TEN YEAR PLANNING GUIDE

SHASTA LAKE ELECTRIC UTILITY

2011 - 2020

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PowerPlus Engineering
A Department of STAR Energy Services, LLC

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CITY OF SHASTA LAKE, CA

Prepared by PowerPlus Engineering

July 2011

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July 29, 2011

City Council
City of Shasta Lake
1650 Stanton Drive
Shasta Lake, CA 96019

Attention: Tom Miller – Electric Utility Director

Dear Council Members:

We are pleased to present our "Report on the Ten Year Plan" which has been prepared for your electric distribution system. This report presents the results of studies made to determine the ten year requirements for your electric system. The report provides recommendations for the development of the electric system to accommodate load growth and improve reliability for the next 10 years.

The ten year plan analysis is based on providing electric service to approximately 5,000 customers with a peak load of approximately 23 MW (not including Knauf demand) that is estimated to occur in the next ten years. The majority of recommendations for electric improvements to serve the existing and new loads include rebuilding feeder ties to improve reliability and replacing the substation voltage regulators in Central Valley substation. The estimated investment over the next 10 years is approximately $13.2 million in 2011 dollars.

We thank you for allowing us to provide you with professional consulting services.

Sincerely,

Tom Nigon

Tom Nigon, P.E.

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1 EXECUTIVE SUMMARY

This plan covers a ten year system planning period for the City of Shasta Lake Electric Utility (Shasta Lake). Shasta Lake is headquartered in Shasta Lake, California. Shasta Lake is a municipal electric utility serving the City of Shasta Lake.

The economy of the area is based primarily on commercial and light industry. Employment growth in the area is due to expansion in the retail and services such as tourism. The area has growth from residential developments located within the City of Shasta Lake. Shasta Lake serves the large industrial customer Knauf Insulation. The City of Shasta Lake is expected to have low to moderate growth in electrical use over the next 10 years.

This long range plan presented in this report is based on a design load of 23 MW. This demand doesn't include the demand for the Knauf substation which is a dedicated substation for a large industrial customer. This design load is approximately 1.1 times the past peak load and is estimated to occur in approximately 10 years.

The proposed distribution plan includes the following recommended improvements over the next 10 years. The list is prioritized by importance and the estimated timing where the lower numbered projects have a higher priority and are estimated to be completed during the initial time period of the ten year planning period:

1. Update the master SCADA
2. Upgrade Central Valley substation with new voltage regulators
3. Provide service extensions for approximately 500 new members
4. Replace 400 poles
5. Upgrade 2.8 miles of existing distribution
6. Upgrade Central Valley substation with an expanded control house and updated relaying
7. Install new feeders and ties when the Mt. Gate development begins and monitor load growth for a possible future new substation
8. Continue to monitor the condition of the Central Valley substation and replace with a new transformer based on the transformer condition and operating concerns
9. Flanagan upgrade will be planned with WAPA and no cost estimate is available at this time so this upgrade is not included in this plan

The estimated investment over the next 10 years is approximately $13.2 million in 2011 dollars.

This plan does not include a review of the Flanagan 230 to 115 kV substation. This substation is included in the planning process under a separate agreement with WAPA.

2 PLANNING CRITERIA

2.1 General

The plans provided in this report are a guide for the continued improvement of the transmission, substation and distribution system for Shasta Lake. Consideration has been given to service quality, reliability and environmental impact. The planning criterion uses a "one system" concept where the most cost effective plan is evaluated considering all of the delivery components. The delivery components include the transmission, substation and distribution equipment. The most cost effective plan will be recommended that considers the optimum combination of transmission line delivery points, substation locations and size and feeder layout.

2.2 Primary Lines and Distribution Configuration

The existing distribution consists of a 3-wire distribution operated at 12.47Y kV. The majority of existing overhead conductor is 397.5 ACSR for main 3-phase circuits. The majority of existing underground cable is 750 Aluminum for main 3-phase circuits. This conductor is adequate for main feeders and areas where major load developments will occur.

The use of No. 2 or 4 ACSR is acceptable for 1-phase taps for smaller loads such as taps to single customers. The use of No. 2 or 1/0 ACSR can be used for larger loads on branch feeders such as line serving multiple customers or lines that can be looped with branch feeders.

The feeder loading guidelines are based on an average feeder load of 3500 kW. These loading guidelines will prevent an excessive number of consumers being affected by a feeder outage and permit a back-up feeder to carry the load during an extended outage. The planning goal is to be able to restore power to the majority of customers due to a substation transformer or feeder outage by transferring the load to adjacent feeders through feeder switching as discussed below in the section on reliability.

The existing feeder loading with an average feeder length of 3 to 4 miles permits the main feeder ties to carry the load of the feeder and the load of an adjacent feeder during peak loading periods without field regulators assuming an average feeder load of 3500 kW peak demand. There are some feeders with ties to more than 1 feeder where the load should be transferred to the adjacent feeder with the smaller load during peak load periods to avoid overloading the feeder that accepts the load transfer. For example, feeders B and C could have loads exceeding 3500 kW during peak load periods so if feeder B is out of service the entire load from B should not be transferred to feeder C. An acceptable load transfer plan would be to transfer the load from B to feeder D because the peak load on Feeder D is less than 3500 kW. The distribution feeders have ties with more than 1 feeder so the transfer of load to adjacent feeders should be reviewed to determine how much load can be transferred so feeders are not overloaded when loads from adjacent feeders are transferred during peak load periods.

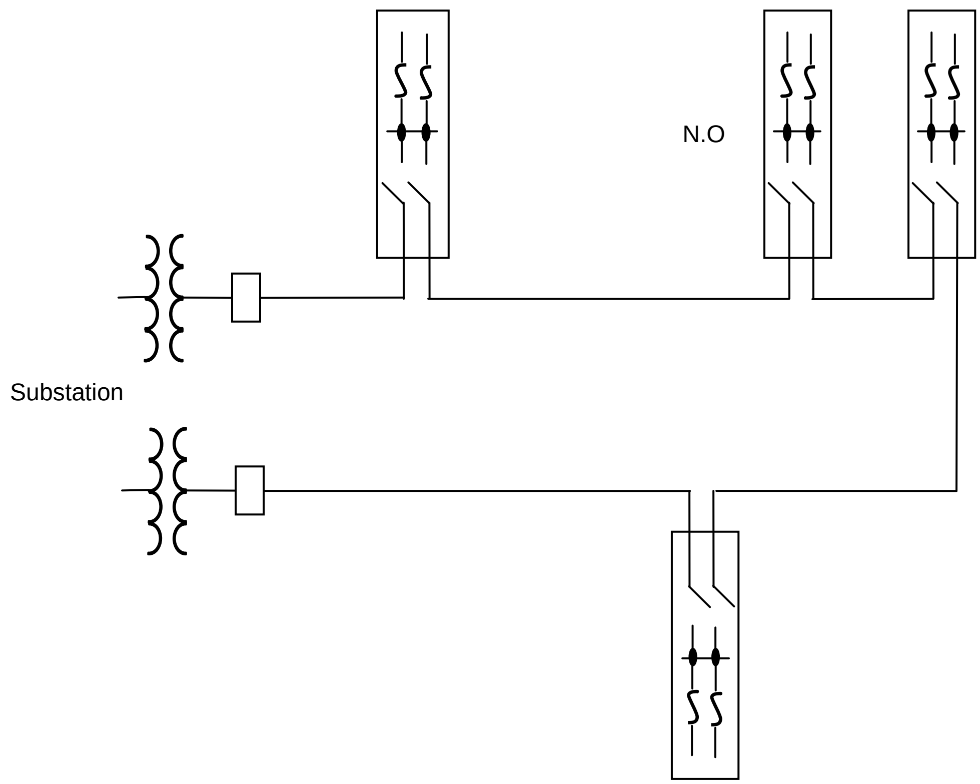
The estimated fault current at the end of a feeder that is 3 to 4 miles with a substation transformer size of 25 MVA is approximately 1200 amps. The minimum trip setting should be no more than 50% of the bolted phase-to-ground fault as recommended by the Cooperative Research Network (CRN) of the National Rural Electric Cooperative Association (NRECA). The minimum trip value of a feeder recloser for a feeder should not exceed 50% of the 1200 amps of fault current or 600 amps. The existing phase trip setting for the feeder recloser is 600 amps which is within the guidelines suggested for the phase trip setting.

The feeder length will increase when load is transferred from an adjacent feeder. The minimum fault at the end of the re-configured feeder during load transfer is estimated to be approximately 800 amps. The minimum trip value should not exceed 50% of the 800 amps of fault current or 400 amps. The minimum phase trip value may be greater than 50% of the bolted phase-to-ground fault during load transfer periods so ground fault sensing protection should be considered for the substation recloser if the feeder recloser does not provide adequate protection for the re-configured feeder.

The majority of faults on the electric distribution involves phase contact with the ground and is referred to as “ground” faults. The phase-current sensing of reclosers will detect ground fault currents when the total current through any phase exceeds the minimum phase trip setting. The phase trip setting is usually 2 to 2.5 times the peak load so this higher phase trip setting may not detect the lower fault current from ground faults. The ground faults that occur towards the end of the feeder may create low levels of fault current due to the line impedance, ground resistance and arc resistance. A three-phase recloser can include a ground trip device that trips based on the current that exists when a ground fault occurs. The ground trip device will have a lower minimum trip setting than the phase trip device because the ground fault currents are much lower than the phase-to-phase or three-phase fault currents. The usual setting for the minimum trip setting for ground faults is the approximate value of the peak load current so the ground trip setting is 40 to 50% of the phase trip setting or approximately 240 to 300 amps. The existing ground trip setting for the feeder recloser is 180 amps as established in the Shasta Lake 2007 coordination study and this setting is within the guidelines for the ground trip setting. The Shasta Lake Coordination Study recommends the phase overcurrent minimum trip should be no more than 50% of the end-of-line phase fault value and the ground overcurrent minimum trip should be no more than 25% of the end-of-line ground fault value.

The distribution for some feeders may consist of underground feeders. The normal practice for underground distribution is to install a radial underground feed to an individual service and plan for a loop system for multiple customers. The loop may be installed when the first customer receives service or the loop may be completed in the future as additional customer services are installed. The normally open point for the loop can be located at a riser pole, pad-mounted switchgear or in one of the transformers. The following is a diagram for a typical feeder configuration for underground distribution.

Figure 1 Feeder Configuration - Underground Distribution



In the above figure showing the distribution configuration for underground distribution, the loop is installed from one feeder recloser to another feeder recloser. The main feeder cable is 750 AL for Shasta Lake. The load area feeder or fused branch feeders are usually installed with No. 2 or 1/0 AL cable. Load area feeders or fused branch feeders may be installed initially as a loop or the loop may be completed later as additional transformers are installed. In some cases the loop may not be completed due to the cost of completing the loop or due to the unavailability of another source to complete the loop at the location near the last transformer.

The switching equipment in the above diagrams is shown as switchgear with 3-phase switches and fuses. Sectionalizing equipment such as cabinets with load break elbows can be used instead of switchgear to reduce costs. The use of switchgear is more expensive than using sectionalizing cabinets with load break elbows; however, the switchgear provides 3-phase switching and protection for branch feeders.

2.3 Voltage Levels

This plan is based on providing a minimum primary voltage of 118 volts during normal feeder configurations on a 120 volt base. Line voltage regulators and capacitors are acceptable to maintain the 118 primary volts in order to defer major line construction or the installation of new substations. Voltage drop calculations are based on the electric distribution model using the MILSOFT program.

The guideline of 118 volts is based on the American National Standards Institute (ANSI) C84.1-1995, Electric Power Systems and Equipment Voltage Ratings. This standard provides guidelines for voltage for two ranges. Range A is the normal operating voltage range and Range B includes voltage levels above and below Range A that may occur for a limited period. During contingencies the voltage standards may have lower limits in order to avoid power outages.

