LOS ALAMOS COUNTY DEPARTMENT OF PUBLIC UTILITIES

2021 ELECTRIC RELIABILITY PLAN

(FOR INFORMATION & DISCUSSION ONLY)

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Executive Summary

This report is the update to the Electric Reliability Plan "ERP" and is a living-document. The purpose for this report is to have a path forward to achieve and maintain a SAIDI (System Average Interruption Duration Index) of 60 minutes or less for the residents of Los Alamos County.

As the SAIDI illustrates, there has been success in the strategy to address and improve the system reliability. However, and because of the single substation source in the Los Alamos town site and White Rock, there is a single point of failure that can cause the loss of power to a large portion of our customers.

The Los Alamos County Department of Public Utilities "DPU", electric distribution "ED" spends most of its operational budget on pro-active and preventive Operations and Maintenance (O&M) and constructs capital projects to improve the system reliability. Section VII of this report provides a summary of the many major system reliability improvement projects completed over the past ten years.

Los Alamos County now has over 333 customers in process or connected to the utility with Solar system installations. The connected load is 3,039 kW with 278 kW pending (as of 11-1-21). The Department goal for distributed generation is 6,000 kW (6 MW), including the 1 MW utility scale solar facility at the Eco Station.

The installation of new Advanced Metering Infrastructure (AMI) system improved outage response times with the implementation of the outage identification. The new Sensus meter software allows staff to see all meters affected by an outage and respond directly to the affected area, eliminating more extensive troubleshooting and inspections previously needed to identify the source an outage. When an outage is detected or reported, the utility will access the scope of the outage and begin the customer notification process.

Projects within the county have been delayed due to the Covid pandemic and are experiencing continued delays associated with the ongoing supply chain issues.

The Electric Distribution (ED) shop is divided into three crews. The first is a 4-person crew assigned primarily to the overhead distribution system, replacing rotten poles, weathered cross-arms and aged or obsolete transformers. The challenge with the overhead distribution system is that a portion of it is at least 40 years of age and operating near or past its useful life. The second is a 3-person crew primarily dedicated to pro-actively replacing live-front and obsolete switchgear, transformers, and sections of underground power lines that have failed multiple times. Line crews also convert old un-insulated service lines to newer insulated service lines. The third is a 3-person crew that primarily works on major capital improvement projects, replacing the aged infrastructure but adds improved reliability features such as new line protection facilities, loops, tie-lines, or 3 phase conversions. In recent years ED has spent a significant amount of time supporting new developments within the County.

As previously noted, the single most important reliability project the department needs to undertake is the construction of a second substation for the Los Alamos town site. The *Los Alamos Switchgear Substation “LASS”* is tentatively planned to be completed within 12 months and located at the County Landfill. The new substation is critical to meet the future electrical supply needs of Los Alamos and maintain the system reliability success ED has demonstrated in the last decade.

The report provides an overview of the existing transmission and distribution system for the Los Alamos County service area, and potential impacts on the overall system reliability. The transmission lines within Los Alamos are owned by DOE-NNSA with the O&M performed by LANL line crews.

The focus and discussion of the ERP is on the electrical distribution system, the department’s Asset Management Program (AMP), strategies for short-term and long-term action plans, and their impact on system reliability and revenue requirements.
Power disruptions due to source outages are not included within the reliability statistics of the county as they are not under our control.

I. System Overview:

Los Alamos Power Pool

The Los Alamos Power Pool (Power Pool) is the product of The Electric Energy and Power Coordination Agreement (ECA) between the Los Alamos County Department of Public Utilities and the Department of Energy (DOE) through the National Nuclear Security Administration (NNSA). The Power Pool purchases, sells, and schedules the power required for DPU and Los Alamos National Laboratory (LANL). The Power Pool currently has 93 MW of summer capacity and 78 MW of winter capacity. LAPP purchases market power as necessary to meet the power demand in excess of LAPP's owned capacity, or sells excess power into the market when the power demand is lower than LAPP's capacity.

Los Alamos Transmission System

Public Service Company of New Mexico (PNM) provides 115 kV transmission service into Los Alamos from the Norton and STA substations. PNM also provides primary and back-up relay protection to the DOE-owned transmission lines since we are connected to the bulk electric system within PNM's Balancing Area. DOE has a looped 115 kV transmission system with several substation internal to the Los Alamos County service area. White Rock has it's own substation and Townsite is fed from the new TA-3 substation as illustrated in Figure 1. DPU Power System Operators operate the transmission system, manage generation resources, and provide merchant desk services for LAPP, 24 hours per day, 365 days per year.

Remote operations are done via a Supervisory Control And Aata Acquisition (SCADA) system, but currently there is limited control over the DPU distribution system. Section VI describes alternativesto expand the SCADA system into the DPU distribution system to improve system reliability.

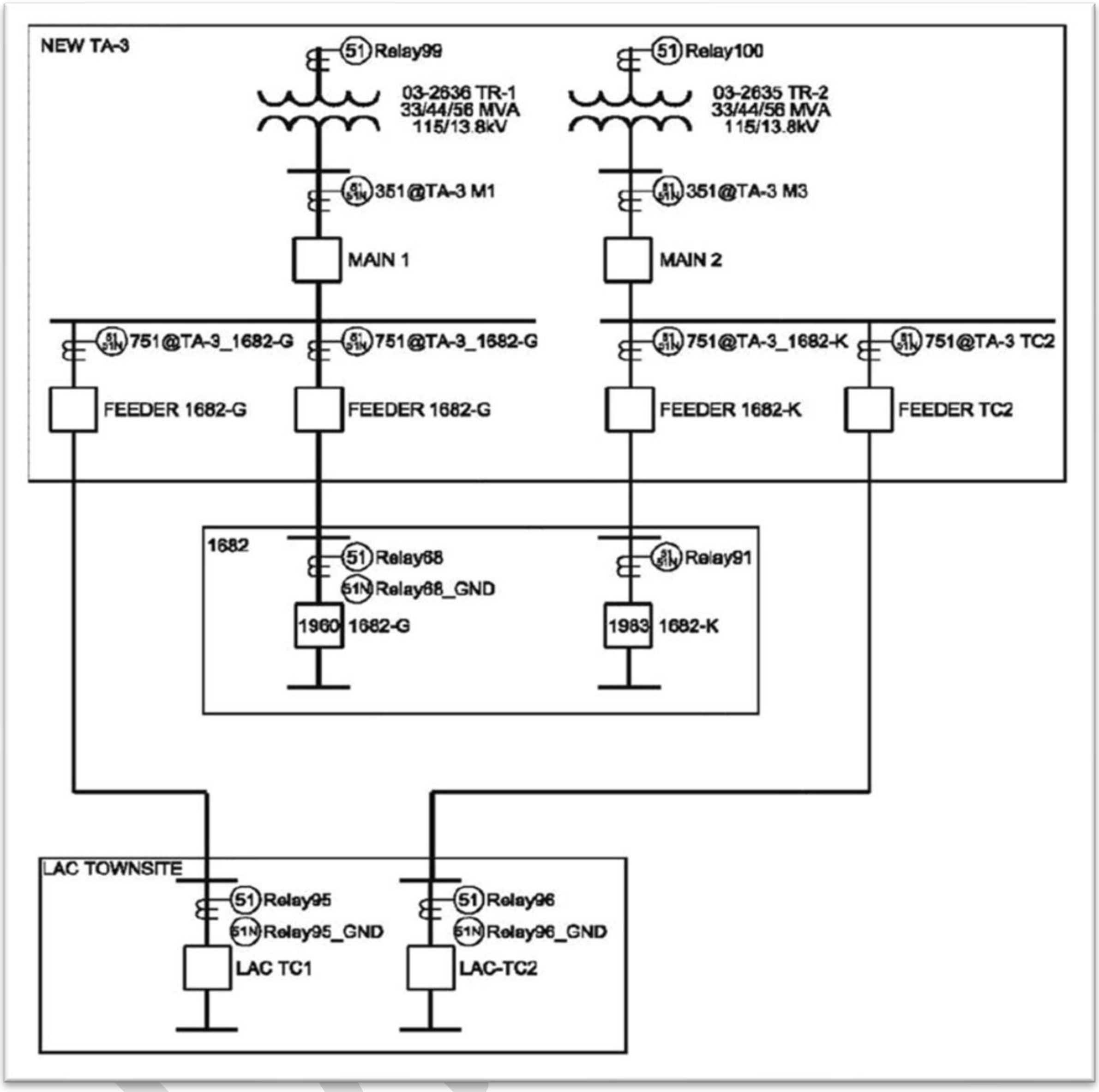


Figure 1. 115KV Transmission lines and TA-3 Substation feed into Los Alamos

Los Alamos Townsite Electric Distribution System

DPU

The Los Alamos Townsite switching station's switchgear, illustrated in Figure 2, provides power to the Los Alamos Townsite community and is fed by LANL's TA-3 substation via two 15 kV express feeders, labelled TC-1 and TC-2; and normally fed from a 30 MVA transformer, labelled TR-1. There is a back-up tie to a second 30 MVA transformer, labelled TR-2. The Townsite switching station bus is configured into two sections, half-bus for TC-1 and half-bus for TC-2. Upon loss of power to TC1 or TC2, DPU can manually transfer the outage bus-section to the energized bus-section.

Circuit 13: Western Area and Ski Hill
Circuit 14: Eastern Area and Pajarito Cliff Site
Circuit 15: Quemazon , NC3, Ponderosa Estates
Circuit 16: North Mesa and Barranca Mesa
Circuit 17: Downtown Commericial North of Trinity
Circuit 18: Downtown Commercial South of Trinity and DP Road

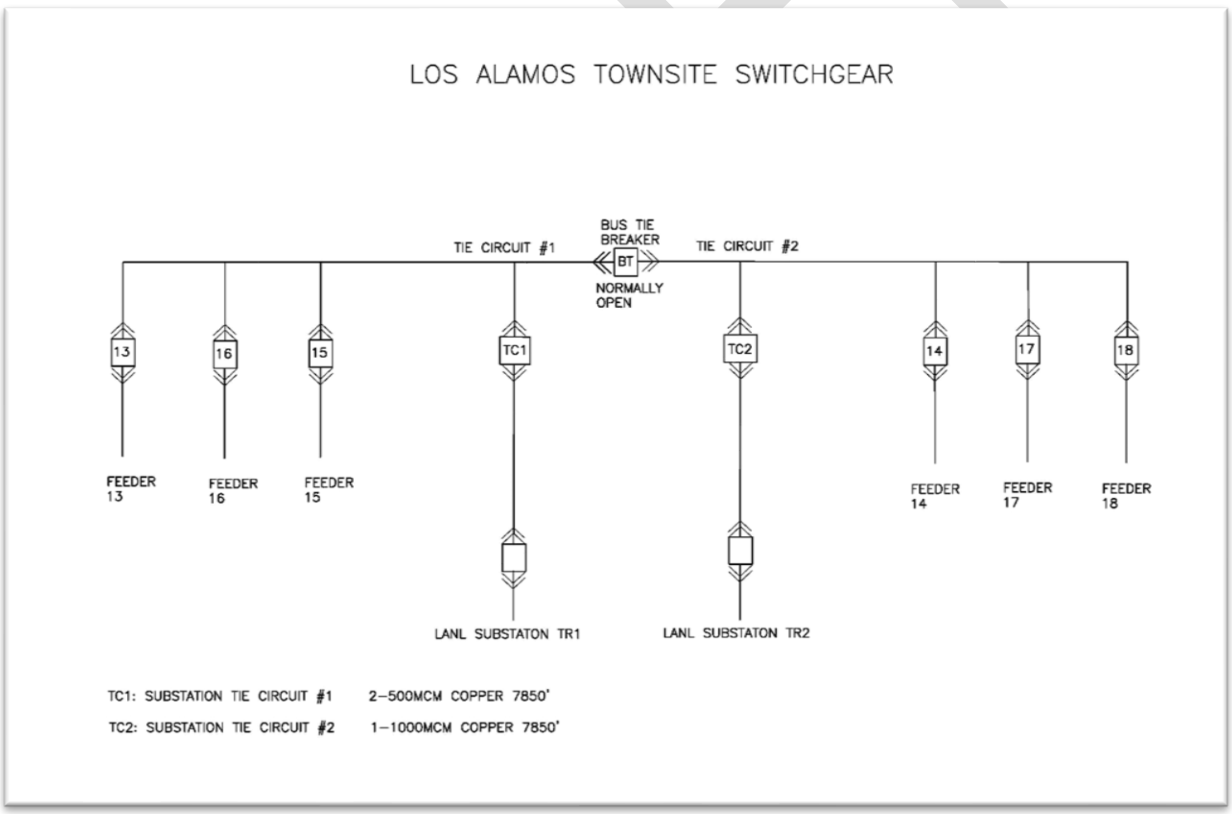


Figure 2. Los Alamos Townsite Switching Station

White Rock Electric Distribution System

The White Rock substation provides power to the White Rock community and consists of primary and back-up 115KV to 12.47 KV transformers with metal-clad switchgear as illustrated in Figure 3. The primary feed TR1 was installed in 2006 and consists of a 10 MVA transformer with metal-clad switchgear. The secondary back-up feed TR2 is the original 50 year old 7.5 MVA transformer and new metal-clad switchgear installed in 2019. The TR2 transformer is also fitted with new primary side breakers. Service is transferred to TR2 when transmission line service is required by LANL or if maintenance on TR1 facilities are required.
Switching between the TR1 and TR2 systems is done manually by paralleling both systems. DPU has a switching procedure in place to ensure the paralleling process is conducted safely. Having the back-up substation transformer has great reliability value.

Circuit WR1: East of Rover
Circuit WR2: West of Rover
Circuit WR3: El Mirador Subdivision

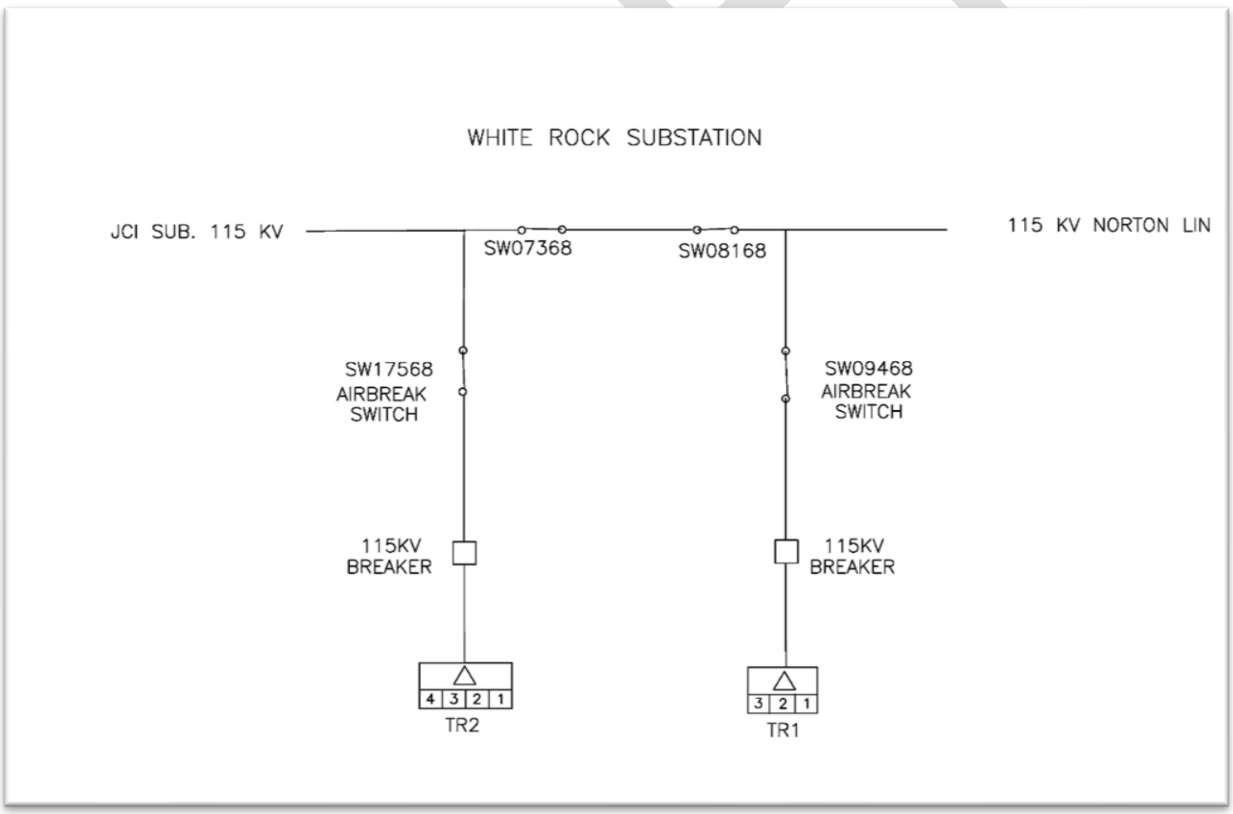


Figure 3. White Rock Substation

Los Alamos County Photovoltaic infrastructure (Landfill Array)

The PV site located at the landfill on East Jemez Road supplies 1.0 MW of energy to the local grid. The integration of the PV sources onto TC-1 and TC-2 is illustrated in Figure 4.

