Function of Distribution Automation System

Remotely monitors the distribution system, facilitates supervisory control of devices and provides decision support tools to improve the system performance

- SCADA

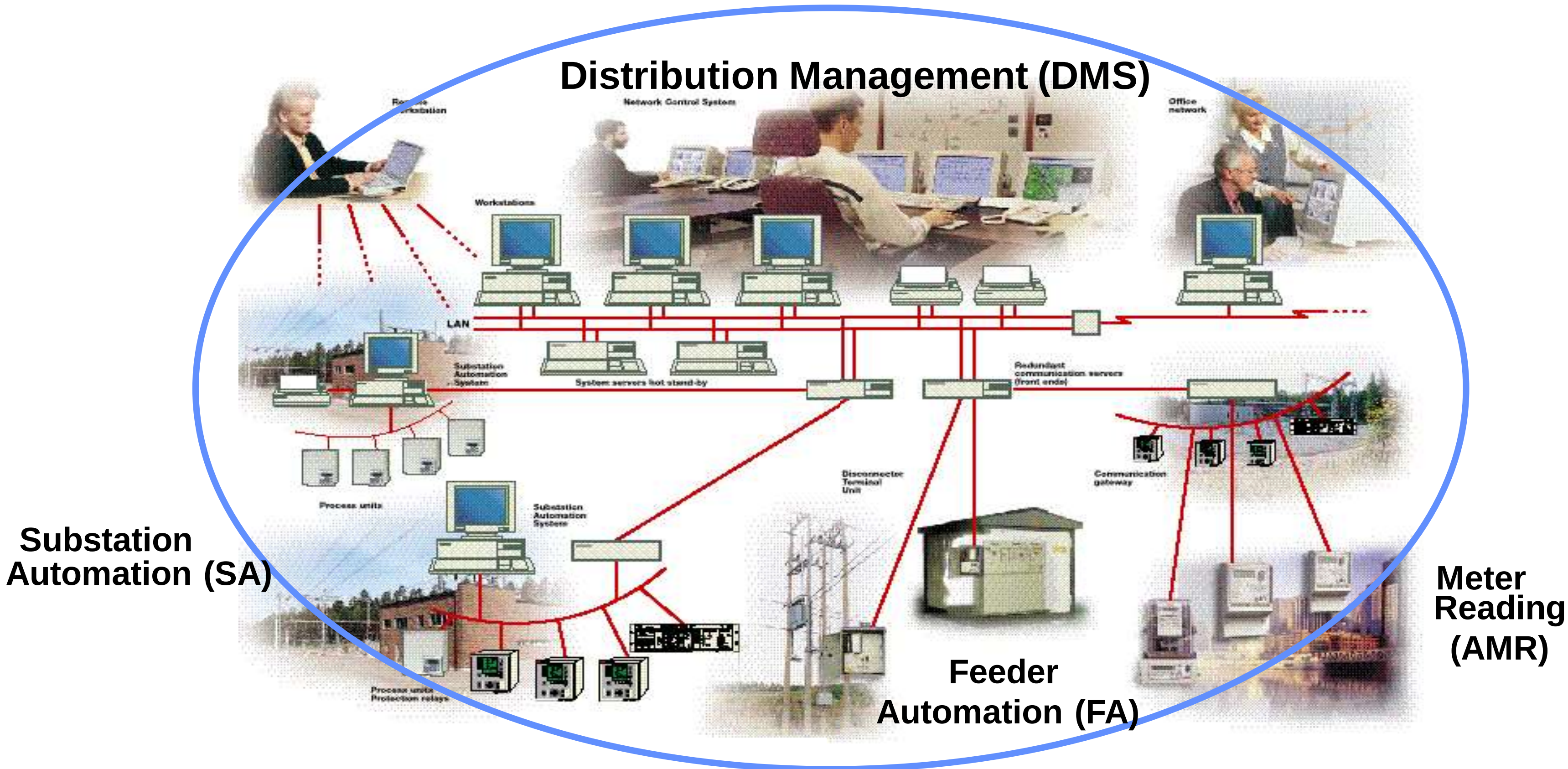
  (**S**upervisory **C**ontrol **A**nd **D**ata **A**cquisition)

- Application Functions

What is Distribution Automation ?

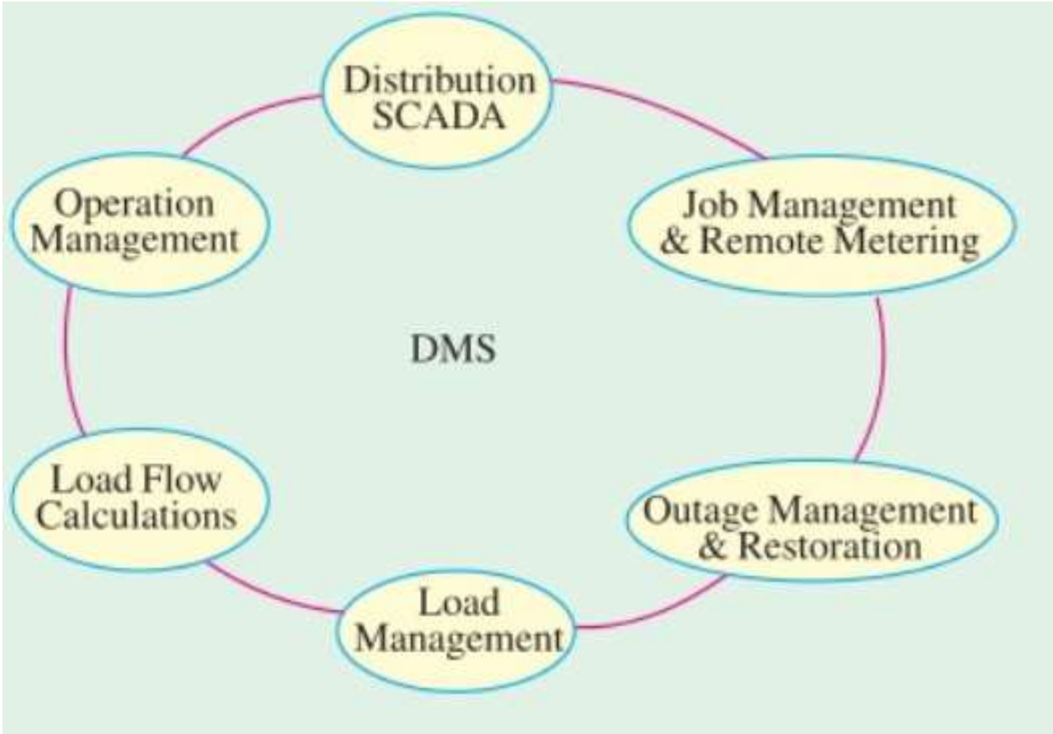
- "A set of technologies that enable an electric utility to remotely monitor, coordinate and operate distribution components in a real-time mode from remote locations" - (IEEE definition)

- DA is an umbrella concept that embraces all the other real-time and operational functions for the distribution network



Distribution Automation functions provide a means to more effectively manage minute by minute continuous operation of a distribution system. Distribution Automation provides a tool to achieve a maximum utilization of the utility's physical plant and to provide the highest quality of service to its customers. Obviously, both the utility and its customers are beneficiaries of successful Distribution Automation.