The Range A minimum service voltage is 114 volts. The primary voltage guideline of 118 volts is based on an estimated 4 volt drop in the transformer and service wires. The Range B minimum service voltage is 110 volts. This corresponds to a minimum Range B primary voltage of 114 volts. This planning guideline for primary voltages during contingencies such as outages when load is transferred to adjacent substations is 114 volts.

These voltage guidelines are recommended to be used by the Rural Utilities Services (RUS). RUS is a federal government agency within the United States Department of Agriculture. RUS provides loan funds for distribution, transmission and generation projects for non-profit electric cooperatives. RUS has planning guidelines that are used by electric cooperatives. Shasta Lake is under no obligation to adhere to these guidelines; however, these planning guidelines are consistent with industry standards for electric utilities so this planning document uses the RUS guidelines as recommendations for Shasta Lake.

2.4 Loading Limits

Equipment loading is determined by thermal loading or primary voltage drop. Thermal loading may be a factor for urban underground feeders with a high load density. The load on a main feeder should be limited to one-half of the emergency thermal loading to provide for capacity to serve adjacent loads during outages. Recommended ratings in amps for various conductors are shown in the appendix based on the maximum temperatures for the Shasta Lake area.

2.4.1 Equipment Loading Guidelines

The following are recommended maximum loading levels for equipment:

- Power Transformers – 100% of rating

- Substation and Line Voltage Regulators – 100% of nameplate rating
- Feeder Reclosers – 90% of nameplate rating for radial lines and 50% for reclosers on tie feeders
- Primary conductors – 80% of thermal loading except 50% of thermal loading for major tie lines

This long range plan uses the above guidelines for normal loading of equipment.

2.4.2 Substation Equipment Loading During Load Transfer

The equipment loading limits used in long range plans may allow for higher loading limits during contingencies when load is transferred to a backup feeder. A higher loading limit of equipment may be acceptable during contingencies because the load transfer is usually temporary and the probability of an outage occurring during peak load periods is low. The overloading of electrical equipment for the City of Shasta Lake should not be used for planning guidelines due to the possibility of extremely hot temperatures during the summer.

The load limit for power transformers during load transfer period is from the IEEE C57 standard for loading of transformers. The loading for normal life expectancy of a transformer for an overload that lasts 8 hours is 105% of nameplate rating using an outdoor ambient temperature of 104 degrees F and a pre-loading of 50% of nameplate before the overload occurs. The transformer loading should be limited to the transformer rating because temperatures in the Shasta Lake area can exceed 104 degrees F.

The loading for normal life expectancy of a regulator for an overload that lasts 8 hours is between 106 to 108% of the nameplate capacity (General Electric Regulator Information). A load limit of 100% is used for regulator loading during load transfer periods due to the possibility of high ambient temperatures in the Shasta Lake area.

2.4.3 Recloser Loading

The load limit for reclosers during load transfer periods is from the Cooper Power Systems. The guidelines allow an overload of 125% of the continuous current rating for 4 to 8 hours. (Cooper Power Systems Guide to Emergency Overload Capability R280-90-4)

2.4.4 Single-Phase Line Loading

A guideline for loading single-phase lines is a maximum of 40 to 50 amperes for protection and phase balance reasons. This loading level is equivalent to 500 to 625 kVA of peak 1-phase demand (single-phase transformers connected phase-to-phase) and approximately 1200 to 1500 kVA of transformer nameplate capacity. The loading can be larger than this range in some areas based on a review of the costs and benefits of adding phases and the existing line loading.

2.5 Economic Conductor Size

The conductor size for the distribution should be selected based on the thermal capacity of the conductor, the voltage drop and the economics of losses and costs of the conductor. The following provides some guidelines on selecting conductors for overhead and underground distribution.

The economic conductor size evaluates the total cost of the conductor including the installation costs and costs of losses. A larger conductor will cost more to install; however, the cost of the losses will be less than a smaller less expensive conductor. The following tables provides guidelines for selecting conductors based on the least overall costs of the capital costs and costs of losses. The cost of losses used in the analysis is based on Shasta Lake wholesale power costs of $0.066/kWH.

Table 1 Economic Conductor Size for 1-Phase Overhead Lines

Conductor Type	Min kW	Max kW	Min Amps	Max Amps
No. 4 ACSR	0	113	0	10
No. 2 ACSR	113	365	10	30
1/0 ACSR	365	563	30	45

The above chart shows that 1-phase lines should be installed with No. 2 ACSR for lines serving an average peak demand of 113 to 365 kW. The maximum recommended loading for a 1-phase line is 40 to 50 amps or 500 to 625 kVA due to protection and phase balancing concerns. Shasta Lake should continue to use No. 2 ACSR for single-phase for loads up to 365 kW and 1/0 ACSR for loads with peak demands exceeding 365 kW.

Table 2 Economic Conductor Size for 3-Phase Overhead Lines

Conductor Type	Min kW	Max kW	Min Amps	Max Amps
No. 4 ACSR	0	230	0	10
No. 2 ACSR	230	742	10	34
1/0 ACSR	742	1533	34	71
3/0 ACSR	1533	1846	71	85
4/0 ACSR	1846	2587	85	120
397 ACSR	2587	5304	120	245

The above chart shows that 3-phase lines should be installed with 397 ACSR for lines serving an average peak demand of 2,587 to 5,304 kW or higher. The above load guidelines are for average loads and the peak load could be higher when transferring load between feeders. Shasta Lake should continue to install 397 ACSR for main feeders based on the economic loading guidelines.

Shasta Lake should install No. 2 or 1/0 ACSR for 3-phase branch lines. The No. 2 ACSR should be installed for loads with demands of approximately 700 kW or less and 1/0 ACSR should be installed for 3-phase branch lines with loads that exceed 700 kW.

The following tables provides guidelines for selecting underground 3-phase conductors based on the least overall costs of the capital costs and costs of losses. The cost of losses used in the analysis is based on average wholesale power costs from Shasta Lake data.

Table 3 Economic Conductor Size for 3-Phase Underground Lines

Cable Type	Min kW	Max kW	Min Amps	Max Amps
No. 2 AL	0	1,572	0	73
1/0 AL	1,572	1,595	73	74
4/0 AL	1,595	3,309	74	153
500 AL	3,309	6,936	153	320
750 AL	6,936	9,310	320	430

The economic underground main feeder size from the above table is 4/0 AL; however, the 4/0 AL may not have adequate capacity during load transfer periods. Shasta Lake should continue to use 750 AL for the underground main feeders. The "Max Amps" for the 750 AL is the maximum recommended capacity for cable installed in risers with an ambient temperature of 50 C.

Shasta Lake should continue to use No. 2 AL underground cable for branch feeders because the normal loading guideline for 1-phase branch feeders is 40 to 50 amps or 500 to 625 kVA at 12.47 kV line-line connected transformers. The maximum recommended load on a 3-phase branch underground feeder is 866 to 1083 kVA assuming a peak demand of 40 to 50 amps on all three phases which is within the economic loading for the No. 2 AL cable shown above. Shasta Lake should consider 4/0 AL UG for a 3-phase underground branch lines with loads greater than 1600 kW in order to reduce costs from electrical losses.

The recommended standard overhead conductor size for Shasta Lake is 397 ACSR for the main feeders and No. 2 ACSR for the branch feeders. The recommended standard underground cable size for Shasta Lake is 750 AL for the main feeders and No. 2 AL for the branch feeders. The standard type of distribution recommended for expansions in existing subdivisions and future subdivisions is underground distribution. This is the common type of distribution installed in subdivisions by electric utilities.

2.6 Reliability

The long-range plan recommends when practical that ties between major feeders and substations be installed to permit backup during outages to main feeders and substations. Shasta Lake's planning goal is to be able to restore power to the majority of customers due to a substation transformer or feeder outage by transferring the load to adjacent feeders through feeder switching. The ability to operate with any one feeder or substation transformer out of service is called an "N-1" capability.

The reason for the "N-1" contingency guideline is to reduce the outage time for a large number of customers affected by outages from failures of substation transformers or problems with main feeders such as a broken pole or failed underground cable. An outage from a transformer failure can be restored by installing a mobile transformer. The time to install the mobile transformer could exceed 12 hours and the time to repair a broken pole or underground cable could exceed 8 hours. The outage times could be reduced to 2 hours or less if the load could be transferred to other substation equipment or feeders. The "N-1" contingency guideline is also useful so substation equipment or feeders can be removed from service for maintenance and the load can be served from a different source during the maintenance period to avoid planned outages to customers.

It's not always economically feasible to design the system to meet the "N-1" contingency guideline. It may not be economically feasible to provide a tie feeder to all radial feeders or to have back-up capacity at every substation. It may not be economical or necessary to install a loop feeder to an area fed by a reliable radial feeder. The costs and benefits of feeder ties and other back-up measures should be evaluated to determine if the projects should be funded.

The loading pattern on substations may allow for backup from adjacent substations with sufficient equipment capacity and with adequate voltage for all periods of time except when the load is at a peak level such as during hot weather that causes higher load from air-conditioner load. The equipment loading and voltage guidelines may be revised to allow additional load and lower voltages when operating during "N-1" contingencies. The equipment loading may exceed the normal capacity of the equipment and the primary voltage may be less than the 118 volt minimum RUS guideline when operating in an "N-1" contingency during the peak load periods as discussed previously in the section on voltage levels and thermal loading limits.

The use of automatic sectionalizing and SCADA should be evaluated in areas of high load growth or high load density. Projects may be recommended to replace poles and wire that are older than 50 years. Replacing this equipment may improve the reliability because the new equipment should be less likely to fail and cause outages.

Most utilities have metrics that are used to evaluate the performance of the distribution reliability. Reliability metrics are the quantitative data collected that defines a level of reliability. The typical reliability metrics or indexes that are measured and compared to other utilities include the system average interruption duration index (SAIDI) and the system average interruption frequency index (SAIFI).

SAIDI is a measure of the average minutes of interruptions for each customer on an annual basis. SAIDI is calculated by summing the customer annual outage minutes and dividing this sum by the number of customers served. SAIFI is a measure of the average number of interruptions for each customer on an annual basis. SAIFI is calculated by summing the annual customer outages and dividing this sum by the number of customers served. The reliability benchmarks are the reliability targets or goals for these metrics. Reliability benchmarks are based on the needs of the customers and a review of the industry standards for these metrics.

The following are the formulas for these outage indices.

SAIDI (SYSTEM AVERAGE INTERRUPTION DURATION INDEX FOR SUSTAINED OUTAGES)
This term represents the average number of outage minutes (due to sustained outages) per customer served.

$$\text{SAIDI} = \frac{\text{sum of all customer interruption durations}}{\text{total number of customers served}}$$

SAIFI (SYSTEM AVERAGE INTERRUPTION FREQUENCY INDEX FOR SUSTAINED OUTAGES) This term represents the average number of interruptions (due to sustained outages) per customer served.

$$\text{SAIFI} = \frac{\text{total number of customer interruptions}}{\text{total number of customers served}}$$

The RUS reliability guideline for the SAIDI metric for rural electric distribution is 200 minutes or less per year to obtain a satisfactory rating of 3 in the RUS Form 300. The RUS form 300 is a review summary used by electric cooperatives participating in the RUS loan program and the form rates the electric facilities, engineering, budgets and operating and maintenance practices of electric cooperatives. The RUS considers this an average level of performance. This should not be considered the long-term benchmark for the SAIDI metric. The benchmark for the SAIDI metric should be based on the electric utility industry practice of approximately 60 outage minutes/year for suburban and 120 outage minutes/year for rural consumers.[1] The following table provides some information on SAIDI (minutes) and SAIFI statistics for six utilities.[2]

Table 4 Average Annual SAIFI and SAIDI (minutes) for Six Utilities 1988-1992

Service Area	Climate	SAIFI	SAIDI
Dense urban area	Hot summers, bitter winters	0.1	16
Urban/suburban	Hot nearly year round	2.7	34
Suburban & rural	High lightning	2.0	97
Urban & rural	Mild year round	2.1	122
Rural, mountainous	Mild Seasons	1.1	168
Rural, mountainous	Bitter winters	2.3	220

The replacement of distribution lines that are 50 years and older and other distribution line improvements recommended in this plan are expected to reduce outage duration and maintenance costs. Distribution improvement projects are evaluated that will achieve Shasta Lake’s reliability benchmarks.

