Walk-through of long-term utility distribution plans:

Part 1 - Traditional Distribution Planning and Enhanced Analysis

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for Mid-Atlantic Region and NARUC-NASEO Task Force on Comprehensive Electricity Planning
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Goal of distribution planning

► Provide orderly, economic expansion of equipment and facilities to meet future demand with acceptable system performance

- Deliver power with required frequency (60Hz)
- Satisfy voltage requirements (within ±5%)
- Deliver adequate availability (<2 hours out/yr)
- Have capacity to meet instantaneous demand
- Reach all customers wherever they exist

… and do it all for the lowest possible cost

Need to plan because it takes time to build capacity

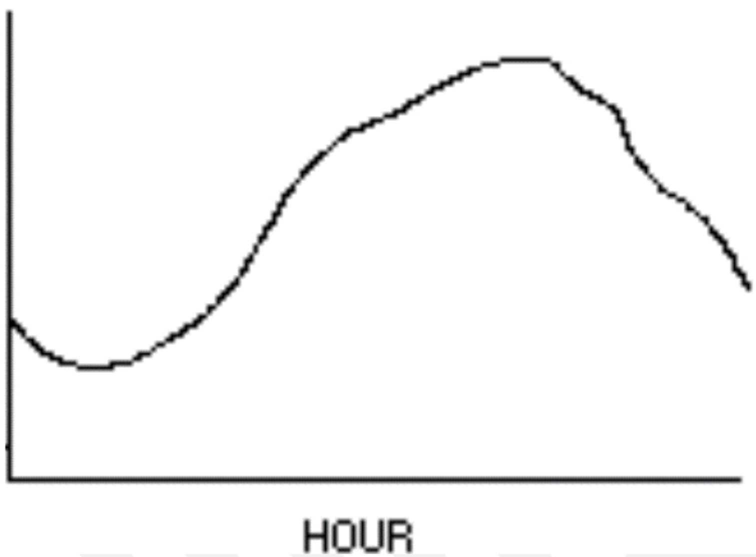
- Effective minimum-cost planning accounts for lead time to deploy T&D assets in developing reasonable alternatives

T&D Level	Lead Time (yrs)
Generation	13
EHV Transmission	9
Transmission	8
Sub-transmission	7
Substation	6
Feeder	3
Lateral	0.5
Service	0.1

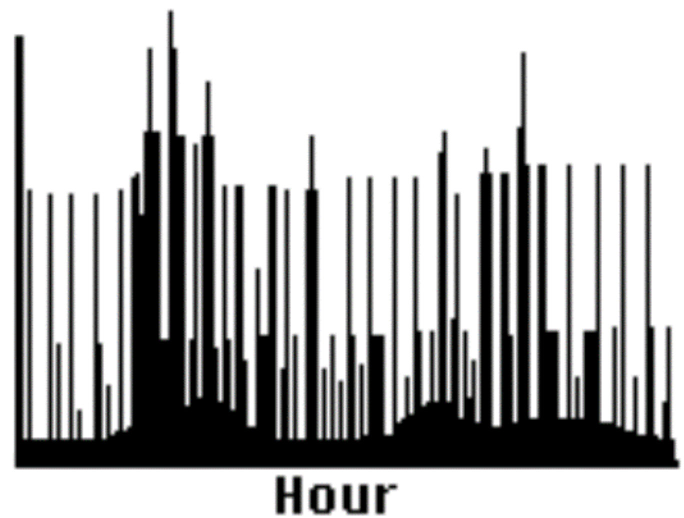
Loads and demand drive distribution planning

- Loads vary over time and space

Typical Feeder Load



Typical Customer Load



Perceived variability depends of level of aggregation and resolution

Example Plan:
Xcel Energy’s Integrated Distribution Plan (2019-2028)

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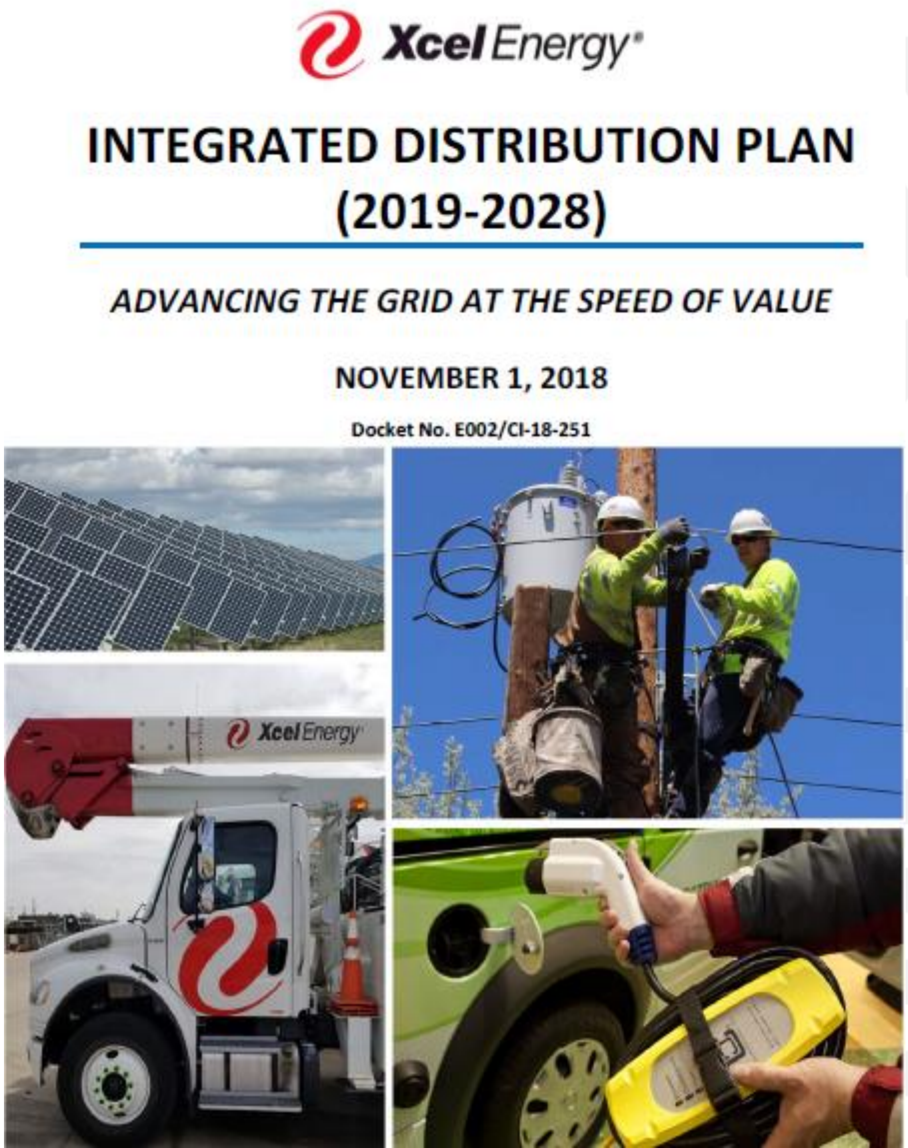
Xcel Energy IDP


Xcel Energy
INTEGRATED DISTRIBUTION PLAN
(2019-2028)
ADVANCING THE GRID AT THE SPEED OF VALUE
NOVEMBER 1, 2018
Docket No. E002/CI-18-251

Presents a detailed view of the distribution system and plans to meet customers' current and future needs

- ► First five years focused on
  - Providing customers with safe, reliable electric service,
  - Advancing the distribution grid with foundational capabilities including AMI, FAN, FLISR
- ► Secure enhanced system planning tools to
  - Incorporate DER and NWA analysis in planning
  - Facilitate integration of distribution-transmission-resource planning

15-Year Advanced Grid Roadmap

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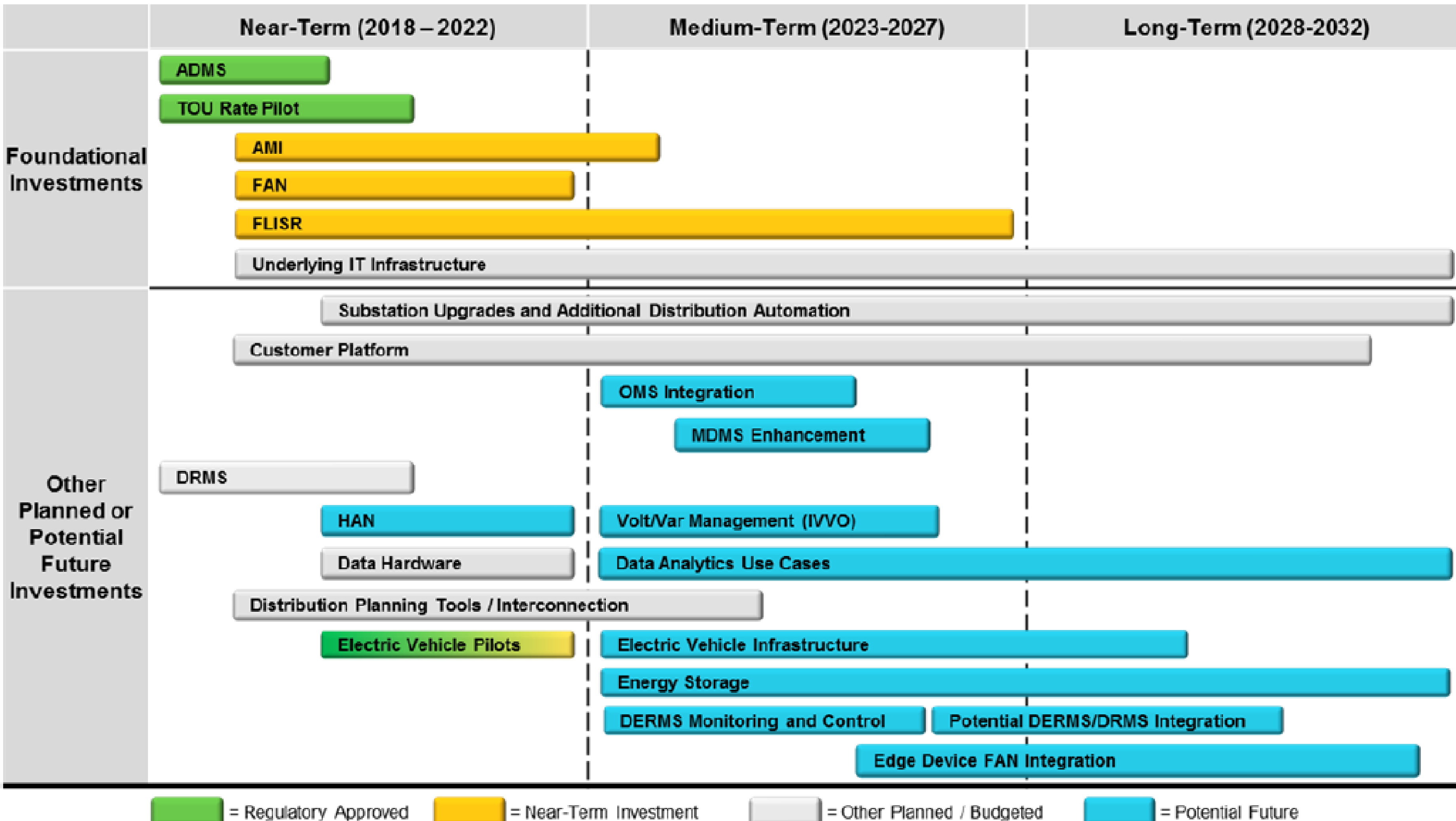


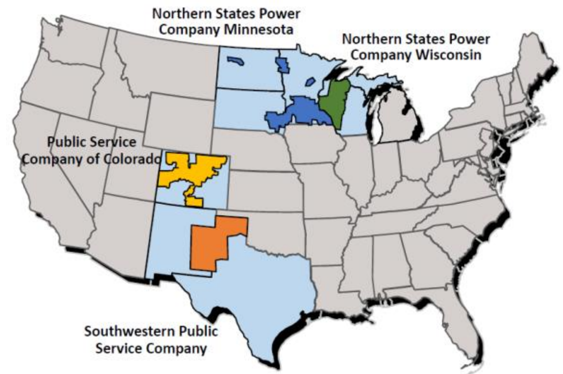
IDP Timeline

March 2015	October 2016	April 2017	April 2018	August 2018
• Commission opens Investigatory docket	• Holds workshop	• Issues notice	• Establishes utility dockets	• Releases IDP requirements for Xcel

First IDP for Xcel Energy due November 1, 2018, and annually thereafter

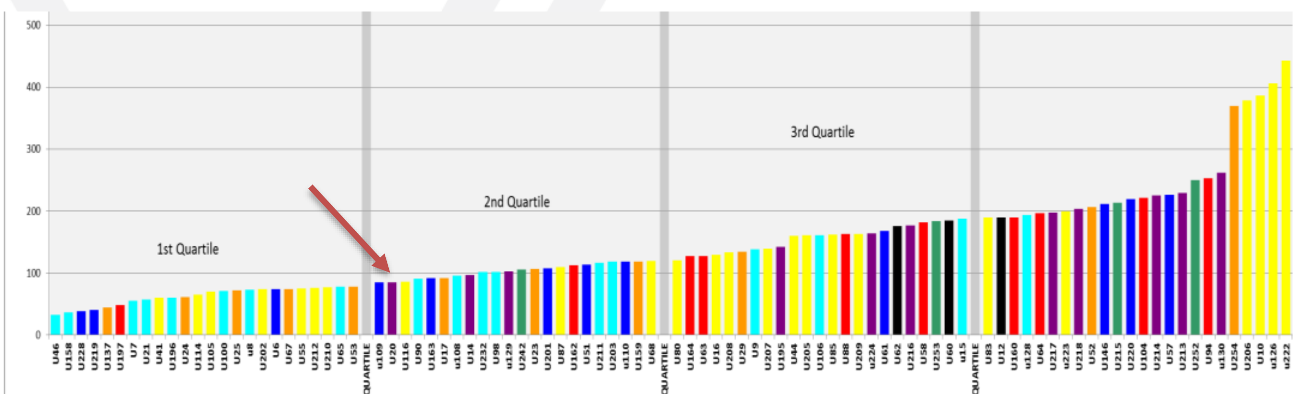
Northern States Power Company Minnesota (NSPM)

- Customer Base:
  - Minnesota, North Dakota, and South Dakota
  - 1.5 million customers (1.3 million in MN)
  - 88% residential; 12% commercial and industrial
  - NSP 2017 system peak: 8,546 MW (MN Portion: 6,484 MW)



- Distribution System:
  - 1,177 feeders
  - 15,000 circuit miles of OH conductor
  - 11,000 circuit miles of UG cable

- Reliability:
  - Reliability rank - top of 2nd quartile
  - Control capabilities at 62% of subs, serving 90% of customers



Xcel Energy Strategic Priorities

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U.S. Department of Energy

Lead the Clean Energy Transition

- Investment in wind, solar and related transmission
- Carbon reduction:*
  - Achieved 35% in 2017
  - Projected 50% by 2022
  - Projected 60%+ by 2030

Enhance the Customer Experience

New program offerings
Investment in enhanced security, reliability, and automation
- DER enablement
- Improved reliability
- Top quartile satisfaction

Keep Bills Low

- Steel for fuel = savings
- Economic development
- Flat O&M
- Average bill increase at or below inflation

Distribution Objective: Safe, reliable, affordable electric service – *with an eye to the future*

Distribution Planning

** Xcel Energy-wide percentages*

"strategic priorities … are embedded in everything that we do – including the way that we plan our distribution system"