Distribution Automation systems are modular, hence they may be implemented in stages, commencing from a modest degree of capability and complexity and growing as necessary to achieve tangible and intangible economic benefits. For example, a utility may start with a limited capability SCADA System for sub station monitoring and control, extend this to the feeders and finally implement a complete integration of automation functions. Systems implemented in this fashion must be designed to accommodate future expansion.



Distribution Automation System offers an integrated 'Distributed Management System' (DMS). The functions of DMS are shown in Fig

Advantages of Distribution Automation

(*a*) Reduced line loss

(*b*) Power quality

(*c*) Deferred capital expenses

(*d*) Energy cost reduction

(*e*) Optimal energy use

(*f*) Economic benefits

(*g*) Improved reliability

(*h*) Compatibility

AUTOMATIC METER READING SYSTEMS

Definition

- AMR
  - Automatic Remote Meter Reading .
  - Automating the process of measurement through digital communication techniques.

METERING SYSTEM

PAST

ELECTRO-MECHANICAL

- Low Accuracy
- Control – NIL
- Communications - Expensive
- Theft Detection – Poor

CURRENT

DIGITAL SOLID STATE

- High Accuracy
- Control – LIMITED
- Communications – External through Retrofit
- Theft Detection – Node only

NEXTGEN

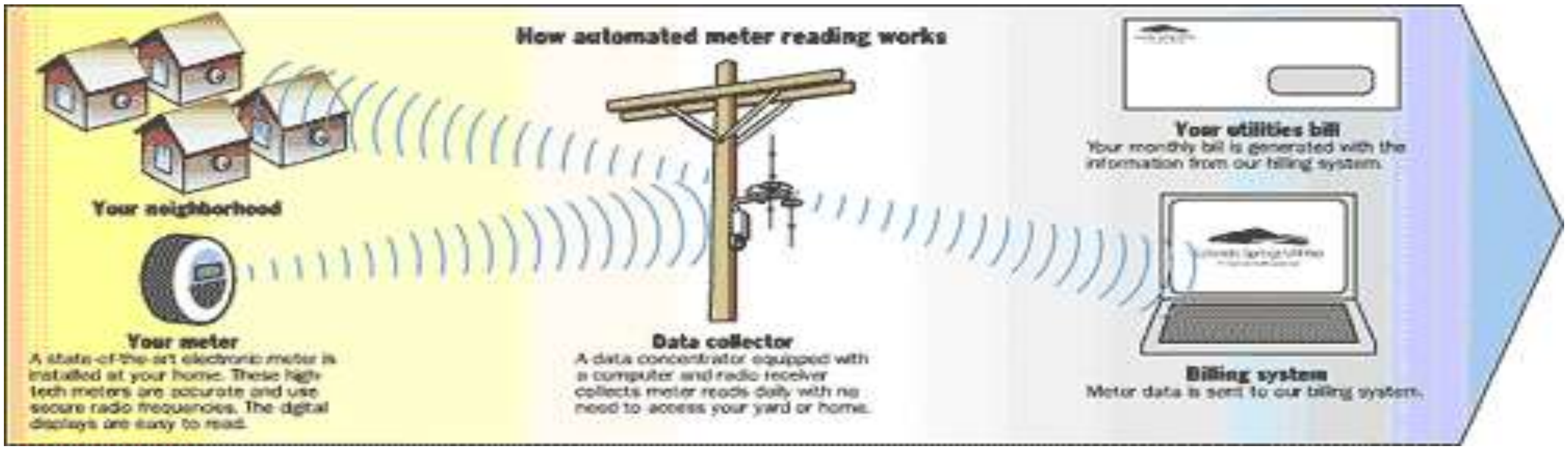
NEXT GEN SMART METER & IT SYSTEM

- Very High Accuracy
- Control – FULL
- Communications – Built in (on chip / PCB)
- Theft Detection – High (Network level)

Critical Benefits from AMRS

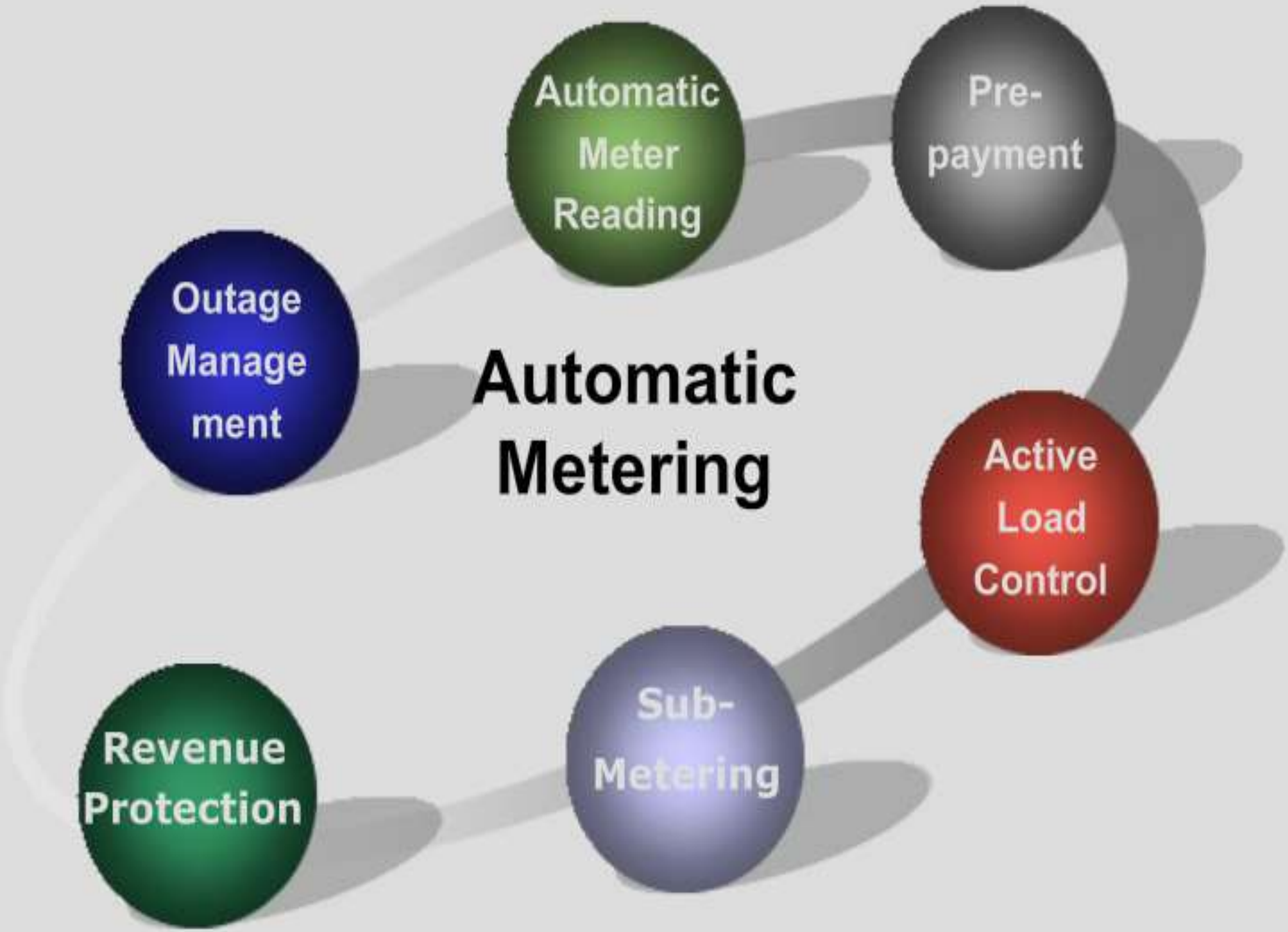
- Ability to detect tamper events and outage occurrences.
- Remotely Connect/ Disconnect power supply through meter.
- Calculate transformer loading and sizing from interval data
- 15 minute interval data gives accurate load information for supply scheduling, switching operations, planning etc
- Monitor voltage at each premise to know conditions when to operate capacitor switches or regulators
- Consistent and granular data for improved accuracy