[1] RUS Bulletin 1724D-101A, page 16
[2] Power Distribution Planning Book, page 118

2.7 Environmental Considerations

Shasta Lake is encouraged to review any proposed construction for the impact the construction will have on the environment. The use of existing right-of-way is recommended for a route to upgrade or build new lines if possible. The Shasta Lake electric utility staff should work with the regulatory agencies when installing facilities in environmentally sensitive areas.

The long-range plan recommends the use of raptor protection in areas where raptors could be electrocuted from power lines. The RUS has guidelines on raptor protection. This long-range plan recommends that the Shasta Lake review the RUS recommendations on raptor protection for further information. This information is available on the RUS website.

2.8 Power Supply

Cost estimates are included for any new transmission lines or substations recommended in this plan for comparison purposes. These facilities are either provided by Shasta Lake or other utilities.

2.9 Distributed Generation

The distribution is designed to deliver power to customers so the connection of distributed generation (DG) units will be allowed if the DG units can operate without causing power quality issues and the DG installations are within the guidelines required by Codes and the State of California guidelines. A DG interconnection study is required to be completed by Shasta Lake prior to the interconnection. DG owners must provide the required information in the DG application before the DG unit will be reviewed for the interconnection. The customer must comply with the Shasta Lake DG interconnection policy.

3 LOAD PROJECTIONS

3.1 Background

The design loads were developed based on the review of past load growth, a review of the land use and from discussions with representatives of the Shasta Lake. The planning period for this study is 10 years.

3.2 Load Forecast

Shasta Lake has load forecasts prepared by Economics Sciences Corporation. The following data is from the latest report for the electric utility demand and customer growth forecast.

Table 5 Annual Growth Forecast

Item	Annual
Customers	0.6%
Peak kW	2.0%

Notes for the above tables:

- Customers – estimated annual growth of all customer classes
- Peak kW – estimated annual growth in the peak demand for Central Valley substation

The load forecast data was completed before the economic recession so the growth could be less than the forecast shown in this last report. The annual peak demand load growth from 1984 through 2009 was 2.0%. This is based on a peak demand of 12,000 kW that occurred in 1984 from the Master Plan report.

3.3 Land Use Analysis

Future load growth is expected to be similar across the service territory except for the possibility of the Mt. Gate development in the North East area. Shasta Lake staff provided information on land use that was used to identify areas that have a potential for higher than the average annual load growth. The Shasta Lake employees used information from various sources to develop the estimate of the area load growth estimates. A new residential and commercial development (Mt. Gate) is planned for the NE area of the City of Shasta Lake. The timing of the loads is uncertain at this time due to the economic recession. Plans are included in this study for options to serve the development when the loads occur in the future.

3.4 Design Load and Allocation

The design load is allocated to the existing substation using existing and projected demands. The projected demands are based on the growth rates over ten years for the substations and feeders discussed previously in the load projections section.

A summary of the load growth in the annual peak demand is shown below.

Table 6 kW Annual Peak Demands and Growth Factors

Period	Year	Forecast
1	2010	19,894
2	2011	20,192
3	2012	20,495
4	2013	20,803
5	2014	21,115
6	2015	21,431
7	2016	21,753
8	2017	22,079
9	2018	22,410
10	2019	22,747

Notes for the above table:

- Data does not include load from Knauf substation because this is a single industrial customer

This 10 year plan uses an estimated annual growth in peak demand of 1.5% for the Central Valley substation loads based on conversation with Shasta Lake staff and a review of the forecast data. This forecast is less than the historical load growth due to the slow growth that has occurred recently from the economic recession. This growth rate is estimated to be uniform across all of service territory except for higher growth in the northeast area from the Mt. Gate development. The projected design load of 23 MW for Central Valley substation and 15 MW for Knauf substation will be used for this ten year plan.

The system load data is shown in the appendix. The energy sales over the past five years have increased approximately 1.4% each year. The average number of new consumers added in the past 5 years is an average of approximately 30 each year.

3.5 Substation Load Projection

The substation demand data is from SCADA information provided by the Shasta Lake electric utility staff. The following shows the existing and ten-year forecast of the peak demand for the Shasta Lake substations.

Table 7 Substation Peak kW Demand Ten Year Forecast

Substation	Exist	Growth	10-year
Central Valley #1	0	1.5%	0
Central Valley #2	19,600	1.5%	22,747
Knauf #1	7,500	0.0%	7,500
Knauf #2	7,500	0.0%	7,500
Total kW	34,600		37,747

The following are notes for the above table:

- Exist – existing peak demand in kW estimated from 2008 summer SCADA (actual kW peak in 2008 was 19,500 kW for Central Valley so 2010/2011 estimate assumes growth to 19,600 kW)
- Knauf – peak demand from load forecast data from Trent
- Growth – estimate of the uniform load growth assumption
- 10-year – forecast of the peak substation demand that is estimated to occur in ten years
- Central Valley demand to be shared by both transformers after transformer/regulator 1 voltage regulation plan finalized

3.6 Distribution Feeder Load Projection

The substation peak demand is allocated to the distribution feeders using an estimate of the connected transformer capacity installed on each feeder. A system model was created using the feeder map provided from Shasta Lake. Shasta Lake provided a list of distribution transformers and some of the transformers had location information. This list of transformers and feeder map was used to create the system model. Shasta Lake should update the model with actual customer energy and demand information in the future when the billing information can be imported to a system model. The following are the feeder loading information.

Table 8 Feeder Loading from Summer 2008 SCADA

Feeder	Max Amp	Avg. Amp	kVA	kW
A	198	187	4,041	3,839
B	226	202	4,373	4,155
C	249	219	4,734	4,497
D	166	141	3,045	2,893
E	131	109	2,367	2,249
F	140	126	2,728	2,592
Total			21,289	20,225

Notes for the above table:

- Max Amp is maximum amps on all three phases
- Avg. Amp is the average of the amps from the three phase reading
- kVA is calculated at 12.47 kV with the average amps
- kW is the kVA times a power factor (PF) of 0.95 where the PF is from the summer 2008 substation loading SCADA
- Total kVA and kW is non-coincident total

The feeder loading from the model is an estimate of the coincident peak feeder loading. The maximum summer demand on the Central Valley substation from the 2008 – 2009 SCADA information was 19,500 kW. The estimated coincident demand used for the electrical model is the peak feeder demand from the 2008 SCADA multiplied by the ratio of the system demand of 19,500 kW to the non-coincident feeder peak demand of 20,225.

The following is the feeder demands used for the electrical model for the existing and 10-year projected demand.

Table 9 Feeder Demands for Electrical Model

Feeder	Exist kW	Ten-yr kW
A	3,839	4,236
B	4,155	4,600
C	4,497	6,196
D	2,893	3,143
E	2,249	2,398
F	2,592	2,794
Total	20,225	23,366

The future feeder loading forecast is obtained by applying the uniform load growth estimate to the existing feeder demands except for an adjustment to feeder C load for the potential load growth at Mt. Gate development. The demand of feeder C is increased by 1000 kW for the Mt. Gate development and the future demand of the other feeders is reduced by 200 kW/feeder to account for this non-uniform growth adjustment.

4 ANALYSIS OF EXISTING SYSTEM

4.1 Power Supply and Transmission

Shasta Lake owns the distribution substations that serve Shasta Lake's customers. Shasta Lake owns 15 miles of 115 kV transmission lines that serve the distribution substations of Central Valley and Knauf substations.

The Central Valley substation is served from a transmission line from the Flanagan Substation and a transmission line from the Knauf Substation. The Knauf Substation is served from a transmission line from the Flanagan and Keswick Substation and a transmission line from the Central Valley Substation. The configuration for the transmission lines is a ring bus. The loop system plus ring bus scheme provides a configuration that is highly reliable.

The transmission system was discussed with the staff from Shasta Lake and the general overview is the transmission delivery points provide a reliable source of power to the distribution substations. The level of transmission reliability is reasonable based on the historical experience of the outages due to the transmission. The age and condition of the transmission facilities is adequate for the existing and future loads.

4.2 Distribution General Description

Shasta Lake's distribution system consists of approximately 60 circuit miles of overhead primary line and approximately 8 circuit miles of underground primary distribution line. The distribution voltage is 12.5Y kV for the primary system. The configuration is a 3-wire distribution with a solid grounded wye on the 12.5 kV secondary of the substation transformers.

The number of consumers receiving service is approximately 4,500. The average consumer density is 66 consumers per mile of line. Total utility plant investment is approximately $19.2 million which is an average investment of $4,300 per consumer.

The 3-wire distribution consists of 3 energized wires with a phase-to-phase voltage of 12.5 kV. There is no distribution neutral installed on overhead lines. The Central Valley substation is the source for the distribution. The Central Valley substation transformers are connected delta on the 115 kV side and solidly grounded wye on the 12.5 kV side. The distribution is grounded at the Central Valley substation transformers secondary wye connection and at the distribution riser poles, pad-mounted transformer and pad-mounted switching equipment. The pole mounted transformers tanks are not grounded. The single-phase overhead and pad-mounted transformers are connected phase-to-phase. The majority of transformers are Current-Protecting (CP) type. The "CP" transformers are equipped with the internally mounted low-voltage circuit breaker and high voltage protective links, but omit the lightning arresters.

The majority of distribution in the United States is a 4-wire, multi-grounded common neutral primary system. The 4-wire system has the following advantages over the 3-wire system:

- Single-phase branch feeders consist of one insulated phase conductor and the neutral rather than two phase conductors.
- Only one lightning arrester and fuse is required at each single-phase distribution transformer.
- A single-bushing transformer can be used on a 4-wire system.
- A fault on a fused single-phase line for a 3-wire system requires 2 fuses to open. There may be some time delay between clearing of the two fuses which could cause some objectionable voltages to the transformers connected to the line.
- The under-built neutral partially blocks access to the phase conductors from ladders and cranes and warns the crews and public that a high voltage phase conductor is overhead. The under-built neutral also may provide a low impedance path for fault current if a phase conductor breaks and falls on the neutral rather than falling on the ground or hanging in the air.

The following are some advantages of the 3-wire system over the 4-wire system:

- Costs are lower to serve overhead 3-phase loads

- Neutral-to-earth voltages are minimal because the transformers are connected phase-to-phase
- Lower magnetic fields
- High impedance faults can be detected if the sensitive earth fault (SEF) relaying is used (Shasta Lake does not use SEF relaying due to problems from nuisance tripping based on interview with staff)

Utilities in Europe and the Middle East use a 3-wire distribution. The distribution is different than the U.S. because the loads are primarily 3-phase including residential services. The 3-wire system in Europe and the Middle East install an extensive secondary distribution with large 3-phase transformers that serve entire blocks of customers. The extensive secondary provides multiple grounds that reduce the safety concerns of a 3-wire distribution.

The following information on the 3-wire distribution was provided from Shasta Lake staff:

- The 3-wire distribution is used mainly in California and is not common in other States
- Ground relays are set for 25% of the phase-to-ground fault current at the end of the protection zone
- GO-95 and 128 (California's Utility Electrical Safety Codes) require common neutrals to have a redundant path back to the source and underground primary neutrals must be fully insulated so these rules could increase costs for a 4-wire system installed for utilities that comply with GO-95 and 128
- There are no operating or safety issues with the 3-wire system used by Shasta Lake

Shasta Lake should review the economic and operational differences between a 3-wire and 4-wire distribution system. There may be some economic and long term advantages to convert to a 4-wire system especially if the City begins to install more underground and replace overhead distribution with underground in the future because single-bushing transformers can be used on a 4-wire system which could reduce the distribution costs.

