Exhibit No.:	
Issue(s):	Distribution Investments
Witness:	Ryan M. Arnold
Type of Exhibit:	Direct Testimony
Sponsoring Party:	Union Electric Company
File No.:	ER-2022-0337
Date Testimony Prepared:	August 1, 2022

MISSOURI PUBLIC SERVICE COMMISSION

FILE NO. ER-2022-0337

DIRECT TESTIMONY

OF

RYAN M. ARNOLD

ON

BEHALF OF

UNION ELECTRIC COMPANY

D/B/A AMEREN MISSOURI

St. Louis, Missouri
August, 2022

DIRECT TESTIMONY

OF

RYAN M. ARNOLD

FILE NO. ER-2022-0337

Q. Please state your name and business address.

A. Ryan M. Arnold, Union Electric Company d/b/a Ameren Missouri ("Ameren Missouri" or "Company"), One Ameren Plaza, 1901 Chouteau Avenue, St. Louis, Missouri 63103.

Q. What is your position with Ameren Missouri?

A. I am the Vice President of Division Operations for Ameren Missouri.

Q. Please describe your educational background and employment experience.

A. I earned a Bachelor of Science degree from William Woods University in 2004, and a Master of Business Administration, also from William Woods University, in 2008. I began my career at Ameren Missouri in 1999 as temporary meter reader. Shortly, thereafter I accepted an apprenctice lineworker position ultimately earning my Journeyman lineworker certificate in 2001, where I had responsibility for many types of line work such as overhead, underground, steel towers, and storm response. In 2005, I accepted a first line supervisor role in Decatur, Illinois with Ameren Illinois Company. In that role, my responsibilities were to lead construction crews and interact with customers during construction and maintenance jobs. I held a similar position with Ameren Missouri starting the next year. In 2011, I was promoted to be a Labor Relations representative for Ameren Missouri, and the following year was promoted to Superintendent, electric operations in the North Metro area of St. Louis. My role as Superintendent was to lead supervisors, multiple crews, and oversee the overall district budget. I was promoted again in 2015 to the Director of Ameren Missouri's Gateway Division which covers the St.Charles, Dorsett, and

Berkeley operating centers. In this role, I was responsible for the safety of customers and employees, financial costs, and direct leadership within this geographic area. In 2019, I took a lateral move to distribution operations and led our distribution control rooms across the state along with our metro first responders. In 2021, I was promoted to Vice-President, Division Operations. As Vice-President, Division Operations, I am responsible for the delivery of safe, reliable, and affordable power to our customers across the state of MO and all division construction related employees that report up through my organization (ex: lineworkers, engineering, fleet, supervisors, etc.).

Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is twofold. First, I provide an update to the Commission on our efforts to address the needs of our energy delivery (i.e., distribution) system as part of the Company's Smart Energy Plan. Second, I report on our ongoing collaboration with the Missouri Public Service Commission Staff ("Staff") and the Office of the Public Counsel ("OPC"), which arose out of our agreements with them as part of resolving our last electric rate review, File No. ER-2021-0240.

Q. Please summarize the Company's investment strategy when it comes to its energy delivery system.

A. As Ameren Missouri witness Mark Birk outlined in his rebuttal testimony in File No. ER-2021-0240, we are engaged in a multi-year effort to make foundational investments in our system needed to modernize and upgrade it given that many of its components are aged or obsolete, and in many cases are near, at, or past their expected design lives. We are making those investments across five main categories – system hardening, substations, underground cable upgrades, revitalization of the Downtown St. Louis underground network, and grid resiliency. In addition, we are investing in a sixth category, smart grid technology, to provide customers multiple benefits. Taken together, this program is designed to get our grid into a condition that will enable us to provide reliable service for decades to come, including laying the necessary foundation for the enhanced demands that will be placed on the distribution grid as greater and greater quantities of distributed energy resources ("DERs")[1] come onto the system.

Q. What are the details of the six categories of investments you listed above?

A. Those details are addressed in Schedule RMA-D1 to my testimony. Schedule RMA-D1 is a slide deck that we discussed in detail with the Commission's Staff and OPC in our first of a series of discussions with them about how we proposed to evaluate and document justification for the investments we are making in these categories. The schedule contains details and data on the age and condition of many components of our system, how that relates to the investment need, what our plans for the next five to ten years are, and where we will stand on addressing system needs in these categories once we execute our plans over the next five to ten years.

Q. Could you please provide a couple of examples?

A. Sure. I will touch on a few slides in the system hardening and substation categories. Slide 9 of Schedule RMA-D1 shows that 39% of our subtransmission circuits (approximately 1,600 miles) – these are the circuits connecting substations to substations across our large service territory – are already older than their expected life, with another 25% approaching that point. On average, these assets are 37 years old versus an expected life of 45 years. As the slide indicates, we start to see failure rates that are several multiples higher than newer equipment once it reaches an age of 31 years or more, with even more failures once it reaches 45 years. As slide 13 shows,

[1] DERs can include a myriad of items, such as solar panels, batteries, hot water heaters, electronic thermostats, and electric vehicles.

we are investing at a level designed to replace approximately 55 miles per year through 2033. Additionally, when we execute upgrades to these aged assets, we are building to a current design standard that includes stronger wood and composite poles, wind and ice deflecting wire, as applicable, and standoff insulators or composite cross arms, all of which will provide customers more reliable service for decades to come.

Another example is our distribution substations. Approximately 280 out of 530 of these substations serving over 600,000 of our customers contain critical components that are, today, beyond their expected lives. Consequently, as shown on slide 19 of Schedule RMA-D1, we are working to replace 70 of those substations (including those replaced starting in 2019) through 2023 and another 210 by 2033. We are addressing these aged assets with current design standards that include fully enclosed switchgear housing, remote communication and control abilities, and sufficient capacity to serve customers well into the future. Additional information on these two categories is provided in Schedule RMA-D1, as well as data and information on the other six categories.

Q. When will refreshing these items and making these foundational investments wind down?

A. There will of course always be a need to continue to replace system components, and the length of the period needed to fully refresh the assets varies by category. We expect to essentially be done with this effort for the Downtown St. Louis underground system by 2028. For substations, if we are able to maintain our planned investment levels, we believe we can get the average age down to a level by approximately 2035 where we can reduce the annual investment in this category by a bit more than one-half of where it is now and where it is expected to be over the next 10 years or so. As we sit here today, we would expect our smart grid investments to reduce from current annual levels after about 2028. The timelines for other categories vary, and for all of the categories we do look at the needs and the progress toward meeting them on an ongoing basis; certainly, each year as we develop our one- and five-year investment plans.

Q. You referenced ongoing collaboration with Staff and OPC arising out of the resolution of the Company's last electric rate review. Could you please update the Commission on those efforts?

A. As the Commission knows, we agreed to meet with Staff and OPC on at least three separate occasions to discuss the categories or projects I referenced above. In sum, the goal from my perspective is to develop more formalized evaluation methodologies that we could apply to investments in these categories and document starting in 2023. We also agreed to consider their input on these topics. The evaluation methodologies will have at least one (and in some cases likely more) quantifiable aspects to them, and will also capture qualitative considerations, which are especially important given the nature of the investments we are making. In June, we provided Staff and OPC with drafts of evaluation methodologies for three of the six categories, which I have attached to my testimony as Schedule RMA-D2. In late June, we met with Staff and OPC to discuss the methodologies and get their feedback. From my perspective, that meeting reflected that there was an alignment among all parties that the methodologies take the right approach, are reasonable, and will be useful to Staff and OPC in reviewing our investments in future rate reviews. We will be making some minor updates based on feedback from OPC and Staff, including providing baselines in the methodology, to those three categories we discussed and providing methodologies for the other three categories, and then will meet again in early September. I am optimistic that we will align on the appropriateness of the methodologies.

Q. Has this collaboration been helpful?

A. From my perspective, yes. We view these discussions as an opportunity to increase transparency on what we are doing and why we are doing it, and to get better at explaining the projects we need to complete in order to refresh and maintain our vast energy delivery system, which in the end we believe will serve to benefit our customers. It is very obvious to us that our system has very significant needs and will continue to have significant needs for some time, but it is of course a good thing to align with Staff, OPC, and others and formalize as much as we reasonably can, and explain the reasons why we are doing which projects when. This is so we can get the most bang for our buck so-to-speak as we replace these aging components and otherwise modernize our system.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Ameren Missouri Energy Delivery Investments Discussion:

April 6, 2022

Agenda

First of a Series of Three Meetings (or more, as needed)

1. Introduction – Tom Byrne
2. Presentation Regarding Energy Delivery Investment Needs and Plans
   - Kevin Anders
   - Ryan Arnold
   - Jim Huss
3. Next Steps – Tom Byrne

State of the Missouri Grid

Ameren Missouri's Service Territory

Ameren Missouri delivers electricity to ~1.2M customers across 33,000+ circuit miles (including over 800,000 poles), 62 counties and more than 500 communities

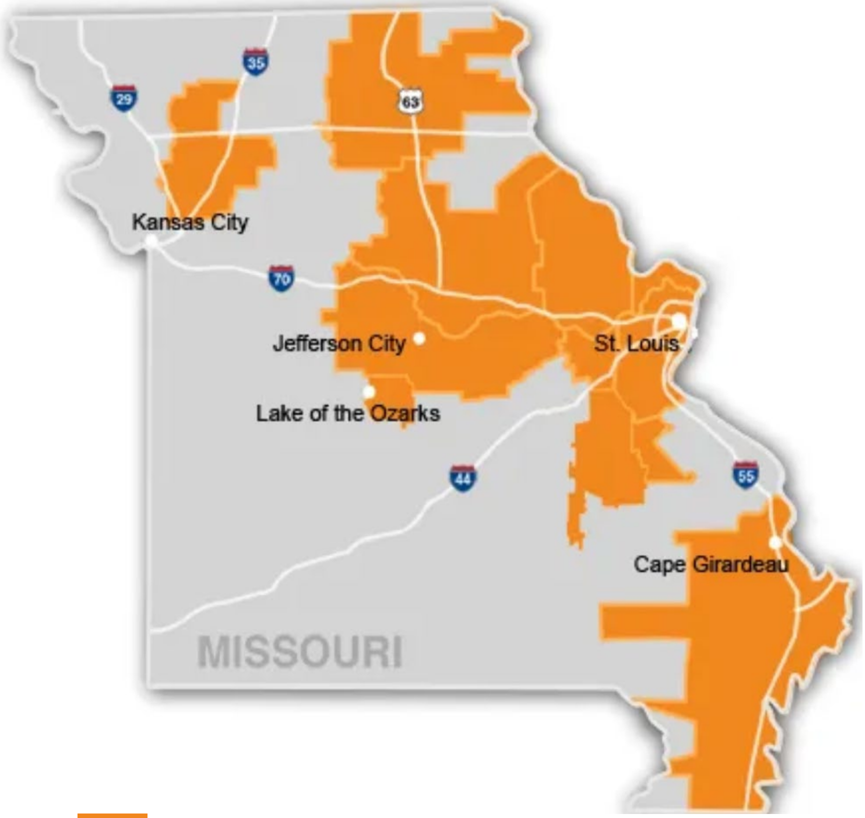
Overview

- Much of Ameren Missouri's existing system was built-out during the 1950's and 1960's.
  - This was a period of increased electricity use driven by **significant suburbanization, increased use of air conditioners and industrial growth**
  - Today, decades later, Ameren Missouri must upgrade these aging assets, not only to reduce equipment failures but also to continue to meet the expanding needs of our customers
- When SEP investments began in 2019, **over 250 of our distribution substations** contain either a transformer or circuit breaker that was installed more than 50 years ago.
  - These substations with aged critical components serve over 500,000 of our 1.2 million customers.
  - If we had not begun upgrading our substation fleet in 2019, by 2023 over 50 additional distribution substations serving an additional 200,000 customers would have a critical component reach 50 years of age.