How AMR works ?

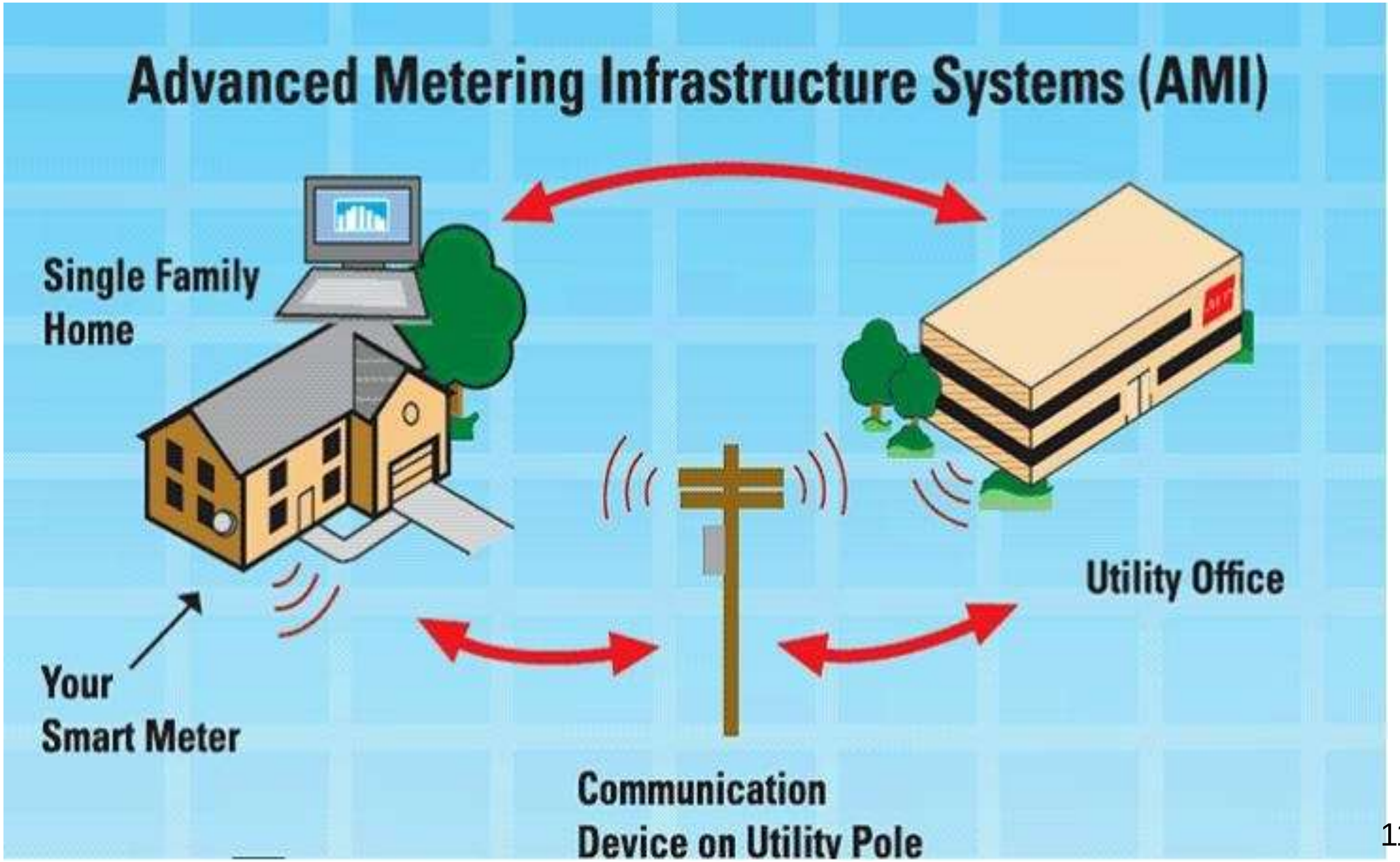


- Remotely reads customer meters and then transfers the data into the billing system
- Reduce the need for meter readers to manually gather utility meter readings each month.