4.3 Reliability

Utilities are either required by regulatory agencies to calculate outage statistics or they voluntarily calculate the statistics. The process to collect the outage data, calculate the indexes and evaluate the results is useful for improving the system reliability.

The following is an estimate of the service interruptions for Shasta Lake.

Table 10 Average Annual Outage Reliability Indexes

Year	SAIDI	SAIFI	CAIDI
2008	122	2.1	57
2009	69	2.1	33
2010	86	2.4	36
3-Yr Average	92	2.2	42

Notes for the above table:

- SAIDI (system average interruption duration index in minutes) estimated from outage logs provided from the City of Shasta Lake. The quantity of customers with a loss of power for each outage was provided by Shasta Lake staff.
- SAIFI (system average interruption frequency index) estimated from outage logs provided from the City of Shasta Lake. SAIFI is a measure of the average interruptions per customer each year.
- CAIDI (customer average interruption duration index) is the average minutes for an outage for customers that have an outage. The duration of the outage is measured from the time Shasta Lake is informed of the outage until the power is restored.

The following is a comparison of the outage indices for Shasta Lake with other neighboring utilities.

Table 11 Outage Comparison with Neighboring Utilities

Utility	SAIDI	SAIFI	CAIDI
NORTH AMERICA MEDIAN	90	1.1	82
SOUTHERN CAL EDISON	106	0.9	113
PG&E (COMPANY WIDE)	153	1.2	128
PG&E (NORTH VALLEY ONLY)	265	1.6	168
CITY OF SHASTA LAKE	92	2.2	42

Notes for the above table:

- SAIDI and CAIDI – annual duration in minutes/year/consumer
- SAIFI – annual average interruptions/year/consumer
- North America Median – source is IEEE standard 1366 for the year 1998
- PG&E company wide from 2008 company report
- PG&E North Valley from CPUC Feb. 29, 2008 report

Cost-effective management and consistent implementation of reliability investments and initiatives are critical to maintaining and/or improving customer satisfaction and system reliability. The City strives to choose the most cost effective discretionary projects with the greatest benefit to cost ratio to improve reliability.

Some of these projects and practices include:

- Aggressive Tree Trimming (The city currently spends over $100k per year on contract tree trimming to minimize tree related outages)

- Mitigate recurring outages by employing such things as squirrel transformer bushing cover-ups (Started July 2010)
- Installed Advanced Metering Infrastructure (AMI) so Shasta Lake is notified of an outage sometimes before the customer is aware of the problem. This project was implemented from 2007-2009.
- Fusing distribution tap lines so the size of protection zones are decreased.
- Installed additional line reclosing devices to break the circuit into segments to keep the majority of customers on when outages occur.

This plan provides recommendations that may reduce outages and improve the reliability. The projects may reduce outages by providing new equipment, poles and conductor that may be less susceptible to failure from extreme weather conditions such as wind and lightning. The installation of new equipment may improve the SAIDI index by reducing failures of the equipment so outages are prevented.

The 5-year SAIDI average is less than the RUS satisfactory rating of 200 minutes or less per year. The long term goal for SAIDI is 120 outage minutes/year for rural consumers and 60 outage minutes/year or less for urban consumers. The goal for Shasta Lake should be 60 outage minutes/year or less due to the urban nature of the service territory. The City of Shasta Lake is reviewing software products for tracking SAIDI. This information will be useful to develop strategies to improve the reliability.

The outage records show numerous outages due to lightning. Shasta Lake should consider installing lightning arresters every 1000 feet on the main feeders and at transformer locations to reduce outages from lightning. Implementation of the recommendations from the long range plan should continue to improve the reliability of the distribution system.

4.4 Substations

The substation loading was reviewed based on the existing peak loads and the projected peak loads using the ten year forecast.

The following shows information on the existing substation equipment.

Table 12 Substation Equipment

Substation	Trf 55C MVA	Trf 65C MVA FA	Reg Type	Reg amps
Central Valley #1	25	28	Bus	1,093
Central Valley #2	25	47	LTC	2,156
Knauf #1	16	30	LTC	1,380
Knauf #2	16	30	LTC	1,380

Notes for the above table:

- Trf 55 C MVA - substation transformer nameplate rating in kVA at 55C oil temperature

- Trf 65 C MVA FA – the load limit in MVA of the transformer at 65C with forced air cooling (Central Valley #1 does not have fans so the existing top rating is 28 MVA)
- Reg Type – Bus regulator with regulator equipment separate from transformer or LTC (load tap changing transformer)
- Reg amps – rating of the regulator or LTC in amps
- Transformer voltage – 115 kV delta to 12.5 kV grounded wye

A review of the equipment loading shows the substation equipment has adequate capacity for existing and the 10 year peak demands with normal substation and feeder configuration and with substation and feeder configurations when load is transferred from adjacent feeders or substation transformers. The following is information on the loading of substation equipment.

Table 13 Existing and 10-year Substation Loading

Substation	Exist MVA	Trf% exist	Reg% exist	10 Yr MVA	Trf% 10 yr	Reg% 10 yr
Central Valley #1	0.0	0%	0%	11.9	43%	50%
Central Valley #2	20.6	44%	44%	11.9	26%	26%
Knauf #1	7.3	24%	24%	7.3	24%	24%
Knauf #2	7.3	24%	24%	7.3	24%	24%

Notes for the above table:

- Central Valley #1 has voltage regulators, other are LTC
- Exist – equipment loading (MVA or percent of equipment capacity) with existing summer peak demands from 2008 – 2009 SCADA
- 10 yr – estimated loading (MVA or percent of equipment capacity) with load growth over 10 year planning period

The substations were reviewed during site visits to assess the condition of the substations. The following is a summary of the comments from the substation site visits.

Table 14 Substation Site Visit Review Summary

Substation	Comments from Review	Action
Central Valley	CV #1 transformer rated 7.97/13.8 kV	Options reviewed in this planning study
Central Valley	CV #1 regulators oil tests indicate “warning” for overall equipment condition	Options reviewed in this planning study
Central Valley	Control house space is inadequate for future SCADA equipment	Expand control house
Central Valley	Portions of the relays and controls are older electronic	Upgrade relaying and controls to digital
Knauf	No issues	None

Notes for the above table:

- Action may not include minor equipment replacement that is optional depending on future budgets for substation work.

4.5 Current System Studies

4.5.1 Coordination Study

Shasta Lake had a protection study prepared in 2006. This plan has been utilized in the development of this ten year plan.

4.5.2 Master Plan

The most recent master plan was developed in 1986. It is based upon a system peak demand of 24 MW for the median load forecast and covers the period through 2005. The information from this plan has been utilized in the development of the ten year plan.

The major recommendations from the master plan included constructing a 115 kV loop system, a second substation in the northeast quadrant of the service territory and converting the distribution voltage to operate at 12.5 kV. These recommendations have been implemented except the second substation was not installed and instead a second transformer was installed at the Central Valley substation.

The conversion of distribution transformers from 13.8 to 12.5 kV has been substantially completed. The 12.5 kV voltage was recommended in the master plan because 12.5 kV is a common voltage in the area and is used by neighboring utilities so spare equipment could be used from other utilities in the area if required in an emergency.

The Master Plan indicated the Central Valley 13.8 kV substation transformer could be used for the 12.5 kV distribution voltage by setting the taps so the transformer voltage is 95% of 13.8 kV or 13.1 kV. The distribution transformers rated 13.8 kV with taps could be utilized by adjusting the taps for a 5% voltage reduction allowing the transformer to operate at the 12.5 kV distribution voltage.

4.5.3 Load Forecast

Load forecast studies have been prepared for Shasta Lake. Spreadsheets from “Economic Sciences Corporation” were reviewed. The data is from spreadsheets that were prepared in 2007. This information has been utilized in the development of the loading data used in this plan.

4.6 Distribution Feeders

4.6.1 Feeder capacity and voltage

Feeder loads are based on the allocation of loads as discussed previously in this report. The loading of distribution feeders is limited by the thermal capacity of the underground feeder exits.

The system model using MILSOFT was used to calculate the voltage and currents with the existing peak loads, the projected peak loads using the ten year forecast and the peak loads using the ten year load forecast with load transfers from adjacent substations. The primary voltage for all feeders and locations is estimated to be 118 volts or greater during normal feeder configurations for the existing and 10-year peak loads. The primary voltage could be less than 118 volts during load transfer periods for the 10-year peak loads. The following table shows the area with the highest voltage drop with the 10-year peak loads and normal configuration of the distribution feeders.

Table 15 Highest Voltage Drop Location with 10-Year Peak Feeder Loads

Feeder	Vdrop	Location
A	2.7	Ashby, Tibbitts Rd
B	3.5	Summit City area
C	6.3	Twin Lakes Mobile Park
D	3.2	Lake Blvd
E	1.0	Twin View Blvd
F	2.7	Indian Ave.

Notes for the above table:

- Vdrop – primary voltage drop with 10-year peak feeder demand

The voltage on the feeders could be less than 118 volts when load is transferred from one feeder to an adjacent feeder with the projected 10-year load. The 750 AL feeder exits could be overloaded when load is transferred between feeders with the 10-year projected peak feeder demands. Options to improve the voltage and reduce the feeder loading during load transfer are discussed in the distribution exploratory options of this report.

There could be voltage and capacity concerns with the additional load that could develop in the Mt. Gate development. The following table shows the estimated voltages on feeders serving the Mt. Gate area with a project load of 1.8 MW. The plan is to serve the initial development by extending feeders C and F.

Table 16 Feeder Voltage with Mt. Gate Load Addition

Feeder	Condition	Low V	Location
C	Normal	123	Mt. Gate area
F	Transfer	113	Feeder C substation exit

Notes for the above table:

- Feeder – feeder with load
- Condition normal – Mt. Gate load served from feeder C
- Condition transfer – Mt. Gate load transferred to feeder F. This assumes the portion of No. 2 ACSR on feeder F is upgraded to 397ACSR.

The following section on exploratory plans in this report explores various options to reduce the potential low voltages for the above feeders serving the future Mt. Gate load. The options will be reviewed for costs and benefits of the options.

Distribution improvements are discussed in the following section on exploratory options. These improvements include upgrading feeders due to the age and condition of the feeder, upgrades related to reliability improvements and upgrades to serve new load.

4.6.2 Energy losses

Energy losses as a percent of energy purchased averaged 3.9% in 2009. The following tables show the calculation of the annual losses and benchmarks for the metric of overall system losses for Shasta Lake.

Table 17 Energy Losses 2009 for City of Shasta Lake

Description	MWH
MWH sales	71,546
MWH purchase	74,430
Loss MWH	2,884
Loss%	3.9%

Table 18 Loss Benchmarks for Rural Electric Shasta Lake

kWH/mile/year	Loss% REA 45-4	Loss% NRECA
10,000	12.7	10.5
20,000	10.4	9.5
50,000	9.0	8.0
100,000	8.5	7.0
200,000	8.3	6.5
500,000	8.1	6.0
1,000,000	8.1	5.5
2,000,000	8.1	5.0

Notes for the above table:

- kWH/mile/year – Annual energy sales billed per mile of distribution line
- Loss% REA 45-4 – System loss percentage from REA Bulletin 45-4
- Loss% NRECA – Recommended maximum system losses from the National Rural Electric Association Rural Electric Research

Shasta Lake averages approximately 43,000 kWH/mile/year of energy sales so the maximum system losses should be less than 8.0% based on the NRECA guidelines. The 2009 year average loss percentage for Shasta Lake is below the target level of 8.0% so there are no specific exploratory plans that will be considered only for the purpose of reducing line losses. The majority of recommended projects will replace existing conductor with larger conductor so line losses will be reduced as the recommended long range plan projects are implemented.