Electric System	# of Circuits	OH Miles	UG Miles	Total Miles
Distribution	~2,300	~21,300	~7,600	~28,900
Subtransmission	~470	~4,200	~300	~4,500
Total Line Miles	**~2,770**	**~25,500**	**~7,900**	**~33,400**

Substation Type	Total Number of Substations
Distribution Substations	~530

Ameren Missouri's Service Territory



Ameren Missouri Service Territory

Our System Continues to Age

As our assets continue to age and approach or exceed end-of-life, they contribute to reliability issues and safety risks

- As the system continues to age, many of Ameren Missouri's assets are nearing or exceeding their expected life
  - End-of-life assets lead to an ever-increasing chance of failure due to malfunction or breakage
  - Additionally, many assets deployed more than 50 years ago were built to standards now generally considered outdated and not sufficient to reduce or prevent outages
- Aging assets pose a significant and ever-increasing risk due to their susceptibility to failure
  - Substantial portions of Ameren Missouri's distribution grid require upgrades:
    - ✓ ~325 substation transformers are currently over expected life
    - ✓ ~250 substation Oil Circuit Breakers (OCBs) are currently over expected life
    - ✓ ~775 substation Air Circuit Breakers (ACBs) are currently over expected life
    - ✓ ~2,900 miles of Underground Cable is currently over expected life, with another ~700 miles quickly approaching expected life (next 2-8 years)
  - Almost 1,600 miles of subtransmission have end-of-life assets requiring upgrades, including poles, cross-arms and insulators, and brittle conductors
    - ✓ ~39% of poles are currently past their expected life

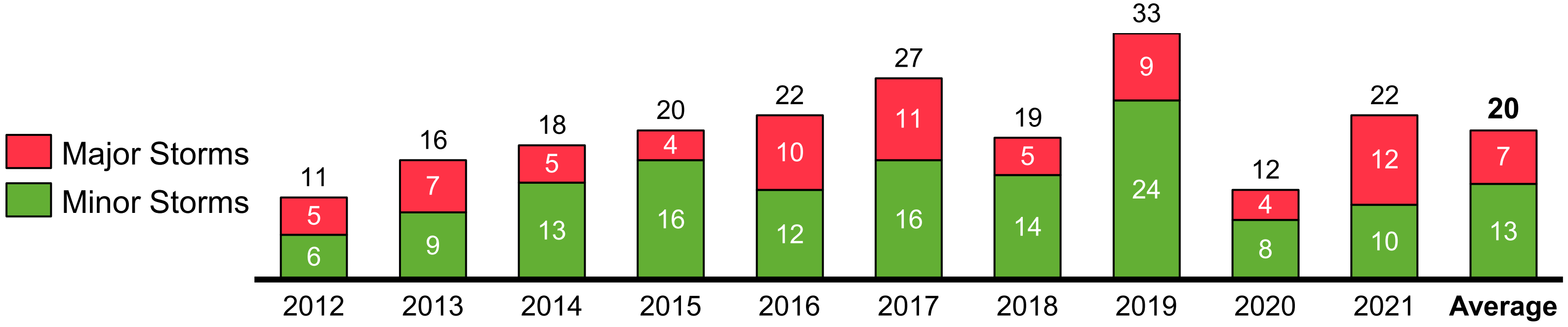
> “*Most of the nation's transmission and distribution lines were constructed in the 1950s and 1960s, with a 50-year life expectancy, meaning they have reached or surpassed their intended lifespan.*”
>
> **American Society of Civil Engineers**
> “Failure to Act: Electric Infrastructure Investment Gaps in a Rapidly Changing Environment”
> 2020

Our System Is Increasingly Impacted By Weather & Other Major Events

Ameren MISSOURI

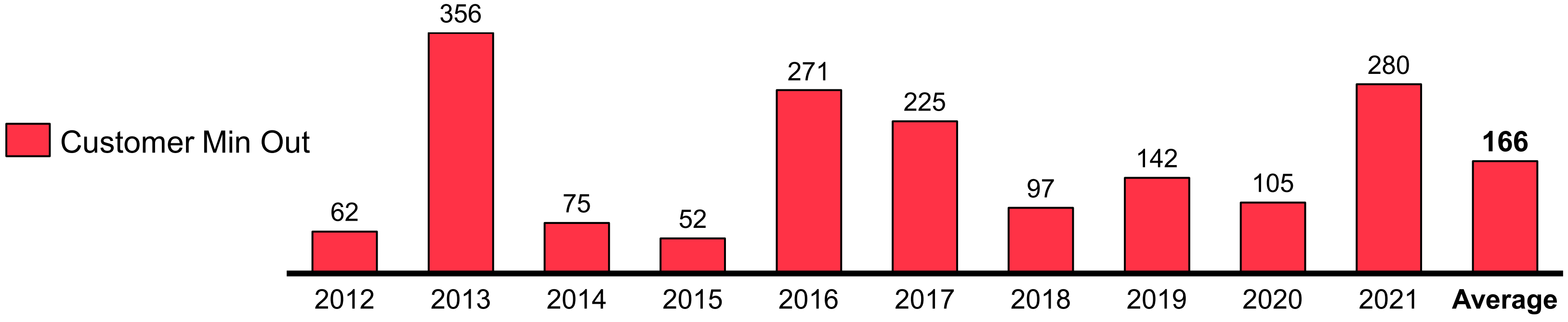
While our reliability metrics have held up relatively well (w/o considering storms), aging infrastructure poses an increasing risk to performance, esp. during storms

Major and Minor Storms for the Previous Ten Years



On average, number of major storms from 2017-2021 rose nearly 32% compared to 2012-2016

Customer Minutes Out Due to Storms (Million Minutes)



On average, customer minutes out from 2017-2021 rose nearly 4% compared to 2012-2016

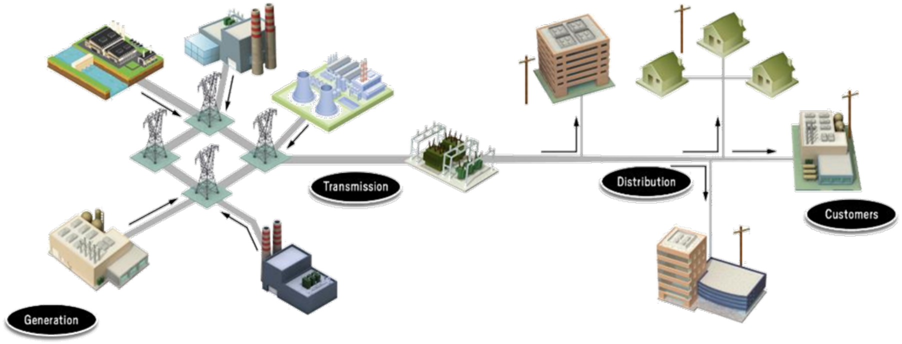
[1]Geophysical Research Letters, *Increasingly Powerful Tornadoes in the United States*, December 2018.
[2]Environmental Protection Agency, *What Climate Change Means for Missouri*, 2016.
[3]NOAA's National Centers for Environmental Information, "Missouri Billion-Dollar Weather and Climate Disasters: Time Series", 2021.

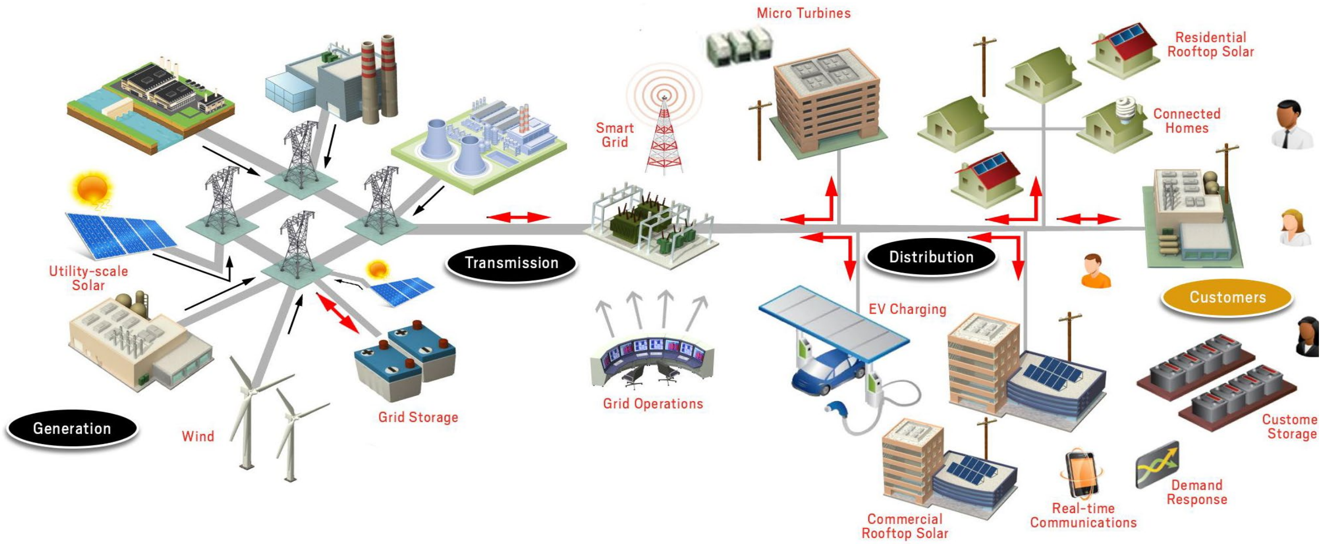
Key Takeaways:

- **Storms and extreme weather events have a significant impact on system reliability**
- The worst outages on Ameren Missouri's system are usually caused by major storms and these events are **increasing in both frequency and intensity**:
  - ✓ Tornadoes and windstorms have increased 5.5% annually during the last decade[1]
  - ✓ Annual precipitation has increased 5 to 10% during the last 50 years[2]
  - ✓ Rainfall on the four days per year with the greatest precipitation has increased 35% and the worst flooding has increased 20%[2]
- This has led to ever **more frequent major damage and significant losses due to these extreme events**
  - ✓ The average number of billion-dollar climate disasters in Missouri over the last ten years was ~4, which is a significant increase compared to the average from the prior ten years, ~2 disasters annually[3]

Building Today's Grid into the Grid of the Future

The journey towards the grid of the future starts with securing the foundational infrastructure of today's grid as the platform for the what's to come





Today

- Grid – Reliable, efficient, meets peak demand, aging infrastructure, one directional energy flow
- Customer – Homogenous service, few special offerings

Tomorrow

- Grid – Upgraded infrastructure, resiliency, smart technology, sensors and data analytics to drive reliability, efficiencies,
- Customer – Expectations include highly reliable service with few momentaries and quick storm response times

Category Discussion:
System Hardening

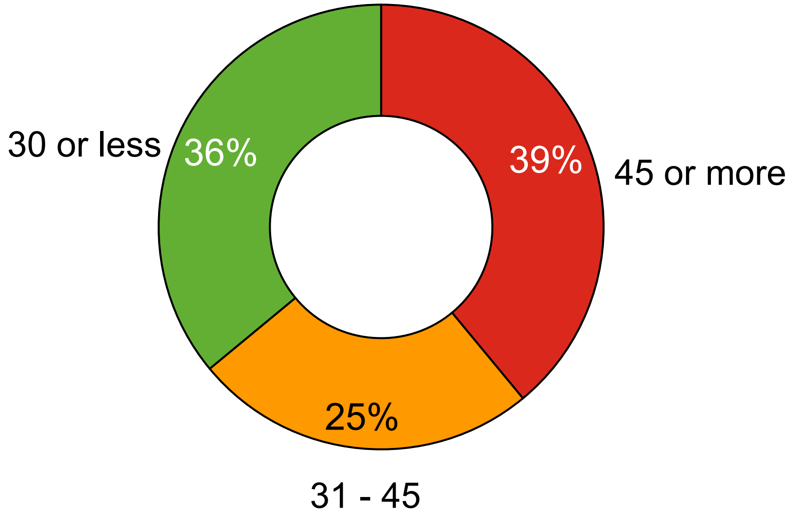
The Infrastructure That Supplies Dx Substations Is Rapidly Aging

Each subtransmission circuit feeds an average of 2,500 customers, ~39% of them have a majority of assets that are beyond their expected life

Asset	Total OH Miles	Expected Life (Years)	Timeline to Refresh System at Current Investment Levels	Current Average Age of the System	Miles Over Expected Life Today	# of Customers Served by Old Asset
Subtransmission System (Proxy: Wood Poles[1] Age)	~4,200	45	~76 years (@ forecasted 55 mi/yr.)	~37 years	~1,600	~460,000

[1]On average, one line mile includes 26 poles

What's the distribution of the age of our poles (years)?



What's the inspection failure rate by age group?

**Based on ground line inspections*

1. Poles age 31 – 45 are **four times more likely** to fail inspections than those 30 or less.
2. Poles age 45 or more are **eight times more likely** to fail inspections than those 30 or less.

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected life

We See The Impact Of An Aging Subtransmission System

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As equipment and hardware age, there is an ever-increasing chance of causing customer outages