S&C Vista padmounted switchgear is utilized to integrate the PV generation source onto TC-1 and TC-2. The Vista's utilize bi-directional SEL 451 (Schweitzer Engineering Laboratories) relays to accommodate the reverse power flow conditions from the PV site that can support batttery storage in the future if needed. The PV site is currently operated byToshiba's prototype control system called micro-EMS. Currently it is only used for monitoring the solar PV output now that the batteries have been decommissioned. The prototype will need to be replaced in the future if there is a need to control any facilities on the distribution system. The Power Pool does have the capability to provide emergency power to some of its customers upon complete loss of 115KV transmission power to Los Alamos (this procedure has not been tested and would require full cooperation and control from LANL).

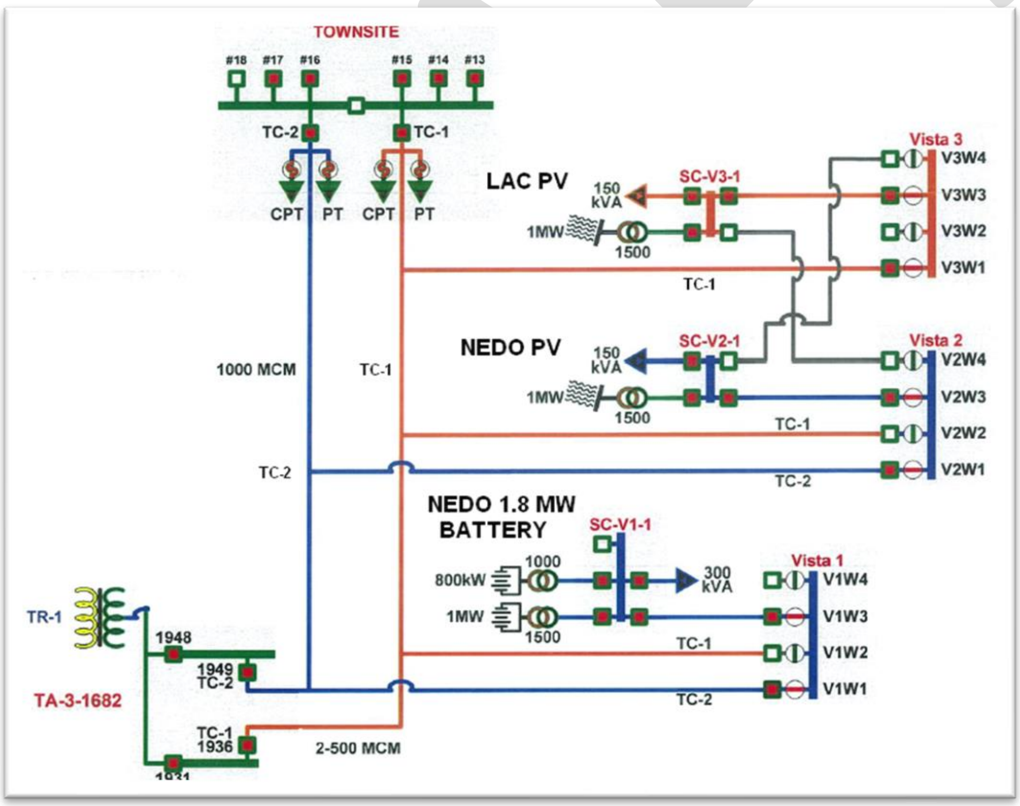


Figure 4. PV Integration onto TC-1and TC-2

II. Description of Relevant Systems and Impact on Reliability

The Regional Transmission Grid:

There are two 115 KV transmission lines into Los Alamos as illustrated in Figure 5. The transmission line from the Norton Susbstation to the White Rock Substation is jointly owned by PNM and DOE. PNM owns approximately five miles of the line from Norton to the River and DOE owns approximately 9 miles from the river to the White Rock substation. PNM operates the Norton Substation and DOE-LANL operates the STA substation at PNM's direction. The White Rock, ETA, TA-53, TA-3 and WTA substations are all operated by the Power Pool. The Norton line (NL line) originates at the Norton Substation west of Santa Fe and the Reeves line (RL line) originates at the B-A Substation north of Albuquerque. The two transmission lines are primarily "H" wood structures and are approximately 53 and 46 years old respectively. PNM performs an annual line patrol and maintains the transmission lines to provide reliable and continuous service for Los Alamos.

The RL and NL transmission lines have a service capacity of 115 MVA and 130 MVA respectively and are presently loaded at 77% and 68% of capacity; under a single 115KV transmission line operating condition. Currently DOE-NNSA is completing the National Environmental Policy Act (NEPA) environmental review process for a third 115 kV line from the Norton to the STA substation. Today the need for this third line is primarily driven by LANL's programatic load forecasts. Looking 10+ years into the future, electrification of the space heating and transportation sectors to achieve DOE and County carbon reduction goals could become a significant driver of transmission capacity needs.

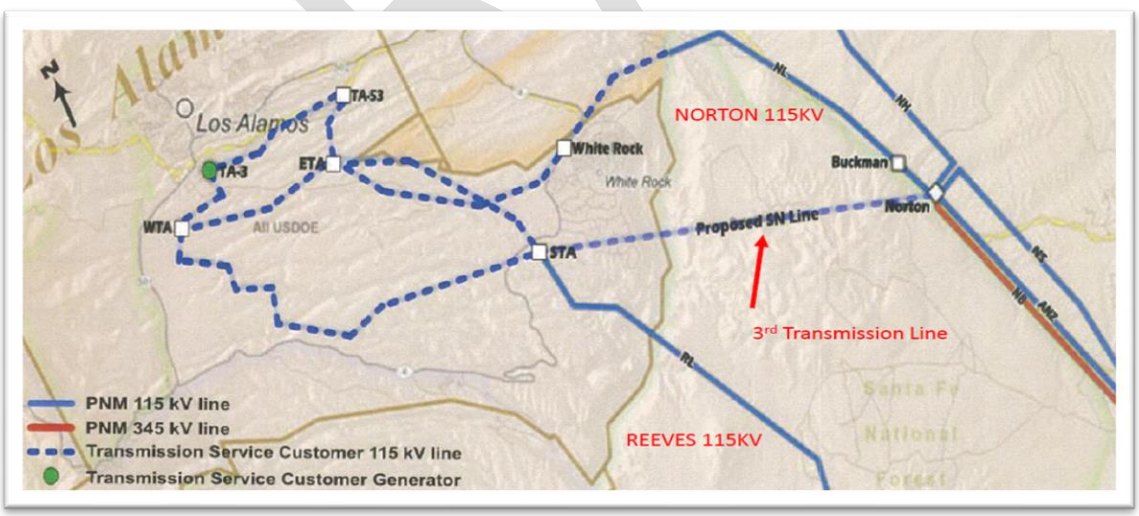


Figure 5. Regional 115KV transmission to Los Alamos

The NL and RL transmission lines are normally operated in a looped configuration. However, there are times when a section of the transmission line is taken out of service due to emergency maintenance or annually to comply with the North

American Electric Reliability Corporation (NERC) service reliability standards. NERC requires that relays and breakers be removed from service and tested periodically to ensure the protective equipment is functional when called upon. However, operating the NL or RL transmission lines in single radial mode exposes Los Alamos to full loss of power should there be a transmission line contact during these NERC testing periods. LANL should continue and ensure that NERC testing is completed when good weather avails. LANL provides DPU with advance notice for scheduled line maintenance, equipment outages, configuration changes, etc. LAC pre-plans and places its engineering and line operations staff on stand-by notice until LANL can place the system back to normal.

<u>Outages due to Gas Supply Shortages</u>

During February 2011, severe cold fronts caused natural gas shortages and outages affecting the northern part of the State. During these natural gas shortage events LAC may be asked to curtail a percentage of their gas use. In the event LAC is asked to curtail some gas load, DPU has developed an electric load shedding plan that will reduce gas heating consumption with the planned power outage. The curtailment of electric supply will cause gas appliance to stop without losing pilot light. The gas demand by circuit is illustrated in Table 1.

Table 1. Gas hourly usage per feeder (estimated)

Feeder	Number of Customers	Ccf per hour (High)	Ccf per hour (Mid)	Ccf per hour (Low)	% Cust Dropped
13	1675	838	1256	1675	16.3%
14	537	430	580	644	10%
15	1871	936	1403	1871	19.6%
16	1839	920	1379	1839	20.3%
17	193	193	338	591	9.2%
18	212	212	371	649	3.6%
WR1	1590	795	1193	1590	10.5%
WR2	963	482	722	963	9.5%
WR3					1%
TOTALS	8880	4806	7242	9822	100%

<u>The Local Transmission Grid:</u>

LANL owns the 115 kV transmission lines within the DOE laboratory area and operates them in a looped configuration to link its five (5) substations; STA, ETA, WTA, TA53, and TA3 as illustrated in Figure 6. The 23.5 miles of transmission lines are patrolled and maintained annually. All transmission right-of-way is within DOE property, readily accessible and could be repaired quickly in the event of a major problem. Therefore, the regional transmission system within LANL is expected to be very reliable.

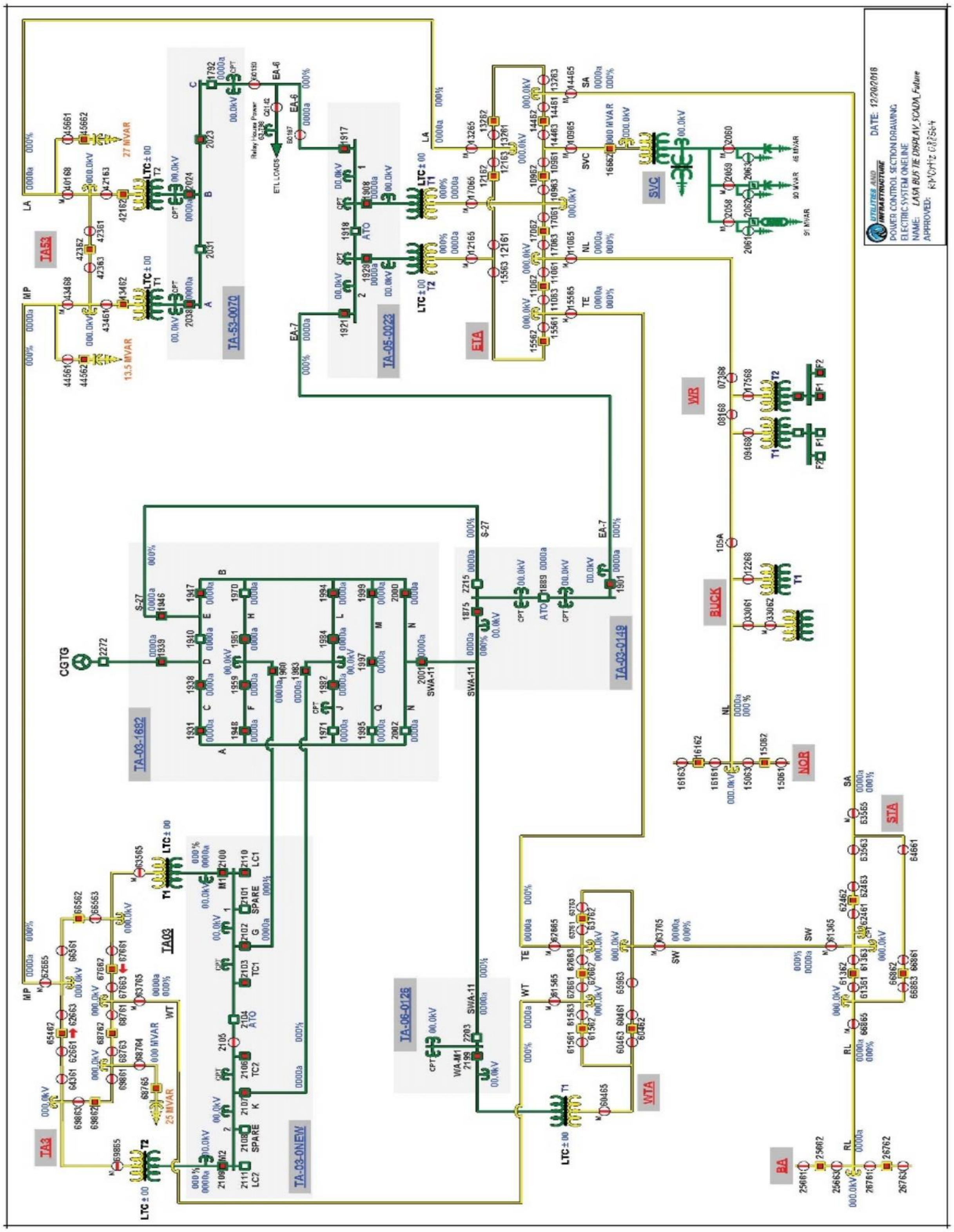


Figure 6. DOE 115KV Transmission Lines (draft diagram)

The Townsite switching station is fed from LANL's TA3 substation which is served by LANL's WTA substation (WT line) and TA53 substation (MP line). However, the Townsite switching station is fed at *distribution voltages* (13.2 KV) and would be considered as having less reliable transmission service simply because it isn't tied to the 115 KV transmission system directly.

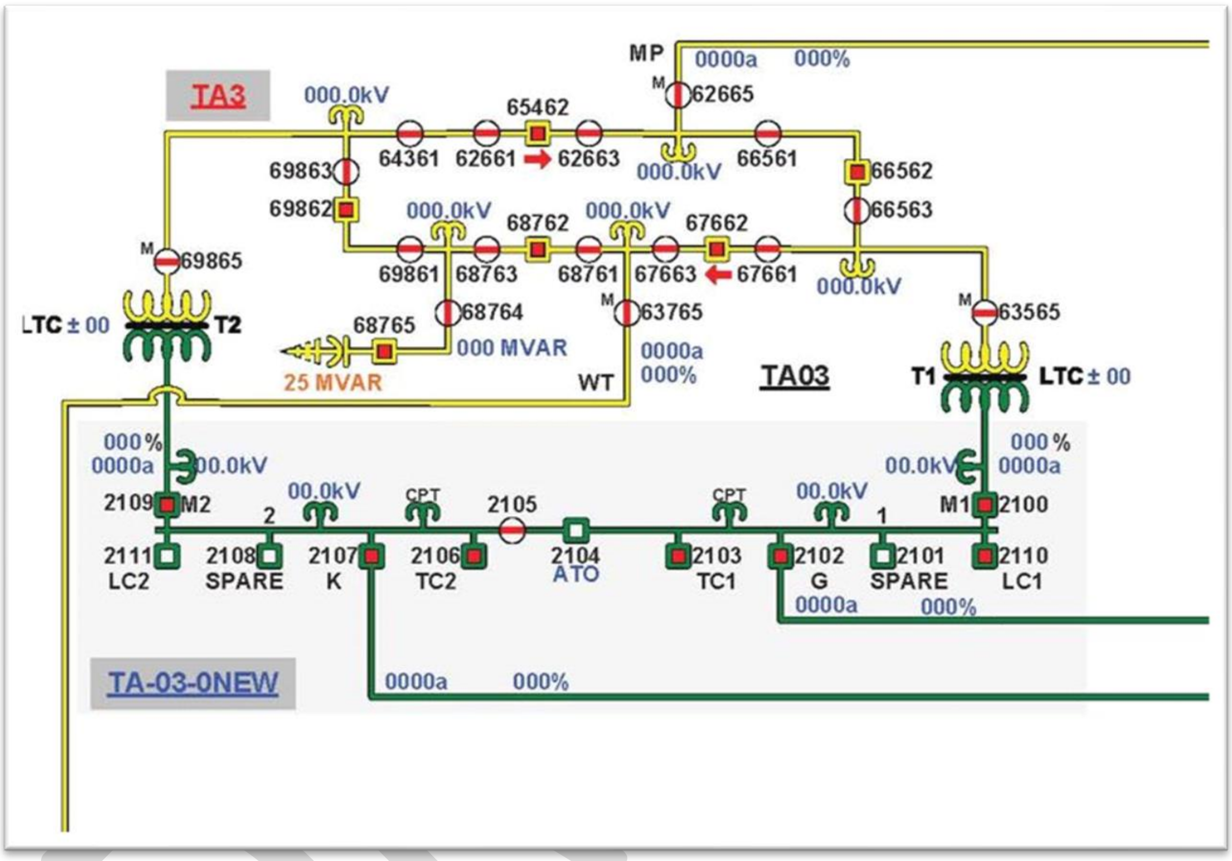


Figure 7. Green section shows TC1, TC2, LC1 and LC2 fed from T1 and T2 (Draft diagram provided by LANL)

The White Rock substation is fed from PNM's Norton substation (NL line) and via LANL's ETA substation (NL' line). The substation is fed directly from the looped 115 KV transmission system, has redundant transformers and therefore, can be considered as having very reliable transmission service.