The following is a comparison of annual losses of other electric utilities with the distribution losses for Shasta Lake.

Table 19 Energy Loss Comparison

Utility ID	Loss
Coop A	6.6%
Munic A	5.9%
Munic B	5.8%
Munic C	5.6%
Munic D	5.4%
Coop B	5.1%
Munic E	5.0%
Coop C	4.9%
Coop D	4.1%
Coop E	4.0%
COSL	3.9%

Notes for the above table:

- Coop – rural electric cooperative
- Munic – City owned electric municipal utility

Shasta Lake has the lowest annual losses as compared to the utilities shown in the above table. The utilities in the above table are rural electrical cooperatives and municipal utilities located in Iowa, Minnesota and Wisconsin. Shasta Lake should review the electrical losses each year and find similar utilities in California to compare the losses with.

The majority of distribution losses are due to transformer losses. An estimate of losses due to distribution transformers are shown in the appendix. Shasta Lake should purchase low loss transformers and use life cycle costs for evaluating transformers when purchasing new transformers.

5 EXPLORATORY PLANS

5.1 Comparison Analysis Assumptions

Engineering economics are used to compare the costs of alternative exploratory plans. The present value of the costs are compared in alternative plans. In most cases the plan with the minimum present value cost will be the recommended option unless there are other factors that may favor the more expensive option. Some factors that may cause the higher cost plan to be recommended include the plan's flexibility to accommodate future load growth, reliability and operating improvements or other benefits.

A present value factor (PV) may be used in the economic analysis of alternatives. The PV is multiplied by the installed cost of an option to convert the installed cost to a common year used for the analysis. For example, some options have capital investments that occur in the future. The PV factor is used to convert the future dollars to present value dollars so the costs for each option can be compared in the same year. The following formula is used for the PV factor:

$PV = \text{Future value} / (1 + i)^n$

The Future value is the cost of the option in the future, i is the discount rate and n is the number of periods from the base year. A discount rate of 8% is used in the economic analysis. The discount rate is also known as the minimum acceptable return or present worth rate. The value may be represented as the rate of return on investments, blended interest rate or other assumed rate. The discount rate used in this report is estimated to be the desired rate of return on investments.

The costs of losses are included in the comparison of alternative plans. The types of losses considered in the plans are distribution line losses and substation transformer core losses. The substation transformer has winding losses that are similar in the alternative plans considered so the winding losses are not included in the loss comparison. The present value of losses is calculated for a 30 year time period. The following shows the present value cost of losses used in the studies.

Table 20 Cost of Losses

Description	Distribution	Core
Energy Cost - $/kWh	$0.0660	$0.0660
Load Factor Estimate	56.0%	100.0%
Loss Factor	35.3%	100.0%
Escalation/year	3.0%	3.0%
Discount Rate	8.0%	8.0%
Years of study	30	30
PV Factor - escalating Amount	15.2	15.2
PV cost/kW	$3,098	$8,774

Notes for the above table:

- Energy Cost from Shasta Lake power supply budget 2010 spreadsheet
- Loss Factor = $(\text{load factor})^2$ x 0.84 + load factor x 0.16
- PV cost/kW = 8760 hours/year x Loss factor x Energy cost/kWH x PV factor

The cost/kW for distribution is multiplied by the calculated distribution line losses for each alternative plan to determine the cost of losses. The cost/kW for core losses is calculated by the calculated core loss for substation transformers to determine the cost of losses. These costs are included in the total cost of each plan so the cost of losses are a factor in the review of the options.

5.2 Transmission Options

The existing lines are adequate to serve the load over the next 10 years. There are no transmission options reviewed.

5.3 Substation Options

The existing substations have capacity to serve the load over the next ten years. The oil tests for Central Valley transformers 1 and 2 show acceptable conditions and recommend normal monitoring. Central Valley transformer No. 1 has a low voltage rating of 13,800Y/7970 instead of the operating voltage of 12470Y/7200. This causes some operating concerns when transferring load between the No. 1 and No. 2 transformers.

Shasta Lake staff provided information on the age of the Central Valley substation transformers and regulators. The estimated age of the No. 1 transformer and regulators is 30 years old (purchase date of 1981 from G.E.) and the No. 2 transformer was purchased installed in 1991 or 1992 so the No. 2 transformer is approximately 18 to 19 years old. The City of Shasta Lake engineering staff has concerns that the No. 1 transformer could fail due to the age of the transformer.

The transformer 1 has 3 – single-phase regulators to regulate the voltage. Oil tests have indicated the regulators have the possibility of heating that may have caused the contacts to be inoperable. The overall condition from the tests for the regulators is a "Warning" so there are concerns that the regulators could fail.

The following is a review of options for the issues with the No. 1 transformer and voltage regulators.

Option 1 – Rewind the transformer to 12.47Y/7.2 kV.

The following is the cost estimate to re-wind the No. 1 transformer to a low voltage of 12.5 kV to match the voltage of transformer No. 2 and the system distribution voltage. A cost estimate for replacing the regulators is included.

Table 21 Cost Estimate Rewind CV1

Description	Unit	Cost/Unit	Cost	Year	PV
Re-wind transformer to 12.47 kV	1	$406,000	$406,000	2011	$376,000
Replace regulators	3	$26,000	$78,000	2011	$72,000
Costs for removal/install and oil treatment	1	$164,000	$164,000	2011	$152,000
PV core losses @ 0.08% loss	1	$176,000	$176,000	2011	$163,000
Total Cost			$824,000		$763,000

Notes for the above table:

- PV core losses – from G.E. test data dated 9/21/81 using a present value cost of $8,800/kW

MTC Transformers from Louisville Ohio provided a budget estimate for re-winding the transformer. The re-winding replaces the existing coil and with new coils and insulation. The existing steel and core is reused in the transformer. The budget estimate includes freight both ways for shipping the transformer without oil. An estimate is included in the remove/install costs for removing the oil and either re-conditioning the oil or filling the transformer with new mineral oil.

The unknown cost with the rewinding option is the cost of losses. Core loss is a major component of the transformer losses so the core losses of CV1 transformer will not change with the new windings. A new transformer could have lower core losses so a comparison of the losses of a rewound CV1 and a new transformer should be completed before a decision is made to rewind the transformer.

The No. 1 transformer does not have fans so the top rating for the transformer is 28 MVA. Fans are not required to be installed during this ten year planning period because the load forecast is not estimated to exceed the 28 MVA top rating of the transformer.

Option 2 – Replace the Central Valley No. 1 transformer with a new transformer

The following is the cost estimate to replace the No. 1 transformer with a new 25/47 MVA transformer with a low voltage of 12.47 kV to match the voltage of transformer No. 2 and the system distribution voltage. The new transformer includes load tap changing (LTC) equipment so the voltage regulators would not be needed.

Table 22 Cost Estimate Replace CV1 with 25/47 MVA Transformer

Description	Unit	Cost/Unit	Cost	Year	PV
New 25 MVA with LTC 115 to 12.47 kV	1	$727,500	$728,000	2011	$674,000
Construction costs for removal/install	1	$200,000	$200,000	2011	$185,000
PV core losses @ 0.08% loss	1	$176,000	$176,000	2011	$163,000
Total Cost			$1,104,000		$1,022,000

Notes for the above table:

- PV core losses – estimated to be 0.08% (same as CV2 transformer) of 25 MVA rating with present value cost of $8,800/kW
- Cost estimate for transformer is an average of budgetary price quotes from transformer vendors

Option 3 – Replace the Central Valley No. 1 transformer with a new 15/25 MVA transformer

The following is the cost estimate to replace the No. 1 transformer with a new 15/25 MVA transformer with a low voltage of 12.47 kV to match the voltage of transformer No. 2 and the system distribution voltage. The new transformer includes load tap changing (LTC) equipment so the voltage regulators would not be needed. This transformer has capacity for the ten year forecast so the smaller transformer is an option for replacing the existing transformer. The 15 MVA transformer would cause the fault current to be less than the fault current with a 25 MVA transformer so this could reduce equipment failure due to over-stressed equipment.

Table 23 Cost Estimate Replace CV1 with 15/25 MVA Transformer

Description	Unit	Cost/Unit	Cost	Year	PV
New 15/25 MVA with LTC 115 to 12.47 kV	1	$588,000	$588,000	2011	$544,000
Construction costs for removal/install	1	$200,000	$200,000	2011	$185,000
PV core losses @ 0.08% loss	1	$105,600	$106,000	2011	$98,000
New 25 MVA with LTC 115 to 12.47 kV	1	$1,435,784	$1,436,000	2034	$226,000
Total Cost			$2,330,000		$1,053,000

Notes for the above table:

- PV core losses – estimated to be 0.08% (same as CV2 transformer) of 15 MVA rating with present value cost of $8,800/kW
- Cost estimate for transformer is an average of budgetary price quotes from transformer vendors

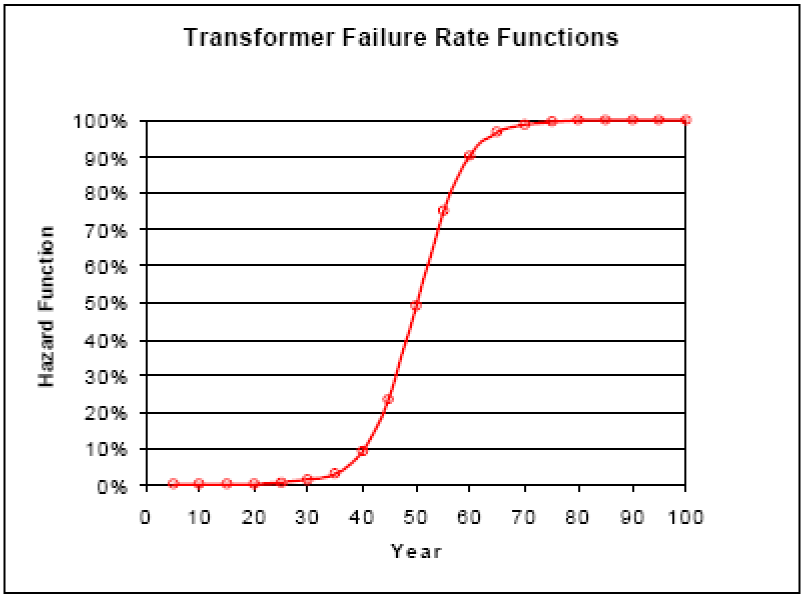
The 15/25 MVA should have capacity to serve the entire Central Valley load for approximately 23 years assuming an annual load growth of 1.5%. The estimated cost includes replacing the 15 MVA transformer with a 25 MVA transformer when the Central Valley load forecast reaches 28 MVA.

Option 4 – Operate CV1 at the 120,750 volt tap

The existing No. 1 transformer is 30 years old. The life of a transformer is difficult to predict. Some studies from manufacturers and utilities recommend the normal operating or useful life of power transformers is 35 to 45 years. The life of a transformer can be extended by testing the transformer oil and doing the maintenance based on the results of the oil test data. Oil tests of the transformer were completed and the data from the 2007 and 2008 tests were reviewed. The tests show the condition of the transformer is acceptable. Utilities will continue to operate substation transformers until the units fail or until the oil tests indicate a high probability of failure. The costs of substation transformers are a major cost for utilities so the transformers are operated as long as possible.

The following is one example of a model used to predict transformer failure.

Figure 2 Transformer Failure Model



This model was created by an insurance company. The above graph is a model for transformer failures showing a 50% failure rate of transformers when the transformer age is 50 years old. The above graph is a statistical prediction and doesn't take into account manufacturing differences or loading history.