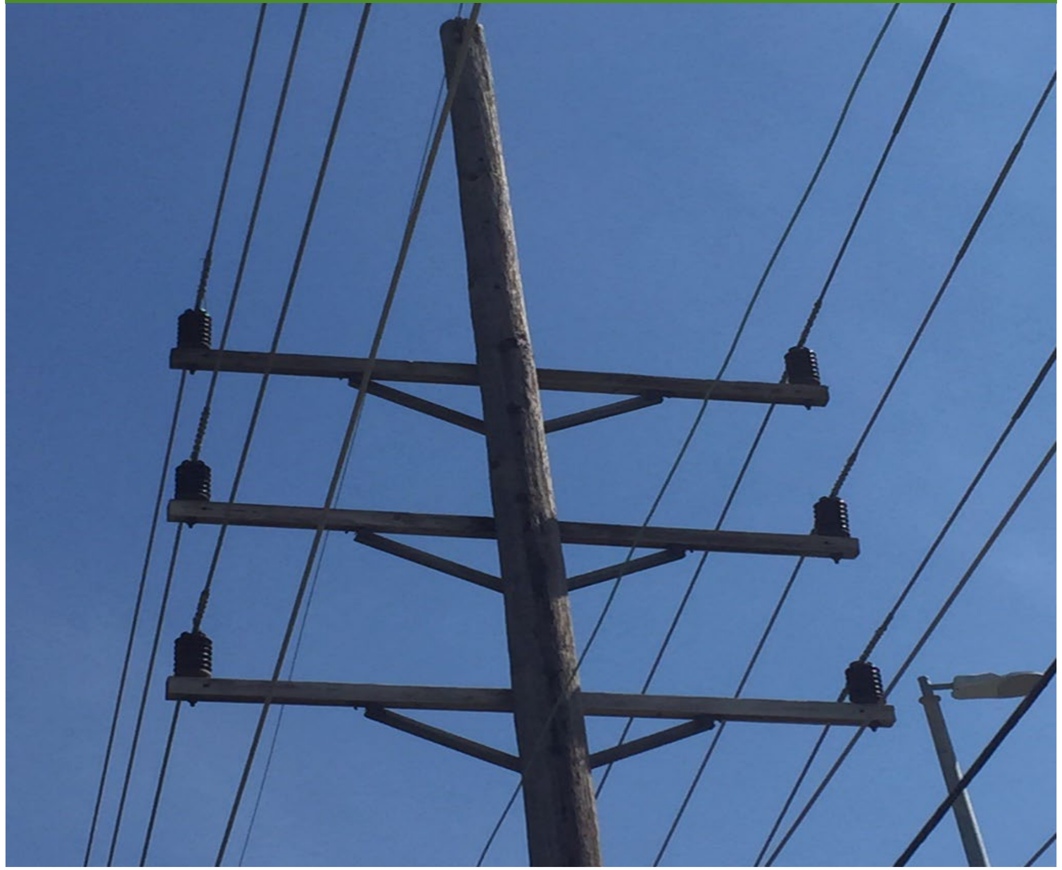
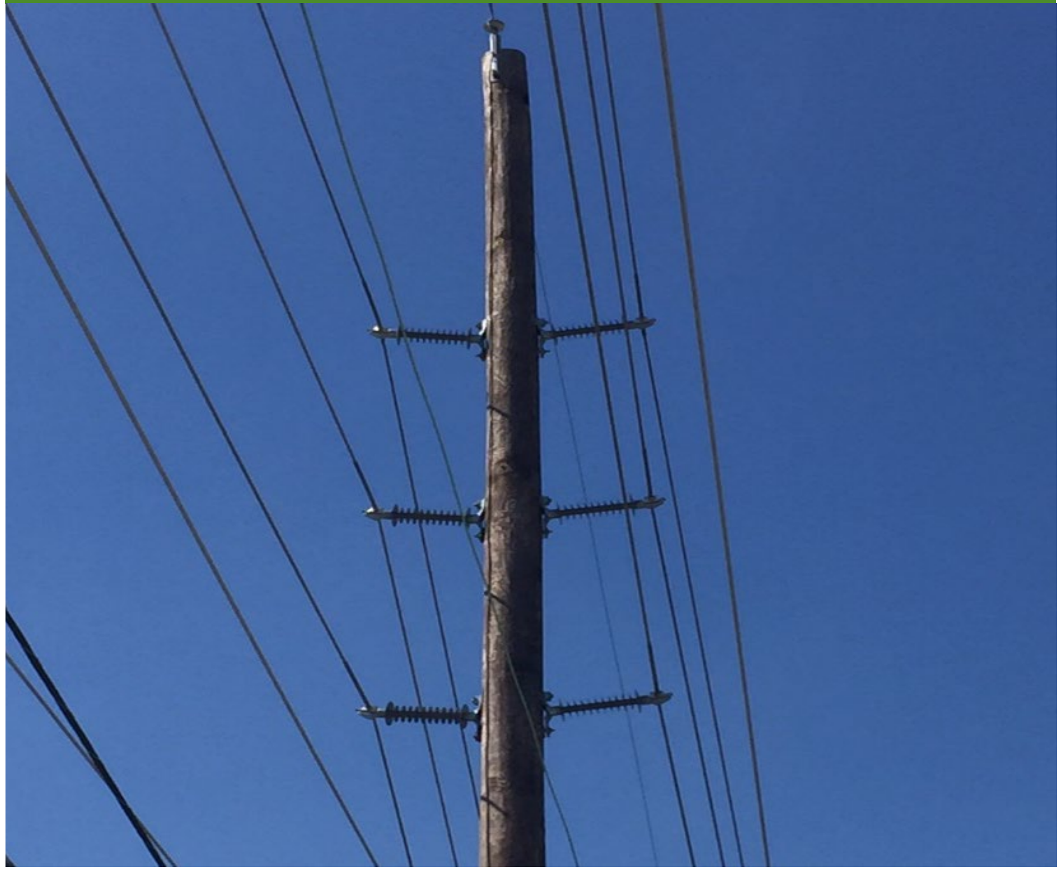
Narrative

- The photo illustrates the fragility of an aging system
  - In this case, a single insulator caused the cross-arm and pole to catch fire resulting in a circuit outage
- Tree damage, lighting damage, or aging insulators can create an extended power outage on a large portion of our existing facilities that were built with a previous design standard
- One damaged piece of hardware took this entire circuit out of power

We Are Upgrading The System With A Modern Design Standard

Ameren MISSOURI

The new standard reduces the number of potential failure points, increasing the resiliency of the system, while making it easier and safer to operate

Before: Previous Design Standard	After: Updated Design Standard
	
<u>15 total</u> pieces of hardware (minus bolts)	<u>6 total</u> pieces of hardware (minus bolts)

We Are Upgrading The System With Stronger Poles

Use of composite poles allows for faster restoration, even with a direct impact from a tornado

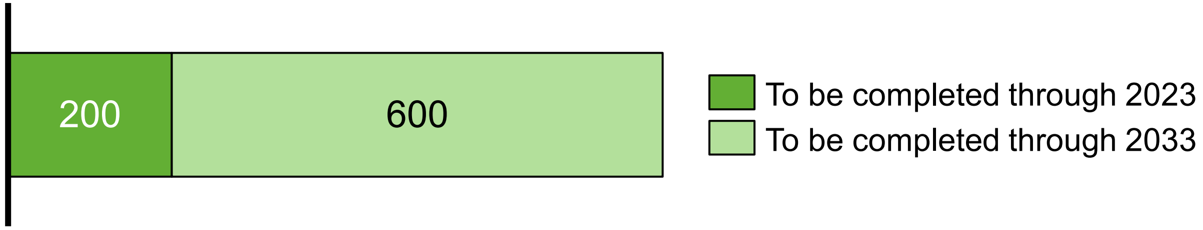
Non-Hardened Line, Cascading Failure

Hardened Line, Limited Cascading Failure

Subtransmission Hardening Plan & Refresh Rate

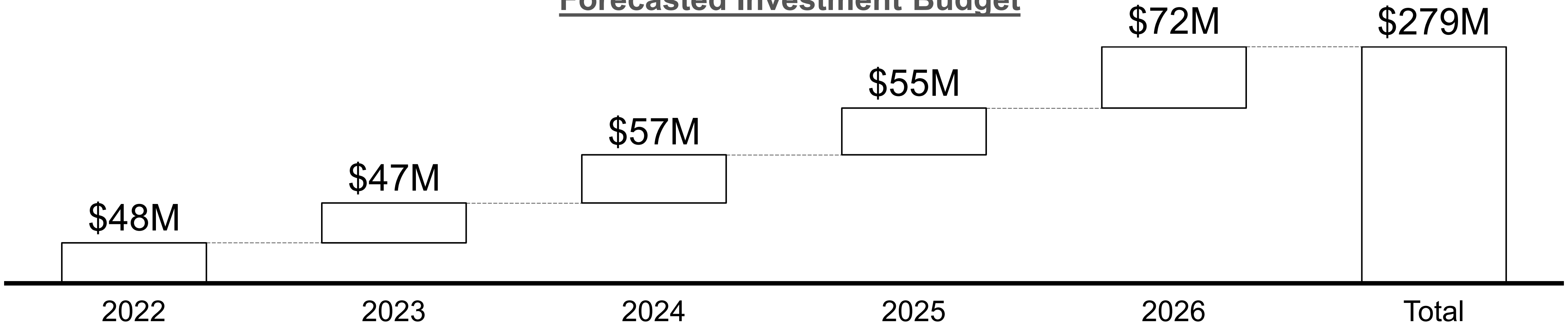
While current investment levels help reduce the degradation, the system is still aging beyond its expected life

Upgraded Power Line Miles[2]



Miles of OH Subtransmission	Forecasted Average Yearly Upgrades	Required Yearly Upgrades to Maintain System
~4,200	~55 Miles	~90 Miles

Forecasted Investment Budget



[2]*Long-term targets are contingent on funding levels*

Category Discussion :

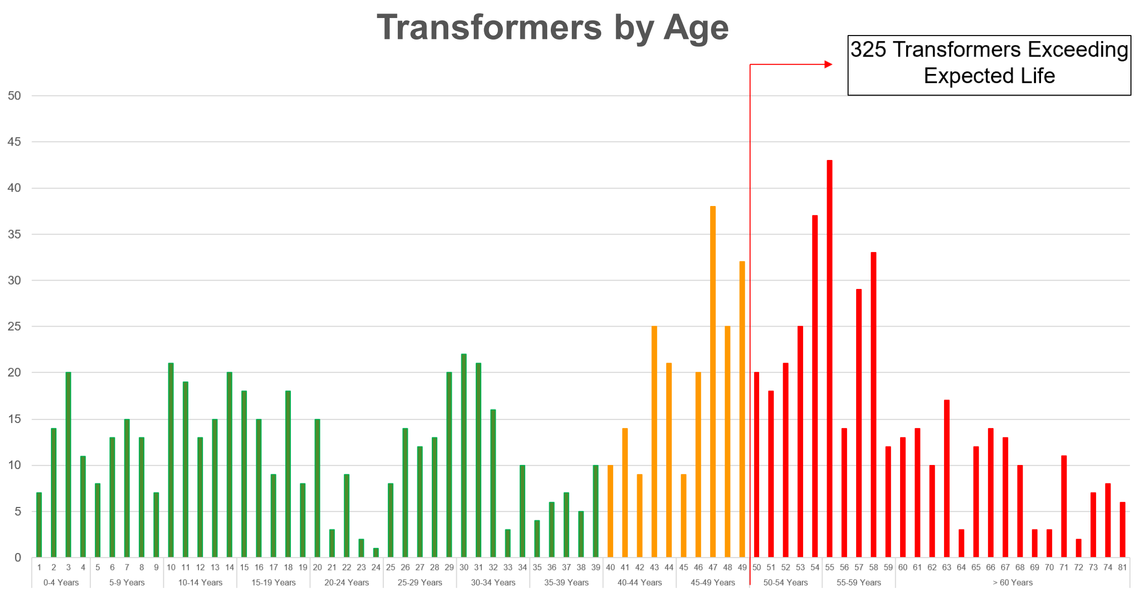
Substation – Condition Based Monitoring

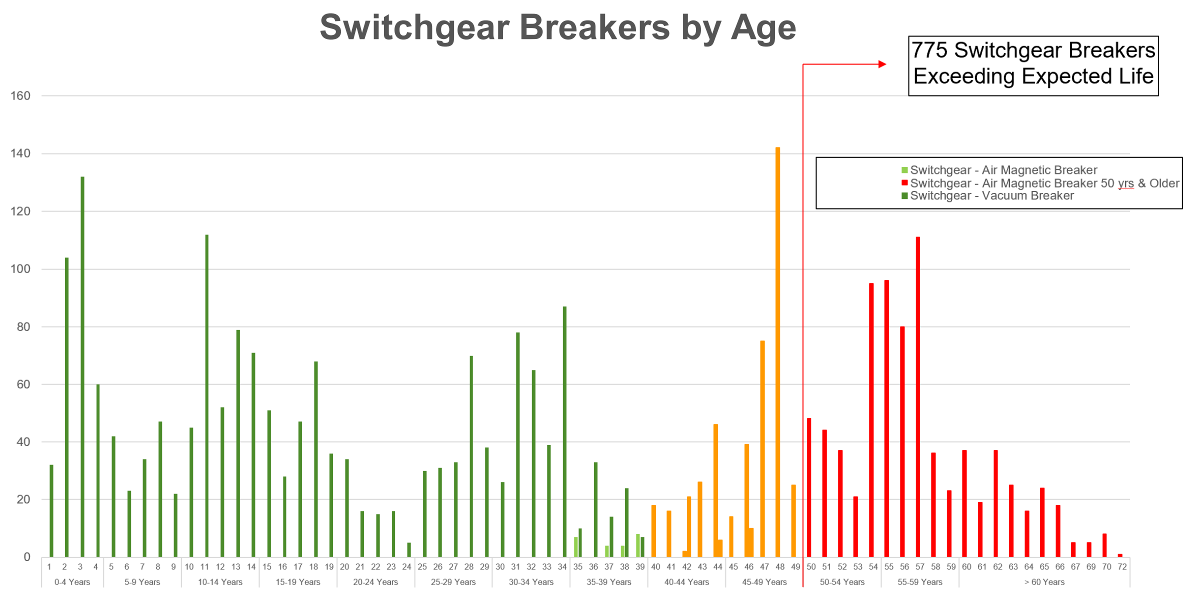
Ameren MISSOURI

Distribution Substation Key Components

Distribution substations, with critical components beyond their expected life, serve over 700,000 of our ~1.2 million customers

Asset Type	Total Distribution Assets	Expected Life	Average Age (Years)	Assets Over Expected Life	Customers Served by Assets over expected life
Transformer	~900	50	**~41**	~325	~450k
OCBs	~350	50	**~53**	~250	~700k
ACBs	~1,200	50	**~53**	~775	~400k

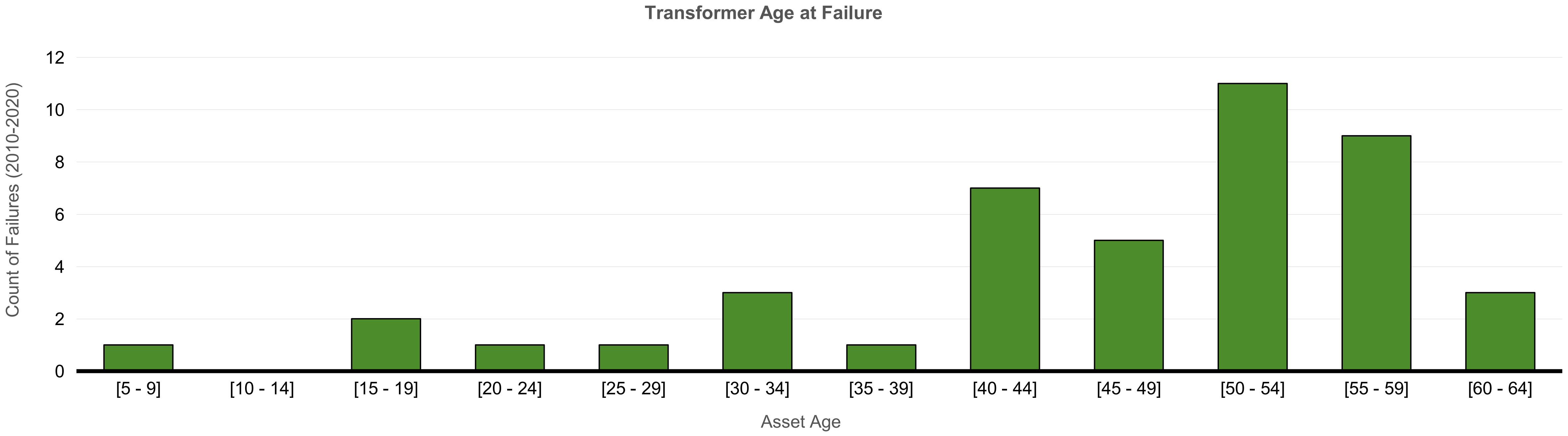




Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected life

Expected Life of Substation Transformers – 50 Years

Transformer Failure Data Illustrates Risk Of Aged Assets, Particularly At 50+ Years Old And Confirms That Certain Vintages Are Problematic (1960 To 1969)