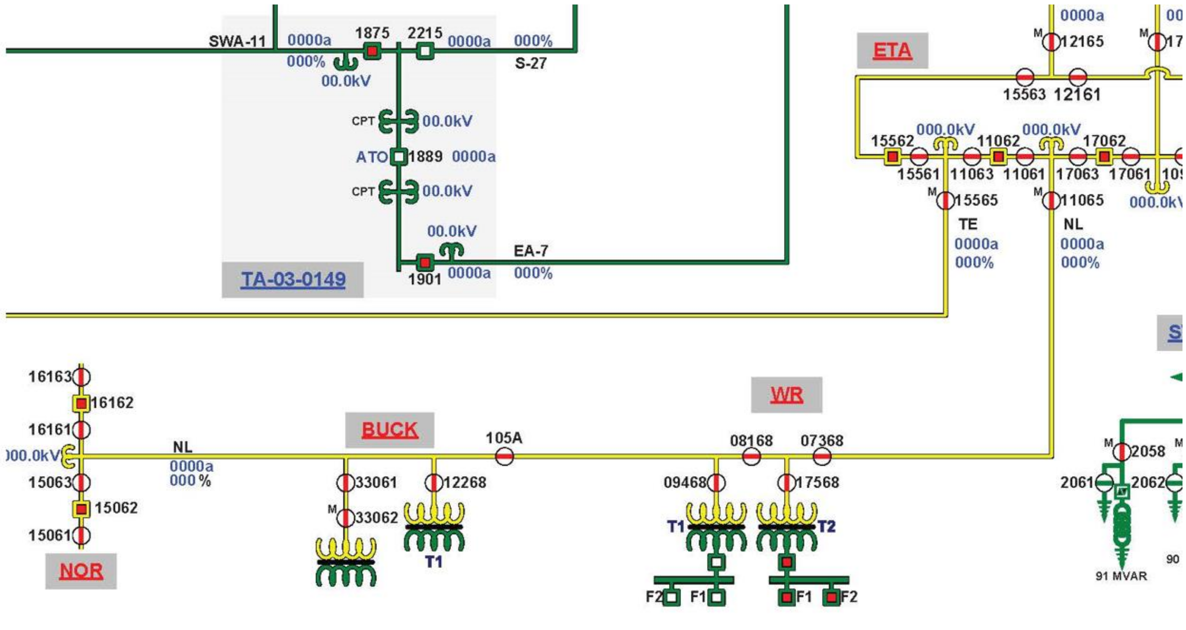


Figure 8. Lower section shows White Rock Substation (WR) (Draft diagram provided by LANL)

LANL's old TA-3 substation is 50-60 years old including its two 30 MVA transformers, TR-1 and TR-2, and the TR-1 unit failed in 2019. In 2010, LANL and DPU commissioned the "TA-3 and TA-53 Substation Replacement Feasibility Study" which looks at the replacement options for TA-3. LANL secured congressional funding for the TA-3 substation replacement project for 2016; 2 years beyond earlier estimates. The new LANL substation TR-1 and TR-2 were commissioned in July 2021.

With the installation of the LANL TA-3 substation replacement project, DPU is adding a second switching station, the Los Alamos Switchgear Station (LASS). LASS is installed next to the DPU's battery site. The new LASS was installed in December of 2018 awaiting the completion of the new TA-3 Substation and the installation of new LC1 and LC2 feeders to connect the two stations. The installation of the LASS feeders LC-1 and LC-2 are not yet scheduled. The connection should be completed by Fall 2022.

The Local Distribution Grid:

At the distribution level, the vulnerability is the lack of redundant substation sources in Los Alamos and White Rock. For comparison purposes, Los Alamos is served by 9 water wells and White Rock is served by 3 water wells, yet each location has a single substation electrical source! The water well comparison is illustrated because water distribution networks function very similar to electric distribution networks. Having multiple sources for water supply eliminates the threat of any one system failure. On the electrical side of things, there are no back-up electrical substation sources to re-route power in the event of a catastrophic failure at either Townsite or White Rock substations. This means that a failure at either substation location would have to be repaired to restore full electrical service.

Case in point:
Townsite outage October 14, 2021 (report from LANL engineering)
The cause of the outage that occurred last Thursday night was found to be an Old TA-3 Substation Transformer TR2 differential relay that triggered both high side breakers and low side secondary main (03-1682 breaker 1983) to open. Breaker 1983 opening interrupted power from the new TA-3 Substation via duct bank k to 1682 loads (Both TC-1 and TC-2). LANL crews restored power in 10 minutes remotely via the SCADA system.

Townsite outage October 22, 2021
The outage was caused by a failure of a potential transformer in the new TA-3 substation. A breaker opening interrupted power from the new TA-3 Substation via duct bank K to 1682 loads (Both TC-1 and TC-2). The townsite was being supplied power from that station. LANL crews restored power in 2 hours.

The Townsite substation serves almost 6500 customers with primarily 6 feeders; and a feeder outage may affect between 800 to 3600 customers. Section VI illustrates how having two additional sources will configure the Los Alamos distribution grid such that the 6500 customers that can be served by 12 feeders, thereby substantially reducing the customers per feeder, i.e., potential feeder power outages would affect less customers in the future.

The Townsite switchgear substation (Townsite) has six (6) feeders, #13, #14, #15, #16, #17, and #18. In addition, LANL provides *primary metering* points to DPU to serve other LAC customers via LANL distribution lines including Royal Crest mobile home park, NM Consortium Building, Los Alamos Medical Center (LAMC), Ski Hill, Pueblo & Rendija Canyons, and Totavi in San Ildefonso Pueblo. Overall, eight (8) distribution feeders serve the Los Alamos community as illustrated in Figure 9.

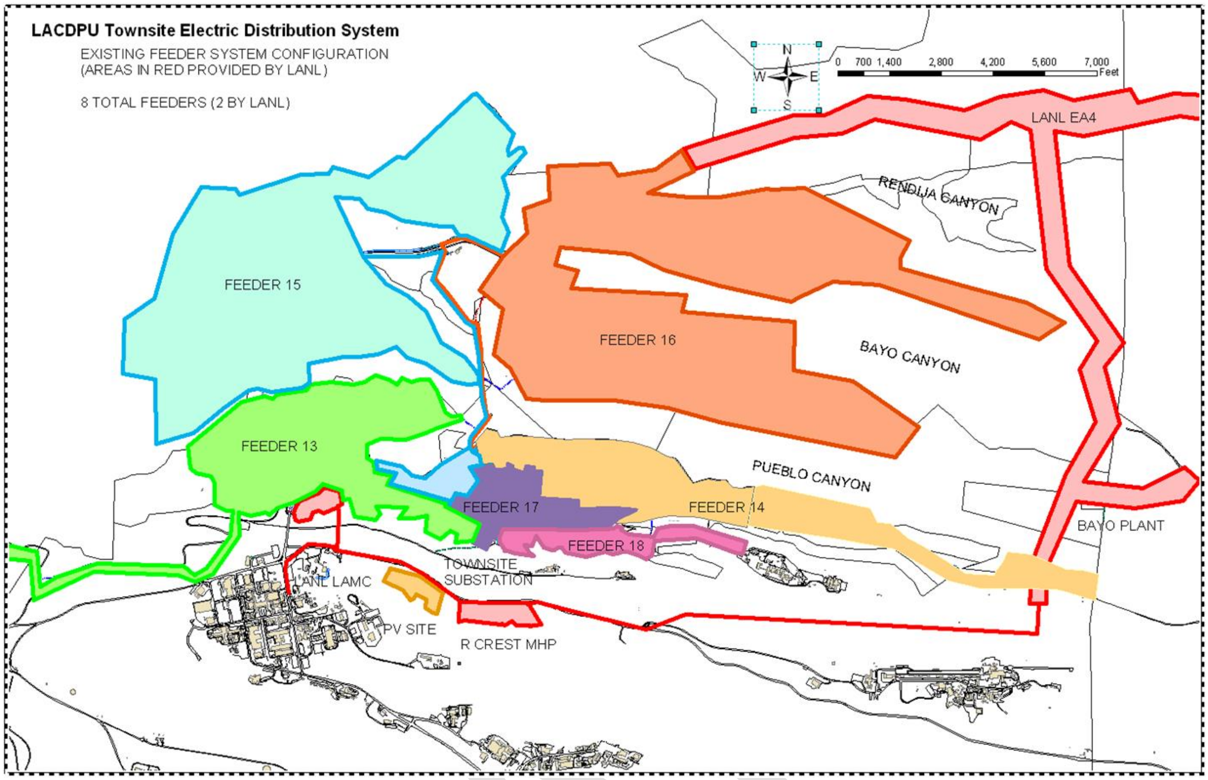


Figure 9. Existing Los Alamos Distribution Area

The White Rock community is served by the White Rock substation as illustrated in Figure 10. The substation was upgraded during 2006 with the installation of a new 10 MVA transformer and the addition of a new 15 kV metal-clad distribution switchgear bus. The substation transformer is presently operating at 60% capacity during the winter peaks. The new switchgear substation contains four circuit breakers for Feeders WR1, WR2, WR3 and one spare. The substation includes an older 7.5 MVA transformer and the new 15 kV switchgear substation bus installed in FY20. The 7.5 MVA transformer and switchgear is utilized when LANL requires 115 kV transmission line outage on the Unit TR2 side of the substation. From a transformer reliability perspective, having two transformers is certainly a plus. From a switchgear bus reliability perspective, having the spare 7.5 MVA transformer tied to the new switchgear is the best and only alternative.

On the distribution side, the WR1 and WR2 feeders can be paralleled within a quarter mile but it has limited use because each feeder remains mostly radial. An ideal looped configuration is when the feeders can be paralleled at each end. For example, the WR2 feeder was looped during 2013 with the construction of the mile long WR2 UG Feeder tie. The project consisted of a new UG power line along SR 4 with new loops to La Senda areas A and B, and Pajarito Acres 1 and 2. The addition of the WR3 feeder provides a tie between WR2 and WR3 on State Road 4.

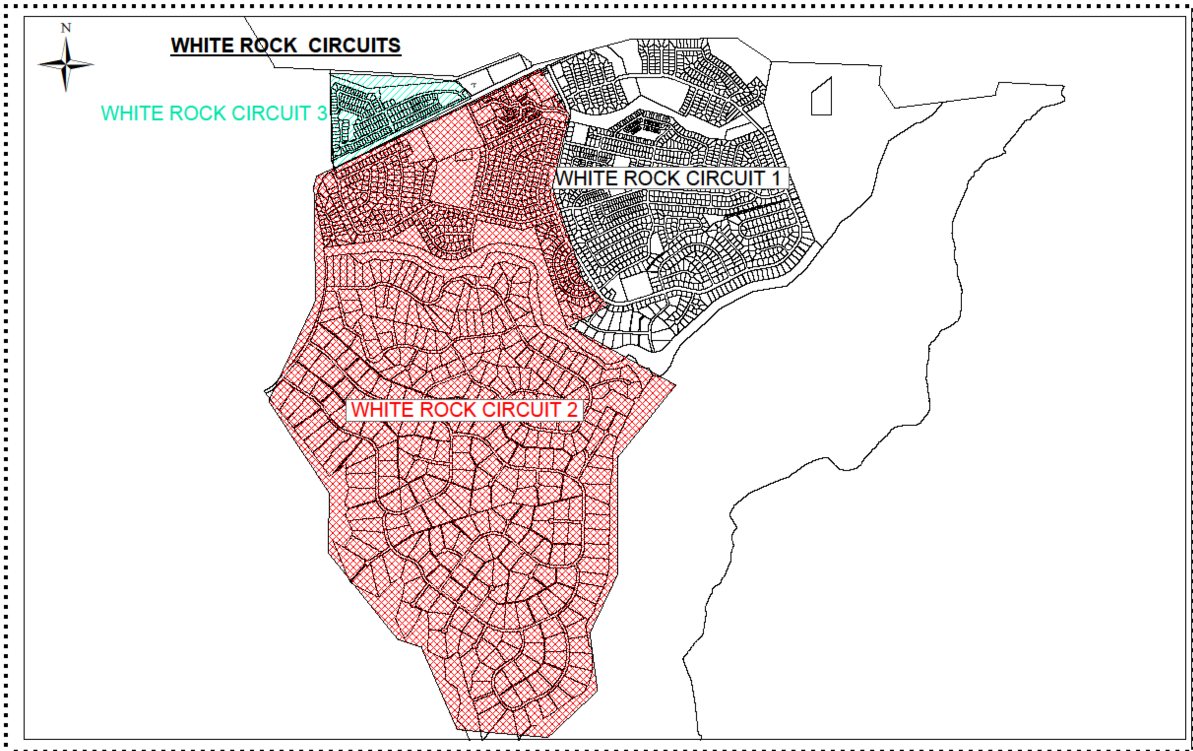


Figure 10. White Rock Distribution Area

The projected load in the White Rock service area does not require the need for a second substation now or in the foreseeable future. From a distribution source perspective, the reliability for the White Rock service area is dependent on keeping the substation energized having two transformers and two independent switching stations.

III. Discussion of SAIDI Performance

Analysis of Performance Measures

DPU measures its system reliability with four (4) performance factors as defined by IEEE Standard 1366-2003.

SAIDI = System Average Interruption Duration Index. This is the total duration of interruption for the average customer during a predefined period of time; or

$$\text{SAIDI} = \frac{\text{Sum of all customer outage durations}}{\text{Total number of Customers Served}}$$

SAIFI = System Average Interruption Frequency Index. This is how often the average customer experiences an outage over a predefined period of time; or

$$\text{SAIFI} = \frac{\text{Total number of customer interruptions}}{\text{Total number of Customers Served}}$$

CAIDI = Customer Average Interruption Duration Index. This is the average time required to restore service; or

$$\text{CAIDI} = \frac{\text{Sum of all customer outage durations}}{\text{Total number of customer interruptions}} = \frac{\text{SAIDI}}{\text{SAIFI}}$$

ASAI = Average System Availability Index. This is the fraction of time that a customer has received power during the defined reporting period; or

$$\text{ASAI} = \frac{\text{Service hours available} - \text{SAIDI}}{\text{Customer demand hours}} = \frac{8760 - \text{SAIDI}}{8760}$$

Table 2. Reliability Performance Measurement Factors

Twelve Month History	September 2021	_
Total # Accounts	9045	_
Total # Interruptions	39	_
Sum Customer Interruption Durations	11028:48:00	hours:min:sec
# Customers Interrupted	7262.0	
SAIFI (APPA AVG. = 1.0)	0.80	int./cust.
SAIDI (APPA AVG. = 1:00)	1.13	hours
CAIDI	1.31	hours:min/INT
ASAI	99.9994%	% available

The calculations are based on a 12-month history. All outages' effects will remain in the calculations for one year as demonstrated in Figure 11.

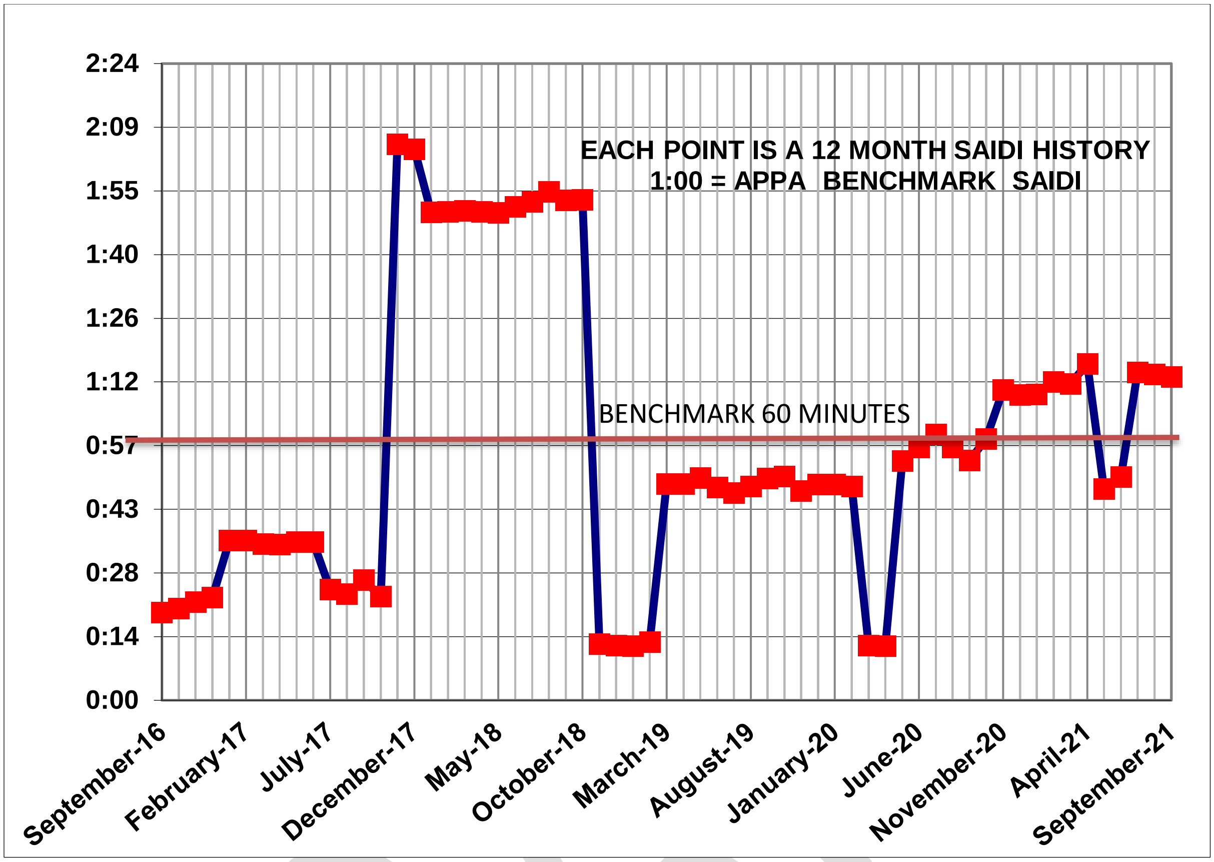


Figure 11. Graph of LAC SAIDI with 60-minute TARGET

Table 3. illustrates the SAIDI of each feeder and the SAIDI due to weather or on LANL source feeders. The high SAIDI for the EA4 feeder was due to a LANL source failure and beyond LAC control. The WR1 SAIDI has been largely due to overhead line failures due to human causes. The WR2 SAIDI is largely due to faults in single phase primary UG sections with secondary or residual caused problems.