Key Overall 2018 Electric Distribution Business Priorities

- **Operational Excellence** – Improve reliability performance level
- **AGIS/Grid Modernization** – Install key equipment and systems to operate the new modern grid
- **System Health** – Targeted maintenance of key assets designed to improve reliability and safety
- **System Capacity Additions** – Installation or reinforcement of key substations and feeders to serve new load and provide backup

System Planning

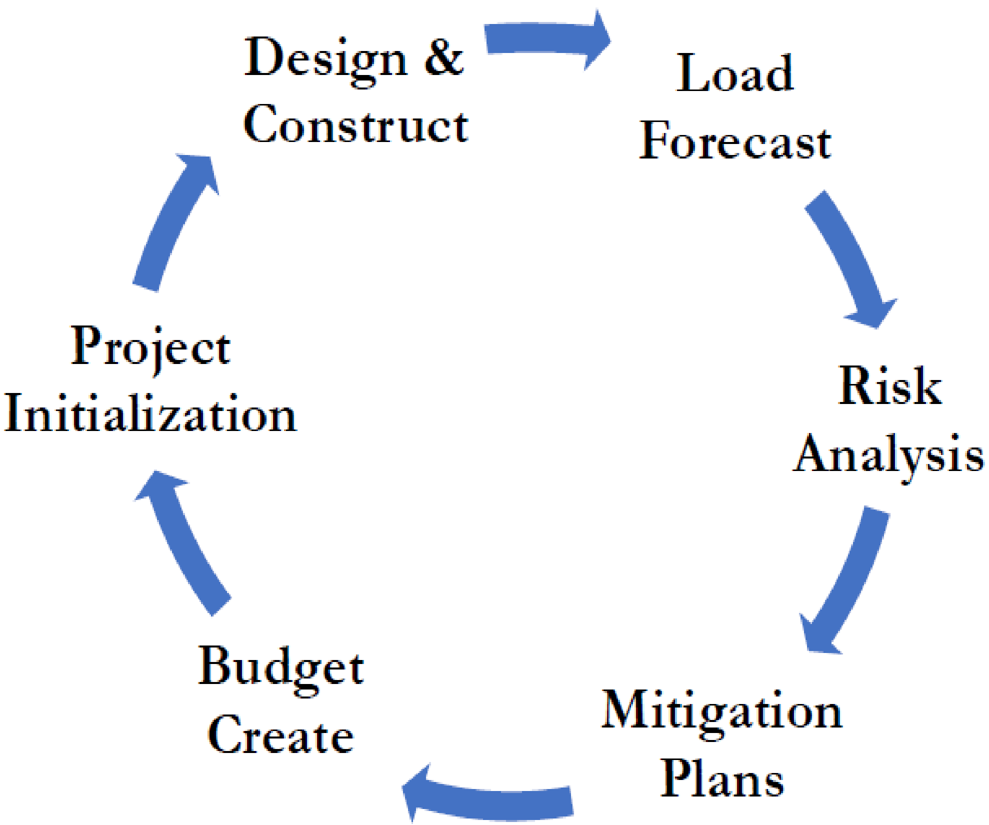
"An important aspect of distribution planning is the process of analyzing the electric distribution system's ability to serve <u>existing</u> and <u>future</u> electricity loads connections by evaluating the <u>historical</u> and <u>forecasted</u> connection load levels and utilization rates of major system components such as substations and feeders."

System Planning Studies

- Proactively identify existing and anticipated capacity deficiencies or constraints that could lead to overloads
  - During *normal* ("system intact" or N-0 operation) operating conditions
  - During *single contingency* (N–1) operating conditions
- Take corrective action
  - Traditional Actions:
    - Construct new feeder or substation
    - Add feeder tie connections
    - Install regulators, capacitors, or upsizing substation transformers
  - Non-Wires Alternatives/DER
- Factors to consider:
  - Cost
  - Operational requirements
  - Technical feasibility
  - Future year system need

Proposed projects are funded as part of an annual budgeting process, based on a risk ranking methodology

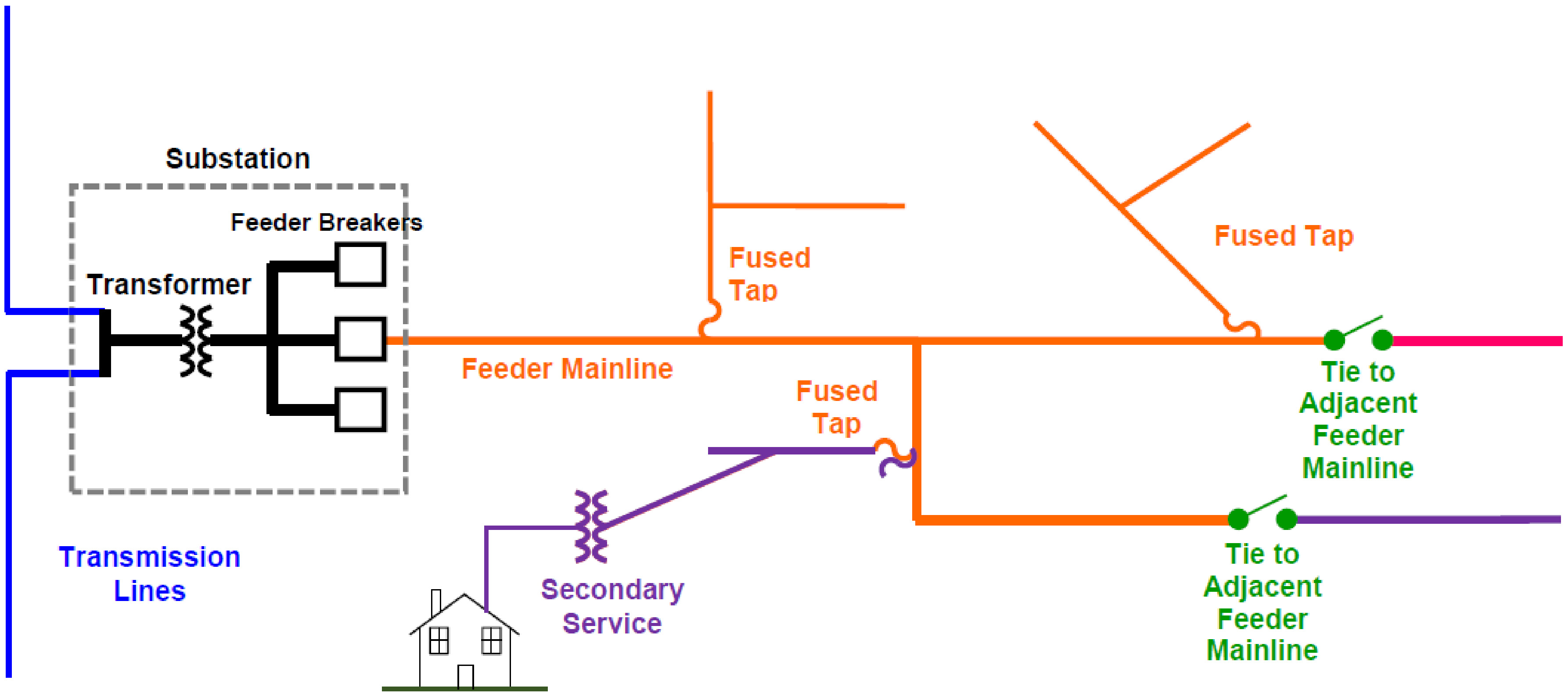
Annual Distribution Planning Process



Review existing and historical conditions, including:

- Feeder and substation reliability performance
- Equipment condition assessments
- Current load versus previous forecasts
- Quantity and types of DER
- Total system load forecasts
- Previous planning studies

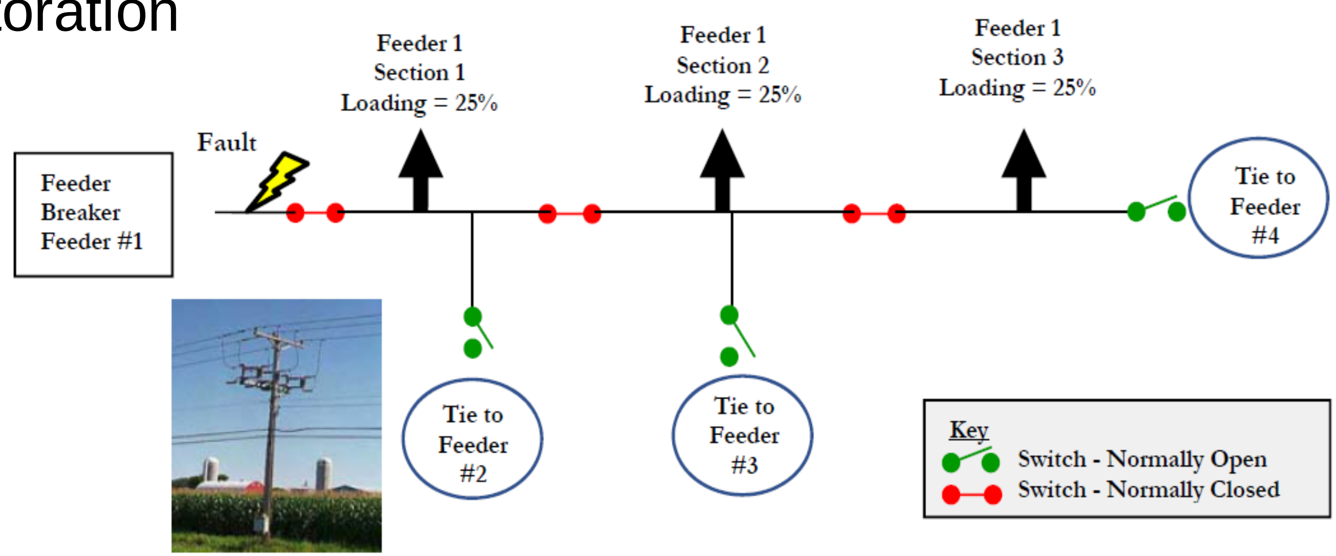
Typical Radial Distribution Circuit Design



System is planned to facilitate single-contingency switching to restore outages within ~1 hour

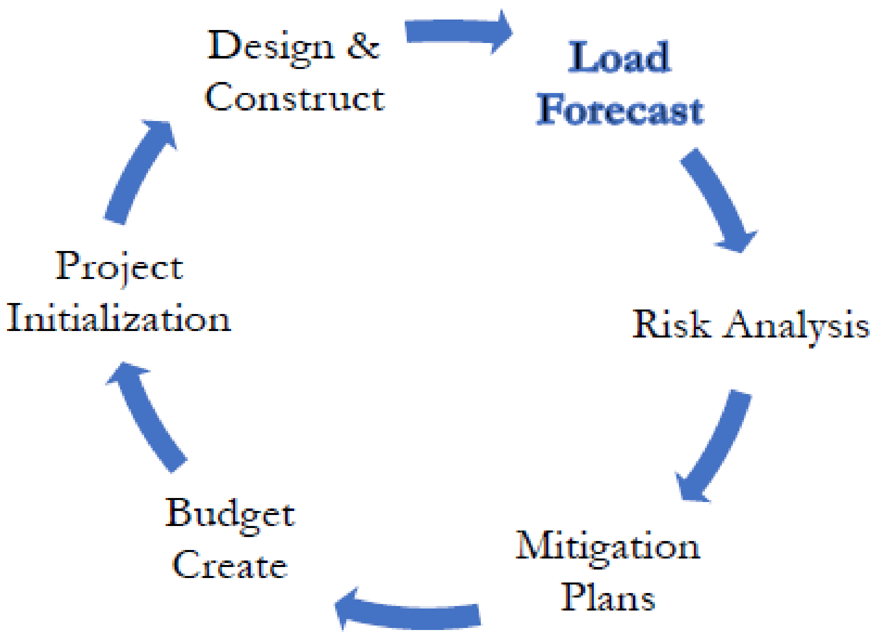
Planning Criteria and Design Guidelines

- ► Voltage at the customer meter **within 5%** of the nominal
- ► Voltage imbalance **less than or equal to 3%**
- ► Balanced phase current phases (as much as possible) to minimize total neutral current at feeder breaker
- ► Feeder loading under N-0 (normal) conditions **less than 75%**
- ► Adequate field tie capabilities for first contingency (N-1) restoration



Switch

Distribution Planning Process: Load Forecast



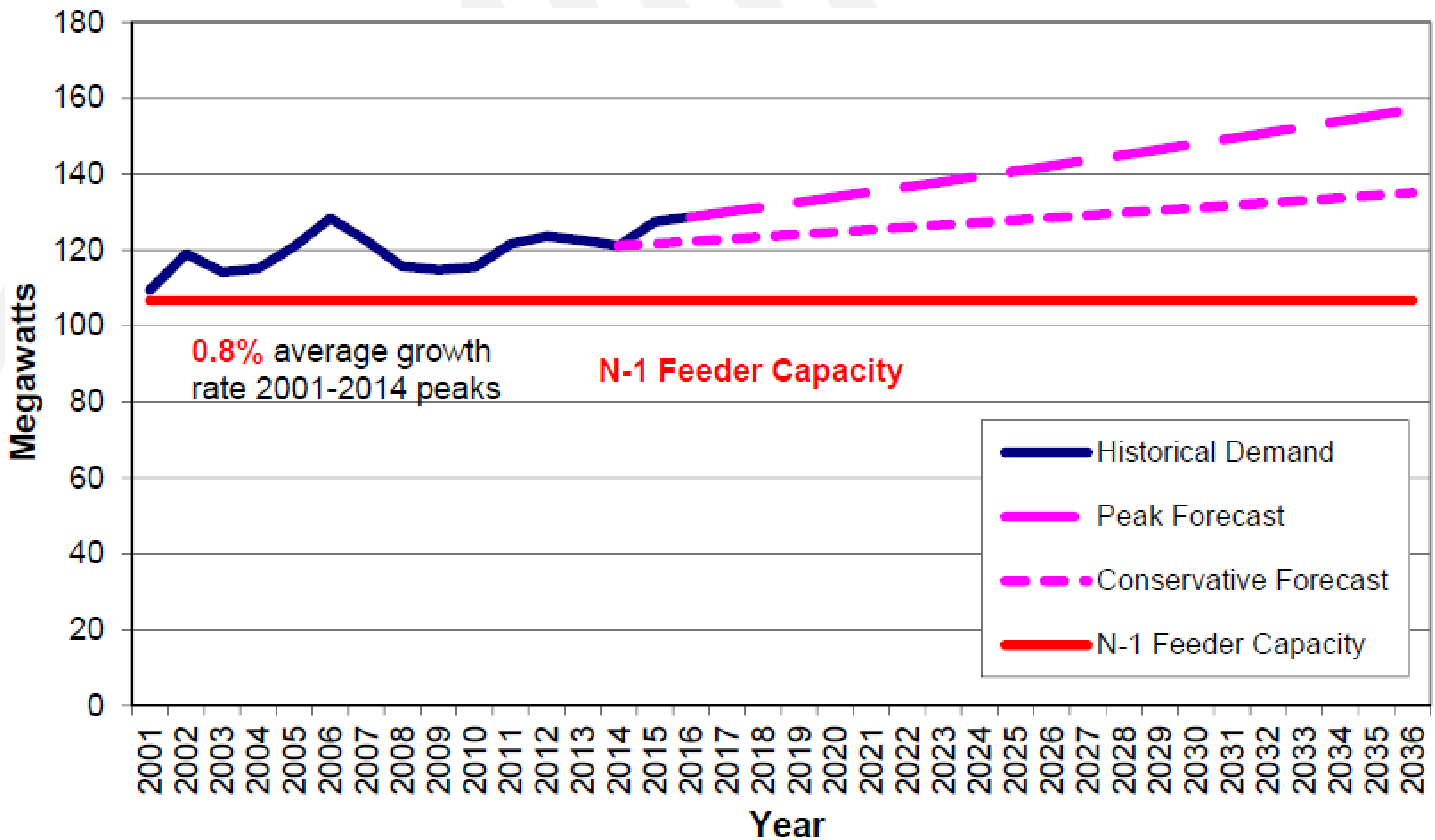
Tools and Processes:
- ITRON DAA (Distribution Asset Analysis)
- SCADA (Supervisory Control and Data Acquisition)

- Performed for both feeders and substations
- Focuses on demand, not energy, to ensure loads can be served during system peaks
- Trending method considering:
  - Historical load growth
  - Weather history
  - Customer planned additions
  - Circuit reconfigurations
  - New sources of demand (e.g., EV)
  - DER applications
  - Planned development or redevelopment in study area

Generate five-year forecast, aggregate, and compare with system projections.