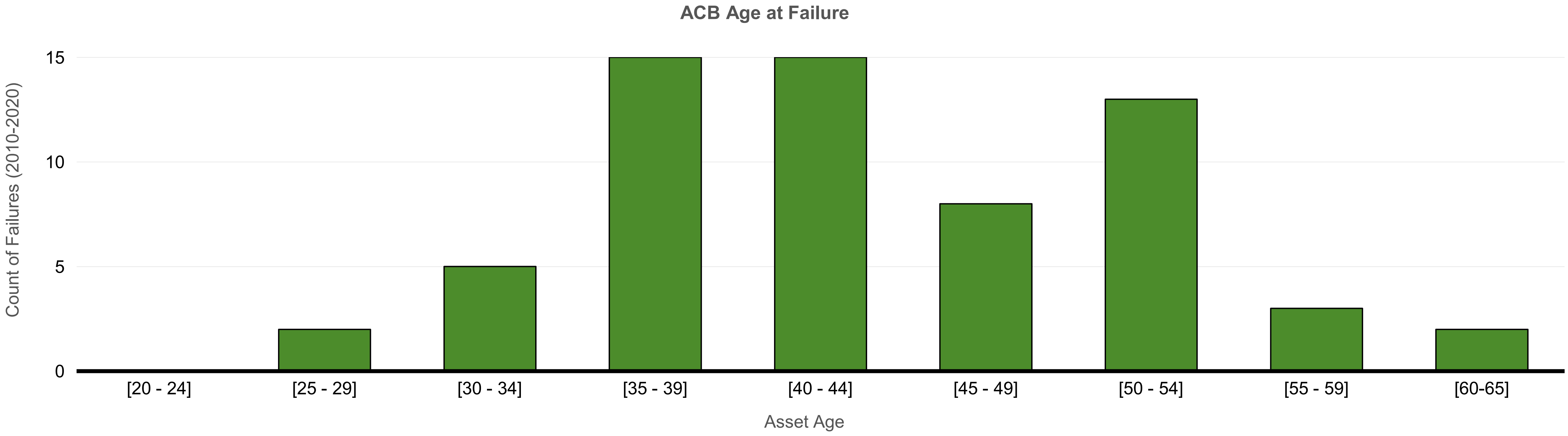


Observations

- **Transformer Age at Failure**: Transformer failures increasingly occur as assets near and exceed 50 years in service.
- **Manufacturer Year of Transformer at Failure:** Most of the transformers experiencing failures were manufactured between 1960 and 1969, suggesting that these units are failure prone. In particular, from 1964 to 1969, manufacturers were producing transformers quickly with lower quality in response to a rapid increase in demand from the growth of the electrical system from around the country.

Substation ACB Failure Trends

ACB designs are more complex and generally less reliable than modern technology and standards



Observations

- **ACB Age at Outage**: Greater counts of outages around 35-45 years old
- **Asset Design Challenges:** The air blast technology used across the industry up to the 1980's has proven to cause stress on the asset components due to the force exerted to extinguish the electrical current and arc. Over time, this repeated circuit breaking operation impacts the asset's future ability to successfully break the flow of electricity and restore service as intended.

Instances of Substation Asset Failures

Substation modernization will support customer reliability and co-worker safety by mitigating risk of asset failure

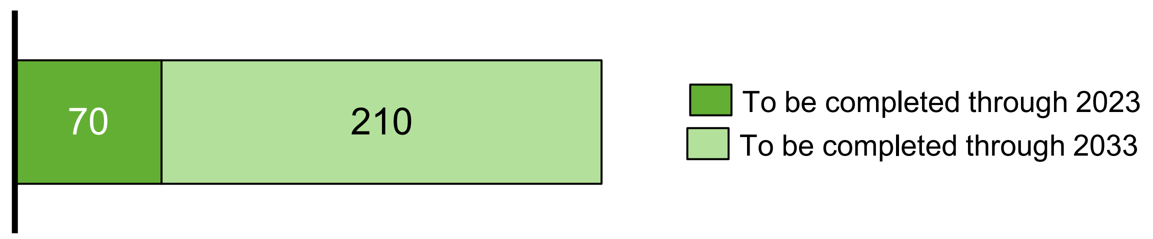
Transformer Failure (O'Fallon 21)

Switchgear Failure (Mullanphy)

Substation CBM Plan

While current plan helps slow the rate of degradation due to an aging system, assets are still aging past their expected life

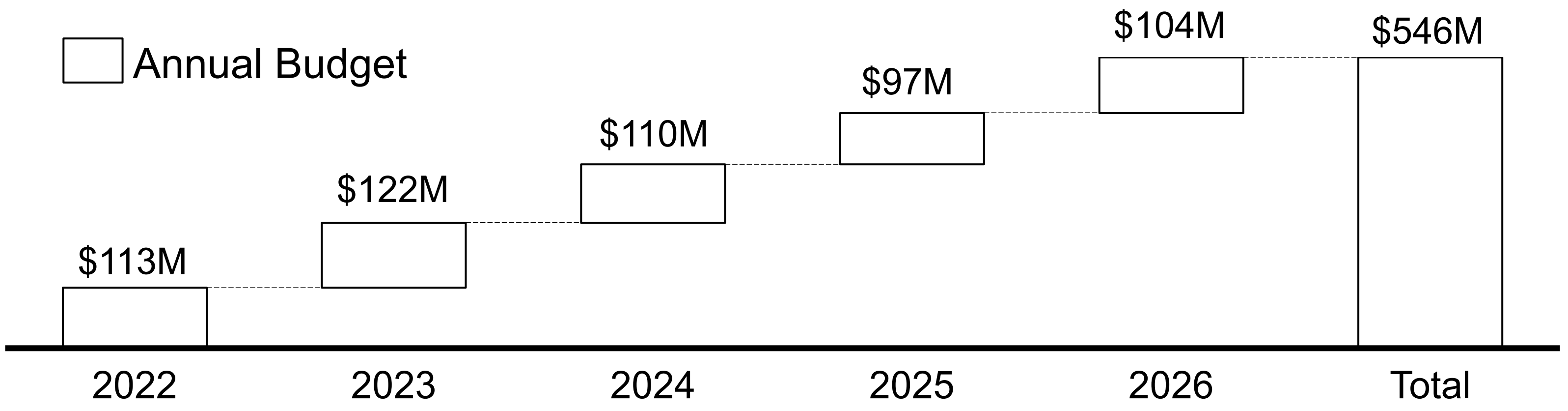
Upgraded Substations[1]



[1]Long-term targets are contingent on funding levels

Asset	Pre-SEP Investment (2019) Avg Age	Current Investment Levels (2023) Projected Avg Age
Transformers	~37 years	~39 years
ACBs	~50 years	~54 years
VCBs	~18 years	~19 years

Investment Timeline



To proactively replace aged equipment prior to failure:

- Substation CBM investments need to average ~**$120 Million per year for the next 12 years** (2023 - 2035)
- After 12 years, Substation CBM investments could **levelize at ~$50 Million per year** (post 2035)

Figures above do not include inflation

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected life

Category Discussion :

Underground Cable Upgrades

The Age of Our Underground System Continues to Increase

2,900+ miles of our underground system has already exceeded its expected life, and presents an increasing risk to customer reliability and safety

URD Cable Vintage	Mileage	Cable Age (Years)	Expected Life (Years)	Lateral Failures per Mile
First Generation & Older	**~850**	**45+**	40	2.42
Second Generation	**~1,600**	**38 – 45**	40	1.70
Third Generation	**~700**	**32 – 38**	40	1.22
Fourth Generation	**~4,300**	**Present - 32**	40	0.88

Obsolete Feeder Exit Cable Type	Mileage	Cable Age (Years)	Expected Life (Years)	Feeder Outages Due to Lead Cable
Lead Cable (PILC)	**~450+**	**32 – 101**	60	~60 outages per year

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected life

Instances of Asset Failure

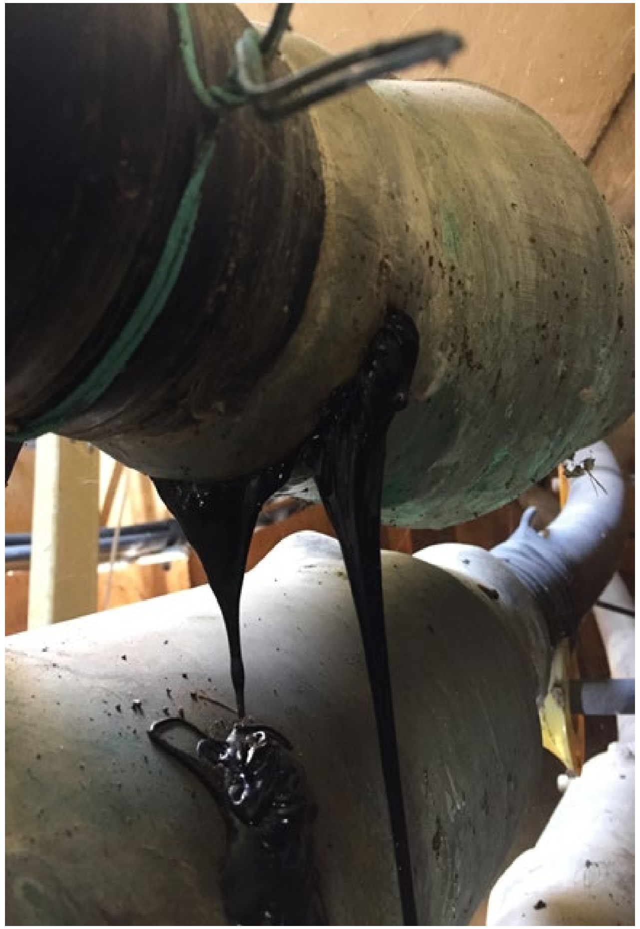
Faulted UG Cable with exposed concentric neutral

Exposed concentric neutral cable in ground with the neutral eroded away

Faulted Direct buried #2 Al Cable with exposed concentric neutral

Abnormal PILC Joints Present Significant Safety Risks to Co-Workers

As the system ages and repairs to PILC become necessary abnormal joints can occur, of which there are many instances recorded across the system



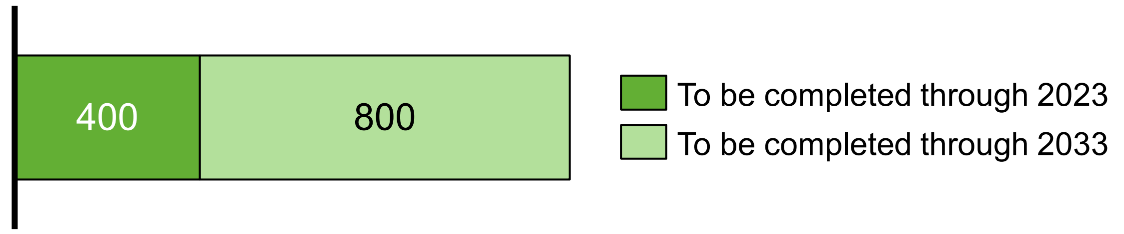
Paper Insulated Lead Cable (PILC)

- Conductor is wrapped in oil impregnated paper which is surrounded by a lead jacket
- Becomes very brittle with age
- Leaking oil causes this cable to present an environmental hazard
- When failures occur, it is commonly repaired in small sections using EPR. This can lead to an abnormal/at risk joint due to imploding and/or swelling at the repair site

Underground Cable Plan & Refresh Rate

While current plan levels help slow system degradation, the system is still aging beyond its expected life

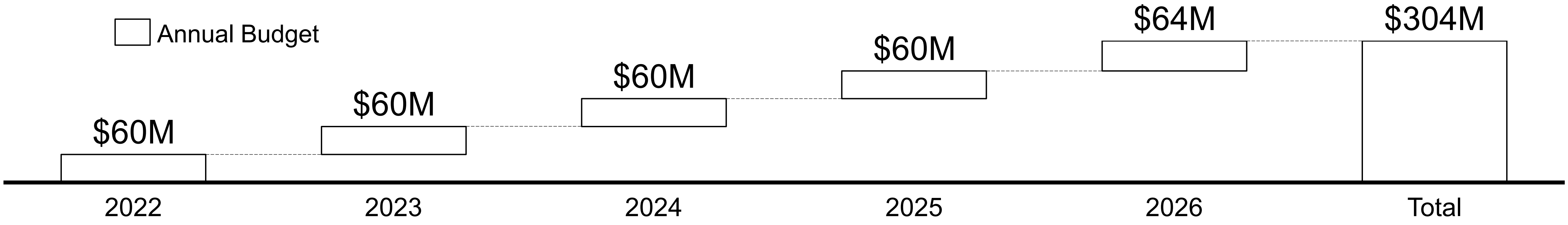
Upgraded Line Miles[1]



Miles of UG Cable	Forecasted Average Yearly Upgrades	Required Yearly Upgrades to Maintain System	Average Age of Cable (years)	# of Customers Served by Aged Asset
7,900	~80 Miles	~200 Miles	URD - 28 Lead - 61	~370,000

[1]*Long-term targets are contingent on funding levels*

Forecasted Investment Budget



Category Discussion :

Underground Revitalization

Underground Revitalization Category Strategy

Underground revitalization will increase reliability and safety by upgrading aging infrastructure and reduce single points of failure

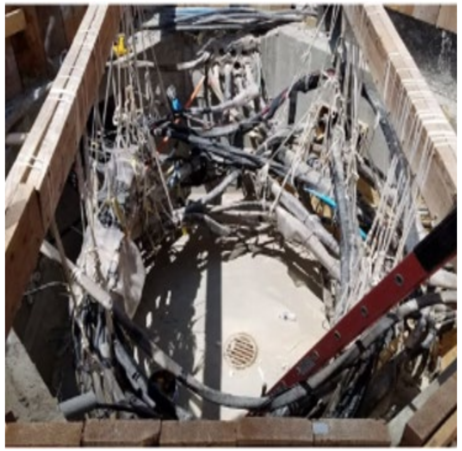
Why Revitalize?