Table 3. Reliability Performance on a per Feeder Basis

Most Recent SAIDI, 1 Year Running (September 2020 - October 2021)											
Number of Customers per Feeder										Weather	LANL
1655	539	1875	1842	209	213	165	1586	961	9045		
Circuit 13 4:49	Circuit 14 2:54:27	Circuit 15 14:24	Circuit 16 41:32	Circuit 17 0:00	Circuit 18 0:00	EA4 13:38	WR1 6:55:04	WR2 21:34	TOTAL 0:40	SAIDI 28:51	SAIDI 2:06

SAIDI

The SAIDI is illustrated in Table 4. DPU's service area is like that of Kit Carson Electric Coop (KCEC) and Jemez Mountains Electric Coop (JMEC); whereas PNM's service area is more urban. KCEC, JMEC, and DPU service area includes mountainous terrain with heavy winter snow fall. The five (5) year SAIDI average for DPU is around 1 hours and 3 minutes and is typical for utilities serving mountainous terrain but the County's goal is 60 minutes or less.

Table 4. LAC SAIDI at the end of each calendar year

SAIDI 5 YEAR TOTAL (MINUTES)					
2016	2017	2018	2019	2020	AVG
23	124	110	12	48	63

Overview of past year's SAIDI & Disturbances

We continue to have sporadic and random underground line section failures throughout the system, and this can be expected into the future. Areas with direct bury conductors, 30 years of age or older are subject to failure. Human causes of outages also occur due to digging without proper locates and automobile accidents hitting above ground equipment.

With the overhead system, we've had a few tree issues blowing into the open-secondary (un-insulated) service lines in customer back-yards. The utility has an ongoing contract with a tree trimming contractor to proactively trim trees as they grow into the lines. The replacement of open secondary conductors with insulated triplex conductors prevents these outages. The utility also prevents major pole and transformer failures largely because of our pole and transformer replacement program.

Strategy for improving the SAIDI

Improving system reliability is working based on the following strategy:

(1) Continue to perform a root-cause analysis for every power outage.
(2) Continue with the Asset Management Program, "AMP", for line inspections, O&M, etc.
(3) Continue to monitor line sections which have failed in the past; prioritize, and place into the AMP.
(4) Continue to dedicate one crew for overhead power line O&M.
(5) Continue to dedicate one crew for underground power line replacement.

(6) Manage Outage Response to minimize outage times and reduce SAIDI. The procedure for outage response is attached in the appendix “A”.

IV. Description of Distribution System and impacts on Reliability

Distribution System

DPU owns and operates the Electric Distribution System (EDS) in Los Alamos and White Rock areas. The EDS is comprised of approximately 66% underground (UG) distribution and 34% overhead (OH) distribution serving approximately 9045 customers. There are approximately 6645 customers in the Los Alamos area and 2,400 customers in White Rock.

For OH distribution, the major components are power poles, overhead conductor, and pole mounted transformers. The transformers are either two (2) bushing conventional or single (1) bushing completely self-protected (CSP). The two-bushing transformers are often referred to as *delta* transformers by the line crews because they require two energized primary phases to produce full customer service power of 120/240 volts. The CSP transformers require only one energized primary phase to produce full power.

For UG distribution, the major components are switchgear, primary junction boxes, primary cable, pad mounted transformers, secondary cable, and secondary junction boxes. Single phase pads provide power to residential areas and three-phase pads provide power to commercial businesses.

There are two operating distribution voltages in the DPU’s system, 13.2 kV line-to-line (7.62 kV line-to-neutral) in Los Alamos Townsite; and 12.47 kV line-to-line (7.2 kV line-to-neutral) in White Rock. LAC can utilize the same distribution system components such as poles, fuses, wire, insulators, rubber goods, switchgear, etc. in both areas because the components are rated at 15 kV line-to-line. However, DPU must keep different transformer inventories for Townsite and While Rock because of the different operation voltages.

Age and replacement challenges

Any portion of the OH system that exceeds 50 years of age is operating at or near the end of its useful life. Similarly, a large portion of the UG system was installed during the 1970s with cable technology that had an expected useful life of 30-40 years. Therefore, DPU must proactively replace these sections of the distribution network within the next 15 years or sooner. DPU has estimated the cost of these replacements to be approximately 16 million dollars pre COVID.
The OH and UG systems have repair and replacement challenges which may impact the SAIDI as replacement projects are underway. Figure 12. illustrates a map showing inaccessible areas due to right-of-way encroachment or customer blockage. Having inadequate work access or having to work around landscaped areas, etc.,

make it difficult for DPU to replace rotten poles and overloaded transformers. For the UG system, having to dig in and around areas congested with buried utilities makes it difficult to dig for routine repairs.

For the overhead system, most of the replacement work needs to be performed while the existing power line is energized or while *hot*. *Hot* work safety procedures require the feeder over-current protection be disabled (from normal reclosing) while the work is being performed. This means that an inadvertent line contact may kick-out an entire feeder (or line section) while the *hot work* is underway. Similarly, and with underground systems, replacing of live-front (uninsulated) equipment will generally require an outage *before and after* the work; again, for safety purposes. Therefore, replacing portions of the existing system will generally require the disabling of the overcurrent protection, small power outages or switchovers, additional safety precautions, slower work process, etc. Replacement projects may impact the SAIDI.

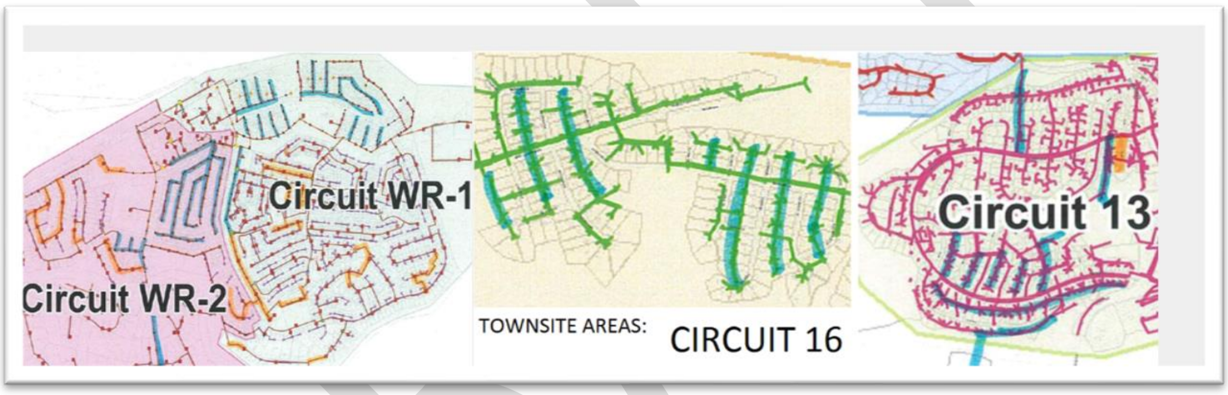


Figure 12. Areas not readily accessible

<u>Maintain, repair, or replace</u>

Through the AMP process, the lingering question is whether to maintain, repair or replace. Based in the AMP process success, DPU will continue to operate under the following guidance:

1. DPU must adequately maintain its electric distribution system moving forward so that equipment can reach and exceed its useful life. For OH, this means pole inspection and treatment every 10 years for new poles and 5 years for older poles. For UG, this means continuing with the AMP with respect to quarterly inspections & routine O&M.
2. DPU must continue to track repairs to its distribution system; after several failures, UG sections must be planned for replacement.
3. DPU must continue to prioritize replacement efforts to critical feeder sections which impact the most customers and have the biggest impact on the SAIDI.

Sections V and VI provide short-term and long-term action plans that must be pursued in parallel largely because of the age of the distribution system. These plans can impact the revenue requirements for the utility, but LAC is conscientious about implementing the plans over several years. The DPU strategy is to continue to improve the system reliability while maintaining electrical rates below rates of neighboring utilities. Also, DPU will continue to ask for utility board feedback with regards to electric reliability, value, and the impacts to rates to support those two efforts. DPU strives to provide the highest level of reliability, while maximizing the life of the existing infrastructure and maintaining competitive rates.

V. Discussion of Short-Term Action Plans

<u>Asset Management Program for OH</u>

Under the department's AMP, each of 10 crew members is responsible for his Feeder. Six linemen are assigned the six overhead distribution feeders: 13, 15, 16, EA4, WR1 & WR2. Each year, the AMP program requires that each lineman perform quarterly line patrols, a detailed feeder assessment, and provide input with regards to feeder areas that require immediate and long-term action plans. For example, tree trimming, leaning pole, loose guy wire, etc. would be considered an immediate action. Feeder conversions, tie-lines, reconductoring, etc. would be considered long term actions.

<u>Overhead Pole Replacement Program</u>

In 2005, all distribution poles were inspected and treated at the ground line. Almost 268 poles or roughly 13% of the system poles were rejected and temporarily braced until they could be replaced. In 2012 and as part of the REDINet project, DPU and Redinet cost-shared for the replacement of approximately 45 poles to accommodate the installation of the REDINet fiber network in parts of Los Alamos and White Rock (government & school facilities).

Inspections were performed again in 2013, 2018, and 2021. In 2013 DPU started an overhead maintenance crew to primarily focus on overhead pole & cross-arm replacement and tree trimming. To date, DPU's in-house crews have replaced over 250 utility poles. To replace rejected and braced poles at inaccessible locations as illustrated in Figure 14., DPU purchased a back-yard pole setting unit and purchased steel replacement poles. Steel poles weigh approximately 50% of what a wood pole type Douglas fir weighs; but cost twice as much. Figure 14. illustrates a typical braced pole and a new steel pole.

POLE REPLACEMENT PROJECT 2015

The department hired contractors to replace overhead line sections across canyons from Canyon Road to Diamond Drive and San Ildefonso. Figure 13. shows OH line sections replaced. The department also replaces poles in a continuous effort to maintain the system. Replacing sections of the overhead conductor wire which have been in service over 50 years; particularly those areas which contain obsolete CWC (copper-weld-copper) wire is an ongoing effort.

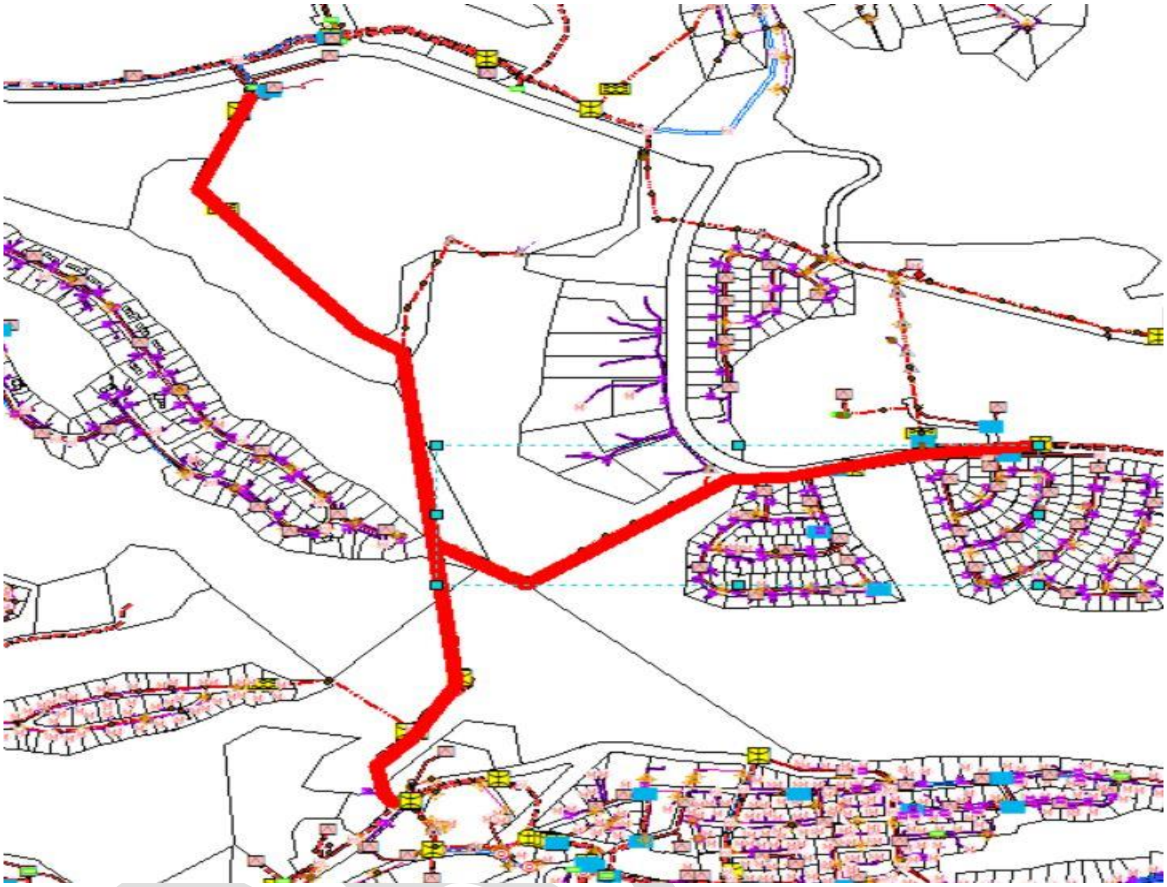


Figure 13. Pole and Conductor Replacement Project 2015

Figure 14. Typical braced pole & backbone broken pole; & new Steel Pole

Infrared OH line inspection

During the winter, the department will continue to *infra-red* critical sections of the underground and overhead systems to look for hot spots as illustrated in Figure 15. Hot spots are areas that have loose connections leading to high-resistant points; these points will eventually burn up, fail, and cause a power outage.

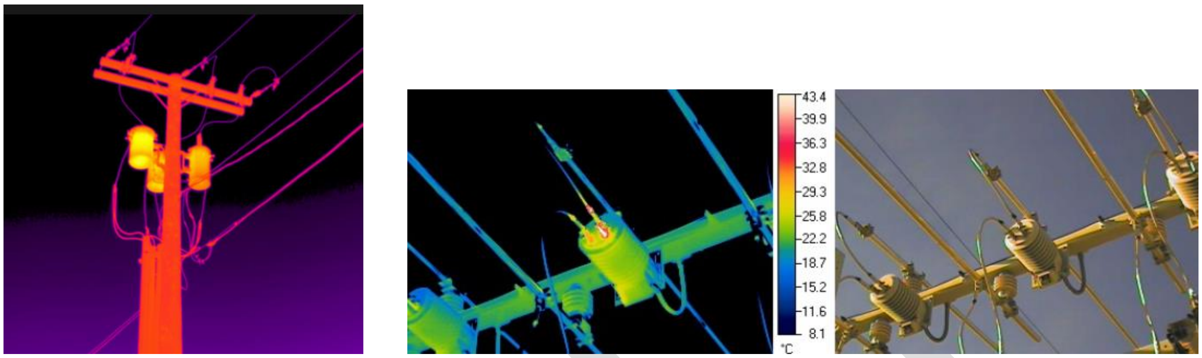


Figure 15. Infra-red picture for transformer pole & air break switch

Asset Management Program for UG

Four linemen are assigned the four underground distribution feeders: 14, 17, 18, & LAMC/Landfill. Similarly, each year the linemen perform quarterly line patrols, a detailed feeder assessment, and provide input with regards to feeder areas that require immediate and long-term action plans. For example, unleveled equipment, equipment oil leakage, rodent intrusion, equipment tagging, etc. would be considered an immediate action. Switch replacement, live-front transformer replacement, rust, or oxidized paint, etc., would be considered a long-term action plan.