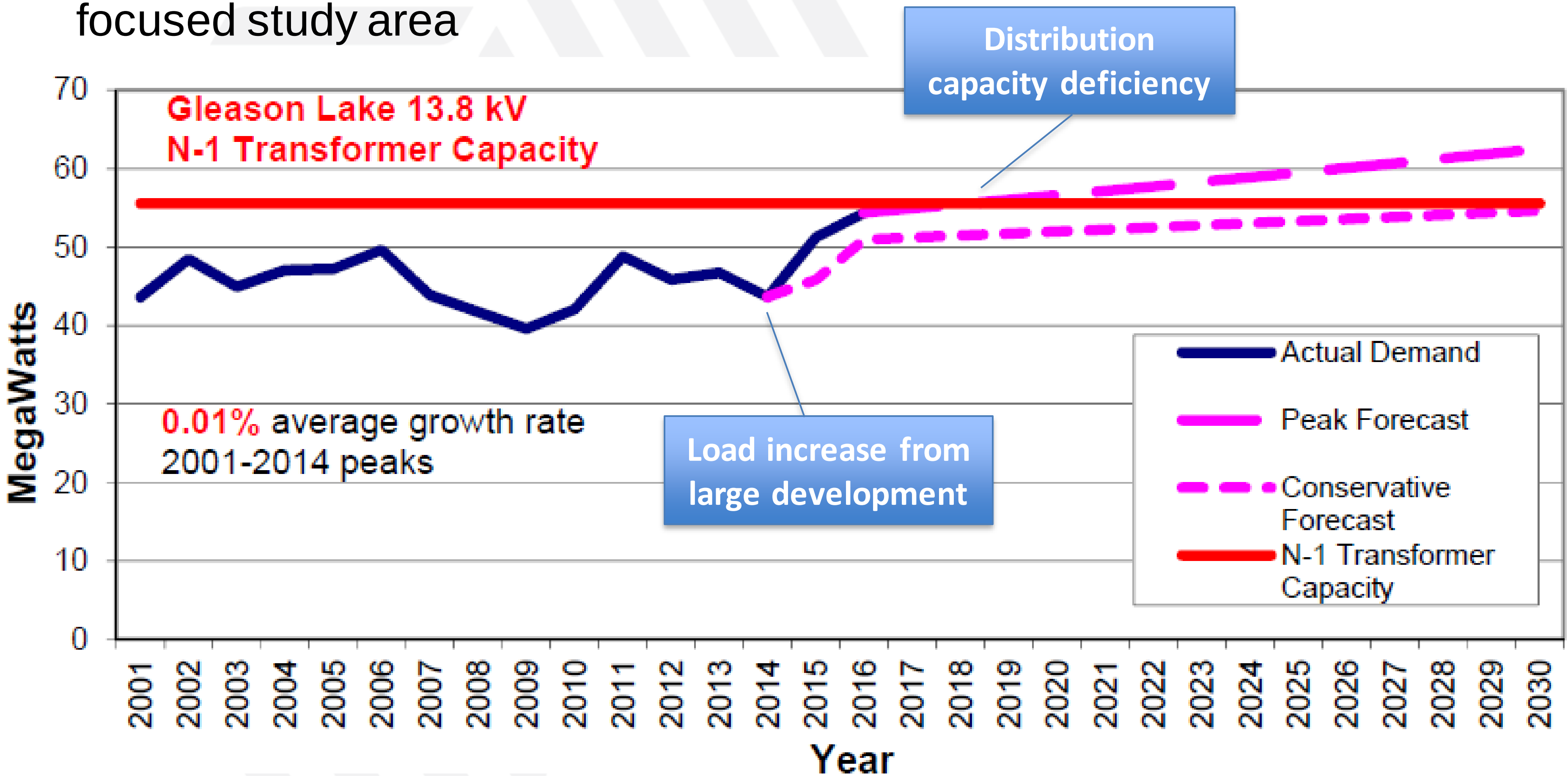
Example: Feeder Historical and Forecasted Demand

► Summer peak demand forecast for eleven 13.8 kV and two 34.5 kV feeder circuits in focused study area

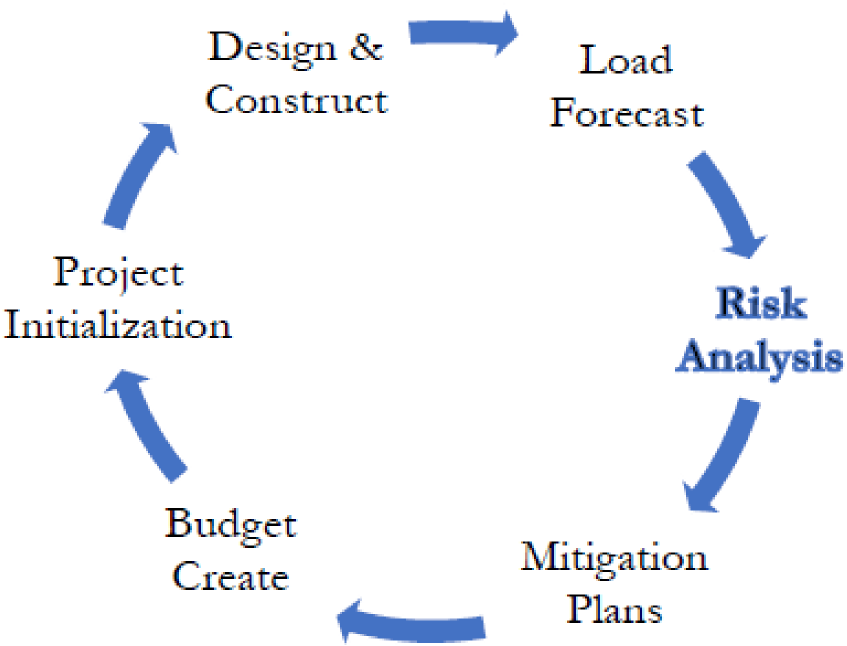


Example: Substation Historical and Forecasted Demand

- Summer peak demand forecast for two 13.8 kV substation transformers in focused study area



Distribution Planning Process:
Risk Analysis



- Identify feeders and substation transformers for which N-0 or N-1 risk is a concern.

- The total number of risks identified in the risk analysis generally exceeds the number of risks that can be mitigated with available funds.

Tools and Processes:
- ITRON DAA (Distribution Asset Analysis)
- CYMCAP (determines circuit ampacity)
- WorkBook (internal project prioritization tool)

Xcel's 2018 to 2022 annual planning process identified the following total risks across NSPM:
- N-0 normal overloads on 56 feeder circuits
- N-0 normal overloads on 16 substation transformers
- N-1 contingency risks on 408 feeder circuits
- N-1 contingency risks on 122 substation transformers

Example: Plymouth and Medina N-0 Risk Assessment: 2016 and 2036

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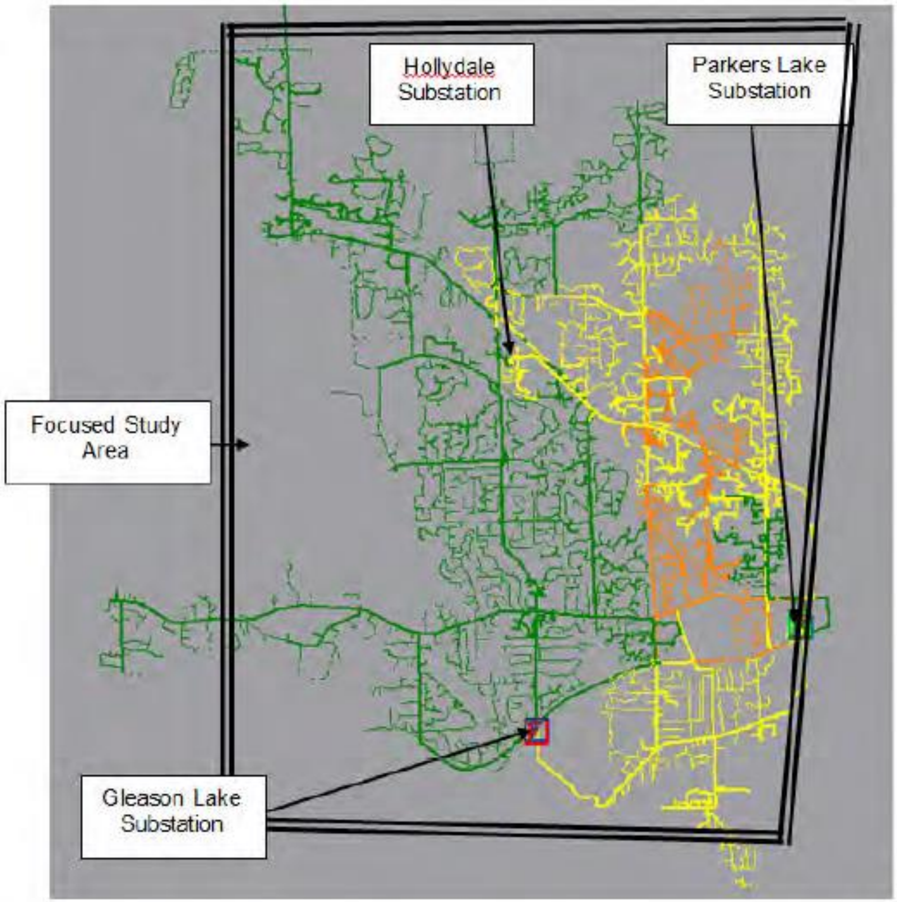
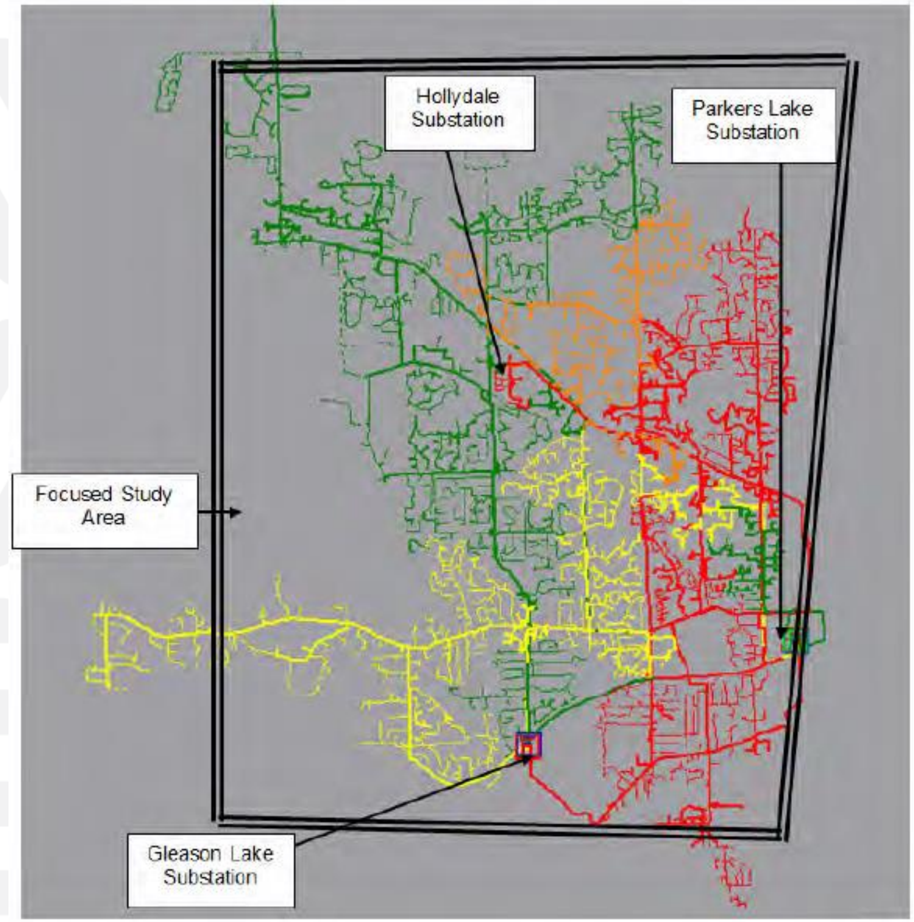


2016

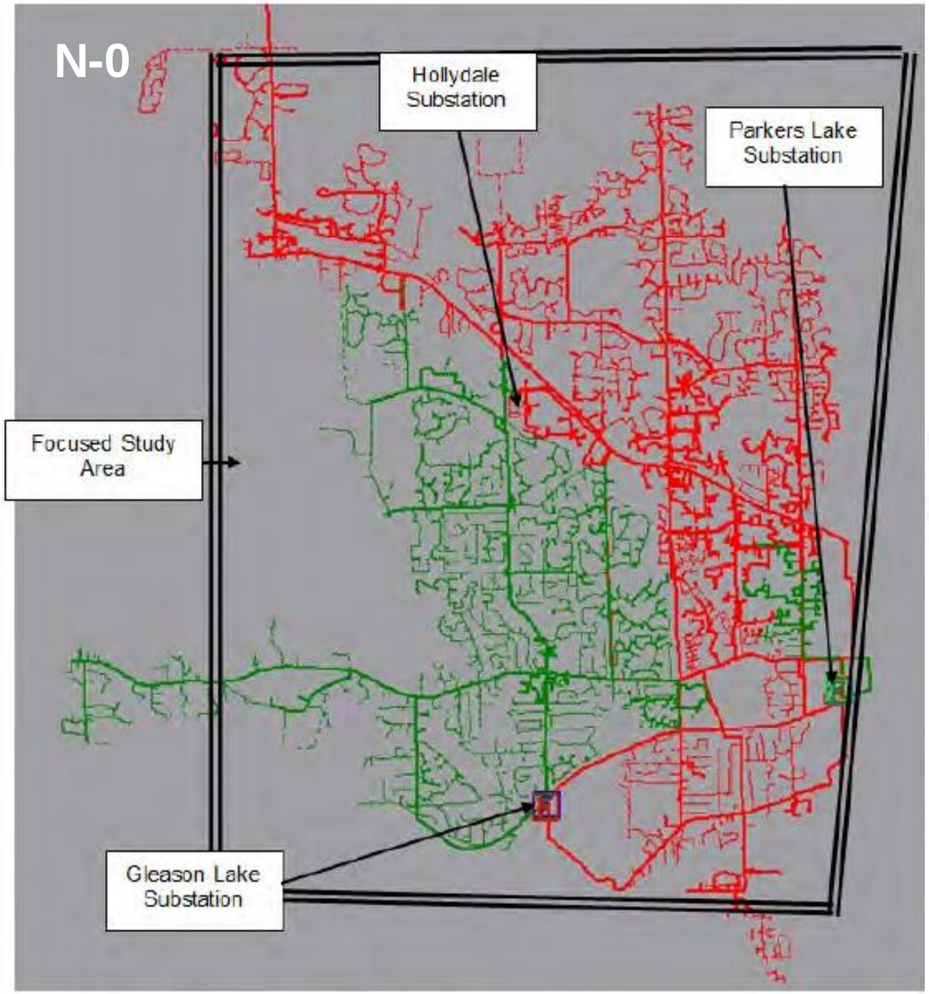
Feeder Circuits Colored by N-0 Circuit Loading:		
5 Circuits	<75% or <50%	
6 Circuits	50or75%-100%	
2 Circuits	100%-115%	
0 Circuits	>115%	