- **Age Of The System**
  - Much of the downtown system was originally installed in the early 20th century
- **Infrastructure Failure**
  - Many original cables and routes are no longer viable due to cable failures and duct bank collapses
- **Lack of Route Diversity**
  - Increased risk of a manhole fire, which could cut power to much of downtown for an extended time
- **Increasing Safety Risk**

Clay tile duct bank in disrepair (still in use with existing fiber)

5” plastic (EB-35) conduit duct face

Abnormal PILC cable joints



Highly congested manhole on 7th St.

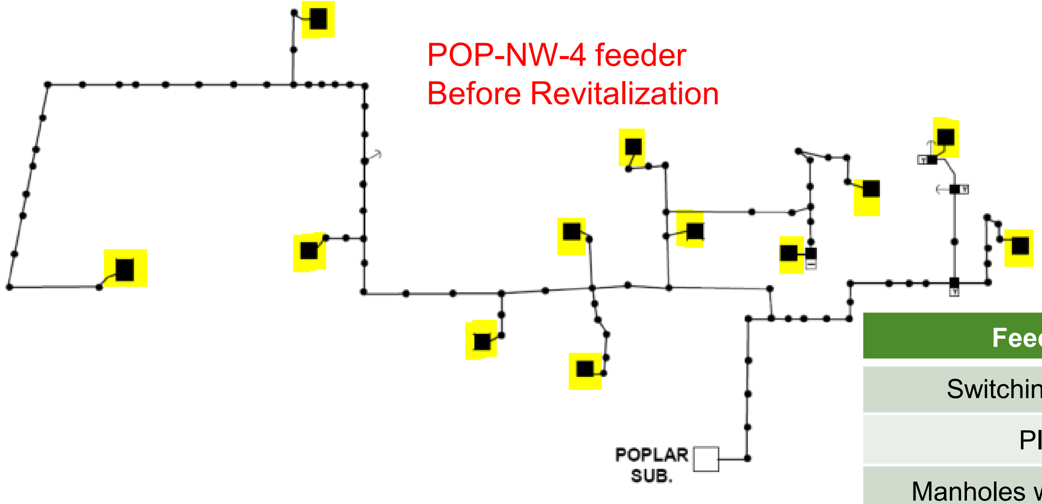
Category Strategy and Related Benefits

Underground revitalization is providing a host of benefits which is positively impacting customers and the community

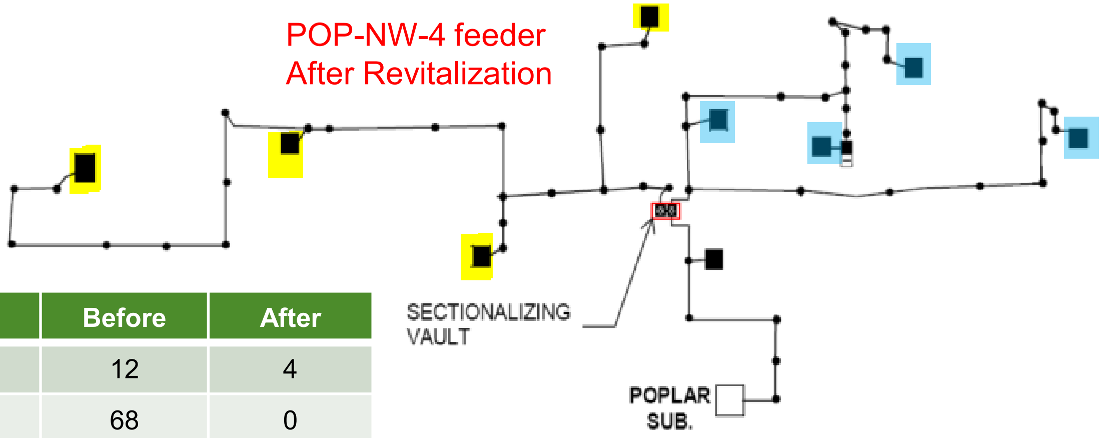
Upgrade Strategy

- **Fully rebuild the Downtown St. Louis system**
  - Conduit replacement
  - Cable upgrades
  - Install pathways for fiber optic command, control, and monitoring protocols
  - Work with the City of St. Louis to limit any potential impact on downtown commerce and street repair/paving efforts
- **Reduce outage frequency and impact risk**
  - Deploy a system where any 2 network primary circuits & any 1 radial circuit can be out of service without additional customer outages or overloading remaining cables
- **3 radial cables and 2 network cables per manhole / duct bank**
  - Limits the risk of one failure impacting many additional cables
- **Limit switching locations to a maximum of 4**

POP-NW-4 feeder
Before Revitalization



POP-NW-4 feeder
After Revitalization



Feeder Stat	Before	After
Switching Locations	12	4
PILC %	68	0
Manholes with > 6 circuits	14	0
PILC Joints	17	0

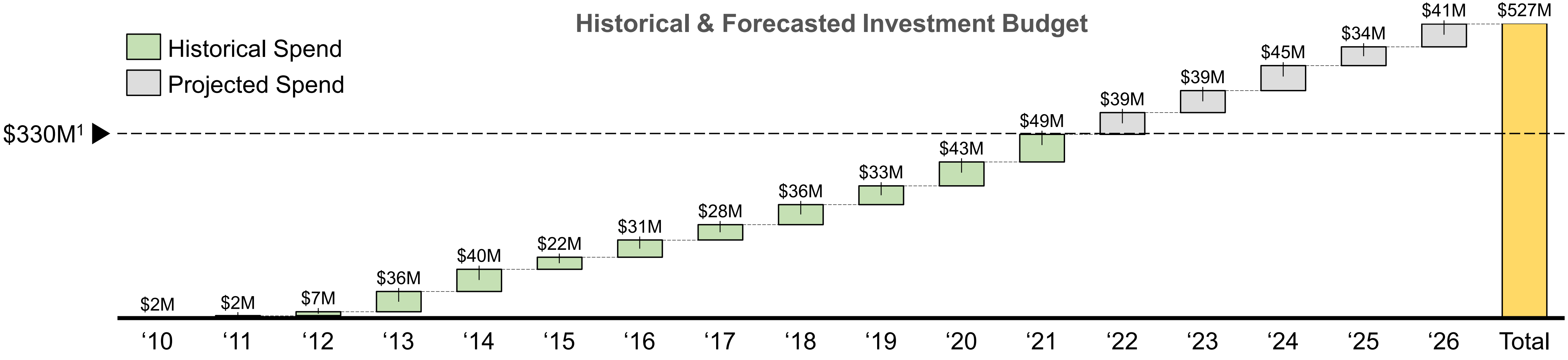
Downtown St. Louis Revitalization Timeline

Our program to modernize the downtown St. Louis grid began in 2010 and will ensure continued safe and reliable service for customers

Asset	Amount
PILC in System	~45 Miles
PILC Joints	~600
Manholes at Risk	~600
Duct Bank at Risk	~2 Miles

Downtown St. Louis UG Revitalization

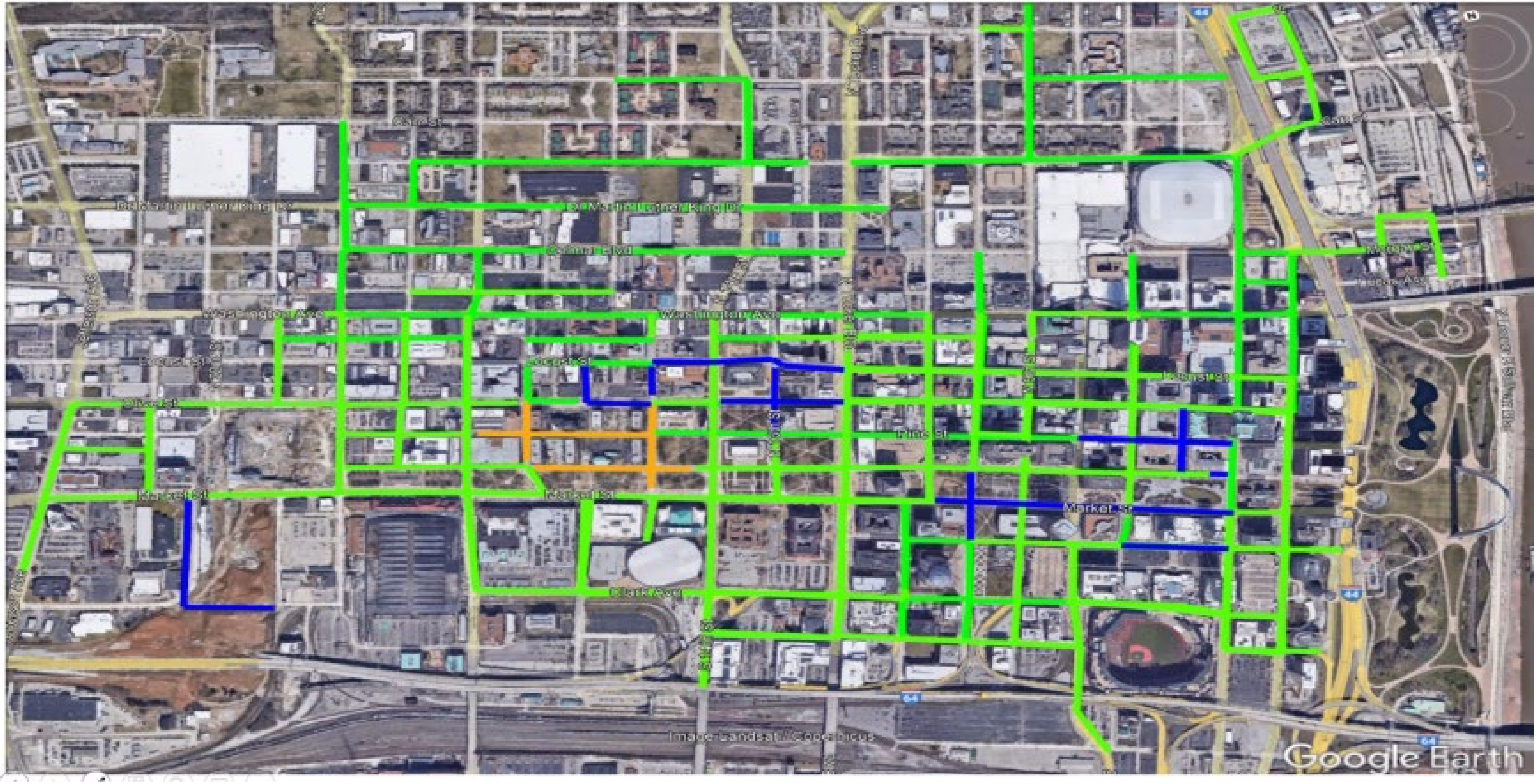
- We have been executing a program to modernize the full downtown St. Louis grid since around 2010
- We expect that once we are complete with this effort, the downtown St. Louis grid will be in place to reliably serve customers for decades to come with only minor ongoing maintenance and minimal capital upgrades



[1]HT=Historical Total (2011 -2021 Budget)

Downtown St. Louis Upgrades

Green lines indicate 5” PL duct banks constructed since 2012, blue lines are duct banks in construction, orange lines are future planned work



Category Discussion :

Grid Resiliency

Category Strategy and Related Benefits

Grid resiliency investments support customer reliability through the grid's ability to respond and reconfigure during severe weather events and other outages

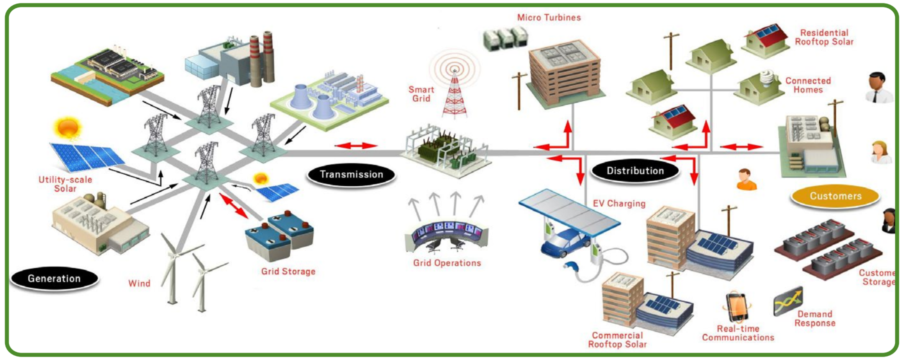
Upgrade Strategy

Grid Flexibility Constraints – addressed on targeted basis

- Line capacity constraints
  - Upgrade conductor to higher capacity rating <u>OR</u>
  - Construct new lines
- Substation capacity constraints
  - Construct new substation <u>OR</u>
  - Upgrade existing transformers <u>OR</u>
  - Add transformers to existing substations
- Convert select 4kV substations to 12kV substations

Why Invest?