UG Primary Replacement Program

As previously stated, much of the existing primary underground distribution system consists of typical 1970s cable standards with 30–40-year cable life expectancy including: non-jacketed, direct buried, 175 mil insulation, XLP (cross link poly), non-strand filled cable. Today's primary underground cable has a 40–50-year cable life expectancy including: exterior jacket, 220 mil (more insulation), TRXLPE (tree retardant cross link poly) or EPR (ethylene propylene rubber), strand-filled and installed in conduit. The department is now in need of a replacement cable pulling machine. The machine is equipped with a winch to pull cable into the conduit. The new machine will cost approximately $175,000.

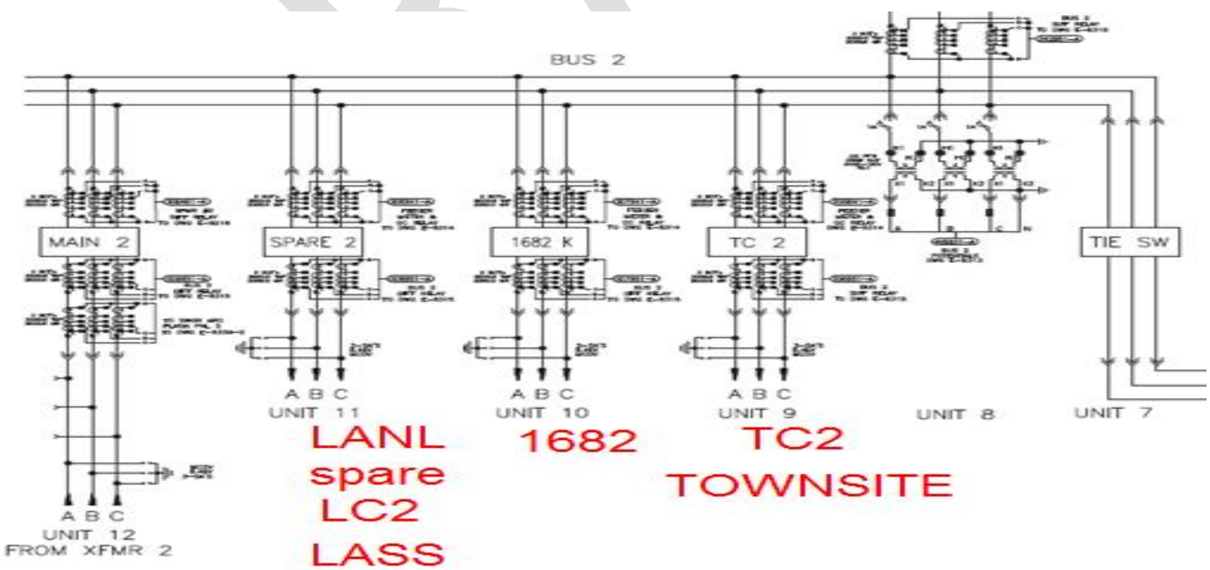
DPU continues to experience primary cable failures in most subdivision areas, but mainly during the wet seasons. Moist ground tends to accelerate the *treeing effect* in the cable insulation leading to primary cable failures. The *tree effect* provides the shorting path, or *fault*, between the energized conductor and grounded neutral.

When primary cable sections experience two or more *faults*, the line section is ranked with a low or high priority. When high priority primary line sections are designed for replacement, other engineering and reliability upgrade features are added. For example, radial lines may be converted to loops, single phase lines may be converted to three phase, ridding of live-front equipment, adding sectionalizing points, re-routing for accessibility, etc. The idea is to ensure that even if the newly installed line fails, power can be restored even faster than before while impacting the least number of customers. For example, the Canyon URD Project, San Ildefonso, Sioux Village, Del Note / Del Sol, Tsankawi, Meadow Lane, NM4, Trinity, Arizona, 35th street, 36th Street, Woodland, Club Road, 48th Street, Diamond Drive, 15th Street, WR2 Loop Addition, Trinity Apartment Replacement Project, NM502, DP Road phase 1, Rim Road, LAMC replacement and the LASS Feeder project are projects which included loops, tie-points, and other reliability improvement designs as part of the original replacement project.

VI. Discussion of Long-Term Action Plans

<u>New LASS Substation Addition</u>

The top reliability project for DPU is the construction of the new LASS Substation addition near the County landfill as illustrated in Figure 17. The LASS Substation is needed to maintain the SAIDI target into the future. LASS is also critical to the supply of steady and reliable electric power to the residents of the Los Alamos Townsite; more so if the Townsite area is expected to grow electrically.



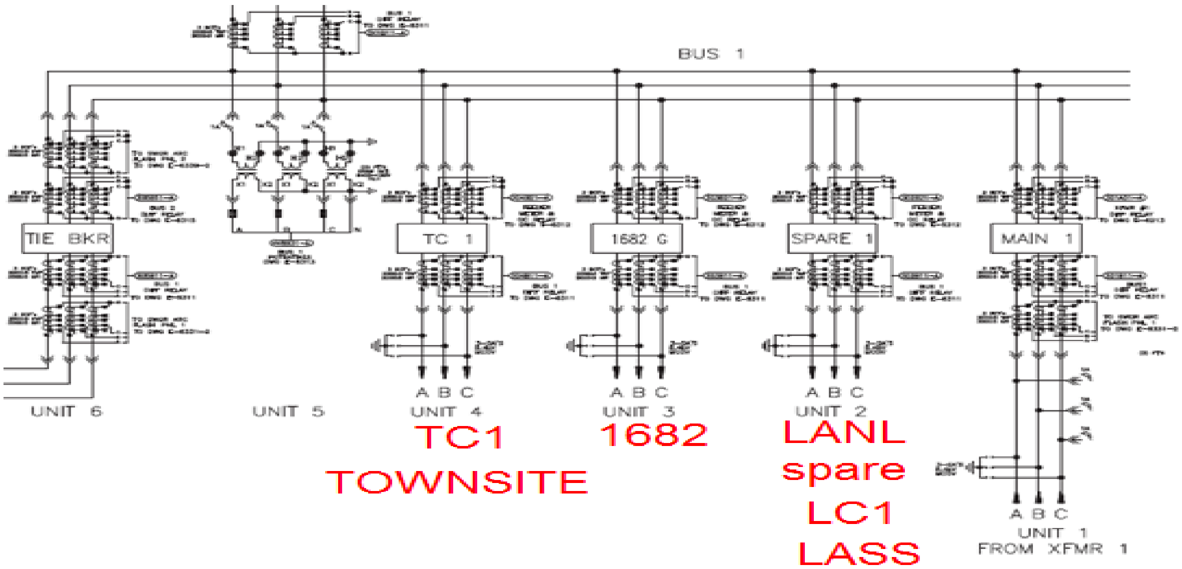


Figure 16. Three-line diagram of TA-3 Substation

Figure 17. LASS station Location Relative to LANL

The LASS substation will relieve load from the existing Townsite switching station. The station will tie to TA-3 on breakers LC1 and LC2. Under existing conditions and for a TC1 feeder outage, the Townsite peak demand exceeds the TC2 feeder ampacity rating as illustrated in Table 5. below.

Table 5. Potential TC2 Feeder Loading for a TC1 Feeder Outage

Feeder	Size	Rating	Max Carrying Load	Townsite Peak Load
TC1	(2) 500 mcm CU	720 amp	16 MW	
TC2	1000 mcm Cu	615 amp	14.1 MW	16 MW

The LASS Substation will add feeder sources to maintain and improve the SAIDI and the system reliability in the Townsite area as illustrated in Figure 18. and as follows:

1. Reduce the number of customers on Townsite substation feeders 13, 15, & 16 (by moving half the customers on those feeders to LASS).
2. Provide new feeders 13T, 15T, 16T, S6, SM6.
3. Provide power to DPU customers with DPU power lines and not from LANL power lines, i.e., Transfer Station, LAMC (S6), Elk Ridge MH Park.
4. Add 50% additional system redundancy during scheduled or unscheduled outages to Townsite Substation Feeders. Feeders 13T, 15T, & 16T on LASS can back feed feeders on Townsite 13, 15, 16, Ski Hill and LAMC.

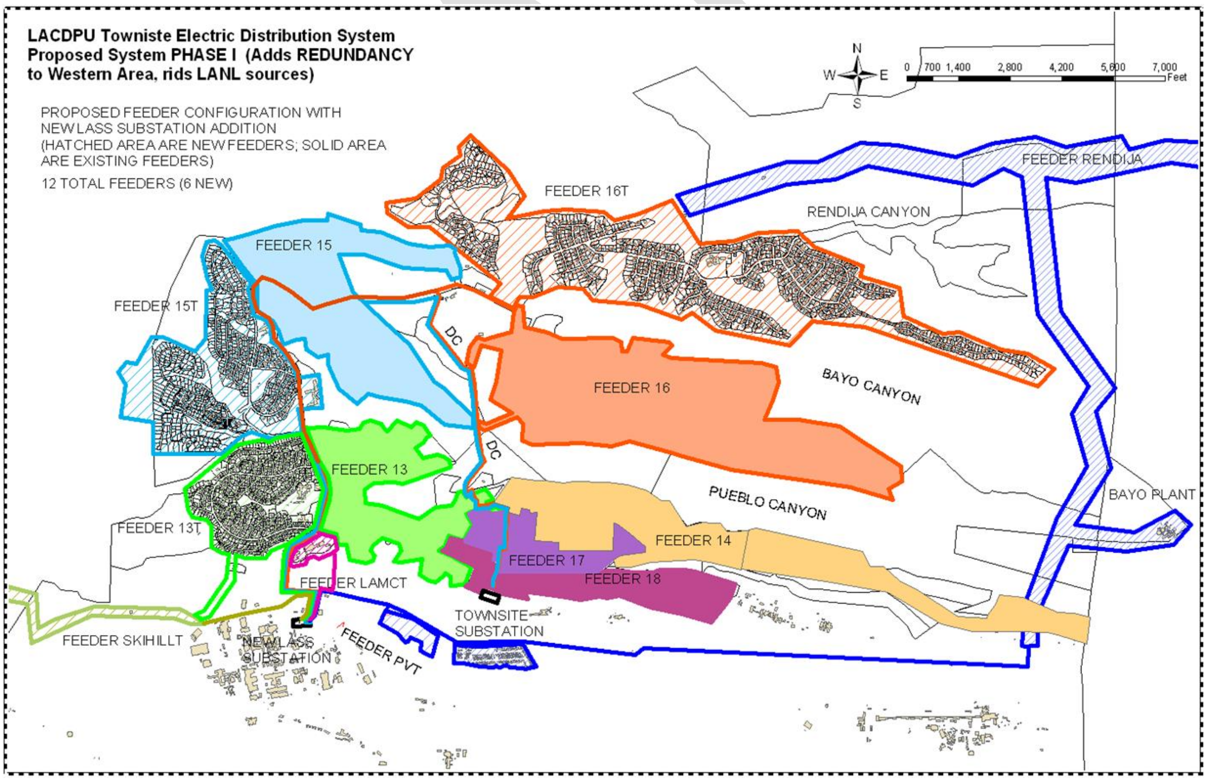


Figure 18. Los Alamos distribution area with LASS substation addition (when compared with Figure 9.)

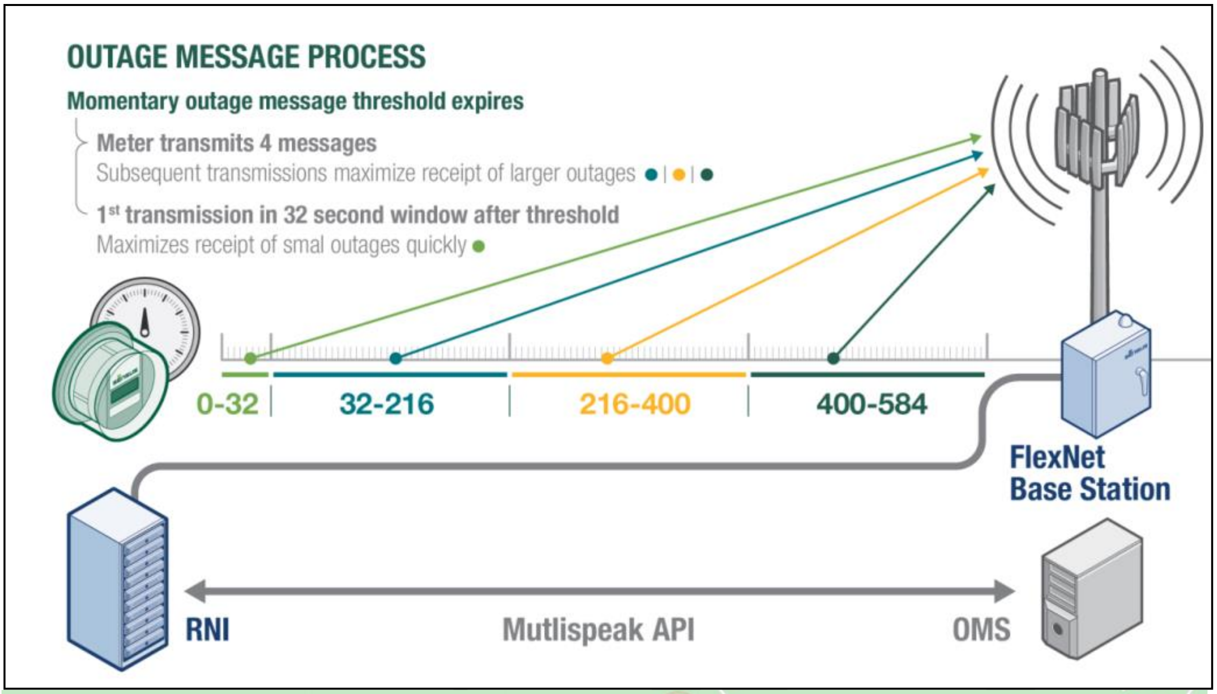
Distribution system SCADA expansion

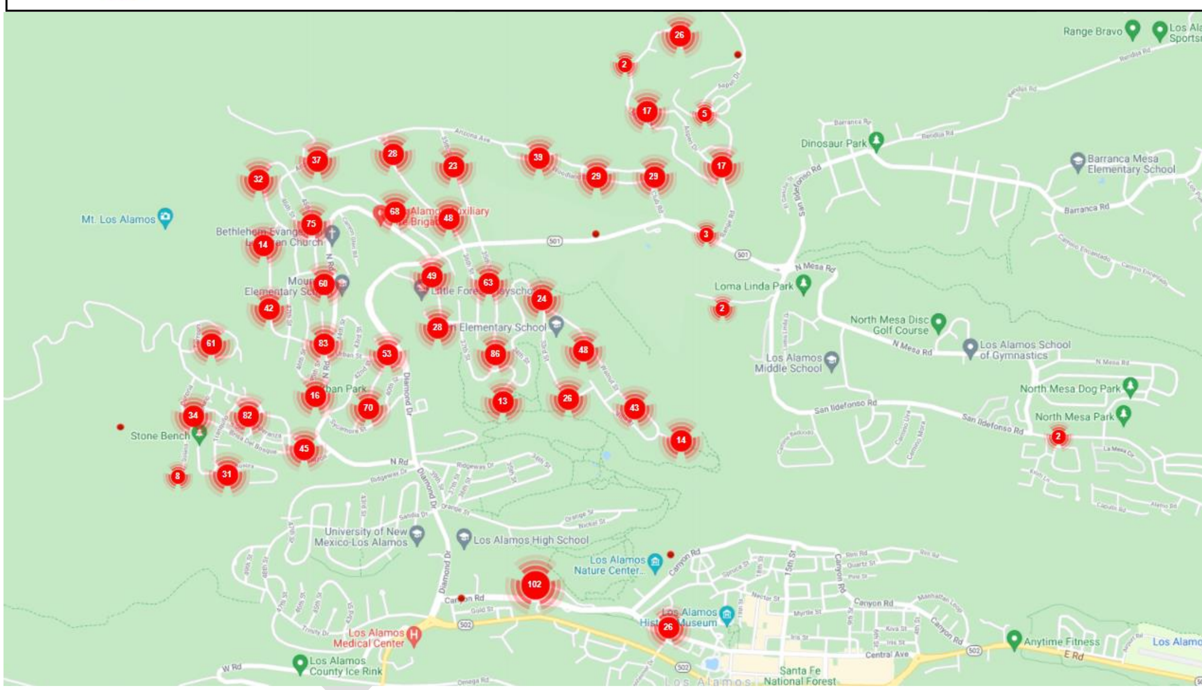
The Power Pool has SCADA capabilities at the Townsite and White Rock substations. The Power Operations Center monitors the individual feeder relay for breaker status and real-time power flows. During a power outage, the DPU lineman must patrol the power line to find and isolate the problem; then, return to the substation to develop a restoration plan and restore power. The Primary Power Operations Center is located at LANL TA-3 with a fully capable back-up center located at PCS building #5.