2036

Feeder Circuits Colored by N-0 Circuit Loading:		
3 Circuits	<75%or<50%	
4 Circuits	50or75%-100%	
2 Circuit	100%-115%	
4 Circuits	>115%	

Example: Plymouth and Medina N-1 Risk Assessment: 2016 and 2036



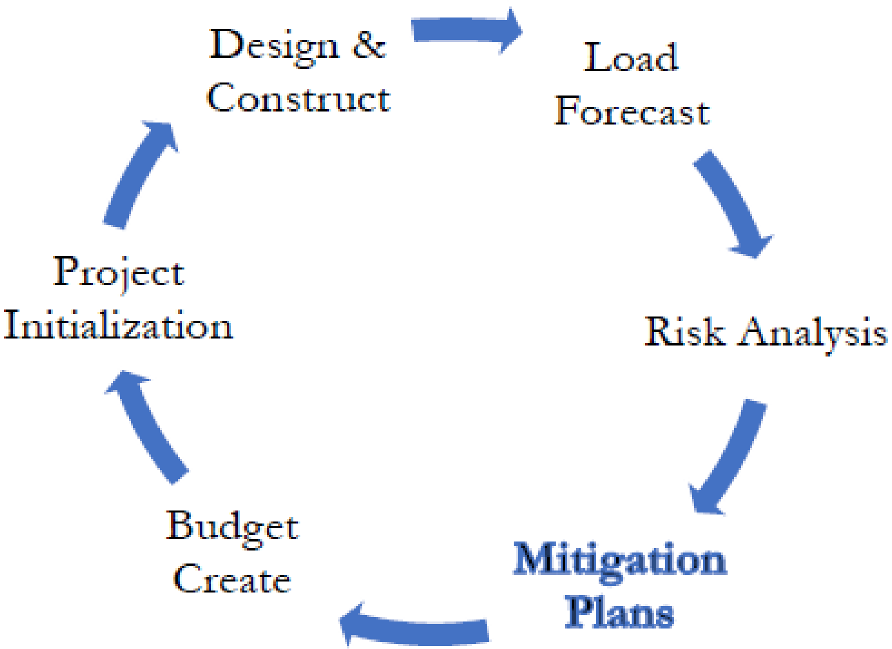
2016

Feeder Circuits Colored by N-1 Circuit Loading:		
5 Circuits	No N-1 Risk	
8 Circuits	N-1 Risk	

2036

Feeder Circuits Colored by N-1 Circuit Loading:		
3 Circuits	No N-1 Risk	
10 Circuits	N-1 Risk	

Distribution Planning Process:
Mitigation Plans



- Identify potential solutions to provide additional capacity needed to address identified system deficiencies
- Risk thresholds that trigger mitigation plan :
  - N-0 conditions: overload > 106%
  - N-1 conditions: load at risk > 3 MVA

Tools and Processes:
- GIS (Geographical Information System)
- Synergi Electric (power flow)
- WorkBook (internal project prioritization tool)

Many mitigation solutions are straightforward, but others require detailed analysis

Solution Identification Process

Is the problem localized and solution straightforward?

Yes

- Identify the solution
- Quantify the risk
- Estimate costs

No

- Identify the options
- Quantify the risk
- Estimate costs
- Obtain stakeholder input
- Perform planning study
- Select the solution

Enter into the budgeting tool

Distribution Planning Process: Mitigation Plans – Plan Comparison Standards

The following criteria are used to compare the potential solutions:

- ► System Performance
- ► Operability
- ► Future Growth
- ► Cost
- ► Electrical Losses

Used to assign projects a risk score, similar to a cost-benefit ratio.

Distribution Planning Location-Specific Studies

1
- Identify the study area

2
- Project future loads

3
- Estimate the saturation of the area

4
- Coordinate with transmission planning

5
- Generate options

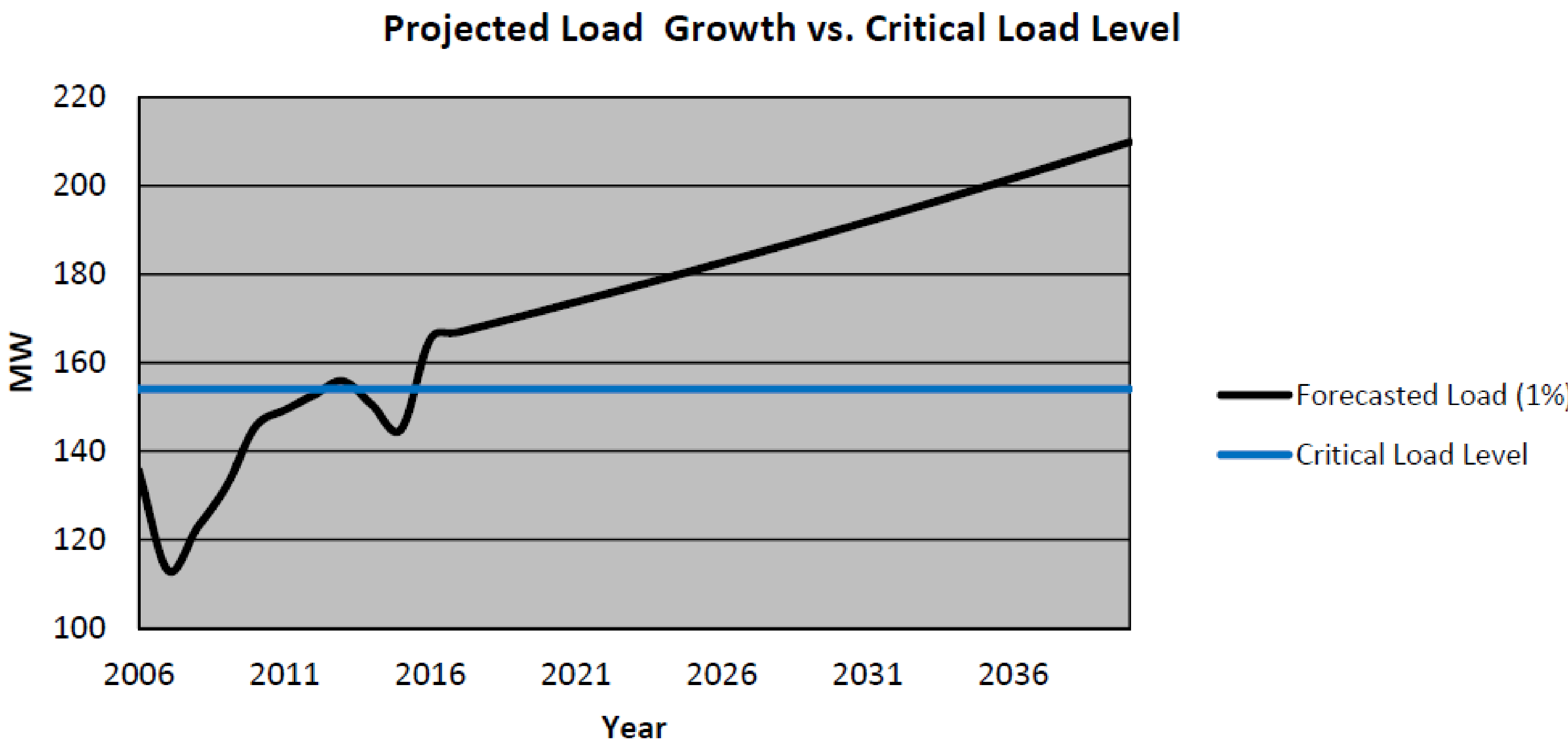
6
- Study and compare the economics and reliability of the alternatives

Potential Solutions:

- Reinforce existing feeder circuits to address isolated feeder circuit overloads
- Add or extend new feeder circuits
- Expand existing substations to address more widespread overloads
- Bring new distribution sources to the area:
  - Substation transformers with associated feeder circuits
  - DER

Historically not considered a viable alternative, but that is changing due to maturing technology, operational experience, and regulatory requirements

Example: Plymouth and Medina Assessment – Load Forecast



Problem: Deficit in the load serving capability of the western Plymouth distribution system.

Example: Plymouth and Medina Assessment – Power Flow

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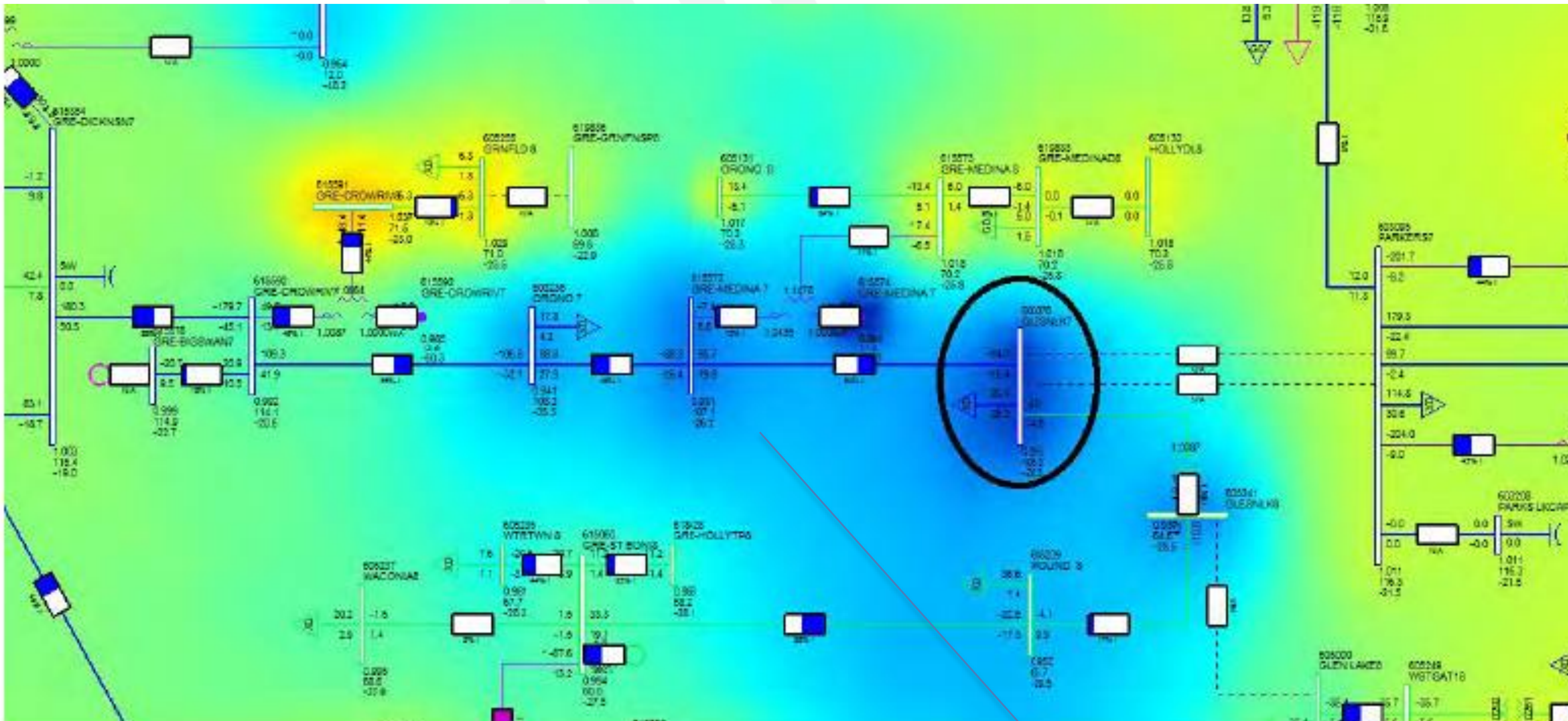
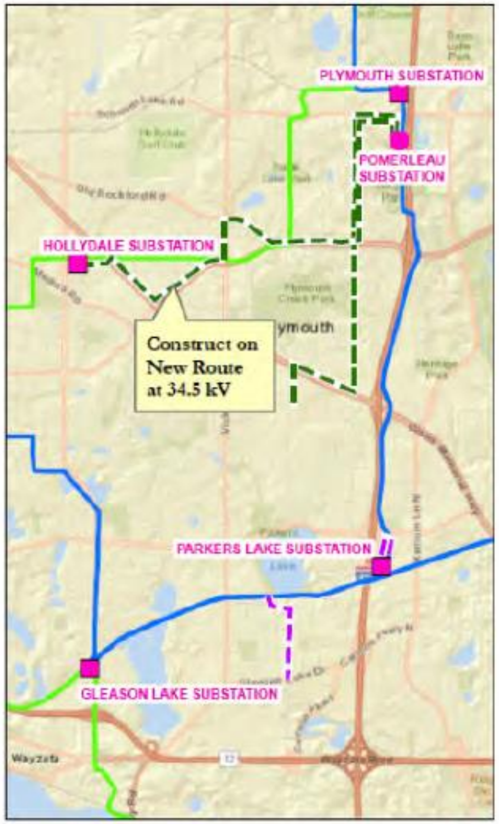
Power flow results for area under critical condition during 2013 peak



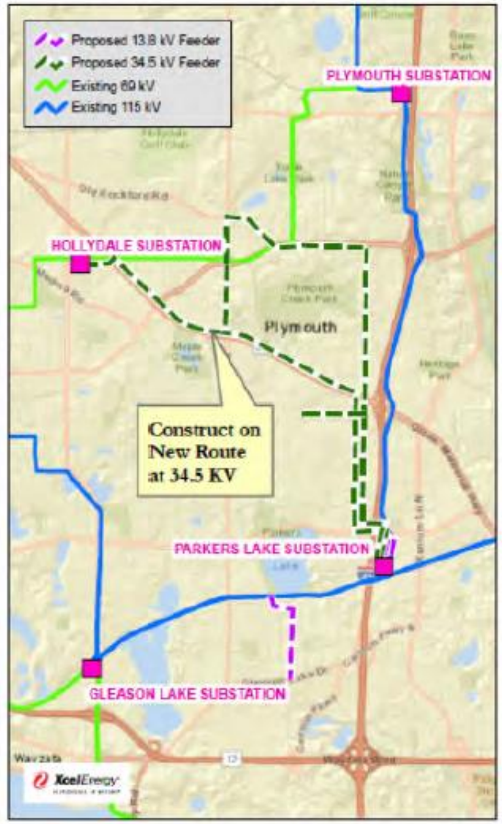
Low voltages due to overloading

Example: Plymouth and Medina Assessment – Potential Solutions

Alternative A



Alternative B



Alternative C

Construct 34.5 kV distribution lines from new Pomerleau Lake Substation to Hollydale Substation.

Construct 34.5 kV distribution lines from Parkers Lake Substation to Hollydale substation.