Shasta Lake can place load on the No. 1 transformer by operating the transformer at the high voltage transformer tap of 120,750 volts. The ratio between the high voltage winding (115 kV) at a tap setting of 120,750 volts and the low voltage winding of 13,800Y/7970 is 15.2 so assuming a transmission voltage of 115 kV, the secondary voltage on a 120 volt basis would be approximately 126.5 volts. The secondary voltage would decrease slightly due to the voltage drop from the transformer impedance.

The following provides an estimate of the minimum and maximum secondary voltage at the CV1 substation bus with a transmission voltage variance of +/- 10% and a voltage regulator with a +/- 10% voltage regulation range.

Table 24 Secondary Voltage with CV1 Tap at 120,750

Trans kV% nominal	Volts sec	Vreg +10%	Vreg -10%
90%	112	123.4	100.9
95%	118	130.2	106.5
100%	125	137.1	112.1
105%	131	143.9	117.8
110%	137	150.8	123.4

Notes for the above table:

- Trans kV% nominal – the transmission voltage at the primary terminals of the substation transformer as a percent of the nominal value of 115 kV

- Volts sec – the un-regulated voltage at the secondary terminals of the substation transformer for a distribution transformer rated 12.47Y/7.2 to 120 volts with a 1.5% voltage drop through the substation transformer
- Vreg +10% and Vreg -10% - the maximum and minimum secondary voltage with voltage regulation with a +/- 10% voltage regulation range

The above table shows the CV1 transformer with a tap setting of 120,750 volts can provide acceptable secondary voltage with 12.47Y/7.2 kV distribution transformers. For example, if the transmission voltage was at 90% of nominal or 104 kV, the secondary voltage of the transformer on a 120 volt basis would be 112 volts. The voltage regulator could increase the voltage to a maximum voltage of 123.4 volts that should provide adequate voltage to the distribution with 12.47Y/7.2 kV transformers. If the transmission voltage was at 110% of nominal or 127 kV, the secondary voltage of the transformer on a 120 volt basis would be 137 volts. The voltage regulator could decrease the voltage to a minimum voltage of 123.4 volts that should provide adequate voltage to the distribution with 12.47Y/7.2 kV transformers.

There is a concern of circulating currents when the CV1 and 2 transformers are operated in parallel for short periods of time to transfer load between feeders served from the different transformers. This should only be done for short periods of time during switching because the fault currents will be higher than the interrupting capacity of the reclosers and fuses. The circulating current can be minimized by manually setting the voltage output on the regulators of CV1 and LTC of CV2 so the secondary voltages are the same. Shasta Lake has written procedures to operate the transformers in parallel. These procedures should be reviewed and updated if this option is selected and new regulators are installed.

The following is the cost estimate to replace the regulators and operate the CV1 transformer at the 120,750 volt tap.

Table 25 Cost Estimate with CV1 Tap to 120,750 volts

Description	Unit	Cost/Unit	Cost	Year	PV
Replace regulators	3	$26,000	$78,000	2011	$72,000
Construction costs for removal/install	1	$50,000	$50,000	2011	$46,000
Parallel operation modifications	1	$10,000	$10,000	2011	$9,000
PV core losses @ 0.08% loss	1	$176,000	$176,000	2011	$163,000
New 25 MVA with LTC 115 to 12.47 kV	1	$977,699	$978,000	2021	$419,000
Total Cost			$1,292,000		$709,000

Notes for the above table:

- PV core losses – existing G.E. losses with new transformer losses estimated to be the same as the G.E. losses with present value cost of $8,800/kW

The above cost estimate assumes the remaining life of the Central Valley No. 1 transformer is 10 years. The previous information from insurance data shows a 10% failure at 40 years and 50% failure at 50 years so 10 years is a conservative estimate for the remaining life of the transformer. Most utilities do not replace a transformer with a new transformer unless the existing transformer has failed or shows serious concerns from oil tests. The No. 1 transformer does not have fans so the top rating for the transformer is 28 MVA. Fans are not required to be installed during this ten year planning period because the load forecast is not estimated to exceed the 28 MVA top rating of the transformer.

Option 5 – New Substation near Mt. Gate Development with Feeder Ties

This report includes exploratory distribution options for serving the possible load addition in the Mt. Gate development. One of the options to serve the new load is to install a new substation near the west area of the development. This substation could be used with feeder ties as a back-up to the Central Valley substation.

This option is to install feeder ties from the proposed Mt. Gate substation to connect to the existing distribution feeders. The No. 1 transformer at Central Valley would not be replaced because the new Mt. Gate substation and feeder ties would replace the capacity supplied from the CV1 transformer. This plan assumes the Mt. Gate substation would be installed.

The following is the cost estimate for the option to replace the CV1 transformer with feeder ties from the Mt. Gate substation.

Table 26 Cost Estimate for Feeder Ties with Mt. Gate Substation

Description	Unit	Cost/Unit	Cost	Year	PV
Mt. Gate Substation	1	$1,600,000	$0	2015	$0
Feeders ties to feeder A	9,000	$50	$450,000	2015	$306,000
Feeders ties to feeder B & D	11,000	$50	$550,000	2015	$374,000
Feeders tie to feeder C	700	$50	$35,000	2015	$24,000
Feeders tie to feeder E	9,000	$50	$450,000	2015	$306,000
Feeders tie to feeder F	10,000	$50	$500,000	2015	$340,000
Substation feeder exits	5	$100,000	$500,000	2015	$340,000
PV core losses @ 0.08% loss	1	$105,600	$0	2011	$0
Transmission from Flanagan/CV	3.5	$198,000	$0	2011	$0
Replace regulators for CV1	3	$26,000	$78,000	2011	$72,000
Total Cost			$2,563,000		$1,762,000

Notes for the above table:

- Units for feeder tie is feet of 397 ACSR
- No costs for substation, transformer core losses and transmission line because these costs are included in the cost of service for the Mt. Gate development

The following study on the Mt. Gate development concludes the substation should be deferred until the load in the development is expected to be approximately 2 MW so this option of additional feeder ties would not be available until the load develops in the Mt. Gate area.

The recommended plan is the least cost option of operating the CV1 transformer at the 120,750 volt tap, replace the existing regulators with new regulators and develop operating procedures and regulation settings so the transformers can be operated in parallel when switching load from feeders or transformers. The City should continue to monitor the condition of the CV1 transformer and replace the transformer with a new transformer in the future due to operating concerns or the possibility of a transformer failure. The remaining life of the CV1 transformer is estimated to be approximately 10 years so funds are included in this plan to replace the CV1 transformer.

The overall condition from the tests for the regulators is a “Warning” so the voltage regulators should be removed from service and replaced with new regulators. The existing regulators should be sent to a repair shop for an evaluation to determine if the regulators should be scrapped or overhauled and returned to stock to be used as spare equipment.

This option is similar to the plan recommended in the 1986 Master Plan that provided recommendations for using the 13.8 kV Central Valley substation transformer and a new 12.47 kV substation transformer for the 12.47 kV distribution. The Master Plan recommended the new 12.47 kV substation to be installed near the Mt. Gate development but the actual installation of the 2nd transformer was installed in the existing Central Valley substation. This was probably done to reduce costs by eliminating the cost of extending the transmission line to the Mt. Gate area. The load in the Mt. Gate area didn’t develop so that could have been another reason for deciding not to install the new substation.

5.4 Distribution Options

The distribution options are based on improving the voltage or capacity concerns identified previously in this report. The option that is typically the least cost to improve the voltage and capacity of the distribution is to upgrade existing feeder ties consisting of older wire such as No. 2 with larger wire such as 397 ACSR. These major feeder ties with the smaller conductor are older and are in need of an upgrade due to the age and condition of the distribution. These feeder ties are required to transfer load between substations so typically the only feasible option is to rebuild these feeder ties at the same location with larger conductor.

Converting to a higher voltage is an option to improve the voltage and capacity of feeders. The option to convert to a higher voltage is not the least cost option because the existing transformers and substations are required to be replaced with new equipment. The introduction of 25 kV is done by some utilities in areas where there are no existing substations and distribution and the type of load can be served economically at 25 kV. The types of load that can be economically served by 25 kV are high load density areas such as downtown commercial areas and isolated areas where it is difficult to install transmission lines to the area. It is economical to serve new loads in high load density areas with 25 kV distribution because the 25 kV cable can deliver more power than the same size of 15 kV cable. Serving remote areas with 25 kV may be an economical option because the voltage drop is less with the use of 25 kV lines, losses are reduced and transmission and substation costs are reduced. Converting existing distribution from 12 to

25 kV is not recommended due to the cost and operating concerns that 25 kV could create due to introducing another operating voltage. The optimum distribution voltage for Shasta Lake is 12.47 kV due to the type of loads and load density of the area and the existing distribution is 12.47 kV.

The following is a review of the areas where there is more than one option to improve the voltage and capacity of distribution feeders. Distribution options will also be discussed for areas where low voltage could exist on newer feeders.

Load Transfer between Feeders

Voltage is adequate with load transfer between the existing feeders with the existing peak demand for all feeders except when load is transferred from feeder C to F. The model estimates the voltage decreases to approximately 116 volts when load is transferred from feeder C to F. The low voltage occurs at the Twin Lake mobile park location. The voltage increases by approximately 3 volts if the No. 2 ACSR on feeder C is replaced with 397 ACSR conductor. A project is included in this plan to upgrade this portion of the feeders and other feeders that have smaller conductor. The following shows the voltage drop and feeder exit amp loading during load transfer with the 10 year peak demand forecast.

Table 27 Feeder Loading with Load Transfer

Fdr out	Fdr Transfer	Vdrop	Amps	Location
A	E	8.0	339	Ashby, Tibbitts Rd
B	D	8.0	396	Summit City area
C	F	9.6	448	Twin Lakes Mobile Park
D	B	8.9	395	Lake Blvd
E	A	3.8	330	Vallecito St.
F	A	7.2	363	Hardenbrook Ave.

Notes for the above table:

- Fdr out – feeder with recloser opened at Central Valley substation
- Fdr transfer – feeder load transferred to the transfer feeder
- Vdrop –highest voltage drop (120 volt basis) on the re-configured feeder with the load transferred from the adjacent feeder
- Amps – highest peak amps on feeder exit with combined load
- Monitor load on Feeder A with load transfer from E due to 4/0 ACSR overhead conductor section after 750 AL underground with maximum load limit of 320 amps for 4/0 ACSR

The feeder exits consist of 750 AL underground cable. The capacity of the cable is 430 amps so the feeder F cable exit from the substation could be overloaded when load is transferred from feeder C to F. The feeder F exit load decreases to 427 amps if a 1200 kVAR capacitor is installed on feeder C near the Mt. Gate development when load is transferred from feeder C to F. This is the least cost option to reduce the possible feeder exit overload. The addition of a capacitor bank on feeder C should be reviewed after the load develops in the Mt. Gate area.

The above provides information on feeder loading for load transfer options that were selected to reduce the voltage drop and overloading of feeder exits. There are some switching options that could overload feeder cable and cause excessive voltage drops. For example, the model predicts a low voltage and feeder overloading condition when load is transferred from feeder C to B with the 10-year load forecast. The model predicts a low voltage of 104 volts at the Twin Lakes mobile park. The model predicts a peak demand of 662 amps for feeder B when the feeder C load is transferred to B. The voltage increases to 116 volts and the feeder loading decreases to 577 amps with the project to upgrade the conductor from No. 2 to 397 on feeder B. The feeder loading of 577 amps exceeds the capacity of the 750 AL underground so this switching option should not be done during peak load periods. Shasta Lake should review all switching options and prepare load transfer procedures to avoid overloading feeders when load is transferred during peak loading periods.

The main feeders with No. 2 ACSR could have higher than normal voltage drops and overloads when load is transferred between feeders. These sections of No. 2 should be replaced with 397 ACSR conductor to reduce the voltage drop and eliminate the possibility of conductor burn down during load transfer periods. Projects are identified in this plan to replace the small No. 2 feeder conductor with 397 conductor.