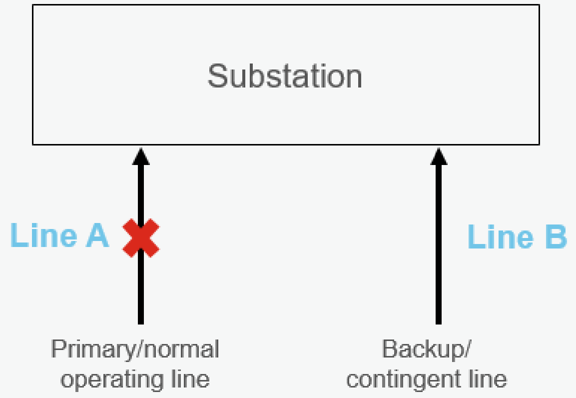
- Conservative operations
  - Operational flexibility
  - Improved ability to handle severe weather events due to the upgrading and replacement of old infrastructure at new standards
  - Less stress on assets & increased asset longevity
- Supports future load growth



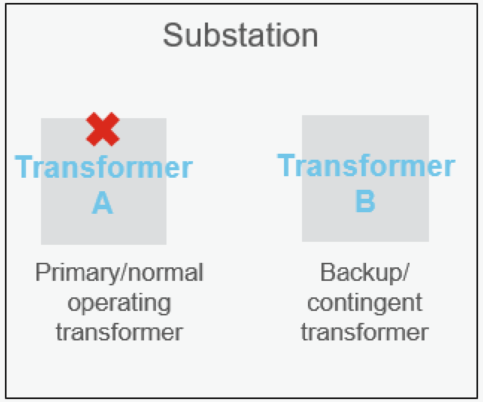
Select Grid Resiliency Projects

Grid resiliency supports customer reliability by providing a contingent supply across lines and substations in the case of a failure or storm damage

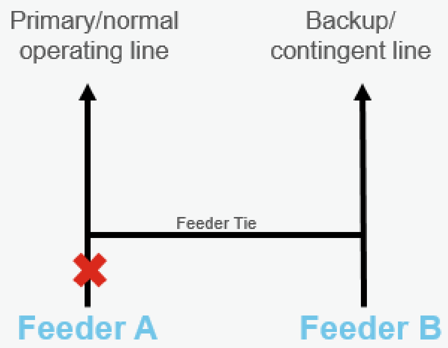
SubTX Line Capacity Increases



Substation Capacity



Distribution Tie Capacity



Select Projects

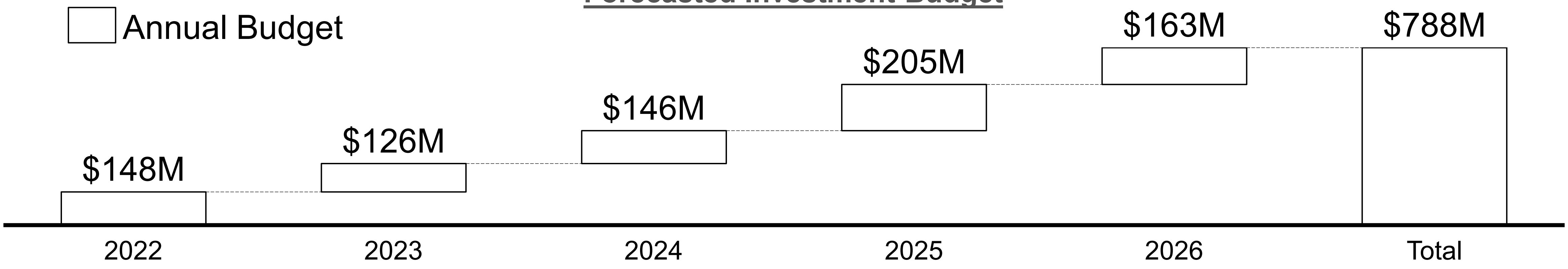
- **Pershall**: This substation upgrade project provides tie capacity to a nearby substation and provides load relief to additional substations in the area which will improve their ability to serve customers
- **Hayti**: A new line was added as the primary supply to Steele substation, leaving the original line as an alternative supply to reduce risk of outages

Grid Resiliency Plan and Timeline

Improving grid resiliency and operating flexibility will ensure continued customer reliability and safe service

Asset	Number at Risk	Customers Served	Timeline to Mitigate at Current Investment Levels
Subs on Manual	~30	~120,000	15 - 20 years
Subs w/ Active ALR	~30	~120,000	15 - 20 years
Load Analysis Risk	~50	~115,000	15 - 20 years
Distribution Line Capacity	Upgrading as needed to provide switching options for faster customer restoration	--	--

Forecasted Investment Budget



Category Discussion :

Smart Grid

Smart Grid Deployment Strategy

Smart grid supports customer reliability through new technologies that enable a smarter and more modernized grid

Strategy

Install Smart Switches System Wide
- Provides increased reliability benefits, up to ~40% improvement
- Allows for fault isolation to smaller zones
- Rapidly restore sensitive loads (hospitals, 911 call centers, large schools, large commercial centers)

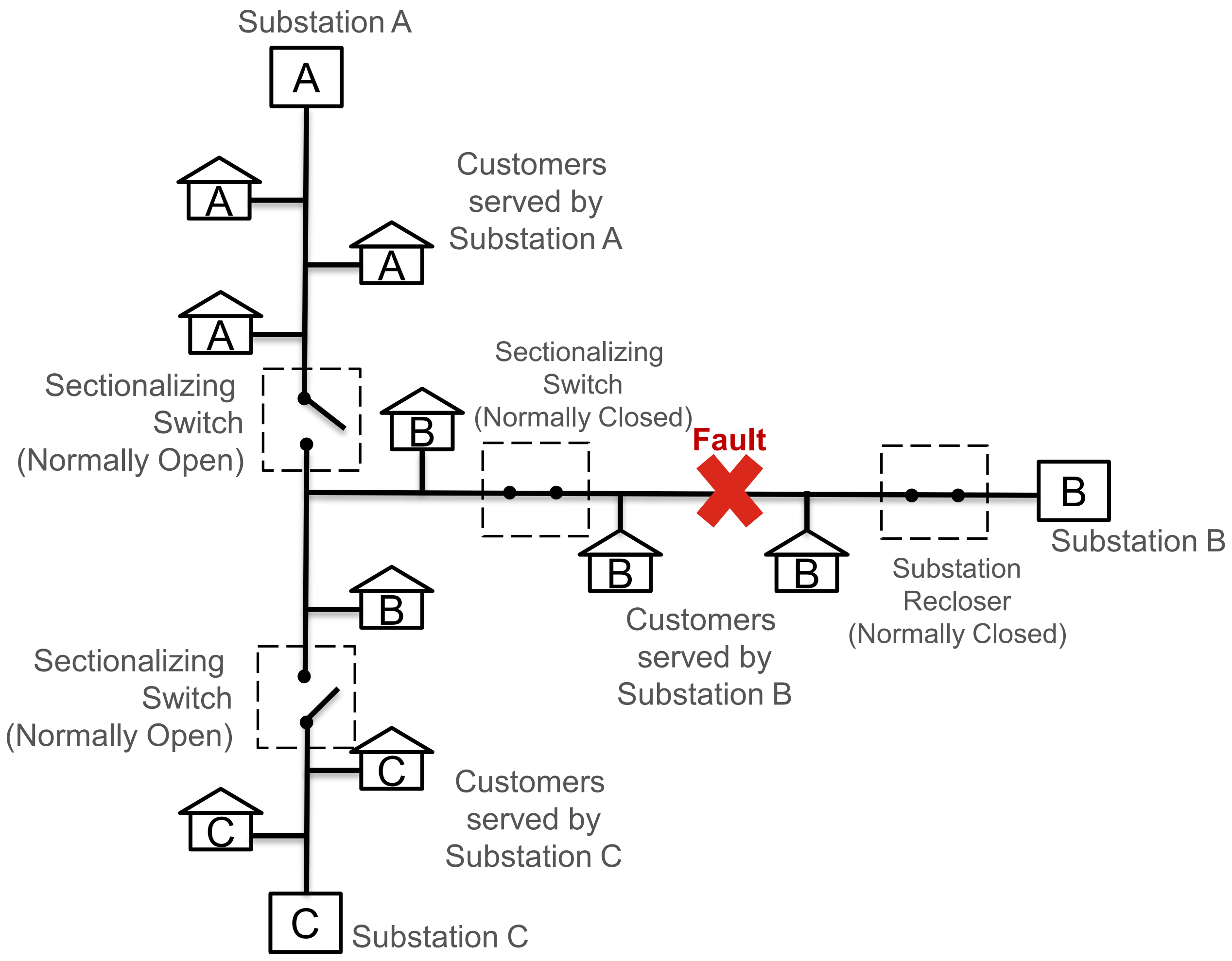
Target installations on yearly 12kV Worst Performing Circuits
- Sectionalizes feeders into sections of approximately 400 customers
- Limits the magnitude of any outage
- Limited 4kV deployment

Install cutout reclosing devices (Tripsavers) in place of fuses
- 140T, 100T, 80T, 65T, and 40T fuses on 12kV
- Help resolve MDI (multiple device interruption) issues
- ~40% of Ameren Missouri's fuse outages in 2018 had no repair action other than replace fuse, reclosers minimize outage time and truck rolls

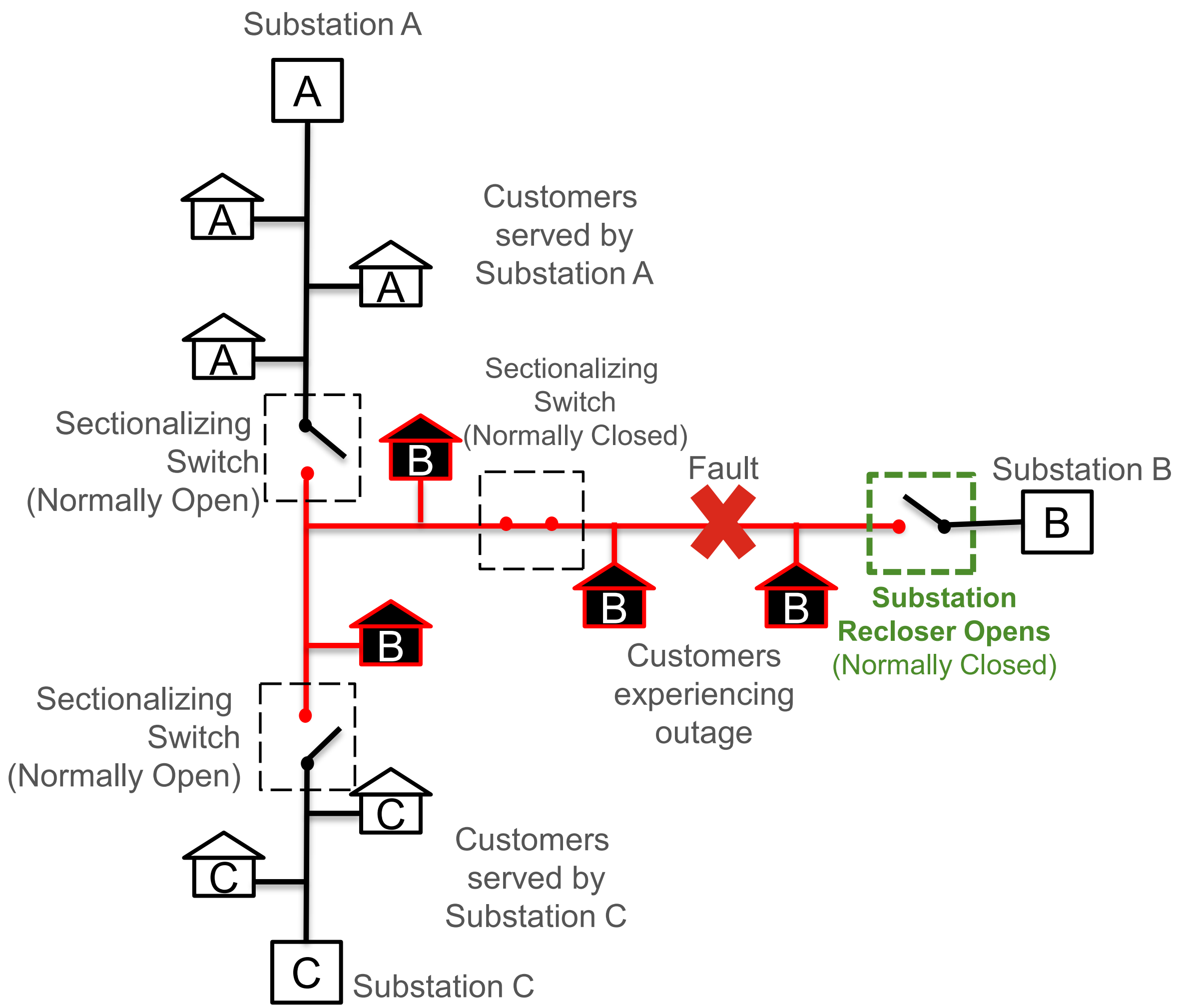
Install FCI's on feeder terminal poles & key midpoints
- More quickly identify the cause and location of an outage
- Rapidly resolve and restore if possible or isolate to smallest zone and quickly restore other customers
- ~12% of all feeder outages are from failing feeder exit cables
- CAIDI improvement

Build a Private LTE network
- Allows us to more economically connect and operate smart grid devices for customer reliability benefit