The DPU electric distribution department will develop and install a SCADA system which will monitor the electric equipment in the field. The system is estimated to cost $250,000. The system will incorporate information from the AMI, ArcGIS, and the Milsoft Modeling system to provide real-time system status to crews in the field and engineering. The new SCADA system will be based in Building #5 at PCS.

Engineering utilizes an electric distribution modeling system developed by Milsoft. The system is called WindMil. The model provides essential information on circuit loading and connectivity options. The model can analyze circuit configurations to ensure that circuits are not overloaded, and loads are balanced. The model is a living system that is modified as improvements are made in the system. With the implementation of a SCADA system, the model will provide real-time system performance. The Milsoft package can then be expanded to provide a full real-time outage management system. The information will be accessible to linemen and engineers remotely, to assist in outage response. This is the future plan for the system.

Feeders 13 and 16 have four feeder line electronic reclosers (EOCRs) that can be integrated into the SCADA system. The EOCRs can be retrofitted with a SCADA card, a microwave radio, and integrated into a new microwave radio communication system. These *node additions* can be mapped into the SCADA system for remote monitoring. With SCADA control, an outage can be detected by LAC electric distribution crews and immediately be aware of the power outage area. This is even more granular with the new AMI outage management system showing power outages down to the meter level. Linemen now can dispatch directly to the problem area and not have to rely on customer outage calls. When the linemen isolate and repair the overhead power line problem, the lineman can restore power quickly. The linemen will notify the public information officer and County Dispatch center to publish press releases, web site information and online medial to inform customers about the outage cause, duration, and scope of repairs.
Sensus outage identification system model and outage map shown here.





Similarly, and after the new LASS substation is constructed, all *back feeding* tie-points can be fitted with SCADA system radios. During power outages, the switches can be remotely monitored by engineers to help the DPU linemen re-route and restore power more efficiently. In summary, developing a new SCADA system into the distribution feeder network will help DPU identify outages quickly; allow lineman to be dispatched directly to the problem areas, re-route power and restore power quickly and efficiently.

Three Phase Primary OH Backbone Rebuild

Table 6. illustrates the feeder length of the main three-phase OH back bone system with pole quantities. The long-term plan is to replace all three phase back bone poles to ensure the long-term reliability; a single major back-bone pole failure could potentially impact thousands of customers. On April 1, 2012, a single WR2 pole failure had a 40-minute impact on the SAIDI for 1 year. Single-phase pole laterals which serve less than 50 customers will be replaced on a lower priority basis. As previously stated, the DPU OH maintenance crew and on-call contractor will work on the pole replacement project. After the major back-bone poles are replaced, DPU will focus on replacing the backbone overhead conductor.

Table 6. Three Phase Main Feeder OH Backbone Lengths

FEEDER #	# OF POLES	MILES OF LINE
13	81	3.44
Ski Hill	70	3.5
15	111	3.15
16	137	4.53
WR1	65	1.83
WR2	73	3.41
EA4	150	9
TOTALS	687	28.86

Primary UG Improvement Projects:

Major underground replacement projects or additions were constructed in the past: 0.8 mile, WR2 Loop Addition, 1.2-mile, Canyon Road Rebuild Project, and 1.0 mile, Tsikumu Village Primary Replacement Project. The three projects had become burdensome to DPU customers and affected the SAIDI year after year. The projects not only replaced the failed underground sections but also added three phase power line sections and new single phase primary loops. Each project cost about $500K and it will be difficult to sustain those type of projects in the future without impacting utility rates. Recently material costs have increased substantially placing more pressure on electric rates.

Major underground capital replacement projects have been identified in the immediate future by the asset management team, see Appendix C. DPU is prepared to deal with major SAIDI impact projects as they may arise in the future. A list of major projects includes the Los Pueblos and Totavi area, La Senda and Pajarito Acres, Timber Ridge, La Vista, and Big Rock Loop.

Other long term UG projects which will provide long-term reliability improvement is the addition of new UG or OH Loops. DPU has many radial lines which power anywhere from 30 to 100 customers; a failure on the radial line leaves few alternatives to restore power in a timely fashion. These long radial power lines, should be looped at some point to minimize the number of customers effect in an outage. Figure 19. illustrates priority areas for Loop additions in White Rock.

Figure 19. Single Phase Loop Addition Targets in White Rock

<u>Vacuum Fault Interrupter Transformer additions in large subdivisions</u>

DPU has many underground subdivisions with single phase primary laterals with 10+ transformers configured in a daisy-chain. When DPU experiences a faulted line section, it must identify the fault, isolate it, then back feed the outage area from a new power source. Back feeding is done by manually transferring electrical load with a 200-amp elbow; at least two times during the restoration process. With continual line section failures, the manually back feeding process is resulting in secondary and residual failures, i.e., elbows or other weakened points.

Therefore, DPU must look at other engineering solutions in identifying and isolating failed line sections so that no secondary or residual failures occur. Figure 20 illustrates a reasonable engineering solution ($8K per Vacuum Fault Interrupter (VFI) transformer) where faults can be detected, identified to smaller line segments, and allows DPU linemen to safely re-route power without utilizing elbows or fuses. The VFI solution will simply trip the interrupter in a safe manner and no secondary failures.

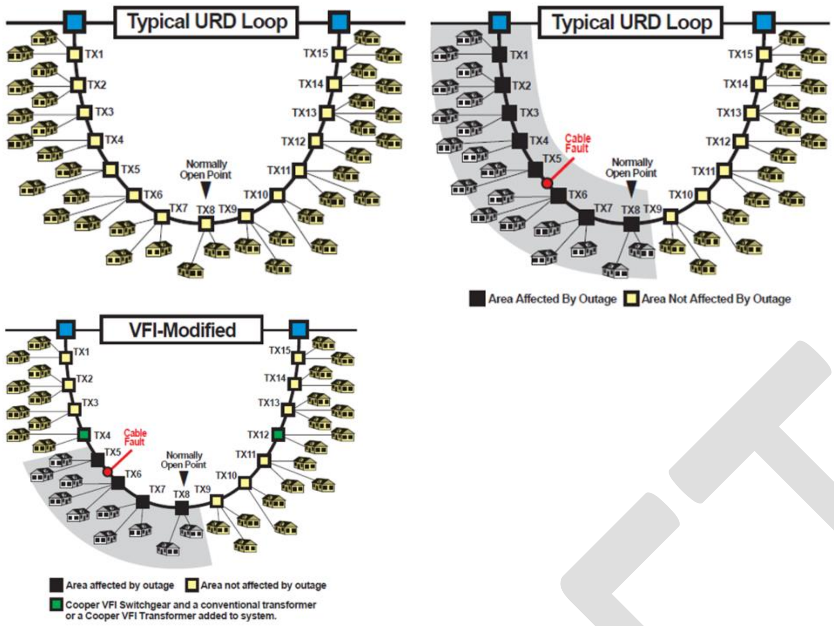


Figure 20. VFI Transformer Fault Isolation & Restoration Solution

<u>New East Gate Substation Addition</u>

The proposed East gate substation is similar in need to the LASS substation except that it provides a power source and feeder redundancy to the east side of Los Alamos. The substation need will be in proportion to the electrical needs for development along DP Road and the Camino Entrada area. The LAC-LANL jointly owned EA4 feeder is 9 miles in length and spans across rough mesa terrain from Pueblo to Rendija Canyons. The EA4 feeder provides power to the wastewater treatment Plant, water wells and pumps along Rendija Canyon, and to the San Ildefonso - Totavi area. The age and condition of the EA4 feeder, construction ability, and inaccessibility may prove to be an unreliable feeder source into the future without major capital investment. Also, power outages to the EA4 feeder may shut-down critical LAC water and wastewater treatment facilities unpredictably. Replacement costs for the EA4 feeder will exceed 2 million dollars.
Figure 21 illustrates the added redundancy to the east side of Los Alamos with the addition of the new East gate substation. The substation adds new feeders for the DP road area (18T), Pajarito Cliffs Site, Bayo Plant, San Idelfonso, and a new feeder 14T to add redundancy to the Townsite substation's Feeder 14. This project would be in the 5–7-year outlook. An alternative prime location is the east side of TA-21, If and when the TA-21 area is converted to county ownership.

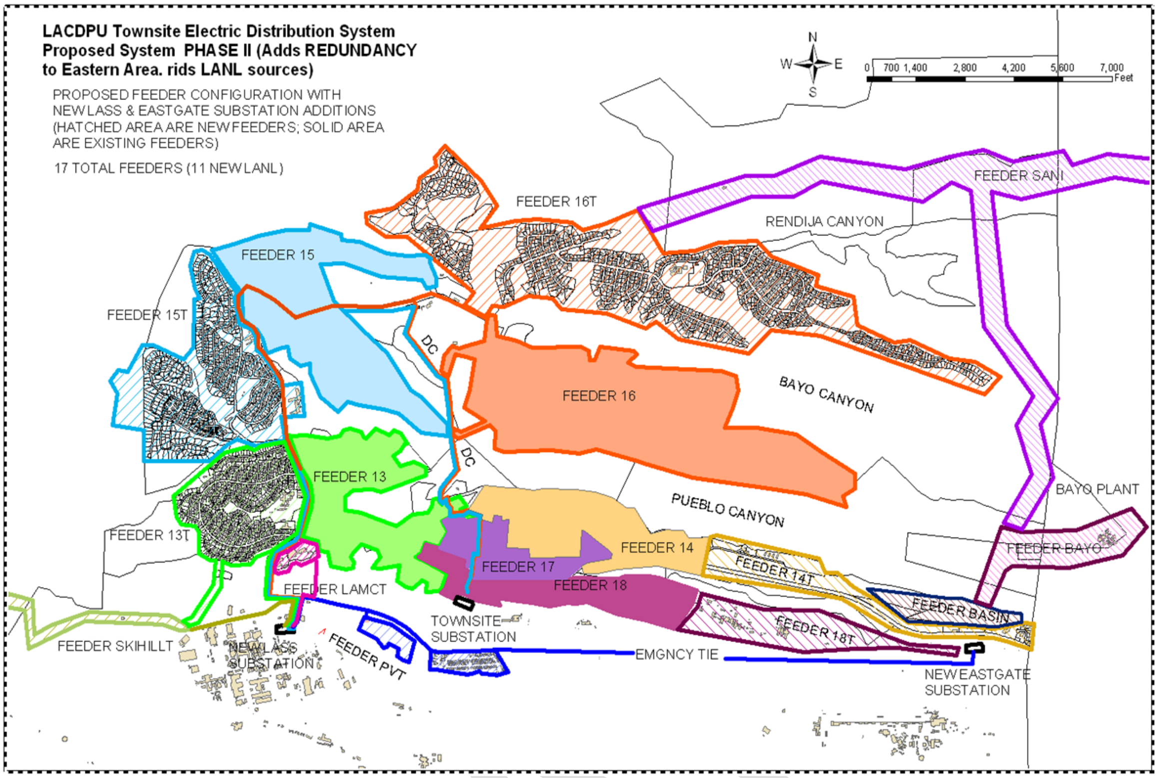


Figure 21. Los Alamos distribution area with East gate substation addition (when compared with Figure 9)

VII. System Reliability Improvement Projects Completed

DPU developed projects that were not high revenue but impacted the SAIDI significantly. For example, performing a new over-current protection study and implementing the suggested changes, assigning each of 10 lineman his feeder of responsibility, performing quarterly line inspections, performing a root-cause after every power outage, increased O&M which required mostly labor such as tree-trimming, insulating every pole-top transformer for animal contacts, etc.

Tables 7 through10 below summarize the System Reliability Improvement Projects (SRIP) completed by DPU since 2011 and Figure 11 illustrates the SAIDI over the past five years. As illustrated, DPU can't overlook the positive impacts of the SRIP with the SAIDI. Also, the SRIP helped mitigate and correct system deficiencies which would otherwise have impacted the deficient SAIDI even more.

Table 7. System Reliability Improvement Projects (est. & rounded)

	Reliability Improvement Projects	Area	Year	Cost
1	Feeder 15-16 OH Rebuild	2.7 miles Feeders 15-16	2011	$1100K
2	Feeder 15-16 UG Rebuild	2 miles	2011- 2012	$600,000
3	Feeder 14 UG Rebuild	Downtown	2011- 2012	$200,000
4	Feeder 17 Expansion	Downtown	2011- 2012	$200,000
5	New Feeder 18 & Expansion	Downtown	2011- 2012	$200,000
6	10 PME Switchgear Replacements	Townsite	2011- 2012	$300,000
7	Padmount Transformer Replacement (live front to dead-front conversion)			
	300 KVA	Golf Course	2012	$12,000
	500 KVA	Smiths	2012	$18,000
	150 KVA	Conoco	2012	$8,000
	300 KVA	Ashley Inn	2011	$12,000
	Four (4) 225KVA	Bomber Field	2011	$50,000
	300 KVA	VFW	2012	$12,000
	300 KVA	Long View	2012	$12,000
				$124,000
8	Overhead to Underground Conversion			
	Sycamore Tank		2012	$10,000
	Golf Course Well		2012	$10,000
	Bomber Field	retire 1200 ft	2011	$25,000
9	Primary Replacement Projects			
	IRIS	1100 ft. 3PH	2012	$50,000
	Loma Vista (replace & add loop)	500 ft 1 ph	2011	$75,000
	712 IRIS primary replacement	300 ft 1 ph	2011	$15,000
10	Contract Tree Trimming	Underway	2012	$100,000
11	30 Utility Pole Change outs	Service wide	end 2012	$150,000

Table 8 System Reliability Improvement Projects (est. & rounded)

	Reliability Improvement Projects	Area	Year	Cost
1	Tsikumu 1 phase replacement	2800 ft.	2014	$ 150,000
	(3 phase addition)	2800 ft.		$ 350,000
2	WR2 3 phase feeder Tie	4200 ft.	2013	$ 400,000
	(3 phase UG loop with 1 ph loops)			
3	Canyon Ph 1 & 2 (1 ph replacement)	5000 ft.	2013-2014	$ 500,000
	(3 phase addition)	900 ft.		
4	LAMC Source-Transfer Replacement		2013	$ 200,000
5	Feeder 13 Diamond Tie	1300 ft.	2014	$ 75,000
6	PME Switchgear Replacements			
	901 Trinity Site	2	2013	$ 50,000
	Trinity Village	2	2014	$ 60,000
	LAMC	1	2014	$ 40,000
	Oppenheimer/Trinity	1	2014	$ 40,000
7	Padmount Transformer Replacement			
	(live front to dead-front conversion)			
	300 KVA	35 Rover	2014	$ 12,000
	Miscellaneous 1 phase	White Rock	2013-2014	$ 30,000
	Miscellaneous 1 phase	Townsite	2013-2014	$ 30,000
8	Primary Replacement Projects			
	Range Road to Cemetery 1 phase	750 ft.	2014	$ 40,000
	Trinity Village 3 phase, 1 phase	200 ft.	2014	$ 50,000
	Knecht to DP Road	1200 ft.	2013	$ 200,000
9	In house Tree Trimming		2013-2014	$ 40,000
10	60 Utility Pole Change outs	White Rock	2013-2014	$ 60,000
		Townsite	2013-2014	$ 60,000
				$ 2,387,000

NOTE:

The Tsikumi, WR2, LAMC, Canyon, and Trinity Village projects replaced the failed primary UG sections but also added new engineering design features including new Loops and tie-points; and replaced live-front equipment with new dead-front (insulated) transformers and switchgear.

Table 9. System Reliability Improvement Projects (est. & rounded)

	Reliability Improvement Projects	Area	Year	Cost
1	Diamond Drive Phases 1 to 5	2 miles Feeders 13,15,16	2015	$875,000
2	Del Norte / Del Sol Subdivisions	2 miles	2005-2006	$800,000
3	Townsite Switchgear	Downtown	2006	1,216,000
4	White Rock Substation Transformer	White Rock	2005	$553,000
5	Central Avenue Upgrade	Downtown	2009	$300,000
6	15 PME Switchgear Replacements	Townsite	2014-2021	$450,000
7	Padmount Transformer Replacement (Live front to dead-front conversion)		2014-2021	$50,000/yr
8	Meadow Lane primary replacement	2500 ft 3 PH	2010	$200,000
9	Primary Replacement Projects Trinity Avenue with Smiths Piedra loop Sioux	 1100 ft. 3PH 3000 ft. 1PH 2400 ft. 3 PH	 2011 2012 2013	 $400,000 $150,000 $200,000
10	Contract Tree Trimming	Underway		$40,000/yr
11	Utility Pole Change outs	Service wide	ongoing	$150,000

NOTE:

The Feeder 15-16 rebuild included new engineering design features such as larger conductor for emergency operations, dampeners to avoid conductor galloping across the canyons, and was raptor protection friendly. A new UG feeder 18 was introduced to the distribution grid to power most of the Los Alamos downtown area. The downtown area is now served by two commercial-only Feeders #17 and #18.