Automatic Metering

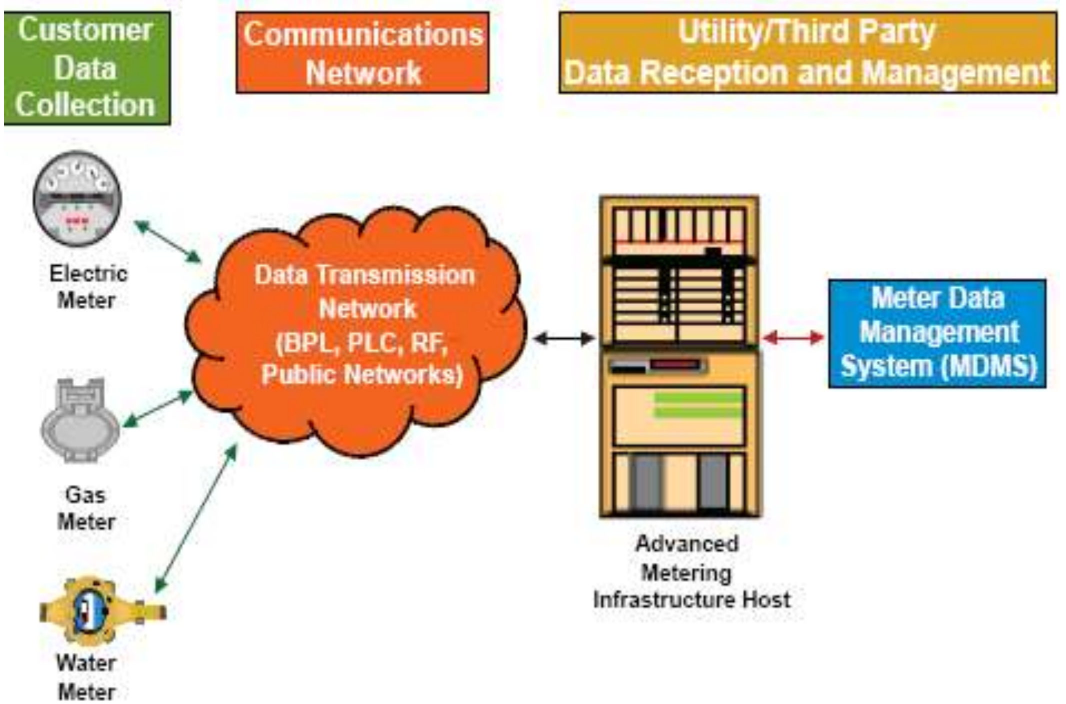


Automated Metering Infrastructure



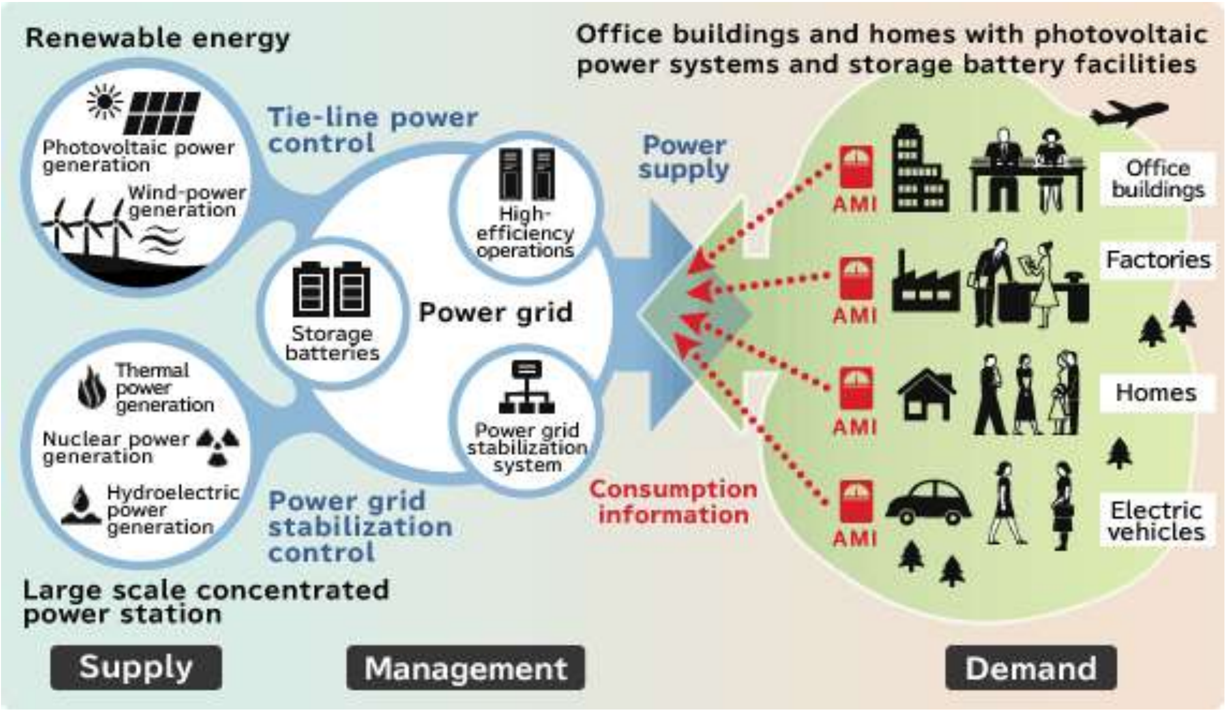
Presentation Overview

1. What is AMI?
2. Why should AMI be implemented?
3. What issues face AMI?



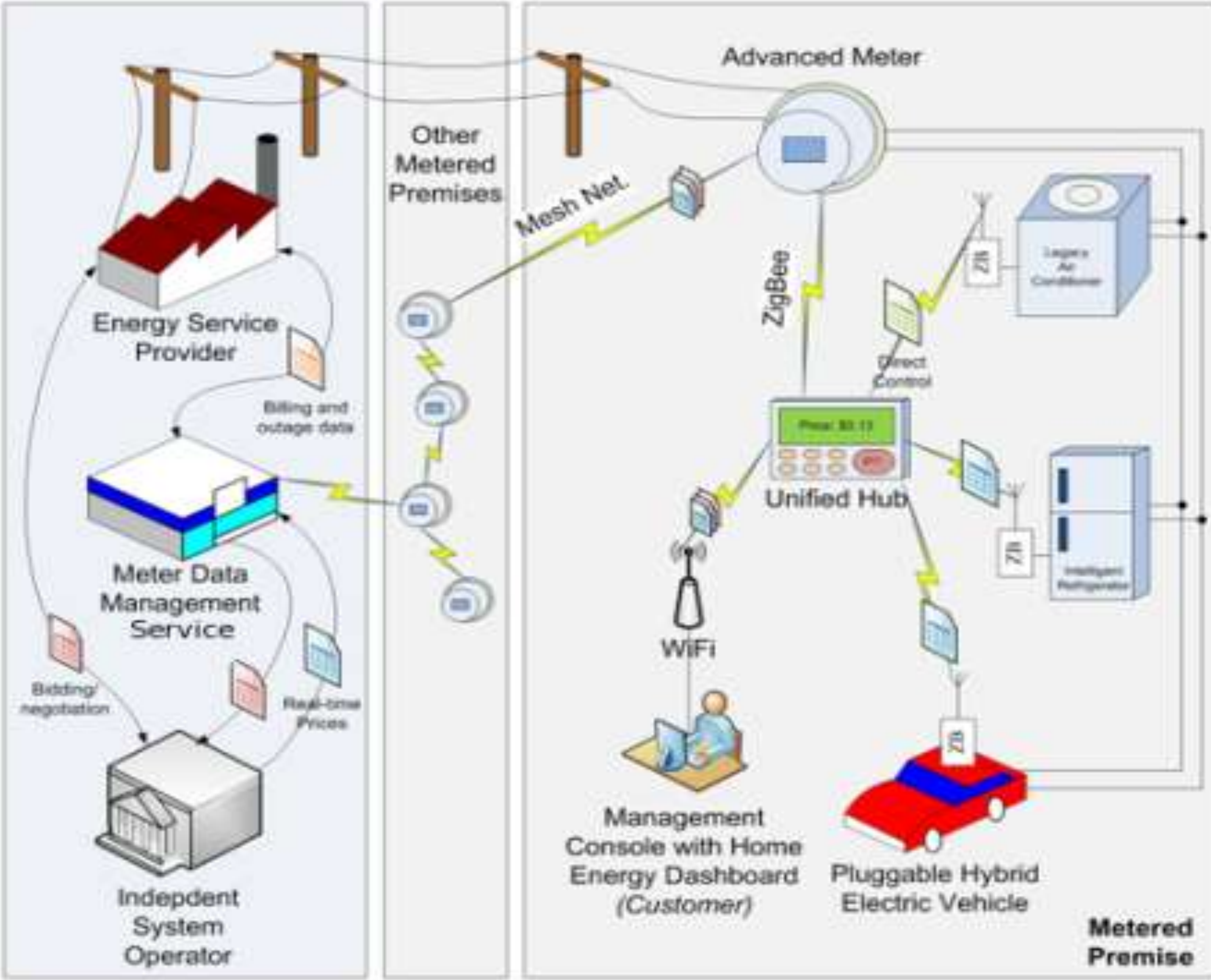
AMI Definition

- Two characteristics
  - Fixed network systems
  - Capable of supporting complex rates



What does AMI do?