Example of Distribution Automation Restorative Actions

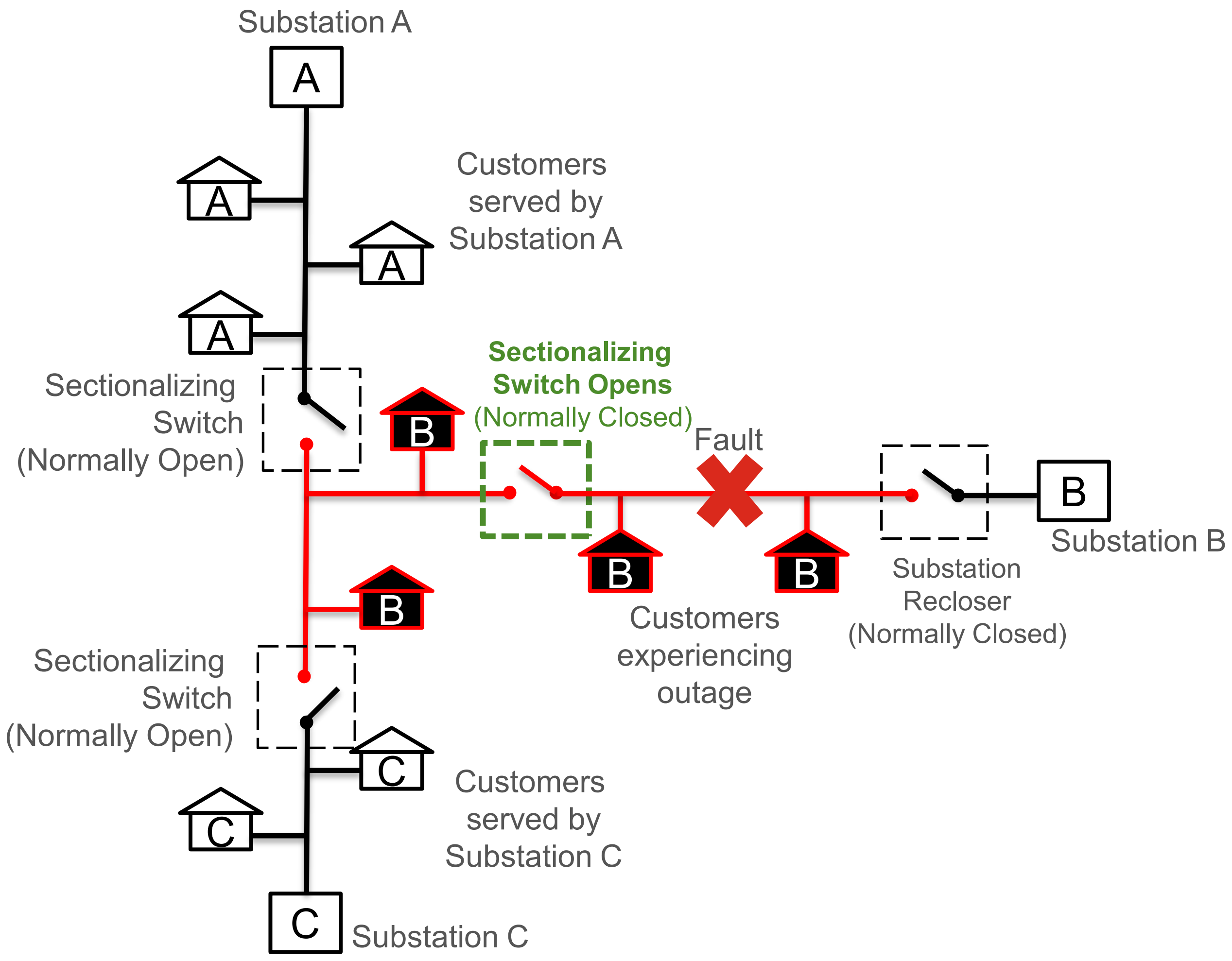


1. Fault Occurs

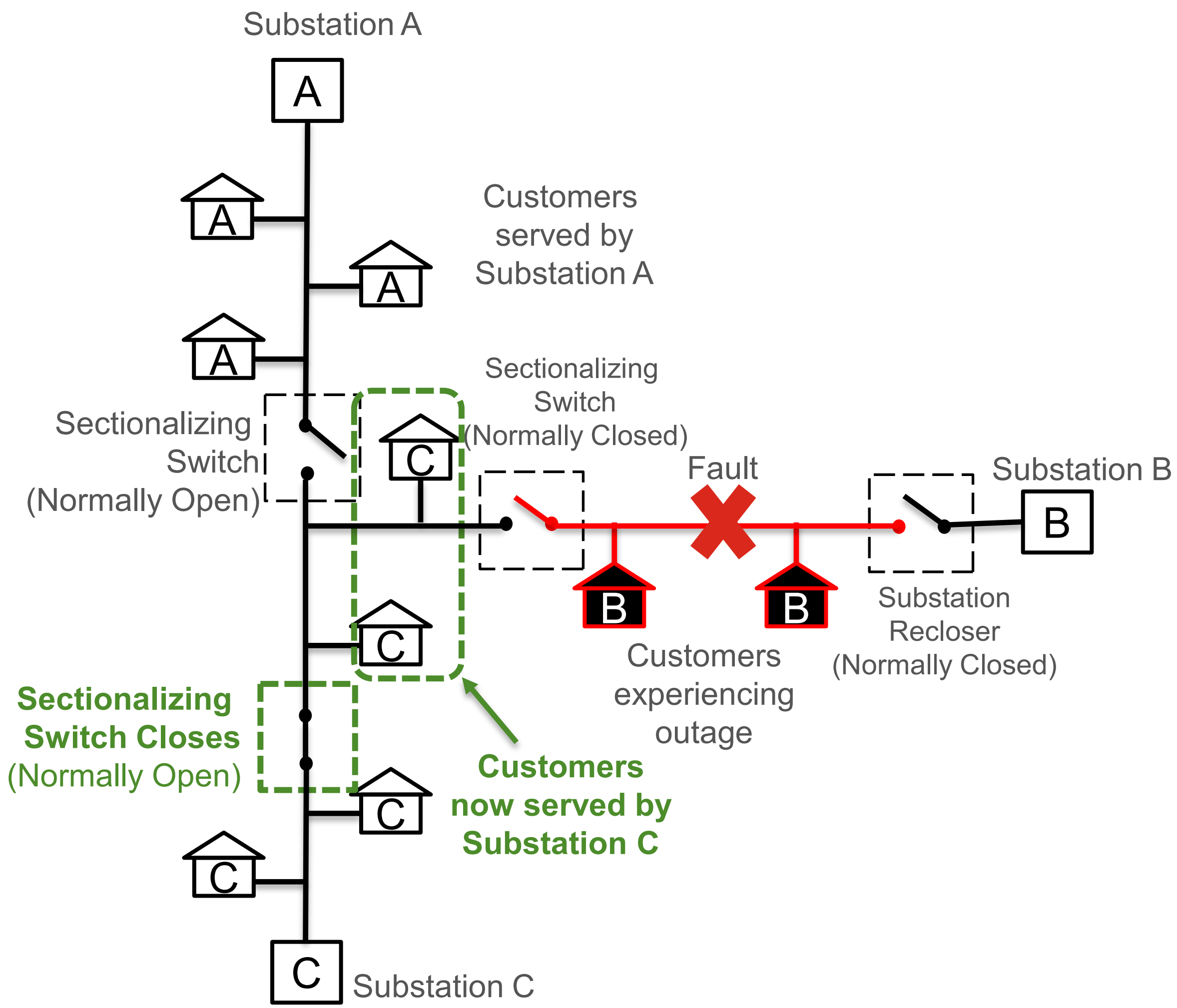


2. Fault Located, Upstream Tie Opens

Example of Distribution Automation Restorative Actions



3. Fault Isolated, Downstream Tie Opens



4. Customers Re-supplied by Substation C

Smart Grid Technologies

Smart grid technologies support customer reliability through enhanced & proactive monitoring of overall operations & health of the system

Manual Switchgear Before Replacement

New Automated Switchgear

Intellirupter

Tripsaver

FCI

Smart Grid Benefits

Smart grid technologies offer a wide range of benefits from reliability and safety to enabling the grid of the future and customer productivity

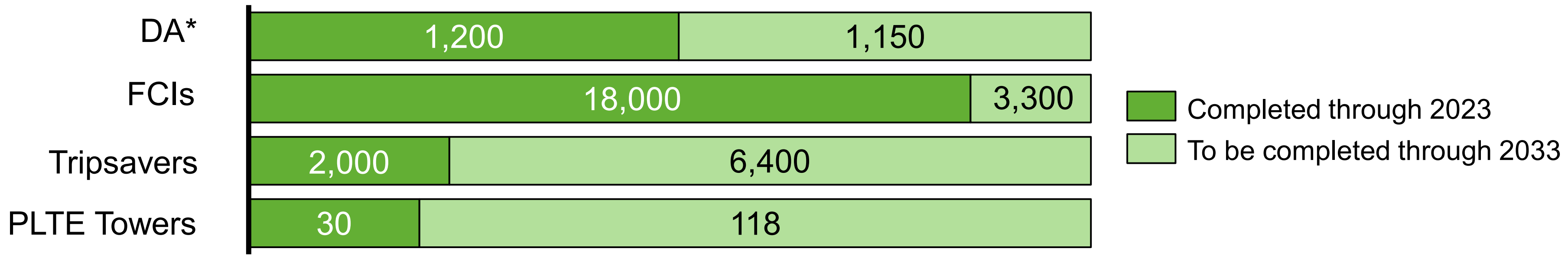
Benefits

- Distribution Automation switches power sources to isolate damage and is delivering up to 40% improvement in reliability on circuits equipped with the technology and other associated upgrades
- Customers experience nearly 9,000 extended outages annually caused by a blown fuse in which no other damage to the system can be found. We expect trips savers will eliminate most of these and customers will only experience a momentary as the device opens to clear the fault & restores service
- FCI's will reduce the time customers are out by allowing Ameren Missouri to inspect predetermined points of a circuit for damage and make faster switching decisions
- Storm Impact Mitigation Examples
  - *July 10th 2021: A storm caused over 50,000 customers to lose power, but an additional 12,000 customers were protected from outages due to the over 200 DA operations over the several days of storms and restoration*
  - *August 12th 2021: Severe weather led to over 90,000 customers without power, but around 8,500 customers were protected from outages due to DA, reducing the total outage count from the storm by 8%*

Modernization Plan

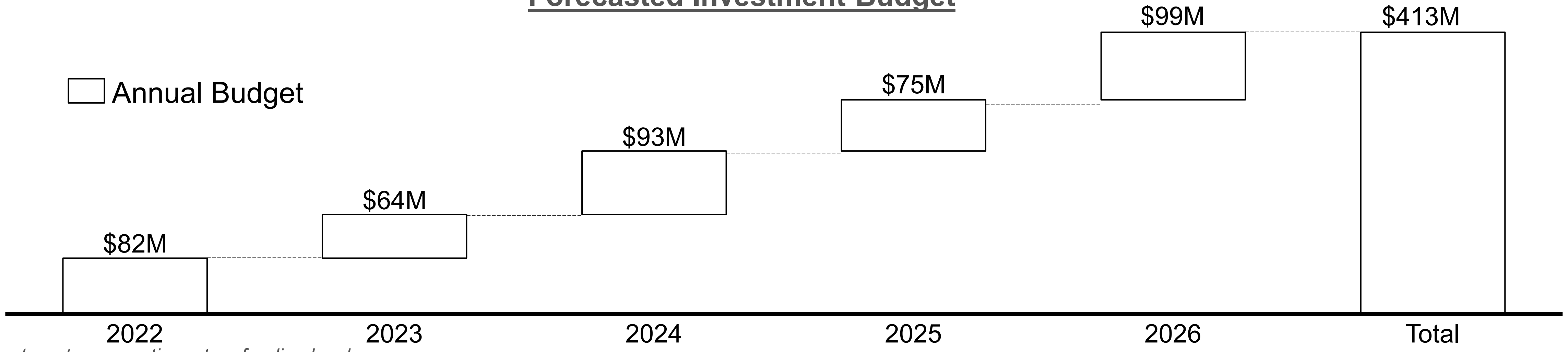
We plan to enable a smarter, more reliable grid, focusing on Tripsavers, DA, FCIs, and fiber / wireless

Devices Installed[1]



*Annual DA/FCI installations expected to decrease significantly after 2028

Forecasted Investment Budget



[1]Long-term targets are contingent on funding levels

Wrap Up

1. Next Steps
2. Next Meeting Date and Location

Ameren
MISSOURI

ED Project Evaluation Methodologies– 2nd OPC & PSC Staff Meeting

June 2022

DRAFT Evaluation Methodology – System Hardening

Criteria	Variable	Definition	Threshold	Documentation / Data Required
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of critical components	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based.
Asset Condition	Engineering Risk Assessment	Estimated asset health and risk of failure based on inspection results and/or operating history of similar vintages	✓ Failed or unfavorable tests/inspections; medium likelihood of near-term failure	Test/inspection records required if criteria is to be used as a justification factor
Asset Performance	Circuit Interruption(s)	The number of times asset-driven circuit interruption(s) have occurred	✓ 2 interruptions in a year or 5 interruptions over 3 years	Quantify historical interruptions; Include documentation of specific interruptions.
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documented impact to the local community is required
Final Evaluation	Two check marks result in eligibility for a System Hardening capital project			

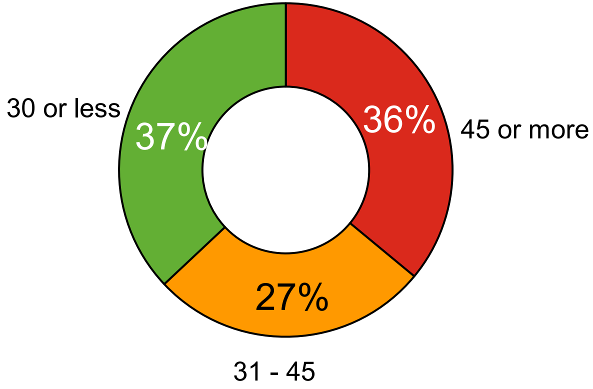
The Infrastructure That Supplies Dx Substations Is Rapidly Aging

Each subtransmission circuit feeds an average of 2,500 customers, ~36% of them have a majority of assets that are beyond their expected life

Asset	Total OH Miles	Expected Life (Years)	Timeline to Refresh System at Current Investment Levels	Current Average Age of the System	Miles Over Expected Life Today	# of Customers Served by Old Asset
Subtransmission System (Proxy: Wood Poles[1] Age)	~4,200	45	~76 years (@ forecasted 55 mi/yr.)	~35 years	~1,600	~460,000

[1]*On average, one line mile includes 26 poles*

What's the distribution of the age of our poles (years)?