Table 10. Project Conductor Footages Installed (not all inclusive of all projects)

LOS ALAMOS TOWNSITE UNDERGROUND CABLE INSTALLATIONS (FEET)				
PROJECT SUBDIVISION OR AREA	1 PHASE PRIMARY CABLE	3 PHASE PRIMARY CABLE	1 PHASE SECONDARY CABLE	YEAR INSTALLED
EASTERN AREA WEST OF CANYON	2821		11978	1978
TIMBER RIDGE, LOMA VISTA, RIDGEPARK, OPENNHEIMER	9724	17088	9506	1975-80
WESTERN AREA	9045	11349	20596	1980
RIDGEWAY, UPPER SANDIA, UPPER TRINITY, UPPER FAIRWAY	5447	16242	12009	2004
PONDEROSA ESTATES	7179	6828	5996	1992
LOS PUEBLOS NAVAJO	11079		20015	1978
BROADVIEW BIG ROCK LOOP LA MESA	25160	12813	23015	1980-90
LOMA LINDA	2410		4988	1980
QUEMAZON	31705	30570	23444	2001-3
NC1 NC2 BURNED AREA	37858	87063	53776	2004-5
DEER TRAIL	2406		1571	2000
TRINITY - DP ROAD TO 20TH		30972		2013
DEL NORTE DEL SOL SUBDIVISIONS	15495		13740	2006
ENTRADA PAJARITO CLIFFS		21792		2012-16
RIM ROAD QUARTZ	4044		9187	2018
SAN IDELFONSO TSANKAWI	11497	40149	12229	2014
EAST ROAD AIRPORT TO ENTRADA		18360		2017
NM502 PROJECT TEWA TO CENTRAL AND TRINITY	5200	12100		2020
DP ROAD PHASE 1	1100	5000		2021
CANYON ROAD NM502 TO 15TH	2821	9832		2006
DIAMOND DRIVE		32760		2007-9

VIII. Future System Reliability Projects

Projects with approx. estimates prior to COVID

EASTERN AREA (WEST OF CANYON ROAD) $200,000
TIMBER RIDGE $150,000
RIDGEWAY $ 250,000
OPENNHEIMER $300,000
WESTERN AREA $200,000
PONDEROSA ESTATES $200,000
LOS PUEBLOS $1.6 MILLION over 2 years
NAVAJO $200,000
TOTAVI $150,000
BIG ROCK LOOP $300,000
LOMA LINDA $200,000
DP ROAD PHASE II $ 300,000
PAJARITO ACRES $1.8 MILLION over 4 years
PIEDRA LOOP $ 800,000 over 2 years
DENVER STEELS $ 300,000
ESTATES $ 300,000
BROADVIEW $ 250,000
BRYCE AVE. $ 400,000
ARAGON AVE $ 400,000

IX. Summary

In 2001 the Cerro Grande Fire North community reconstruction began and was completed in 2004. In 2006 the first system wide condition assessment was completed. DPU was struggling with the system reliability and the SAIDI was over 5 hours per consumer. At that time, there were many problems in the distribution system and DPU needed to develop short-term and long-term action plans to address the different infrastructure issues. In 2005 the townsite switch station was installed providing new breaker control and feeder separations. The cross-canyon loads were separated from the downtown circuits. In 2005 the White Rock substation Unit 2 failed and was replaced in 2006 with new switchgear which provided the additional WR3 feeder. In 2010, the department developed an Electric Reliability Plan, “ERP”; the ERP identified the issues and problems into three different work areas: engineering, overhead, and underground. The 2010 ERP described the strategy for the short-term and long-term action plans in the three work areas. During 2010, increased revenue funds were authorized to address the different action plans and the SAIDI steadily decreased. The workload was tough and DPU crews all too often functioned in a reactive mode, i.e., problem occurs, fix it, move on to another problem.

Also in 2011, the ERP was updated, and the action plans were updated as well. Increased revenue funds were authorized to continue with the action plans and the SAIDI continued to decrease. By 2012, the ED department had started to catch up with the increased workload and the department reorganized its FTES (full time employees). Two operations staff retired but were replaced with two new linemen; this allowed the department to develop a third line operations crew.

By 2013 and 2014, the ED department was able to catch up enough that 2 crews were primarily assigned to pro-active O&M and replacement projects. For the first time in recent memory, DPU can properly plan and replace sections of the electrical distribution grid which have failed in the past. By the same time, DPU had met its SAIDI target. However, the SAIDI target would not have been possible without the increased revenue and operational funds authorized.

The Asset Management Program incorporates field inspections from the linemen into the system condition assessment. The linemen provide the necessary information to prioritize system replacement requirements. These requirements are then entered into the next budget cycle for the Utility Board and Council.

Though DPU has met the SAIDI target of 1 hour or less, there are still challenges ahead as identified in this, the 2021 Reliability Plan update. The drive to meet the SAIDI target begins with the customers who expect a steady and reliable electrical supply but ends with them as well; because the customers must sustain the electrical rates which provide the revenue stream to meet and sustain the SAIDI target. However, DPU recognizes the balance between electric reliability and the retail cost for electricity compared to our neighboring utilities AND how much DPU customers are willing to support. Therefore, DPU will continue to engage its customers through a customer survey on this issue. Also, Increased installation of solar panels in the county and energy conservation measures are decreasing revenue to the department.

Appendix A:
OUTAGE RESTORATION PROCEDURE

The purpose for this document is to formalize a **consistent procedure** when responding to outages affecting the substation breakers or electronic and hydraulic reclosers "OCRs"; collaboratively referred to OCDs.

BACKGROUND:

As you are aware, Engineering and Operations is continuously being graded on its SAIDI which is the Sum of Customer Interruption Durations / Total number of consumers. The goal is to have a SAIDI less than 60 minutes but ours consistently exceeds that value. At the present time, maintaining a SAIDI of 60 minutes will be difficult to achieve due to the age of our electrical system and the lack of system redundancy. As we continue the overhead rebuild process, continue our underground replacement strategy and add additional substations, the SAIDI will trend down. In the meantime, though, it is very important that we don't impact the SAIDI more than necessary during the outage restoration process. The following procedure attempts to minimize outage time but also makes you aware of the potential impacts of energizing the OCDs under 3 phase conditions.

FACTS ABOUT OUTAGES:

According to NRECA and other studies, 70-80 percent of Faults on overhead systems are temporary or of a transient nature. In addition, 70% of all Faults are single-line-to ground Faults. What this means is that 50% - 56% of the time, RESETTING the OCD and CLOSING IN (on 1 shot) will restore power. However, it's also important to recognize that 30% of the time, a larger problem such as phase-to-phase, 3 phase Fault, "tree on line", "downed power pole", etc. could exist. Energizing a PH-PH or 3PH fault, creates substantially higher fault currents than 1 PH faults thereby potentially causing greater equipment damage; even worse, energizing a permanent fault near human contact could be disastrous.

Therefore, the following procedure shall be used when responding to OCD type outages: When a breaker operates –

call Stephen Marez 505-780-0481 and begin public information procedures. Obtain outage information from the Meter Management System. Determine which protective devices have operated.

STEP 1:

BEFORE you energize an OCD, INTERROGATE the substation breaker or OCR control. **Here's what you want to look for**:

- 2 or 3 Phase Faults (other than 1 Ph);

- Ph to Ph (or 2 phase) generally means "slapping of lines" - watch for that on long spans (such as canyon crossings);
- 3 Ph Faults generally means something fell across line, pole down, etc. i.e., a PERMANENT Fault, don't RECLOSE but start patrolling; look for areas with trees, call dispatch to see if anyone reported an accident;
- Faults higher than 4000 amps for **Townsite**; a value this high is within **the first mile** and so take a quick patrol before energizing;
- The OCDs are preprogrammed to provide a distance to the Fault, look for that value and phase;
- Faults around 3000 amps are immediately downstream of the OCRs at North and Barranca Mesas, perform a quick patrol;
- Faults higher than 3000 amps for **White Rock** are within 0.75 miles; 2200 amps (Rover) - 1300 amps (Sherwood) are at the end of the lines.

STEP 2:

If you do want to close the OCD (remember it's OK 55% of the time), FIRST, **place the OCD on Non-Reclosing** or 1-Shot before energizing.

- For the Multilin substation breakers, place the breaker on "Recloser Disabled". Note: any operation within 30 seconds after a manual close, even when placed on NORMAL (reclosers ENABLED), will lock-out the breaker; we experienced this before.
- For the ABB OCRs, place the breaker on "Recloser Blocked".

STEP 3:

If the OCD holds after the several minutes, place the OCD back to NORMAL by disabling the Non-Reclosing or Recloser Blocked functions or Enabling the Recloser Function.

ADDITIONAL INSTRUCTIONS:

- Do not respond on the FIRST OCCURRENCE when Dispatch calls about a voltage sag or blink to the LANL system. When there is a substation breaker operation at The LAC Townsite substation, EVERYONE tied to the substation (including LANL) will experience a voltage sag or flicker. Keep note of the occurrence; if the problem persists SEVERAL times (say 3 blinks), then go to the substation, determine which feeder experienced the operation, interrogate the OCD, and patrol.

- Similarly, if someone calls that their lights went off-and-on; take note of the call but don't respond unless it happens on SEVERAL occasions. It's obvious the OCD/OCR is doing its job; recall that 70-80% of Faults are momentary or transient in nature.
- In either situation, notify Stephen Marez about the incident on the following day. We will then download the OCD information and follow up on the cause and location of the disturbance.

ANY QUESTIONS ASK!!

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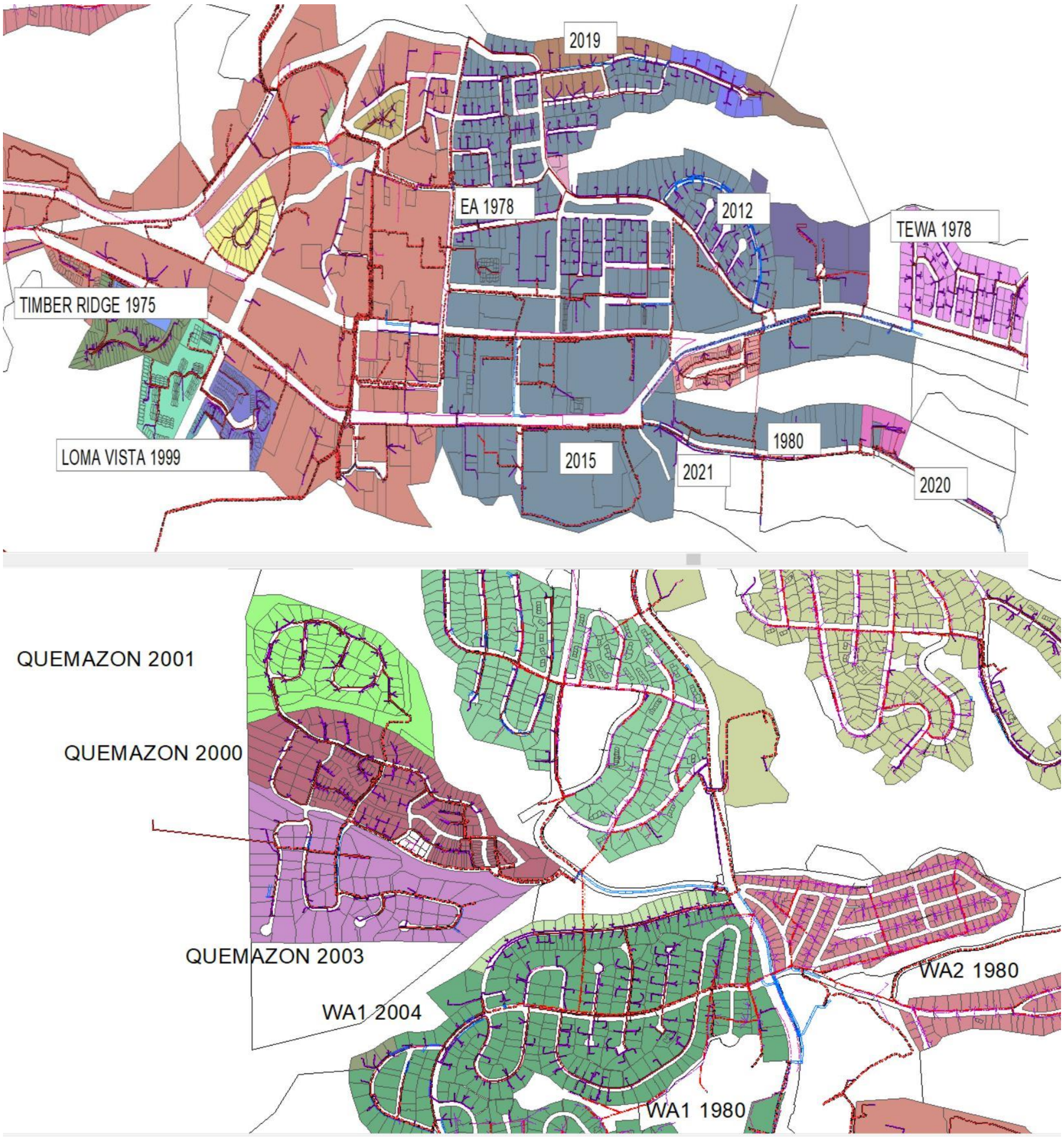
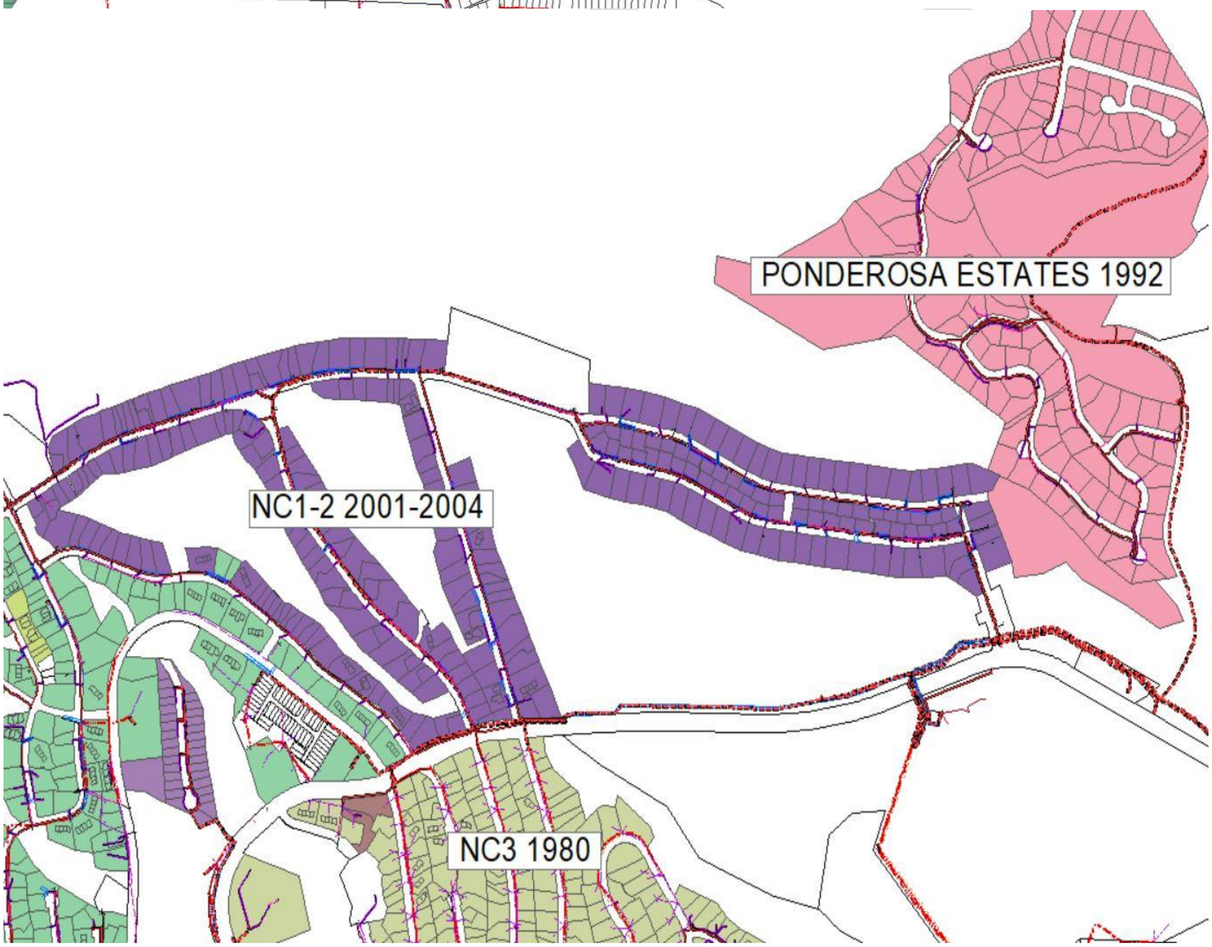
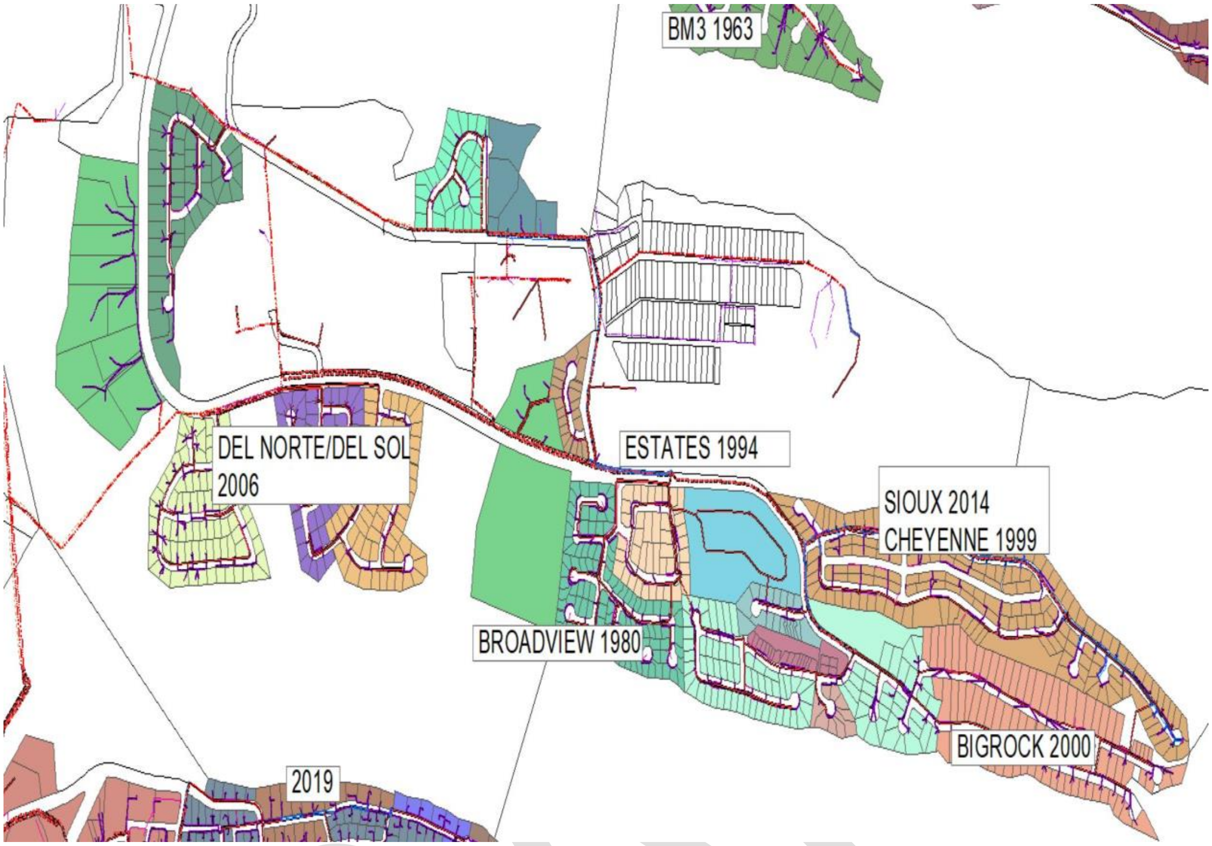
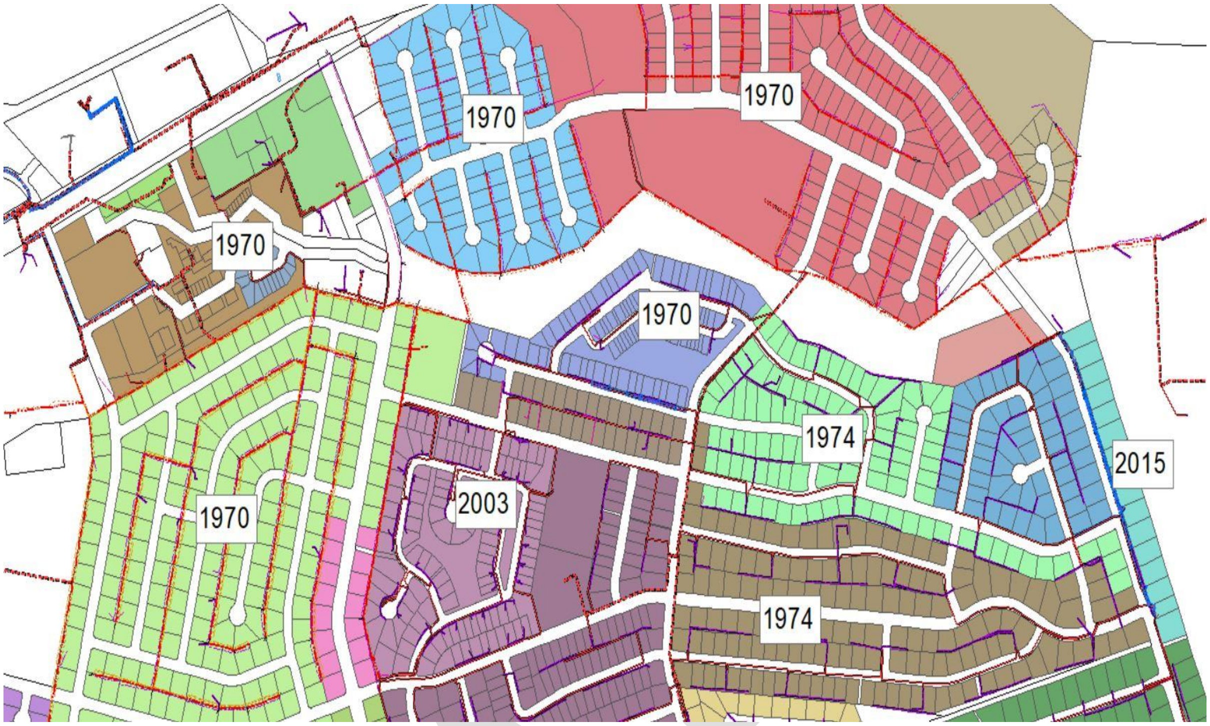
Appendix B:
SUBDIVISION MAPS WITH AGE