- Enables a two-way flow of information between consumers and utilities
- Enables proliferation of demand response
- Allows service provider to control consumers' electricity usage (load control)
- Facilitates Smart Grid deployment and distributed generation


Advanced Meter
Other Metered Premises
Mesh Net
ZigBee
Energy Service Provider
Billing and outage data
Direct Control
Unified Hub
Meter Data Management Service
WiFi
Bidding/ negotiation
Real-time Prices
Management Console with Home Energy Dashboard (Customer)
Pluggable Hybrid Electric Vehicle
Indepdent System Operator
Metered Premise

Why implement AMI?

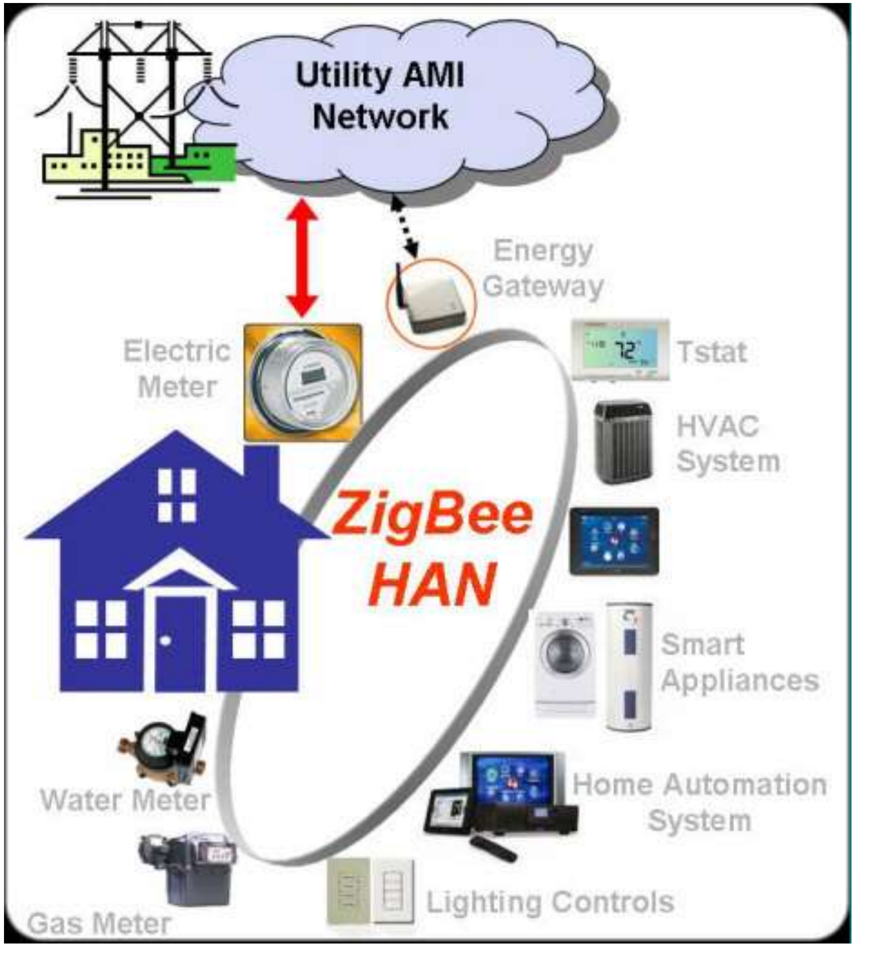
- Public Utilities Regulatory Policies Act section 111(d) mandate
  - As amended by § 1252 of the Energy Policy Act of 2005
- Each utility must offer each class of customers a time-based rate schedule
- And must provide these rates and meter them for those who request

Why implement AMI?

- Public Utilities Regulatory Policies Act section 111(d) mandate
  - Regulators of regulated utilities and unregulated utilities required to “consider and determine” whether smart metering is appropriate
  - If so, these entities must set smart metering standards for the utilities

Another Benefit: Load Control

- Home Area Networks
- Homes can respond to electricity supply in order to maximize efficiency through user-set profiles
- Utilities can alter supply of electricity to homes when demand is expected to spike



EPRI’s Stated AMI Issues

1. Cost-benefit assessment
2. Security
3. Interoperability and standard interfaces
4. AMI specifications
5. AMI and demand response networks

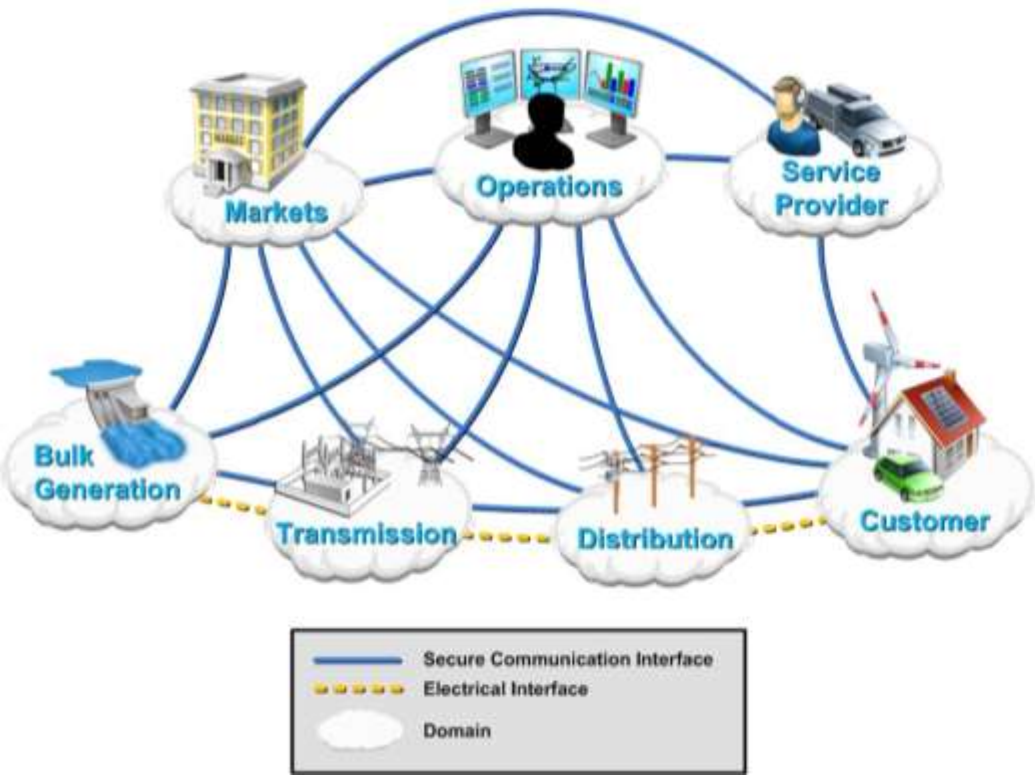
Security Issues

- Privacy
  - Can determine if someone is home
  - Can determine usage patterns
- Exposure to cyber terrorism

Standardization

- How do you ensure that everything can communicate in an AMI system?