Re-energize existing 69 kV line east of Hollydale and construct 13.8 kV lines from Hollydale & 0.7 miles of 69 kV to connect existing line to new Pomerleau Lake Sub.

Example: Plymouth and Medina Assessment – Comparison of Alternatives

Selected Solution:

Alternative C, due to :

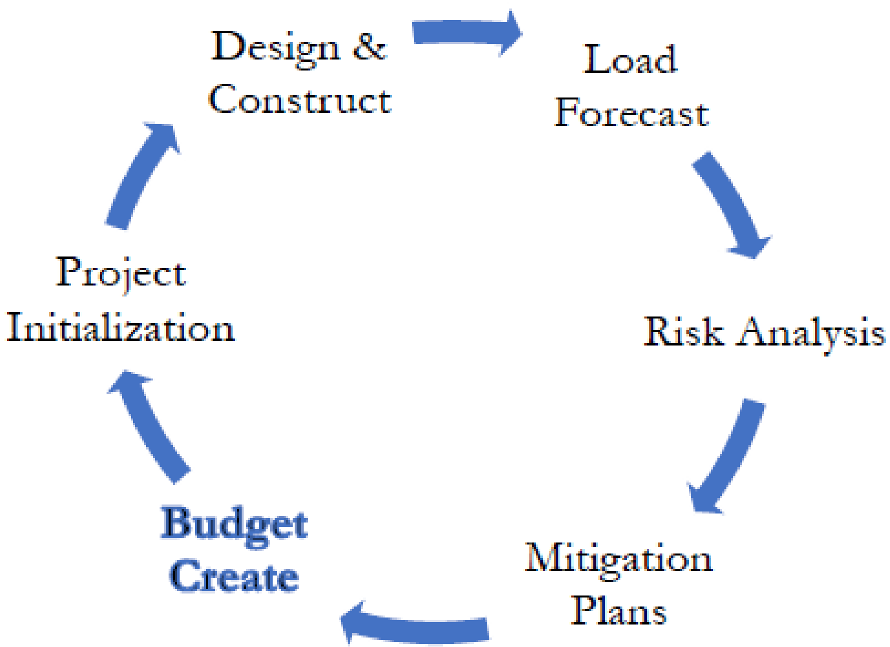
- System flexibility
  - Pomerleau Lake Substation makes additional improvement needs east of I-494 less challenging
  - Ability to efficiently increase capacity if needed in the long-term
- Lowest capital investment
- Least amount of new infrastructure

Project	Total Additional Feeder Length	Average Additional Feeder Length	Distribution System Capacity Added Under N-1	Total Investment	Net Present Value for 2016
Alternative A	9.1 mi	1.8 mi	70 MW	$65.8 M	$45.1 M
Alternative B	11.0 mi	2.2 mi	70 MW	$68.8 M	$41.7 M
Alternative C	4.1 mi	1.0 mi	56 MW[1]	$47.6 M	$38.9 M

Since all three alternatives are comparable solutions from an engineering standpoint, input on non-engineering factors will be gathered during the permitting process to inform the final selection choice.

Distribution Planning Process:
Budget Create

Budget-constrained planning:
Not all projects identified in the previous step will be able to be funded

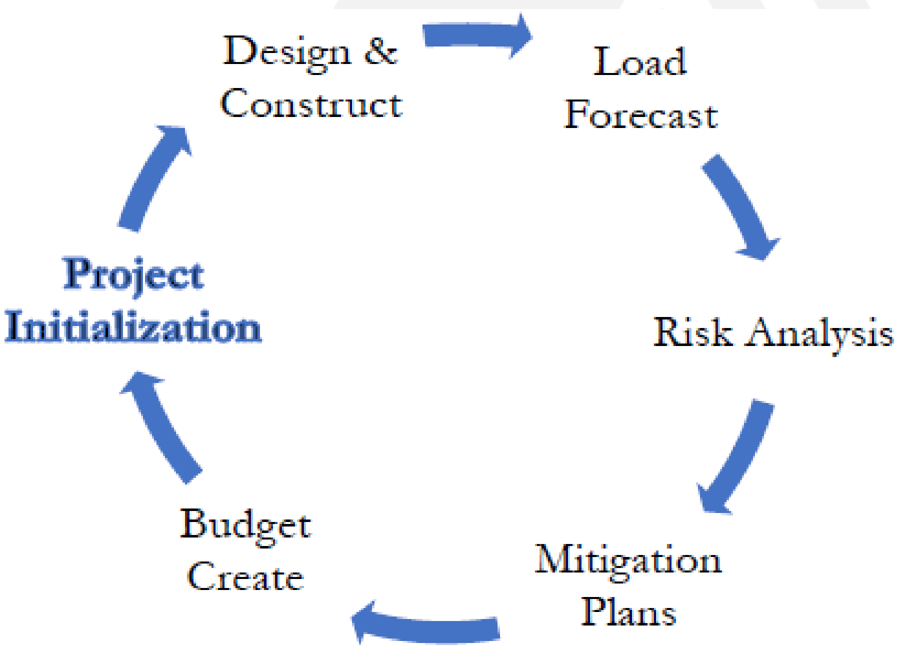


Tools and Processes:
- WorkBook (internal project prioritization tool)

- Xcel's budget includes funding for:
  - New distribution solutions
  - Asset health
  - New business
  - Support of new technologies and DER
  - Unplanned outages due to storms
  - etc.
- Factors used to prioritize investments include:
  - *Reliability*
  - *Safety*
  - *Environmental*
  - *Legal*
  - *Financial*

Results in a ranked project list

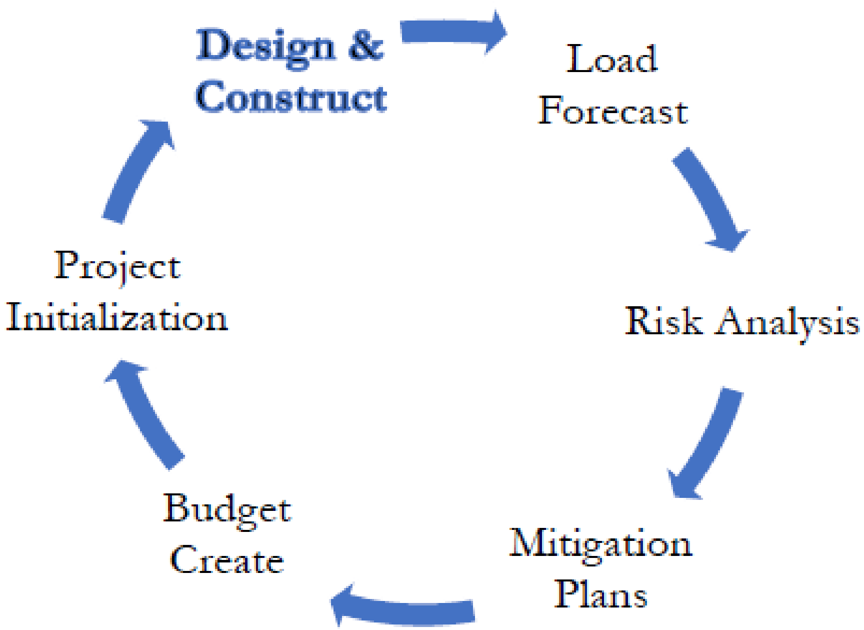
Distribution Planning Process: Project Initialization



Tools and Processes:
- WorkBook (internal project prioritization tool)

- Electric Distribution Planning (EDP) memos are written to initiate the design and construction part of the project.
  - High level step-by-step description of the project that will mitigate an identified risk.
- Describes:
  - The problem being mitigated
  - Any substation design/construction steps to take
  - Any distribution line design/ construction steps to take

Distribution Planning Process:
Design and Construct



Selected projects are communicated to substation engineering and distribution engineers and designers:

- Substation Engineering:
  - For a new feeder bay at an existing substation or a new substation entirely.
- Distribution Design and Construction:
  - For new feeder circuits or modifications of existing circuits.

Current Planning Tools Summary

	Planning Process Component						
Tool	Forecast	Risk Analysis	Mitigation Plans	Budget Create	Initiate Construction - EDP Memo	Long-Range Plans	Hosting Capacity
Synergi Electric			X			X	X
DAA	X	X				X	
MS Excel		X		X		X	
CYMCAP		X					
GIS			X			X	X
SCADA	X						
WorkBook		X	X	X	X		
DRIVE							X

Enhanced Planning Capabilities

Forecasts in the future will need to enable four key features:

► More granular load forecasts that include the impact of DER

► Forecast aggregation

► Forecast scenarios

► Easier identification of possible Non-Wires Alternatives (NWAs)

Non-Wires Alternatives

Non-Wires Alternatives

- Emerging as another advanced distribution planning application
- States with high DER penetration and/or reform measures, leading the way
  - New York, California, Oregon, Arizona
- Decreasing DER costs may present opportunities to address pockets of load growth using DER over traditional build out

Traditional solutions:

- Fixed capacity at known locations: substations, feeders, laterals, etc.

Non-traditional solutions:

- Operational characteristics based on technology, location, time of day

Niche applications with potential to quickly become a cost competitive option

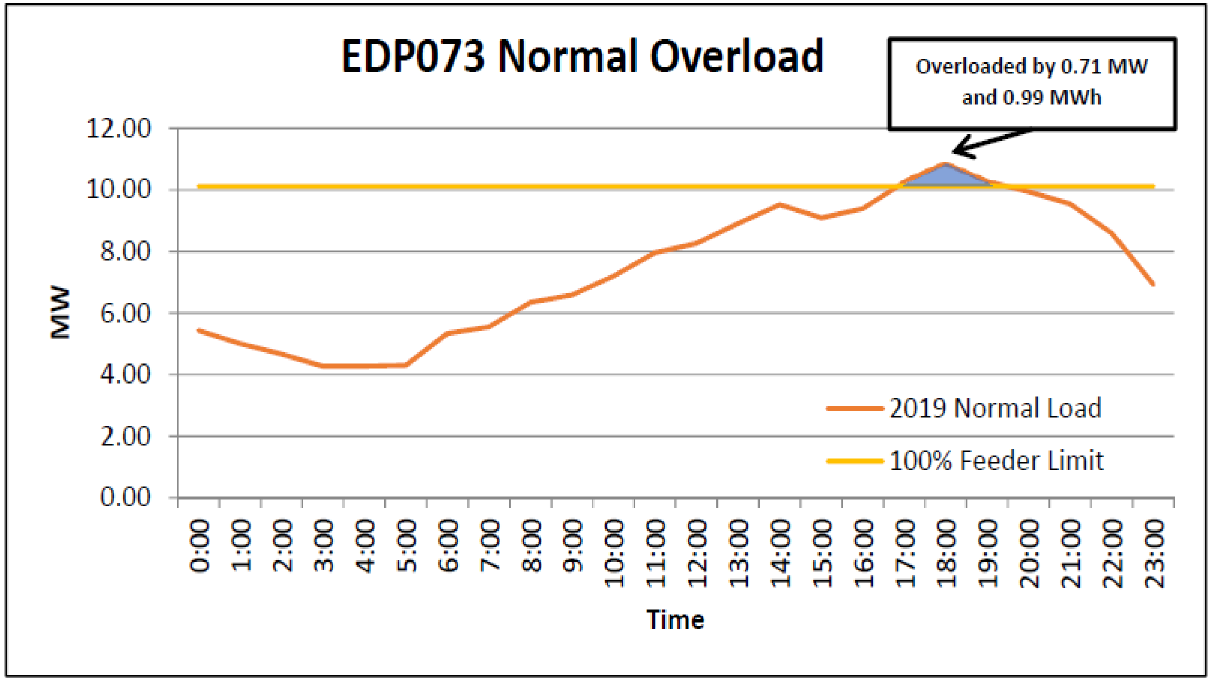
Viability of NWAs by Project Type (*Xcel's View*)

- **Mandated Projects:**
  - Relocating infrastructure in public rights-of-way in order to accommodate public projects such as road widenings or realignments.
  - Replacing with NWA "…*would leave a segment of customers electrically unserved due to having no physical connection to the Xcel system.*"
  - "*Removing interconnectedness takes away .. flexibility and redundancy … and makes [operation] more difficult and less reliable*"

- **Asset Health Projects:**
  - Replacing equipment which are reaching the end of life or have failed (pole replacements, storms, underground cables, etc.)
  - "*Because asset health affects every part of the distribution system and is essential to maintaining reliability, an NWA doesn't make sense*"

- **Capacity Projects (preferred application for Xcel):**
  - Better suited for NWA as they are driven by a capacity deficiency that can be offset or deferred by strategically-sited DER
  - "*NWA must be cost-competitive with a traditional solution to be viable in the budget create process*"

NWA for Capacity Projects: N-0 overload example

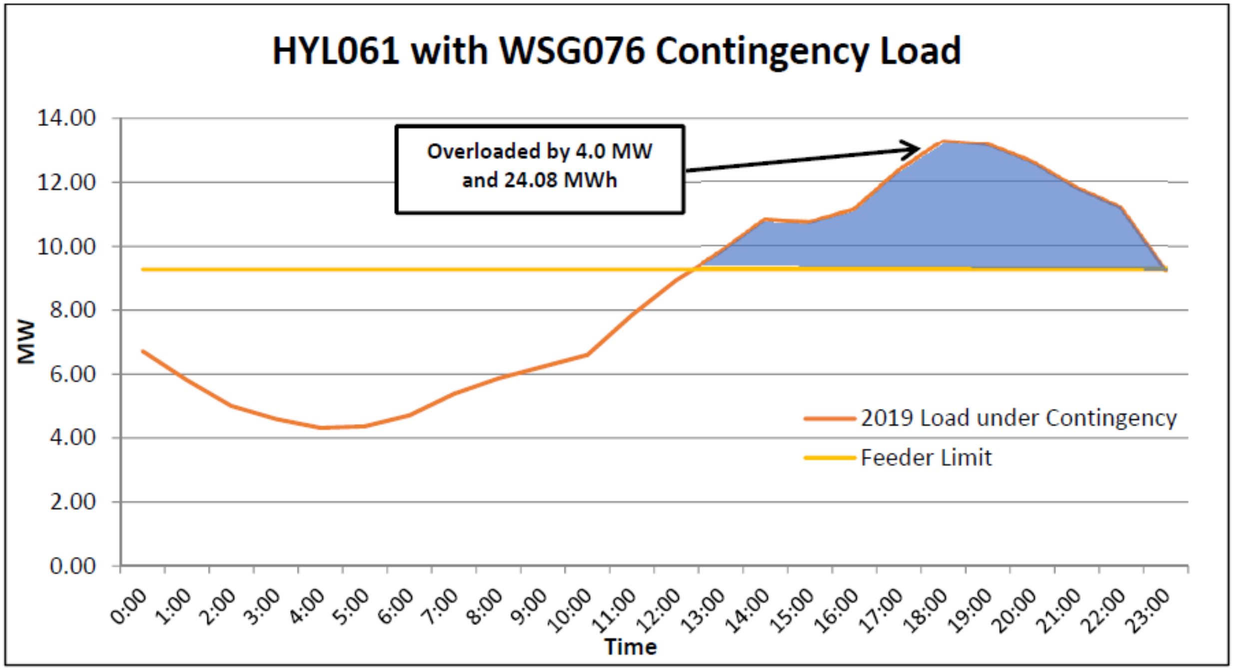


- Small overload with a peak magnitude of 0.71 MW
- Total overload duration is brief, ~ 1 MWh overloaded

Assuming a $600,000/MWh cost for battery storage, overload could be mitigated with DER for $600,000.