BM1 1961
BM2 1961
BM3 1965
BM4 1980
BM5 1980
BM5n 1978
BM3 1963


PONDEROSA ESTATES 1992
NC1-2 2001-2004
NC3 1980


BM3 1963
DEL NORTE/DEL SOL
2006
ESTATES 1994
SIOUX 2014
CHEYENNE 1999
BROADVIEW 1980
BIGROCK 2000
2019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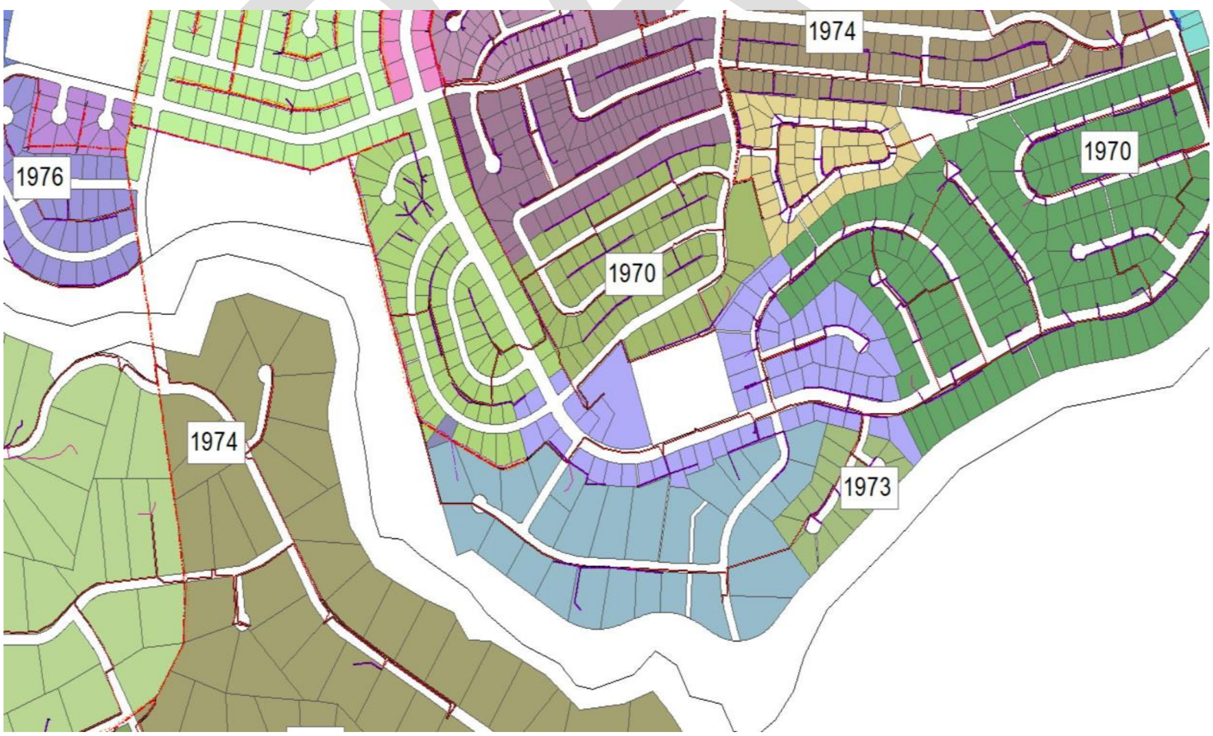
1970
1970
1970
1974
2015
2003
1970
1974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1970
1976
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1974
1973


2020
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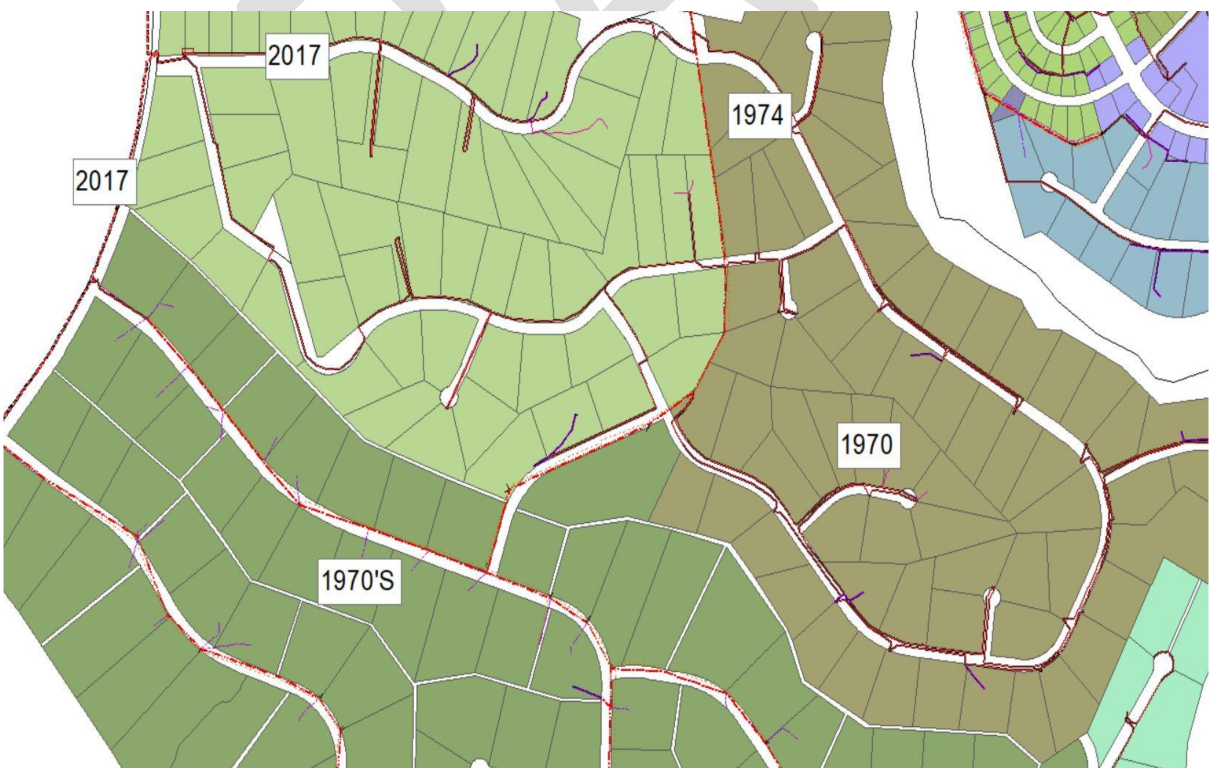
1970
1985
1976
1976


2017
1974
2017
1970
1970'S

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APPENDIX C: ASSESSMENT PRIORITY LIST FY2021

CIRCUIT-PRIORITY-RANK	DESCRIPTION
13-1-1	REPLACE SWITCHES SC1305A, SC1309 AND SC1309A
13-1-2	THREE PHASE LINE FEEDING MARY DEAL - MULTIPLE FAILURES
13-1-3	NEED TO REPLACE TRANSFORMERS 725 AND 726
13-1-4	NEED TO RELOCATE TRANSFORMERS 1058, 1059 TO SIDEWALK
13-1-5	NEED TO REPLACE TRANSFORMERS 856 AND 857
13-1-6	NEED TO INSTALL SWITCH CABINET IN PLACE OF VAULT - CANYON RD ACROSS 3850
13-2-1	REPLACE 1000' 3 PHASE PRIMARY 500MCM FROM STATION TO OPPENHEIMER
13-2-2	REPLACE OVERHEAD CONDUCTORS AND CROSSARMS ALONG ORANGE
14-1-1	REPLACE 15TH AND IRIS SWITCH SC1401A
14-1-2	REPLACE YMCA SWITCH SC1401A2
14-1-3	REPLACE YMCA TRANSFORMER #1117
14-1-4	REPLACE SOMBRILLO SWITCH SC 1404A AND REPLACE LINE TO NM502
14-1-5	REPLACE EASTGATE SWITCH T23201
14-2-1	REPLACEMENT OF TRANSFORMERS: 852,969,787,788,972,968,970,1117
14-2-2	SHANNON SWITCH INSTALL JUNCTION AND ROMOVE SC20505
14-2-3	REPLACEMENT OF SWITCHES SC1404A,1405,1406,1407,1406A,1408,1409,1406B,1410
15-1-1	CHANGE OUT POLES AT ARKANSAS 3091,3093,3095,3098,3087,3095
15-1-2	REPLACE URD PRIMARY LINE FROM SYCAMORE TO PUEBLO COMPLEX
15-1-3	REPLACE SC1517 PMH9 AT QUEMAZON
15-1-4	REPLACE SC 1501A ON ROSE STREET

16-1-1	**INSTALL PRIMARY J-BOXES AT 897 & 921 ESTATES DR.**
16-1-2	**REPLACE PRIMARY CABLE IN LA MESA RRAILER PARK**
16-1-3	**INSTALL PRIMARY J-BOXES AT CORNER OF KRISTI LN AND BROADVIEW**
16-1-4	**INSTALL PRIMARY J-BOXES AT CORNER OF TIFFANY AND BROADVIEW**
16-1-5	**INSTALL LOOP FEED FOR TOTAVI**
16-2-1	**REPLACE 1 PHASE PRIMARY SECTIONS ON LOS PUEBLOS : 2000' TOTAL**
16-2-2	**SINGLE PHASE PRIMARY AT LOS PUEBLOS**
14-2-3	**REPLACEMENT OF SWITCHES 1603A, 1604,1605,1605A,1605B,1610**
17-1-1	**REPLACE POLE #6152**
17-1-2	**REPLACE POLE #6154**
17-1-2	**REPLACE POLE 6137**
17-1-3	**REPLACE POLE #6138**
17-1-4	**REPLACE POLE # 6143**
17-1-5	**REPLACE POLE #6144**
17-1-6	**REPLACE POLE #6034**
17-1-7	**REPLACE POLE #6011**
17-1-8	**REPLACE POLE #6002**
17-1-9	**REPLACE POLE #6037**
18-1-1	**REPLACE SWITCH SC1803**
18-1-2	**INSTALL TRANSFORMER PAD AT MERRICK -**
18-1-3	**REPLACE OPEN DELTA TRANSFORMERS AT DP ROAD**
18-1-4	**REMOVE TRANSFORMER 1101 FROM MAIN TIE TO 18 AT DP ROAD**
EA4-1-1	**REPLACE MULTIPLE POLES AND CROSSARMS**

WR1-1-1	**REPLACE 4000' 1-PHASE PRIMARY: CHERYL CT, CONNIE**
WR1-1-2	**REPLACE 4 PADMOUNT SWITCHES ON ARAGON AVE. WR1-3,WR3-2,WR3-3,WR3-4,WR3-5,WR3-6**
WR1-1-3	**CHANGE OUT TRANSFORMER P3631 AT DNCU MALL**
WR2-1-1	**CONDUCTOR REPLACEMENT LA SENDA AND PIEDRA LOOP**
WR2-1-2	**REPLACE CONDUCTOR VALLE DEL SOL**