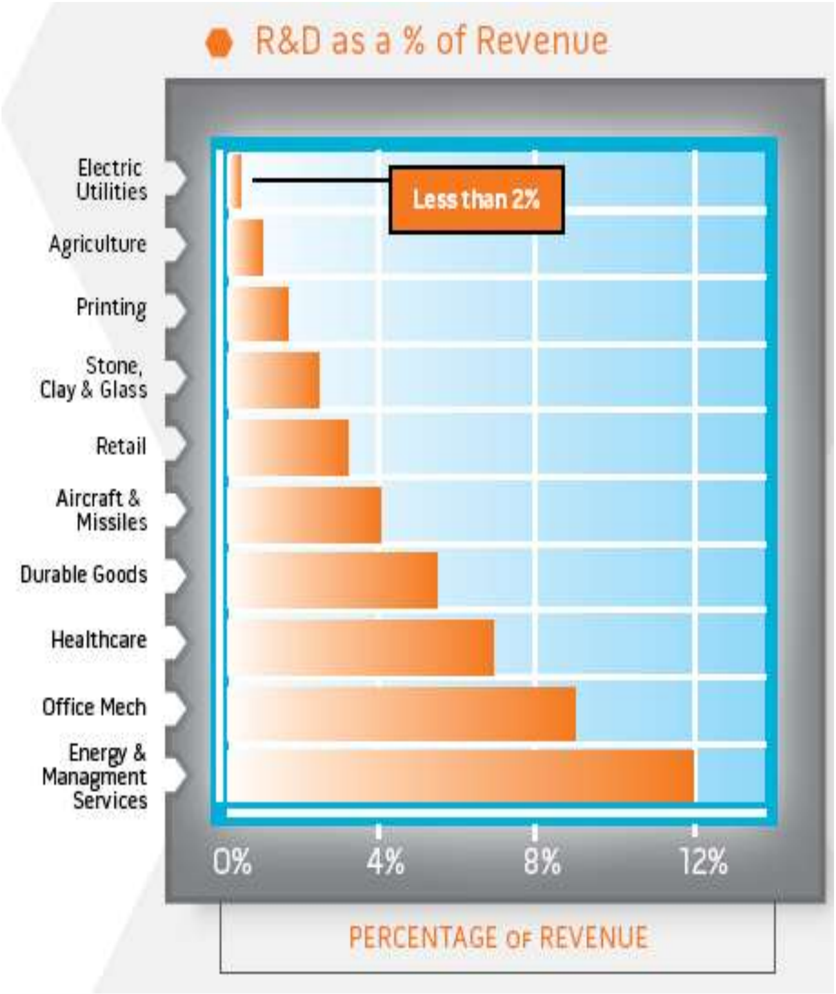
- Communication protocols amongst
  - Load control devices in HANs
  - Fixed networks




ZigBee Smart Energy
ZigBee
Water Meter
Smart Appliances
Electric Meter
Home Gateway
ZigBee
In-Home Display
Thermostat
Gas Meter
Home Area Network
HVAC
Occupancy Sensing
ZigBee
Access Control
BACnet
Lighting
Commercial/Industrial
AMI
Reduce Peak Demand
Real Time Pricing
Demand Response
Utility Company Programs (Electric, Gas, Water)

Conclusion

- AMI faces many challenges but has the potential to greatly increase energy efficiency



Fault location isolation and service restoration (FLISR)

Fault location, isolation, and service restoration (FLISR) technologies are one of the distribution automation (DA) tools SGIG projects are deploying to provide operators greater visibility into disturbances and automatically reroute power to reduce the number of affected customers from downed power lines, faults, or other disturbances. In addition to fewer and shorter outages for customers, FLISR technologies help utilities improve their standard reliability metrics, such as the System Average Interruption Frequency Index (SAIFI) or System Average Interruption Duration Index (SAIDI). In many states, improvements in these metrics are tied to utility financial incentives, often through performance standards or performance-based rates. This section provides an overview of how FLISR technologies improve reliability.

What is FLISR?

Fault location, isolation, and service restoration (FLISR) includes automatic sectionalizing and restoration, and automatic circuit reconfiguration. These applications accomplish DA operations by coordinating operation of field devices, software, and dedicated communication networks to automatically determine the location of a fault, and rapidly reconfigure the flow of electricity so that some or all of the customers can avoid experiencing outages. Because FLISR operations rely on rerouting power, they typically require feeder configurations that contain multiple paths to single or multiple other substations. This creates redundancies in power supply for customers located downstream or upstream of a downed power line, fault, or other grid disturbance.

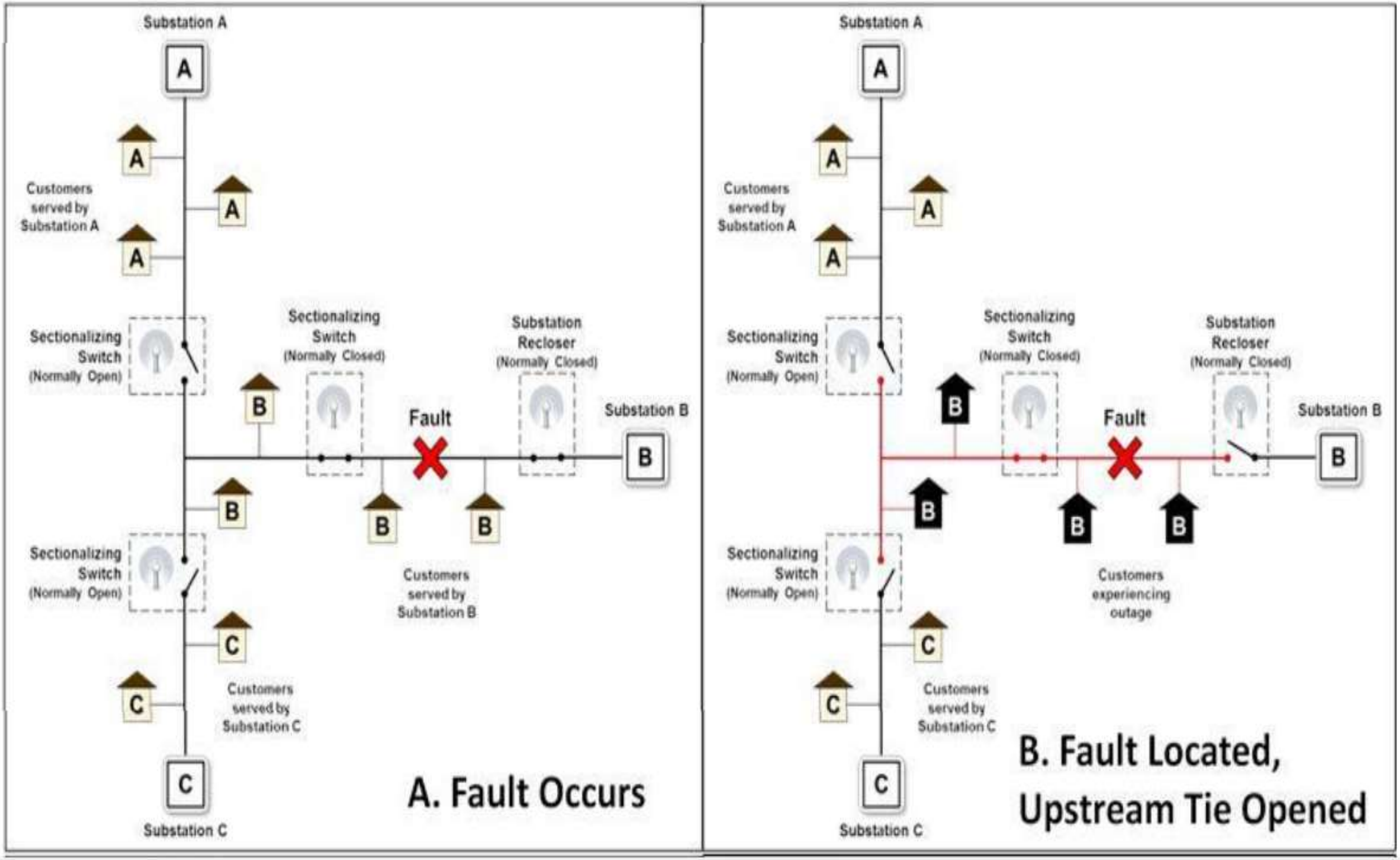
How Does FLISR Result in Fewer and Shorter Outages?