Cost-competitive with a typical traditional mitigation project (upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder)

NWA for Capacity Projects: N-1 overload example



- 4 MW overload (standard for N-1 risks)
- Duration of the overload extends to 10 hours, ~24 MWh overloaded

Assuming a $600,000/MWh cost for battery storage, overload could be mitigated with DER for $14,448,000.

Orders of magnitude higher than a typical traditional mitigation project (upgrading feeder cables or conductors, extending a feeder and transferring load, or installing a new feeder)

NWA Timeline

IDP Requirement E.2 requires in part that the Company:
…provide information on . . A timeline that is needed to consider alternatives to any project types that would lend themselves to non-traditional solutions (allowing time for potential request for proposal, response, review, contracting and implementation).

- ► Xcel assumes ~3 years to appropriately consider and incorporate a NWA solution
- ► Incorporates time for internal analysis and steps surrounding RFP to procure a NWA solution

Xcels' view … "*with more experience timeline could shrink a bit, but is that these projects necessarily take a significant amount of lead time*"

NWA Screening Process

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Project Types

Capacity projects only

Costs

Greater than $2 Million

Timeline

2021-2023 timeframe

Risks

N-0
N-1

NWA Analysis Example: New Viking Feeder Project

Goal:

Relieve identified capacity issues in the distribution system in Eden Prairie, Minnesota.

Relatively few capacity risks:

Feeder	Capacity Risk
EDP073	N-0 overload, 107%
EDP073	N-1 overload on WSG065 for loss of EDP073, 2.3 MVA at risk
HYL061	N-0 overload, 101%
WSG076	N-1 overload on HYL061 for loss of WSG076, 4.2 MVA at risk

NWA Analysis Example: New Viking Feeder Project

Feeder loading was analyzed to identify MW and MWh needed from DER to mitigate risk.

Table 12: Summary of DER Solutions

Capacity Risk	Overload Magnitude		Optimal DER Solution		Estimated Cost
	MW Overload	MWh Overload	Solar PV (MW)	Battery Storage (MWh)	
EDP073 N-0 overload, 107%	0.71	0.99	0	0.99	$595,000
N-1 overload on WSG065 for loss of EDP073, 2.3 MVA at risk	2.04	11.50	0	11.50	$6,900,000
HYL061 N-0 overload, 101%	0.04	0.04	0	0.04	$26,000
N-1 overload on HYL061 for loss of WSG076, 4.2 MVA at risk	4.00	24.08	0	24.08	$14,450,000
Total			0	36.61	$21,971,000

Non-Wires Alternative: $22 million
Traditional project: $2.5 million

Additionally, a traditional solution provides additional capacity for new growth, where a NWA does not

Note:

DSM and energy efficiency programs are already considered in the load forecast (reducing future load growth rates). However, additional targeted marketing of DSM and energy efficiency programs could potentially further reduce the load growth rate beyond expected levels.

Asset Health and Reliability Management

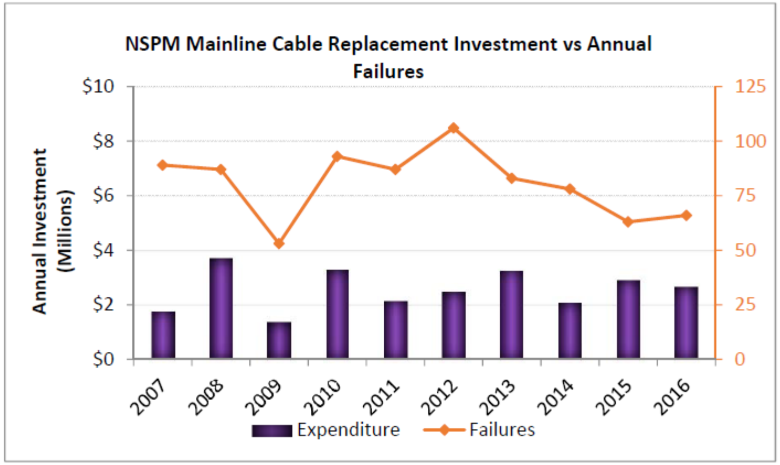
Distribution Function Responsibilities

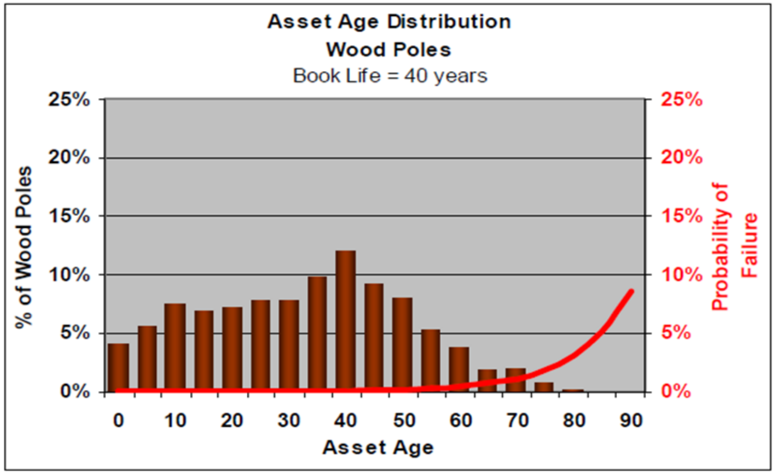
- ► Asset Health:
  - Replacing equipment which is nearing the end of life or has failed
- ► Outage Restoration:
  - Due to unplanned events like severe weather events
- ► Annual Reliability Studies:
  - Remediating existing or anticipated capacity deficiencies or constraints that could lead to overloads

Asset Health

- OH distribution reliability performance dependent on many factors including:
  - Vegetation
  - Weather
  - Health of the many pieces of the OH system

- Identify and prioritize areas based on:
  - Reliability history
  - Age and condition
  - Total restoration time
  - Numbers of customers
  - Potential for O&M cost savings
  - DER adoption potential





Asset Health Key Programs

Key programs to maintaining good reliability:

► Vegetation Management Program

► Pole Health Program

► Feeder Infrared Evaluation Program

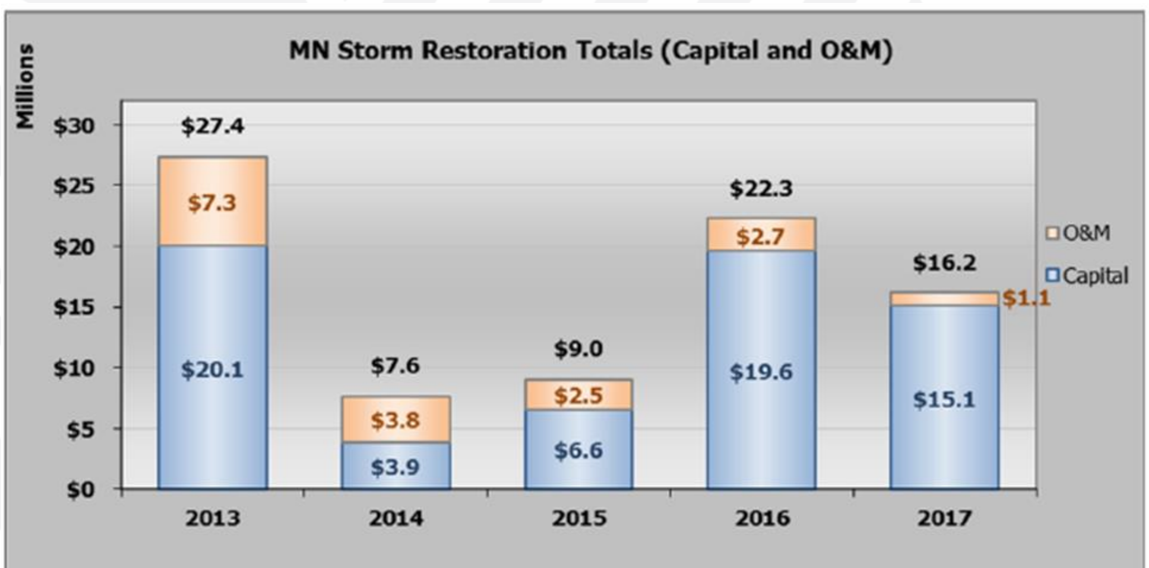
► Feeder Performance Improvement Program

► Reliability Exception Monitoring System

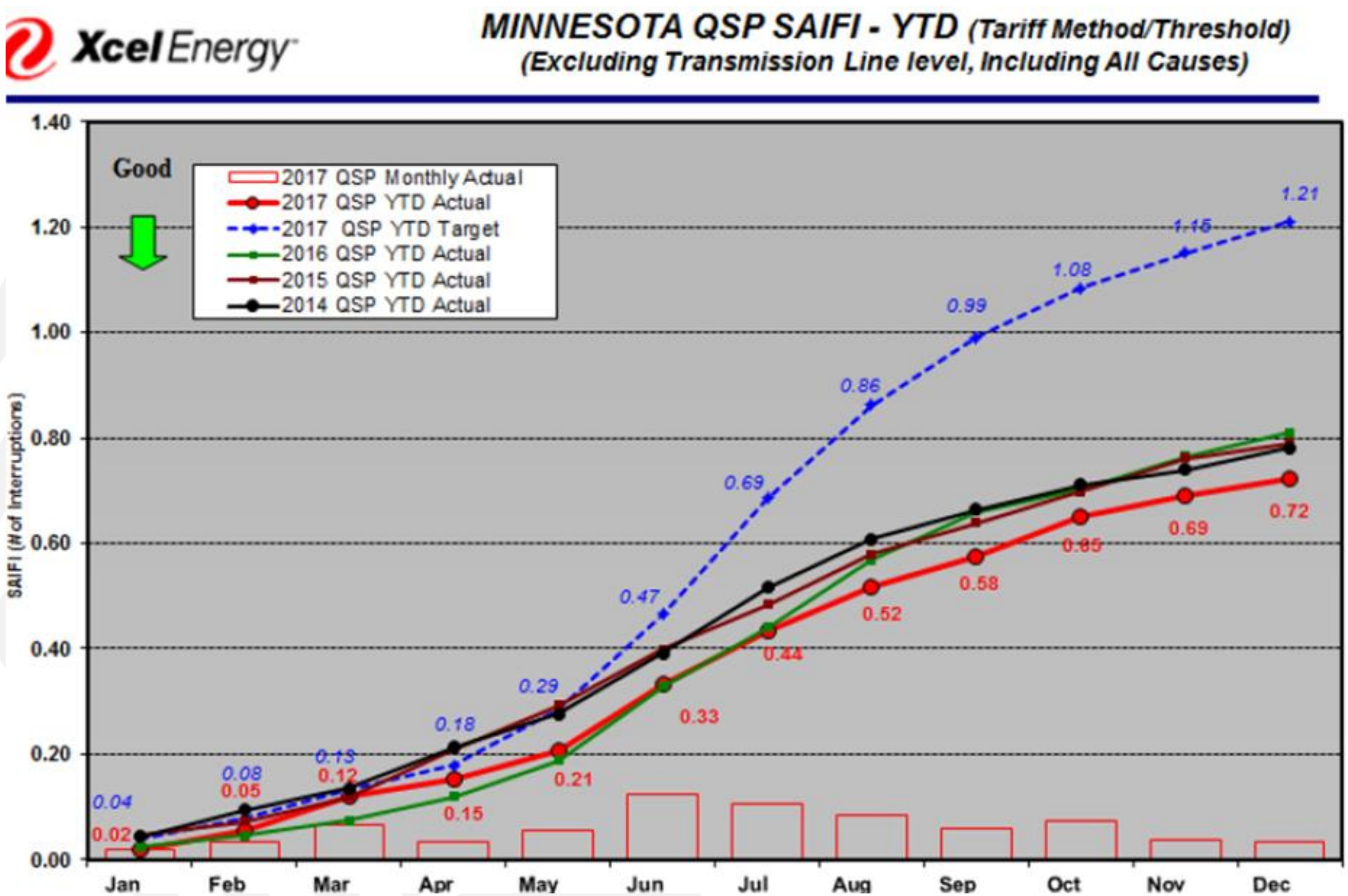
► Identification of customers experiencing multiple interruptions

Long-term Planning for Storm-related Outages

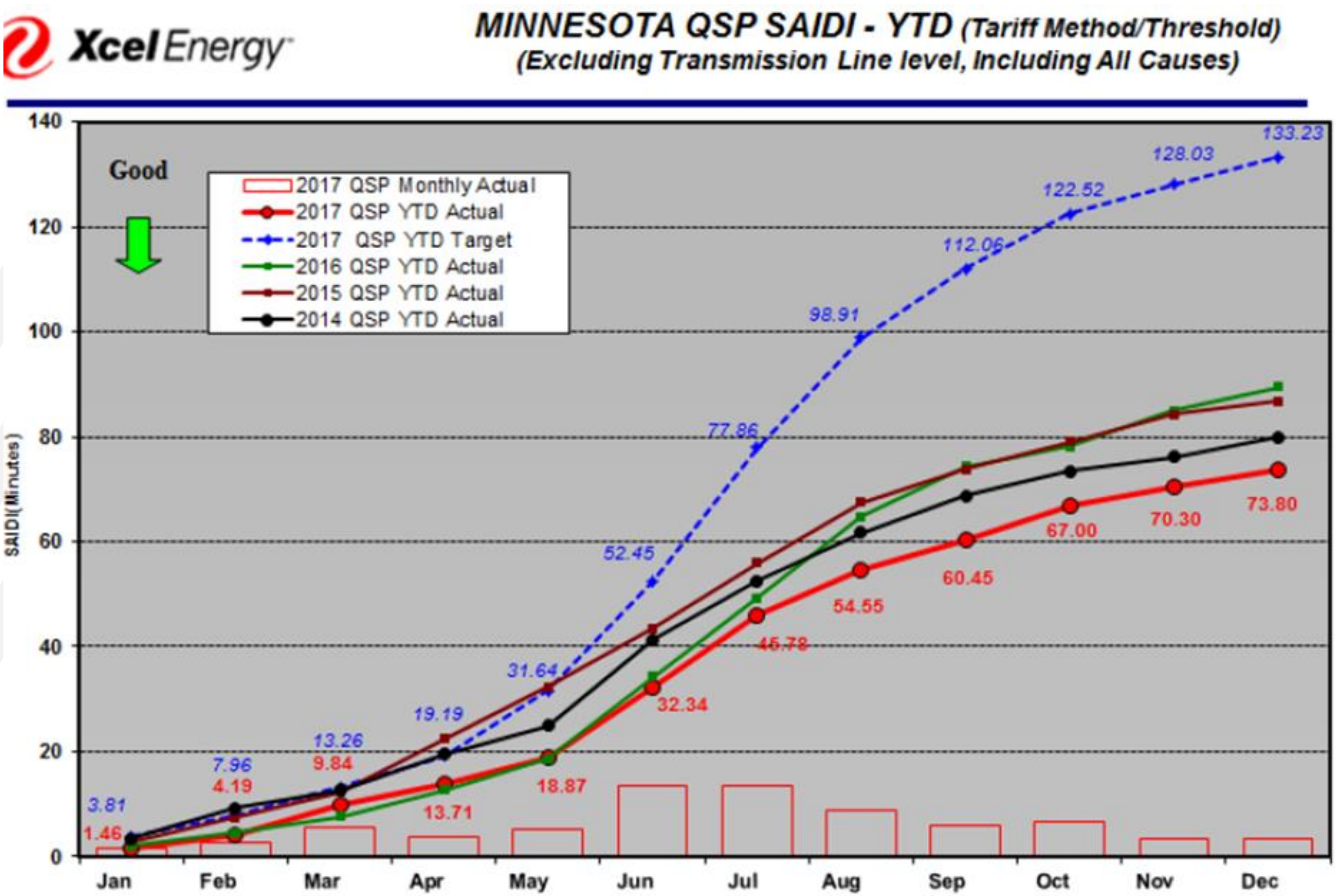
- Ensure sufficient workforce:
  - Agreements with contractors to supplement field forces when needed
  - Mutual aid agreements with other utilities
- Prepare for supporting outage restoration crews:
  - Maintain list of hotel accommodations and conference facilities across the service area
  - Maintain lists of available transportation options
  - Ensure ready access to catering to feed crews, restroom availability, etc.
- Ensure a sufficient **storm restoration budget** is available