Mt. Gate Development

The Mt. Gate Development is planned in the northeast area of the City of Shasta Lake. The development consists of residential and commercial properties. The initial development plan is for 200 homes and a strip mall. The future development could include 3000 homes.

The following is a load forecast for the initial development and maximum demand with the development completely filled with housing and commercial strip malls.

Table 28 Mt. Gate Load Forecast

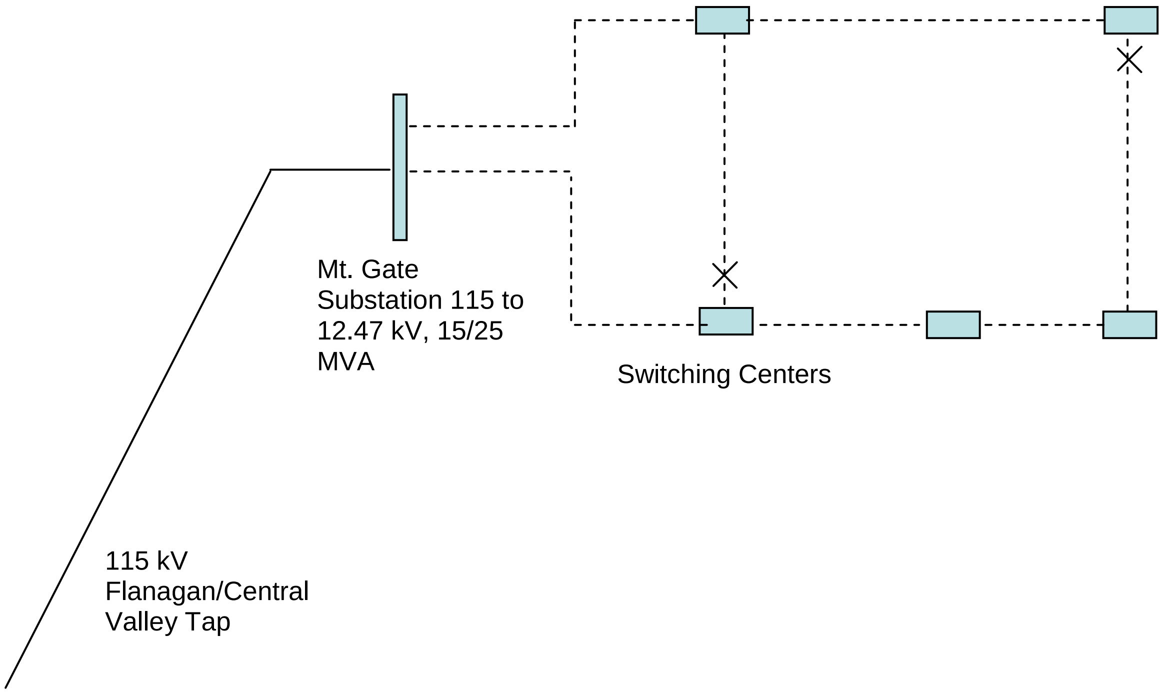
Description	Qty.	kW ea	kW total
Initial Housing	200	4.5	900
Initial Commercial strip malls	1	500	500
Total Initial Demand			1,400
Future Housing	3000	4.5	13,500
Future Commercial strip malls	10	500	5,000
Total Future Maximum Demand			18,500

The demand is estimated to range from 1.4 to 18.5 MW over a 10 to 30 year period. The options to provide service to the area include installing a new transmission line and substation and serving the load from the existing Central Valley substation. The preferred location for the new substation identified by Shasta Lake staff is on the west side of the development in the center.

A new substation would require 3.5 miles of 115 kV transmission line tap from the Flanagan/Central Valley 115 kV line. The line would be installed near the existing Union Pacific Railroad.

The following is a one-line diagram for the new substation and distribution for the development.

Figure 3 One-Line Diagram Mt. Gate Development – Substation Option



The following is an estimate of the plan to serve the area with a new substation.

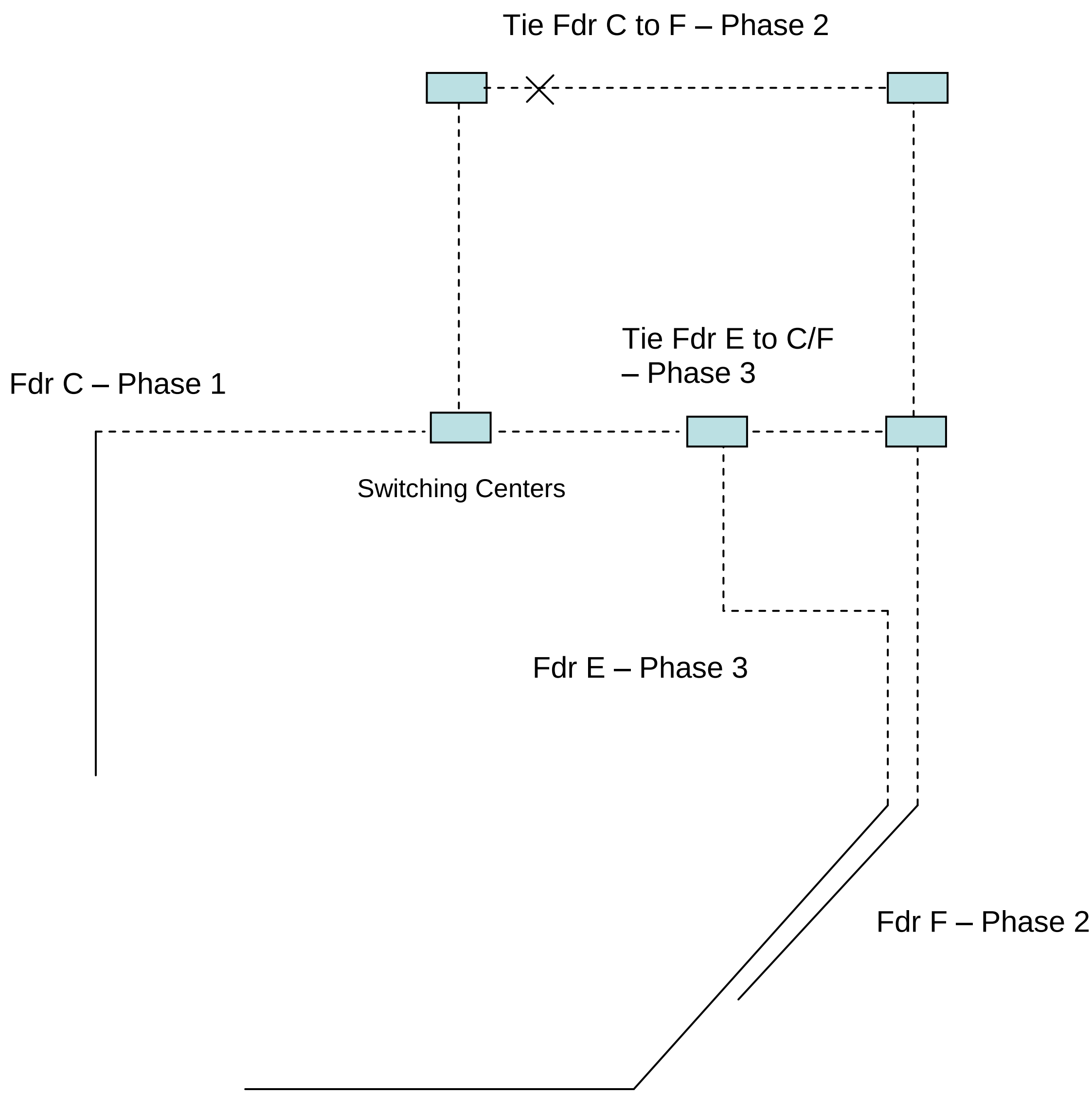
Table 29 Cost Estimate for Substation for Mt. Gate Development

Description	Ft/Mi/Unit	Cost/Mi/Unit	Cost	Year	PV
15 MVA Substation 2 feeders	1	$1,600,000	$1,600,000	2012	$1,372,000
New Feeders from Substation	8500	$50	$425,000	2012	$364,000
Transmission from Flanagan/CV	3.5	$198,000	$693,000	2012	$594,000
Distribution Losses					$498,755
Transformer Losses substation					$175,000
Total Cost			$2,718,000		$3,004,000

The above costs include estimated costs for land, engineering and environmental activities. These costs can vary so the City should obtain updated costs before the development is expected to start construction. The other option is to serve the new load from the existing Central Valley substation. Phase 1 is the initial construction to serve the development and consists of installing a main underground feeder from the overhead feeder C located at the northern end of Mussel Shoals Ave. Phase 2 is the second stage of construction to provide a back-up to feeder C for reliability purposes. Phase 2 consists of upgrading Feeder F along Cascade Blvd. to 397 ACSR and extending an underground feeder from the upgraded line to the development with a tie to Feeder C. This would occur when the demand of the development is approximately 500 kW. Phase 3 of the project consists of installing a third feeder to the development when the load exceeds approximately 1.8 to 2 MW to have adequate voltage when one of the feeders is out of service. The third feeder to be extended in this plan is feeder E.

The following is a one-line diagram showing the plan to serve the development with the existing distribution.

Figure 4 One-Line Diagram Mt. Gate Development – Distribution Option



The following is the cost estimate of the plan to serve the area with feeders from the Central Valley substation.

Table 30 Cost Estimate to Extend New Feeders for Mt. Gate Development

Description	Feet/Unit	Cost/Ft.	Cost	Year	PV	Phase
Feeder C to Mt. Gate 750 AL UG	6,000	$50	$300,000	2012	$257,000	1
Replace 3-ph 2 with 3-ph 397 Fdr F	2000	$50	$100,000	2014	$74,000	2
Feeder F to Mt. Gate 750 AL UG	12,000	$50	$600,000	2014	$441,000	2
Tie Feeder C to F - Mt. Gate	1000	$50	$50,000	2014	$37,000	2
Feeder E to Mt. Gate 750 AL UG	15,000	$50	$750,000	2018	$405,000	3
Tie Feeder E to F - Mt. Gate	1000	$50	$50,000	2018	$27,000	3
Cost of losses estimate					$607,000	
Total Cost			$1,800,000		$1,848,000	

The least cost option is to use the existing Central Valley substation to serve the load. The City of Shasta Lake should plan to serve the initial load with the existing feeders. If the load is expected to exceed 1.8 to 2 MW, then the plan should be reviewed for a new substation. This should be done prior to beginning the Phase 3 distribution projects. The majority of costs for Phase 1 and 2 projects is the distribution within the development so there will not be significant additional costs if the substation option is implemented after the Phase 1 and 2 construction is completed. The City may want to purchase land for a future substation if required due to load growth or require the developer to provide land for the substation.

Further studies should be completed in the future when more information on the timing and size of load is available.

6 RECOMMENDED PLAN

6.1 General

This section provides the recommended additions and improvements to the distribution and transmission facilities over the next 10 years. All improvements are proposed in order to accomplish the following: improve voltage, permit better load balance, improve system reliability, improve system capability and reduce energy losses.

6.2 New Transmission Lines

No new transmission lines are recommended unless the substation is required for the Mt. Gate development.

6.3 Transmission Line Upgrades

There are no changes recommended for the existing transmission lines. The existing lines are adequate to serve the load and are in good condition.

6.4 Substations Additions and Upgrades

Some changes to the existing substations are recommended. Some of the relays for line and transformer protection are older electronic equipment. This relaying equipment should be replaced with digital relays to provide information on breaker operations. The control house at Central Valley doesn't have sufficient space for new relays and equipment so the control house should be expanded. The regulators for the Central Valley No. 1 transformer are recommended to be replaced due to the results of the gas and oil tests showing that the regulator could fail. The Central Valley No. 1 transformer should have at least ten years remaining; however, the engineering and operations staff may decide to replace during this ten year plan due to operating concerns or the possibility of future oil and gas tests that show concerns with the remaining life of the transformer. If the CV1 transformer will be replaced at the beginning of this ten year plan, then the CV1 regulators should be removed when the CV1 transformer is replaced with a new transformer with load tap changing regulation.

