest application combines modeled consequence with asset knowledge and operating evidence. System-wide comparisons identify consequential locations. Scenario comparisons estimate achievable improvements. Historical review tests the assumptions and directs corrective action. Together, these activities help utilities explain why a particular reliability investment or operational change deserves priority and justify their investments.

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This paper may be periodically updated to reflect evolving industry trends, operational considerations, and utility resilience practices. Please refer to the latest published version for updates.

For questions, comments, or feedback regarding this paper, please contact:

Busayo Akinloye, P.Eng
Director, Grid Modernization
& Power Systems Engineering
busayo.akinloye@tetratech.com

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Contact us:



Busayo Akinloye, P.Eng
Director, Grid Modernization
& Power Systems Engineering



Kevin Wan
Manager, Utility Management