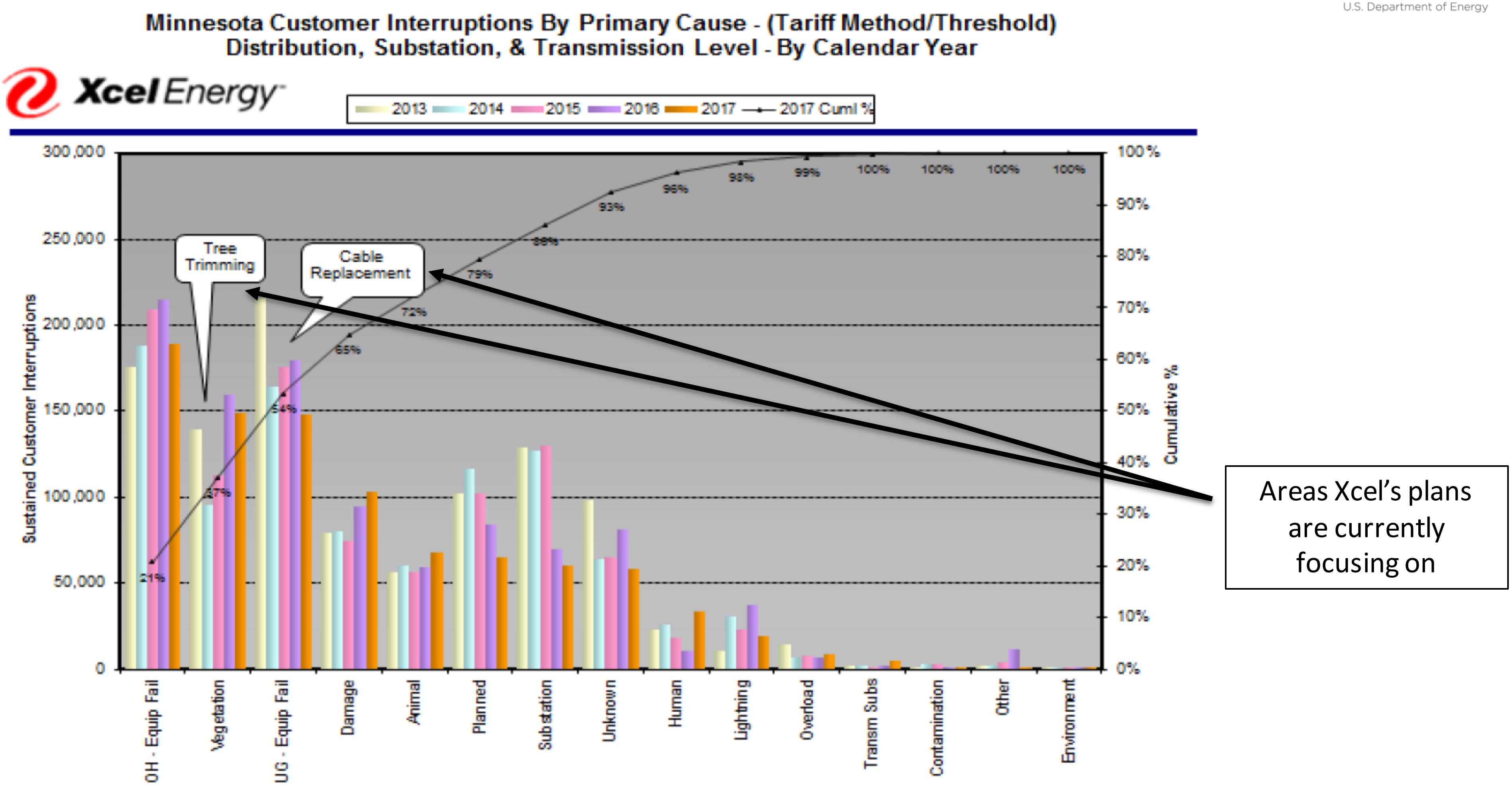
System Average Interruption Frequency Index



System Average Interruption Duration Index



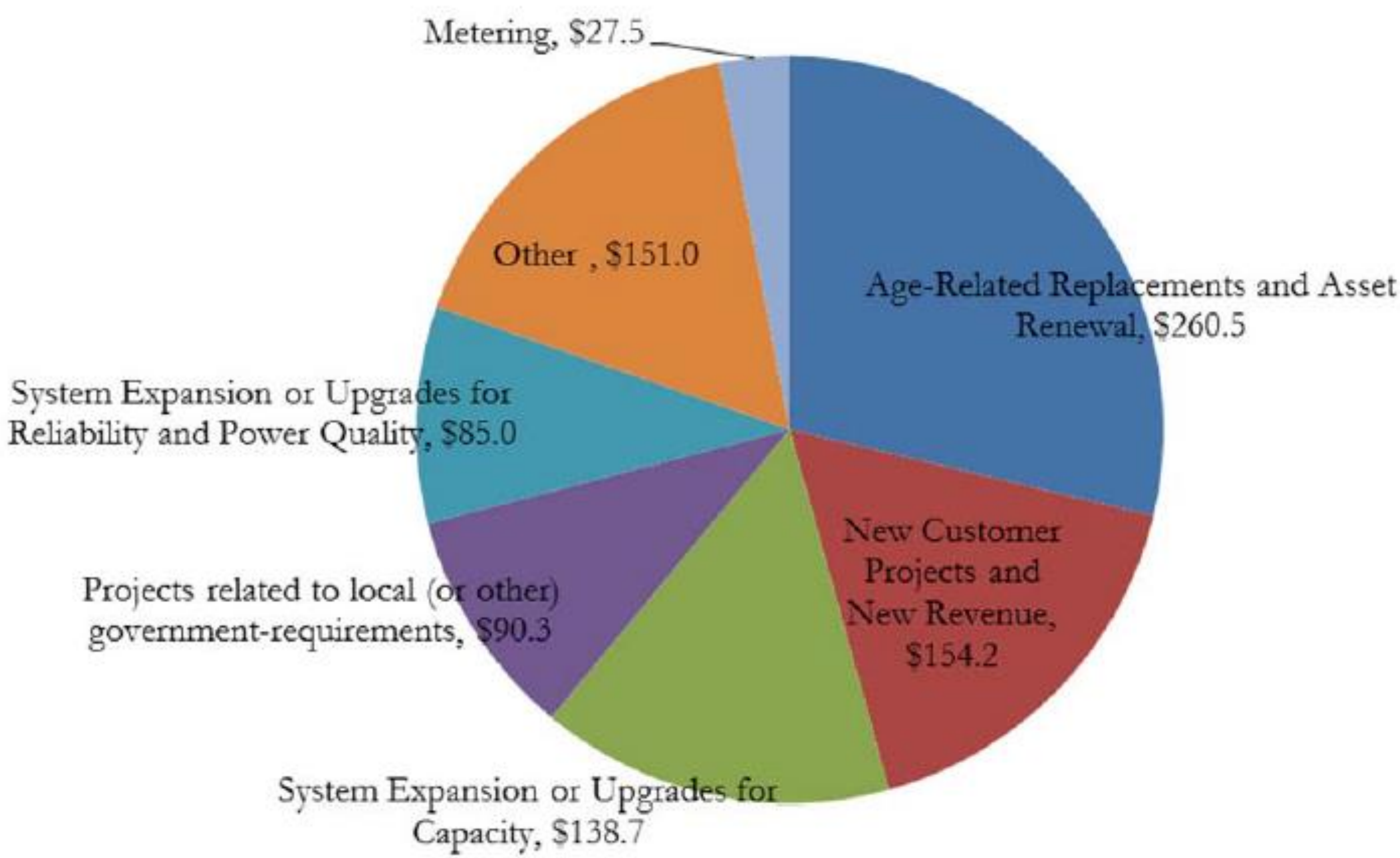
Annual Reliability Planning Process: Cause Analysis



Tariff Method: IEEE Normalized by Region after excluding Transmission Line level, Meter-based customer counts.

Distribution Budgets

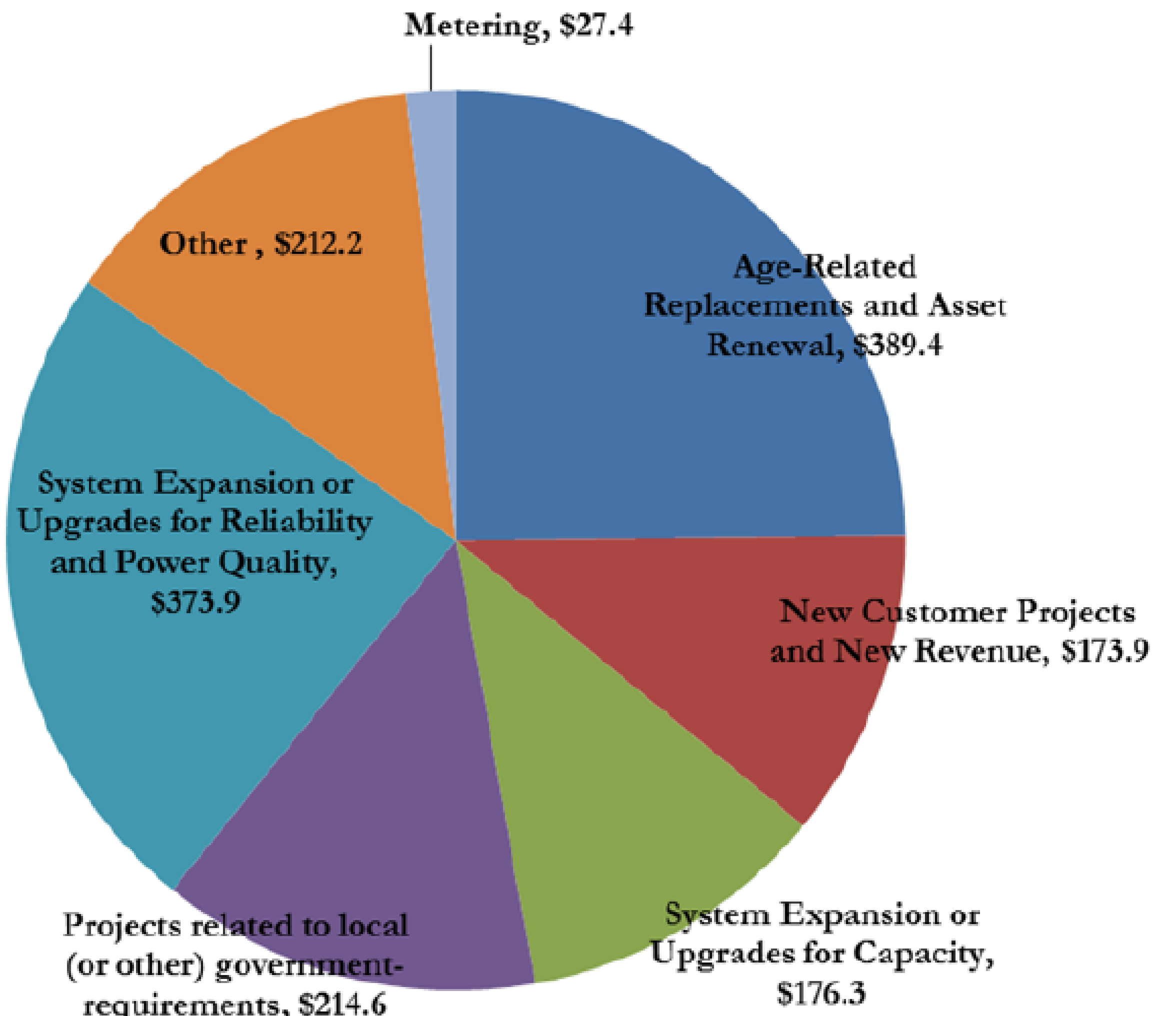
NSPM Historic Distribution Capital Profile by IDP Category (2013-2017)



Note: excludes non-investment amounts.

$ in millions

NSPM Budgeted Distribution Capital Profile by IDP Category (2018-2023)



$ in millions

NSPM Distribution Capital Expenditures Budget (2018-2023)

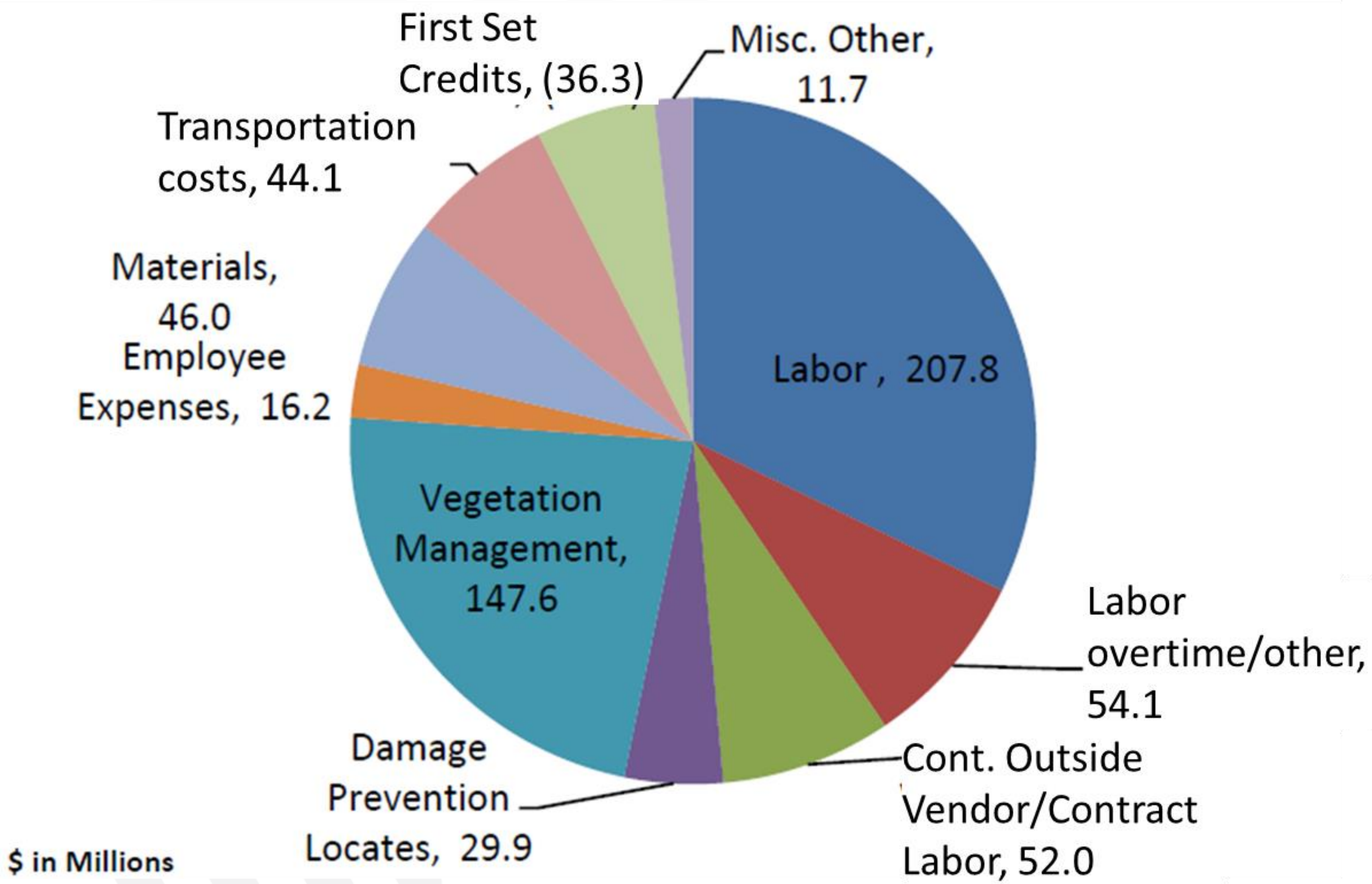
$ in millions

Expenditure Category	Bridge 2018	Budget 2019	2020	2021	2022	2023	Budget Avg 2019-2023
Age-Related Replacements and Asset Renewal	$67.2	$57.9	$60.1	$64.5	$73.0	$66.7	$64.4
New Customer Projects and New Revenue	$37.4	$25.4	$28.2	$26.9	$27.6	$28.4	$27.3
System Expansion or Upgrades for Capacity	$17.4	$14.5	$35.0	$40.2	$33.7	$35.4	$31.8
Projects related to Local (or other) Government-Requirements	$17.9	$50.2	$45.0	$36.1	$32.7	$32.7	$39.3
System Expansion or Upgrades for Reliability and Power Quality	$27.1	$21.4	$27.4	$113.4	$116.4	$68.4	$69.4
Other	$36.5	$28.3	$33.4	$41.0	$42.1	$30.9	$35.1
Metering	$5.9	$5.9	$5.1	$3.9	$3.5	$3.1	$4.3
Non-Investment/CIAC	($12.0)	($3.6)	($3.7)	($3.7)	($3.8)	($3.8)	($3.7)
TOTAL	**$197.4**	**$200.0**	**$230.3**	**$322.3**	**$325.1**	**$261.8**	**$267.9**