What's the inspection failure rate by age group?

**Based on ground line inspections*

1. Poles age 31 – 45 are **four times more likely** to fail inspections than those 30 or less.
2. Poles age 45 or more are **eight times more likely** to fail inspections than those 30 or less.

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected

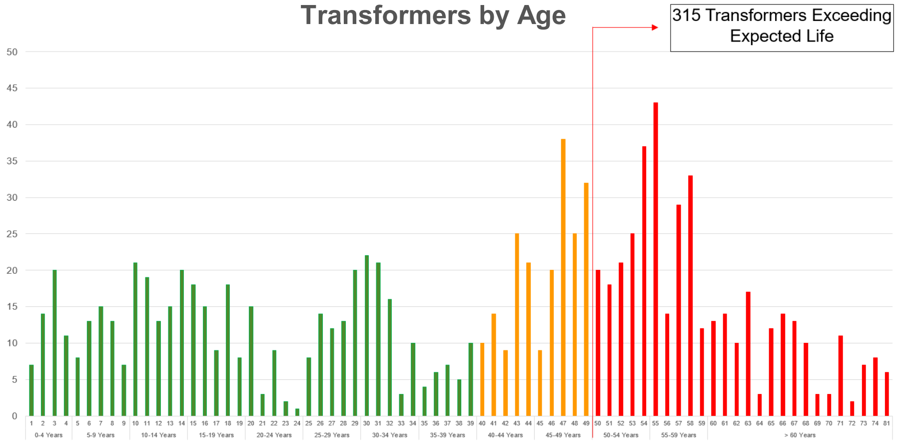
DRAFT Evaluation Methodology – Sub CBM

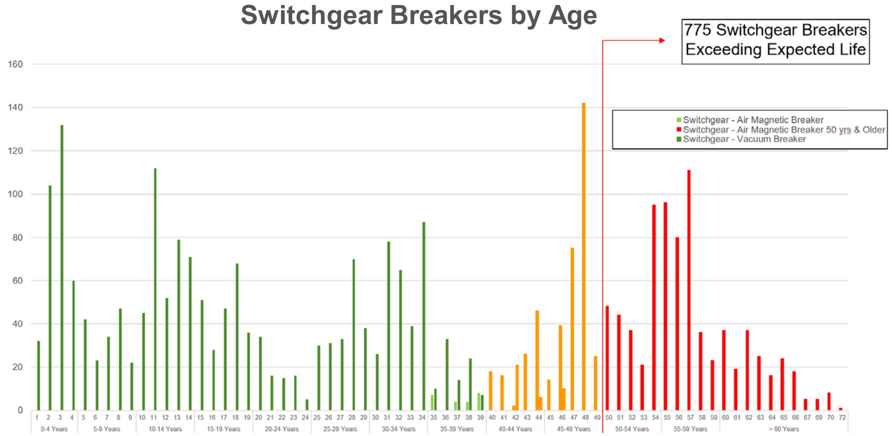
Criteria	Variable	Definition	Threshold	Documentation / Data Required
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of critical components *(Transformers or Breakers)*	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based.
Asset Condition	Engineering Risk Assessment	Estimated asset health and risk of failure based on inspection results and/or operating history of similar vintages	✓ Failed or unfavorable tests/inspections; medium likelihood of near-term failure	Test/inspection records required if criteria is to be used as a justification factor
Asset Performance	Substation Interruption(s)	Substation interruption(s) or instance(s) of non-availability due to malfunction has occurred	✓ Historical substation interruption(s) or instance(s) of non-availability	Quantify interruption(s) or instance(s) of non-availability; Include documentation of specific interruptions or instance(s) of non-availability.
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Document impact to the local community is required
Safety	Physical safety risk to stakeholders (employees, community, etc.)	Potential for safety issue due to old or improperly functioning equipment	✓ Asset has known safety concerns, cannot be inspected/maintained while operating	Include documentation of safety issue
Final Evaluation	Two check marks result in eligibility for a Substation CBM capital project			

Distribution Substation Key Components

Distribution substations, with critical components beyond their expected life, serve over 700,000 of our ~1.2 million customers

Asset Type	Total Distribution Assets	Expected Life	Average Age (Years)	Assets Over Expected Life	Customers Served by Assets over expected life
Transformer	~800	50	~41	~315	~430k
OCBs	~350	50	~53	~250	~700k
ACBs	~1,200	50	~53	~775	~400k





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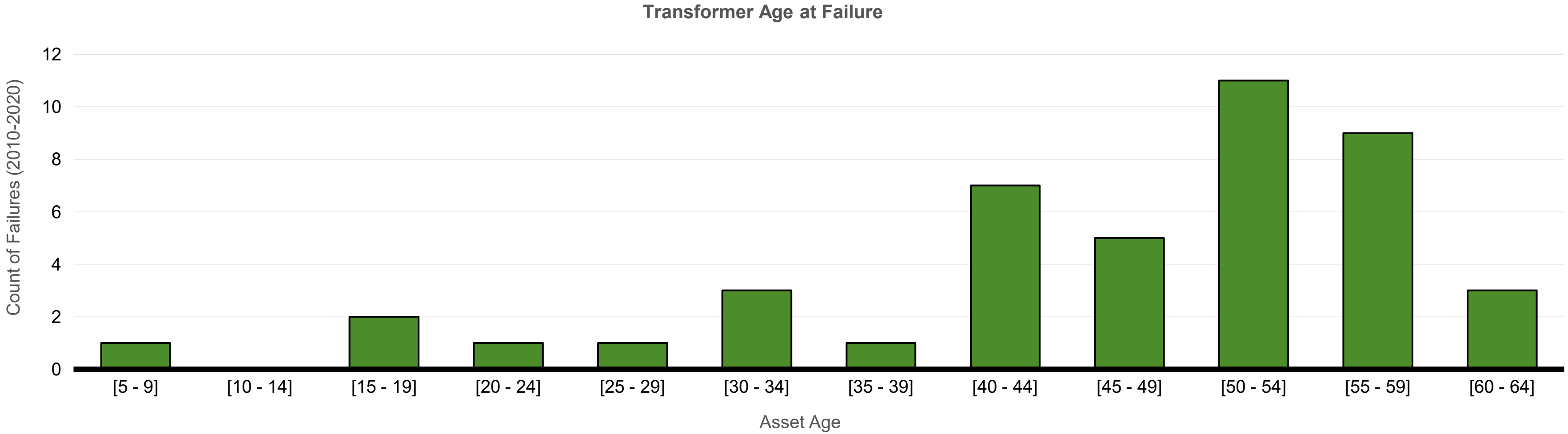
Expected Life of Substation Transformers – 50 Years

Transformer Failure Data Illustrates Risk Of Aged Assets, Particularly At 50+ Years Old And Confirms That Certain Vintages Are Problematic (1960 To 1969)

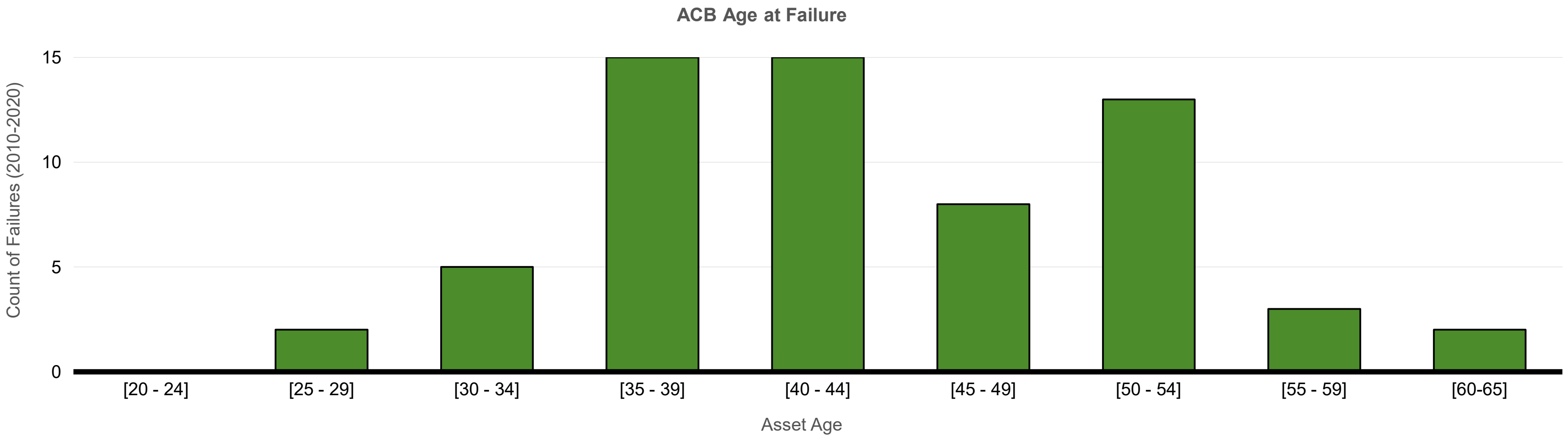


Observations

- **Transformer Age at Failure**: Transformer failures increasingly occur as assets near and exceed 50 years in service.
- **Manufacturer Year of Transformer at Failure:** Most of the transformers experiencing failures were manufactured between 1960 and 1969, suggesting that these units are failure prone. In particular, from 1964 to 1969, manufacturers were producing transformers quickly with lower quality in response to a rapid increase in demand from the growth of the electrical system from around the country.

Substation ACB Failure Trends

ACB designs are more complex and generally less reliable than modern technology and standards



Observations

- **ACB Age at Outage**: Greater counts of outages around 35-45 years old
- **Asset Design Challenges:** The air blast technology used across the industry up to the 1980's has proven to cause stress on the asset components due to the force exerted to extinguish the electrical current and arc. Over time, this repeated circuit breaking operation impacts the asset's future ability to successfully break the flow of electricity and restore service as intended.

DRAFT Evaluation Methodology – UG Cable

Criteria	Variable	Definition	Threshold	Documentation / Data Required
Age/Asset Vintage	Exceeding Expected Engineered/Useful Life	Age of Cable	✓ Beyond expected life ✓ >1.5x beyond expected life	Quantify age; Include documentation on which quantification is based.
Asset Condition	Engineering Risk Assessment	Estimated asset condition based on known risks of asset degradation or change to landscape	✓ Direct Buried or Route Inappropriate	Documentation of asset condition or landscape impacting asset if criteria is to be used as a justification factor
Asset Performance	Cable Failure(s)	Customer interruption(s) resulting from cable failure(s)	✓ Historical Cable Failure(s)	Quantify historical interruption(s); Include documentation of specific interruptions.
Potential for Community Impact	Number or type of potentially-affected customers	High-impact customers (e.g. school or university, hospital, airport), a large employer, or a large number of individual customers (~>1,000)	✓ Potential for substantial community impact	Documentation of impact to the local community is required
Safety	Physical safety risk to stakeholders (employees, community, etc.)	Potential for safety issue due to old or improperly functioning equipment	✓ Asset has known safety concerns, cannot be inspected/maintained while operating	Include documentation of safety issue
Final Evaluation	Two check marks result in eligibility for a UG Cable capital project			

The Age of Our Underground System Continues to Increase

Ameren MISSOURI

2,900+ miles of our underground system has already exceeded its expected life, and presents an increasing risk to customer reliability and safety

URD Cable Vintage	Mileage	Cable Age (Years)	Expected Life (Years)	Lateral Failures per Mile
First Generation & Older	**~850**	**45+**	40	2.42
Second Generation	**~1,600**	**38 – 45**	40	1.70
Third Generation	**~700**	**32 – 38**	40	1.22
Fourth Generation	**~4,300**	**Present - 32**	40	0.88

Obsolete Feeder Exit Cable Type	Mileage	Cable Age (Years)	Expected Life (Years)	Feeder Outages Due to Lead Cable
Lead Cable (PILC)	**~450+**	**32 – 101**	60	~60 outages per year

Red indicates asset has exceeded expected life **Orange** indicates asset is approaching expected life **Green** indicates asset is significantly under expected

BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI

In the Matter of Union Electric Company	**)**	
d/b/a Ameren Missouri's Tariffs to Adjust	**)**	Case No. ER-2022-0337
Its Revenues for Electric Service.	**)**	

AFFIDAVIT OF RYAN M. ARNOLD

STATE OF MISSOURI	**)**
	) ss
CITY OF ST. LOUIS	**)**

Ryan M. Arnold, being first duly sworn states:

My name is Ryan M. Arnold, and on my oath declare that I am of sound mind and lawful age; that I have prepared the foregoing *Direct Testimony*; and further, under the penalty of perjury, that the same is true and correct to the best of my knowledge and belief.

Ryan M. Arnold

Sworn to me this 1st day of August, 2022.