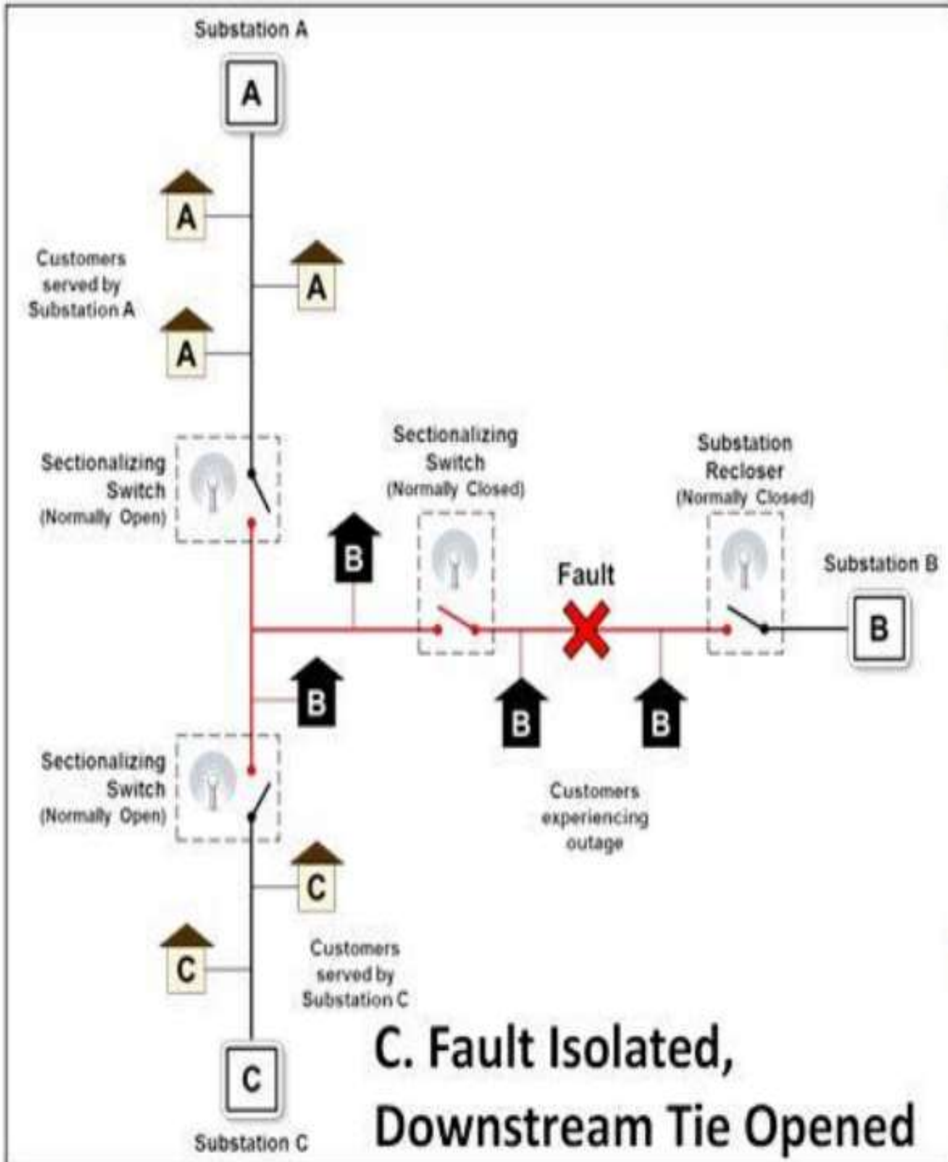
Figure 1 presents simplified examples (A-D) to show how FLISR operations typically work. In Figure 1-A, the FLISR system locates the fault, typically using line sensors that monitor the flow of electricity and measures the magnitudes of fault currents, and communicates conditions to other devices and grid operators. Once located, FLISR opens switches on both sides of the fault: one immediately upstream and closer to the source of power supply (Figure 1-B), and one downstream and further away (Figure 1-C). The fault is now successfully isolated from the rest of the feeder.

With the faulted portion of the feeder isolated, FLISR next closes the normally-open tie switches to neighboring feeder(s). This re-energizes un-faulted portion(s) of the feeder and restores services to all customers served by these un-faulted feeder sections from another substation/feeder (Figure 1-D). The fault isolation feature of the technology can help crews