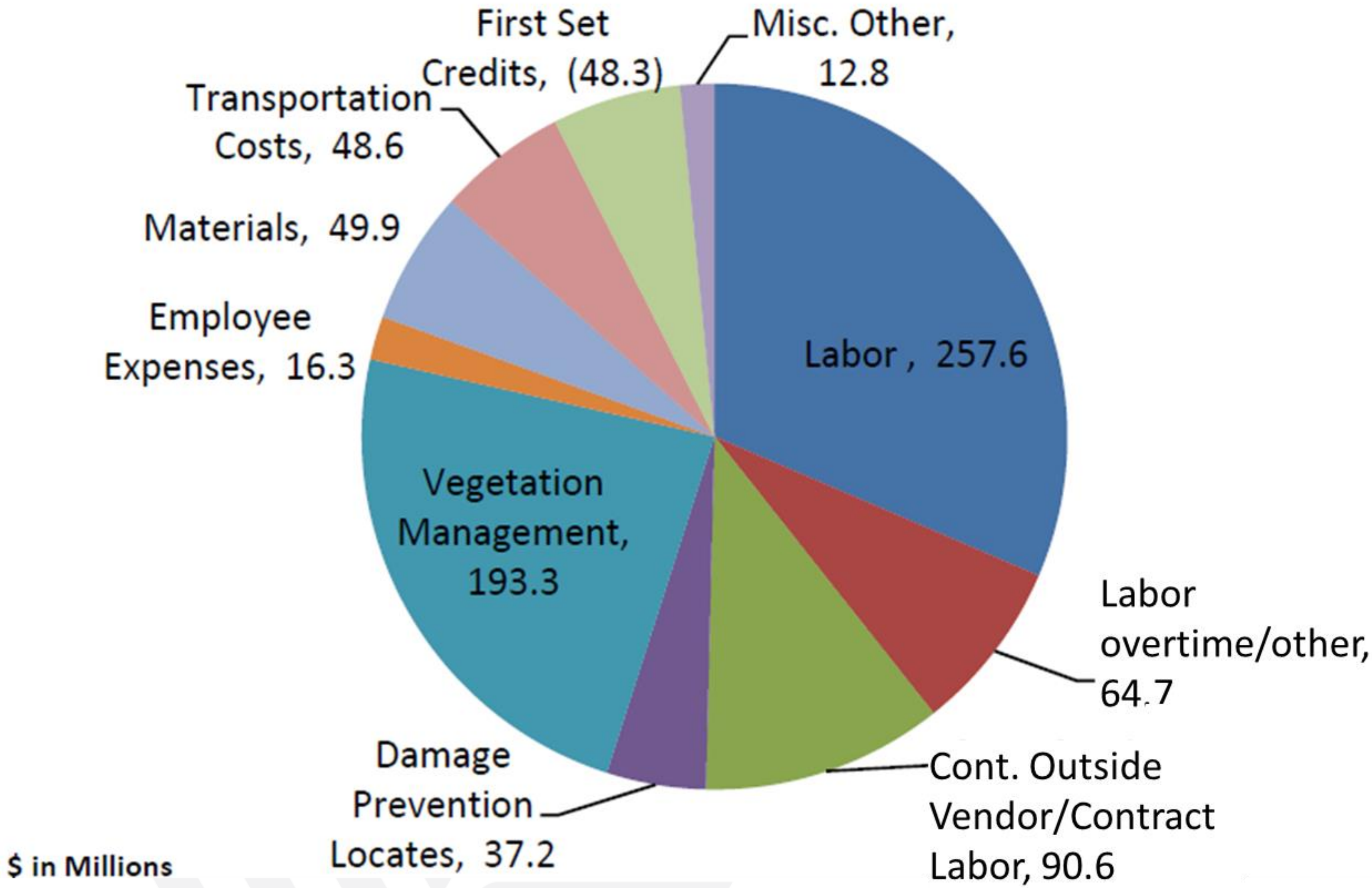
Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Other includes Fleet, Tools, Communication Equipment, Locating and Transformer Purchases; Reliability includes placeholder investments for a new reliability program (Incremental Customer Investment); and Non-investment/CIAC includes Contributions In Aid of Construction (CIAC), which partially offset total project costs and 3rd party reimbursements for system upgrades due to interconnections.

~$1.3B over five years (2019-2023)

NSPM Historic Distribution O&M Costs by Cost Element (2013-2017)



NSPM Budgeted Distribution O&M Costs by Cost Element (2018-2023)



NSPM Distribution O&M Expenditures Budget (2018-2023)

$ in millions

Expenditure Category	Bridge 2018	Budget 2019	Budget 2020	Budget 2021	Budget 2022	Budget 2023	Budget Avg 2019-2023
Labor	$43.0	$42.5	$42.1	$42.7	$43.5	$43.9	$42.9
Labor (overtime/other)	$10.8	$10.8	$10.8	$10.8	$10.8	$10.9	$10.8
Cont. Outside Vendor/Contract Labor	$14.5	$13.8	$14.7	$14.8	$16.1	$16.6	$15.2
Damage Prevention Locates	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2	$6.2
Vegetation Management	$31.5	$32.4	$32.5	$32.3	$32.3	$32.3	$32.4
Employee Expenses	$3.0	$2.7	$2.7	$2.6	$2.6	$2.7	$2.7
Materials	$8.2	$8.5	$8.4	$8.2	$8.2	$8.3	$8.3
Transportation Costs	$8.1	$8.3	$8.2	$8.0	$8.0	$8.1	$8.1
First Set Credits	($7.9)	($8.0)	($8.1)	($8.1)	($8.1)	($8.2)	($8.1)
Misc. Other	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1	$2.1
TOTAL	**$119.4**	**$119.3**	**$119.5**	**$119.7**	**$121.7**	**$123.0**	**$120.6**

Notes: Excludes Grid Modernization – capital and O&M expenditures associated with the advanced grid initiative are presented separately as a holistic initiative; Misc Other includes bad debt, use costs, office supplies, janitorial, dues, donations, permits, etc.

~$0.6B over five years (2019-2023)

Key Take-Aways

- $2 billion in capital and O&M spending projected for the next 5 years
- Investments in physical grid infrastructure (poles, wires, relays, transformers, etc.) provide the necessary foundation for upgrading grid capabilities
- Grid modernization goals cannot be fully met if new technology is deployed on existing aging infrastructure
- Must coordinate advanced capabilities with physical grid infrastructure upgrades
- This will allow advanced communications and intelligent applications to manage the grid as a fully integrated bi-directional system

Any Questions?

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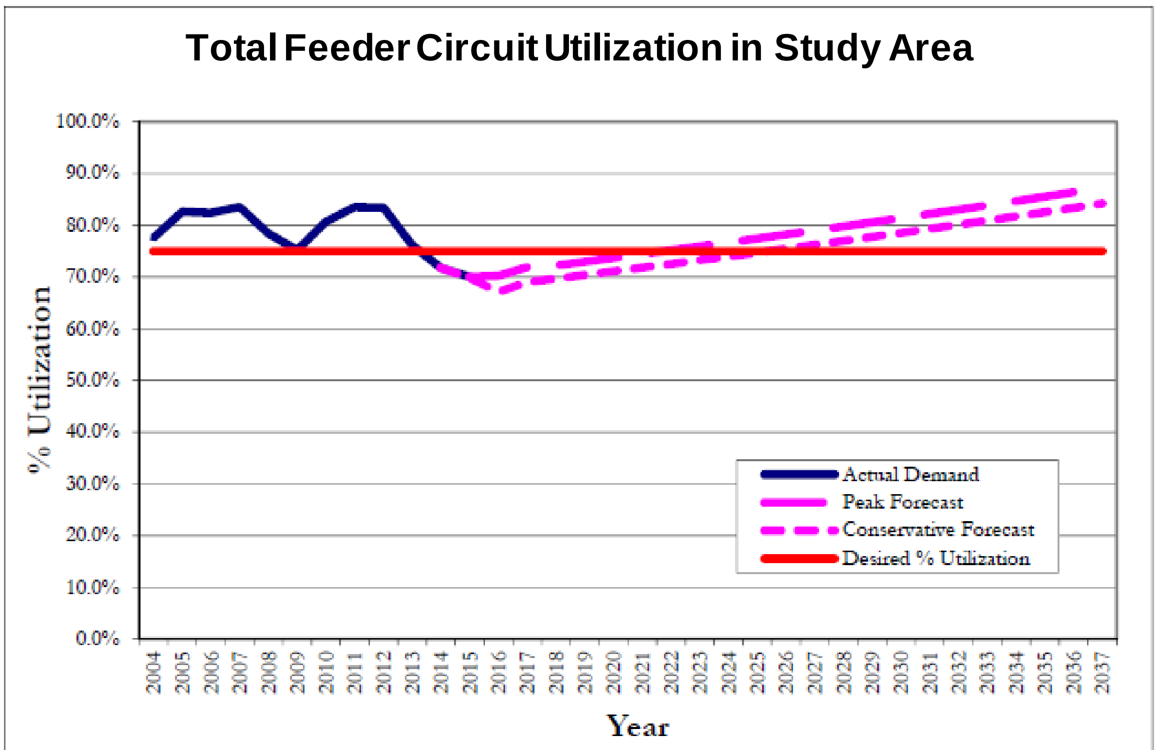
Lavelle.freeman@ge.com

Limitations of Feeder Circuit Design

$$\text{Total Feeder Circuit Utilization} = \frac{\sum \text{Feeder Circuit Load in Area}}{\sum \text{Feeder Circuit Capacity in Area}}$$

When the total feeder circuit utilization **within a study area** exceeds 75 percent, it is generally no longer effective to perform more simple solutions – such as load transfers, or installing new feeder tie connections between existing feeders.

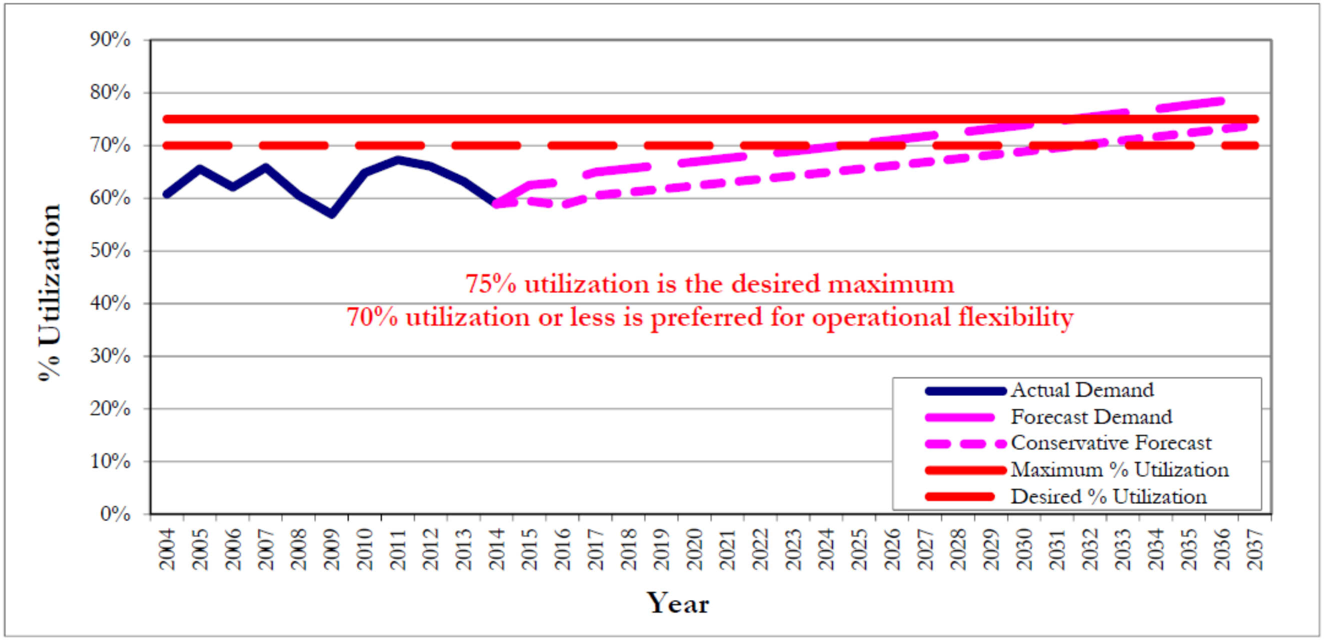


Transformer Sizing

Loading objective for transformers is **75 percent of normal rating or lower** under system intact conditions:

- ► Below 75 percent is indicative of a robust distribution system that has multiple restoration options in the event of a substation transformer becoming unavailable
- ► The higher the transformer utilization rate, the higher the risk of a transformer outage that interrupts service to customers (due to neighboring equipment failure or maintenance)

Total Transformer Utilization Percentage in Study Area



Spatial and Thermal Design Constraints

Options when adding extra capacity to an area:

Option A: Add a feeder circuit to an already existing pole line:

- Only two feeder circuits per pole line allowed

Option B: Bury a feeder cable in an established utility easement:

- Must ensure adequate spacing between cables to avoid overheating
- Cable spacing limitations can occur when many feeder cables must be installed in the same corridor near distribution substations or when crossing natural or manmade barriers

Option C: Construct facilities from a different area to serve load