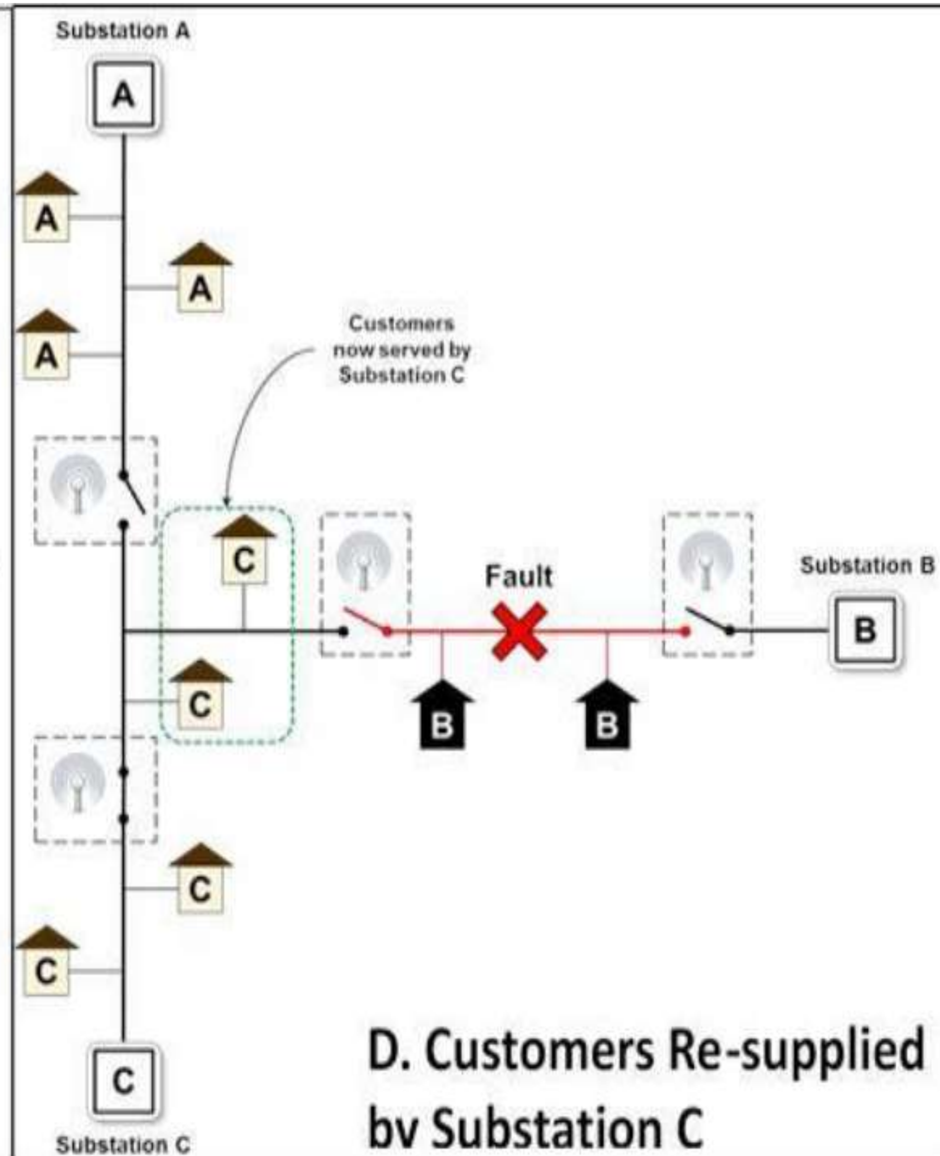
locate the trouble spots more quickly, resulting in shorter outage durations for the customers impacted by the faulted section.

Schematics Illustrating FLISR Operations





C. Fault Isolated, Downstream Tie Opened



D. Customers Re-supplied bv Substation C

FLISR systems can operate autonomously through a distributed or central control system (e.g., DMS), or can be set up to require manual validation by control room operators. Implementing autonomous, fully automated FLISR systems typically requires extensive validation and calibration processes to ensure effective and reliable operations. Automated FLISR actions typically take less than one minute, while manually validated FLISR actions can take five minutes or more. Two standard reliability metrics are typically used to evaluate FLISR operations: 1) the number of customers interrupted (CI), and 2) the number of customer minutes of interruption (CMI). Both of these metrics are components of the equations that are used to calculate SAIFI and SAIDI. CI is a measure of the number of customers interrupted by an outage. CMI is a measure of the duration of interruptions experienced by customers. The avoided CI and CMI can be used to measure the benefits of FLISR operations. It is important to note that FLISR does not avoid outages but works to minimize their impacts on customers when they do occur.

What is Energy Storage?

- Energy storage devices are “**charged**” when they absorb energy, either directly from renewable generation devices or indirectly from the electricity grid.
- They “**discharge**” when they deliver the stored energy back into the grid.
- Charge and discharge normally require power conversion devices, to **transform electrical energy** (AC or DC) into a **different form of electrical, thermal, mechanical or chemical energy.**

Renewable Integration

Renewable Energy Integration focuses on incorporating renewable energy, distributed generation, energy storage, thermally activated technologies, and demand response into the electric distribution and transmission system. A systems approach is being used to conduct integration development and demonstrations to address technical, economic, regulatory, and institutional barriers for using renewable and distributed systems. In addition to fully addressing operational issues, the integration also establishes viable business models for incorporating these technologies into capacity planning, grid operations, and demand-side management.

The goal of Renewable energy integration is to advance system design, planning, and operation of the electric grid to:

1. reduce carbon emissions and emissions of other air pollutants through increased use of renewable energy and other clean distributed generation

2. increase asset use through integration of distributed systems and customer loads to reduce peak load and thus lower the costs of electricity

3. support achievement of renewable portfolio standards
for renewable energy and energy efficiency

4. enhance reliability, security, and resiliency from
microgrid applications in critical infrastructure
protection and highly constrained areas of the electric
grid

5. support reductions in oil use by enabling plug-in
electric vehicle (PHEV) operations with the grid

Outage management systems

Outline

- Outage Management Basics
- Some issues
- Standards for Distribution Management

Definitions

A system of computer-based tools and utility procedures to efficiently & effectively -

- become aware of,
- diagnose & locate,
- provide feedback to affected customers
- dispatch trouble/repair crews,
- restore
- maintain historical records of
- compute statistical indices on

electrical outages

Becoming aware of outages

- Customer telephone calls
  - conventional human communication
  - automatic voice response systems (CTI)
- Auto outage detection/reporting systems
- SCADA detection of breaker trip/lockout
- Ideal: Become aware of outages before the first customer calls in

Diagnosing & locating

- Grouping of customer trouble calls
  - reverse tracing of electric topology
  - determine a common protective device suspected to be open
    - transformer?
    - lateral fuse?
    - recloser?
    - substation breaker?
  - Take into account automatic feeder switching
- Compute extent of suspected outage
  - Number of customers affected
  - Highest priority of affected customers
- Confirm or modify (split/enlarge) based on feedback from crews

Feedback to affected customers

- Timely, accurate feedback is almost as important as fixing the problem
  - Telling customer you are aware of his problem
  - Current status of outage response
  - Expected time of restoration

Crew Dispatch Management

- Computer-aided modeling of crews
  - capabilities, tools, equipment
  - real-time location tracking
  - work load

Repair and restoration

- Simple problems
  - direct repair & restore
- Major outages
  - isolate fault & restore un-faulted portions of feeder
  - OMS tracks partial restorations
- Automated Fault Detection, Isolation, Restoration schemes with feeder automation are considered desirable outside N. America

Historical Records

- Keep track of all outages
  - root cause, number of customers, duration
- Provides the data for
  - Performance statistics SAIDI, SAIFI, CAIFI, etc
  - Planning / budgeting maintenance activities
    - Condition based maintenance

Drivers for current interest in OMS

- Customer expectations of reliability
  - Momentary outages are also important
  - The plague of electronic clocks!
- Performance-based rates
  - More likely a penalty for poor performance than a reward for good performance!

Main Players in OMS

Business Dept.

- Customer
- Customer service representative

New trouble calls

Outage management updates

Operations Dept.

- Dispatcher
- Trouble/repair crews

OMS Suppliers

- “Home-made” systems
- Stand alone OMS
- GIS vendors
- SCADA vendors