6.5 Distribution lines of substations

The following distribution projects by substation are based on improving voltage, capacity and reliability by adding and upgrading feeder ties and other distribution improvements. The improvements are based on meeting the future load growth for the next ten years.

Some of the projects are recommended to improve the backup capability of feeder ties. Some of the existing ties consist of No. 2 ACSR. This conductor is adequate for the normal loads but the voltage drop is excessive during conditions when load is transferred from feeder ties.

The following is a summary of the projects recommended for the distribution lines of the substations.

Table 31 Distribution Projects Details

Project Description	Fdr	Code	Type	Location
Tie Feeder (750 UG) C to F	C	205	G	Mt. Gate Development
Back-feed overhead tie No. 2	C	208	M	Twin Lakes Mobile Homes
Tie Feeder (750 UG) E to C and F	E	210	G	Mt. Gate Development
Replace 3-ph 2 with 3-ph 397	B	305	M	Shasta Dam Blvd N/O S-431 to SB-109 along Rouge Rd
Feeder C to Mt. Gate 750 AL UG	C	310	G	Mt. Gate Development
Replace 3-ph 2 UG with new UG	C	320	M	Twin Lakes Mobile Homes
Replace 1-ph 2 UG with new UG	C	325	M	Twin Lakes Mobile Homes
Feeder E to Mt. Gate 3-ph 397	E	330	G	Mt. Gate Development
Feeder E to Mt. Gate 750 AL UG	E	335	G	Mt. Gate Development
Replace 3-ph 2 with 3-ph 750 AL UG	E	345	M	Freeway crossing S513
Feeder F to Mt. Gate 750 AL UG	F	350	G	Mt. Gate Development
Replace 3-ph 2 with 3-ph 397	F	355	M	Cascade Blvd. to SB-Temp
Replace 3-ph 2 with 3-ph 397	F	360	M	S-315 to S309 along Cascade Blvd.
Replace 3-ph 2 with 3-ph 750 AL UG	F	365	M	Freeway crossing Cascade Blvd to Virginia Ave.

Notes for the above table:

- Fdr – substation and feeder number feeding the line to be upgraded
- Code – project identification number used on the project maps to show the proposed project
- Type – Reason for project where G is for growth driven (added load) and M is to reduce maintenance costs and improve reliability
- Project 360 includes a portion of underground 750 AL for the freeway crossing

The following is information on the specific projects by substation feeder area. The projects are for major 3-phase distribution lines. The long range plan includes a budget amount for minor projects (Code 607 System Improvements) that could be used to upgrade some 1-phase distribution lines and other minor projects. Shasta Lake staff should identify the specific minor projects in the annual construction budget based on age, condition, loading and reliability.

6.5.1 Central Valley Feeder A Distribution

The load flow program shows no voltage concerns.

There are no projects proposed for this area.

6.5.2 Central Valley Feeder B Distribution

The load flow program shows no voltage concerns.

A project is proposed (305) to replace 3-ph No. 2 with 3-ph 397 due to age and condition and to improve the voltage. The feeder is located along Rouge Rd.

6.5.3 Central Valley Feeder C Distribution

The load flow program shows no voltage concerns.

A project is proposed (208) to install a No. 2 overhead 3-ph tie to feeder B to provide back-up for the Twin Lakes Mobile Homes. This back-up will be used to provide an additional source to the area when the existing underground cable is replaced. The tie feeder will improve the reliability by providing a loop to the area.

A project is proposed (310) to extend 750 AL UG to serve the proposed Mt. Gate development. The underground will be extended off the existing 3-ph 397 feeder located near the end of Mussel Shoals Ave. The feeder will connect to pad-mount switchgear with tap fuses for the pad-mounted transformers for the development. This feeder will serve the initial load for the development.

A project is proposed (205) to install a 750 AL UG tie to feeder F to provide back-up capacity for the Mt. Gate development and to serve a portion of the development load as the load increases. The tie feeder will improve the reliability by providing an underground loop to the development so the area can continue to have power when one of the feeders is removed from service. The Mt. Gate development will initially be served from Feeder C and Feeder F.

6.5.4 Central Valley Feeder D Distribution

The load flow program shows no voltage concerns.

There are no projects proposed for this area.

6.5.5 Central Valley Feeder E Distribution

The load flow program shows no voltage concerns.

A project is proposed (330) to extend 3-ph 397 overhead for additional feeder capacity to serve the proposed Mt. Gate development. The overhead will be extended off the existing 3-ph 397 feeder located near Vallecito St. The feeder will connect to an underground feeder that connects to pad-mount switchgear with tap fuses for the pad-mounted transformers for the development. This feeder will be the third feeder for the development and is required when the demand in the development is approximately 1.5

to 1.8 MW. If the demand is expected to be greater than 2 MW over the ten year period, then the option for the substation to serve the development should be reviewed. The feeder E extension project is not required if the Mt. Gate substation is installed.

A project is proposed (335) to extend 750 AL UG to serve the proposed Mt. Gate development. The underground will be extended off the proposed 3-ph 397 feeder extension from Vallecito St (Project 330). The feeder E extension project is not required if the Mt. Gate substation is installed.

A project is proposed (210) to install a 750 AL UG tie to feeders C and F in the Mt. Gate development to provide back-up capacity and to serve a portion of the load for the Mt. Gate development. The tie feeder will improve the reliability by providing an underground loop to the development so the area can continue to have power when one of the feeders is removed from service. The feeder tie should be installed when the demand for the development is approximately 1.5 to 1.8 MW. If the demand is expected to be greater than 2 MW over the ten year period, then the option for the substation to serve the development should be reviewed.

A project is proposed (345) to replace 3-ph No. 2 with 3-ph 750 AL UG for a freeway crossing near Deer Creek Ave. due to age and condition and to improve the voltage.

6.5.6 Central Valley Feeder F Distribution

The load flow program shows no voltage concerns.

A project is proposed (350) to extend 750 AL UG to serve the proposed Mt. Gate development. The underground will be extended from the proposed upgraded portion of feeder F (355) near Cascade Blvd. Feeders F and C will be the initial feeders for the Mt. Gate development.

A project is proposed (355) to replace 3-ph No. 2 with 3-ph 397 due to age and condition and to improve the voltage and to provide a main feeder for the Mt. Gate development. The feeder is located near Cascade Blvd.

A project is proposed (360) to replace 3-ph No. 2 with 3-ph 397 due to age and condition and to improve the voltage. This project includes replacing a freeway crossing with 750 AL UG feeder cable. The feeder is located near Twin View Blvd.

A project is proposed (365) to replace 3-ph No. 2 with 3-ph 750 AL UG for a freeway crossing between Cascade Boulevard and Virginia Ave. due to age and condition and to improve the voltage.

6.6 Service Extensions to New Customers

Shasta Lake expects to install approximately 30 to 50 new services each year based on the number of services installed over the past years and depending on the growth at the

Mt. Gate development. This corresponds to a growth rate of approximately 0.5 to 1.0% each year which is similar to the estimated growth in consumers from the load forecast data.

6.7 Service Upgrades

Shasta Lake expects to upgrade approximately 20 services each year. The estimated quantity and costs are based on the actual historical quantity and costs over the past few years.

6.8 Pole Replacements and System Improvements

Shasta Lake plans to continue to inspect poles frequently to insure the lines are in good condition as advised by the State of California General Order No. 95, rule 31.2. Poles will need to be replaced due to system improvement projects. The annual quantity of poles estimated to be replaced in the next ten years is based on the annual quantity budgeted for replacement in the previous budgets.

6.9 Overhead Single-Phase and Cable Replacements

The 3-phase and 1-phase branch lines that are 40 years old or greater are nearing the end of their useful life. The older single-phase lines include conductor types of No. 6 copper. The 10 year plan provides a cost estimate for system improvement minor projects that can be used to replace a portion of the older distribution lines with No. 2 or 1/0 ACSR.

Shasta Lake has replaced the majority of underground cable that has failed due to corrosion or insulation failures. There may be some projects to replace cable that is damaged from dig-ins or lightning. The 10 year plan provides a cost estimate for system improvement minor projects that can be used to replace the underground cable that fails.

6.10 Fused Cutouts and Arresters

Shasta Lake purchases pole-mounted distribution transformers with internal high voltage fuses. The fault current rating of these protective links is 3500 amps based on information from the transformer supplier ERMCO. The fault current could exceed this level so the back-up protection device such as a branch fuse or recloser would clear a fault caused by the failure of a pole-mounted transformer. The existing transformers are installed without lightning arresters.

The transformers should be installed with fused cutouts and lightning arresters to improve the reliability. There could be additional equipment failures because of the possibility of a failure to the weak link fuse due to the high fault current. A fused cutout has an interrupting rating of 7,100 amps symmetrical and 10,000 amps asymmetrical for multiple shot rating. The one-shot rating is 8,600 amps symmetrical and 12,000 amps asymmetrical for the one-shot rating.

Shasta Lake has reported that the evidence of transformer failures due to fault currents greater than the internal fuse interrupting ratings has been rare over the years. This could be due to lower fault currents caused by the impedance from transformer internal faults. Some utilities are concerned about the fault currents that are higher than the interrupting ratings of the fuses and are using or considering the use of current-limiting fuses.

The high fault current will be greater than the cut-out rating for cut-outs located within 0.8 miles from the substation as measured by the length of distribution line. Shasta Lake should consider installing current limiting fuses for equipment and branch feeder protection within the 0.8 mile feeder length from the substation so the equipment can successfully interrupt the available fault current.

Current-limiting fuses can be used for transformer protection in high fault-current areas to provide protection against violent transformer failures such as a cover blowing off the unit when a fault occurs. The following table provides recommendations for current limiting fuses when the line-to-ground fault at the high voltage terminals of the transformer exceeds the values shown.

Table 32 Maximum Fault Current for Distribution Transformers

Transformer	Current
Overhead transformers	8,000 amps
Under-oil expulsion up to 8.3 kV $_{LG}$	3,500 amps
Under-oil expulsion up to 14.4 kV $_{LG}$	2,500 amps

Notes for the above table:

- Current – RMS symmetrical
- Maximum ½ to 1 cycle fault current rating on distribution transformers based on the test in ANSI C57.12.20-1988
- Under-oil expulsion – bay-o-net fuses in padmounted transformers

The fault current on the Shasta Lake distribution could exceed the values shown in the table. Shasta Lake should consider installing current limiting fuses for transformer protection at locations where the fault current exceeds the value shown in the above table.

Shasta Lake should review the options of installing cutouts and arresters for the distribution transformers so the transformers can be safely isolated with the cutouts. The arresters should reduce the number of transformer failures due to lightning.

6.11 Reclosers

Shasta Lake has field reclosers that have electronic controls. The information from the controls is useful for planning purposes and for investigation of outages. The information is required to be obtained in the field. Communication equipment is recommended to be at the field recloser locations so this information can be obtained from the office. This will be useful to automatically store voltage and current data from the reclosers and obtain information to assist in restoring outages.

6.12 Capacitors

There is no need for additional capacitors at this time because the power factor is above 0.95. The average power factor from SCADA data for July and August of 2008 was an average of 0.98. There could be a need for additional capacitors if the load develops in the Mt. Gate area.

There are times when the capacitors should be switched on or off because of changes in the load. This can be accomplished with capacitor switches and controls. There's a advantage to having remote operation of the capacitor banks so the capacitors could be switched on or off during load transfer periods or at other times when the power factor ca can be improved. This plan includes capacitor switches and controls in the budget so the load information at capacitors locations can be viewed from the office and the switches can be controlled from the office.

6.13 Voltage Regulators

There is no need for field voltage regulators because voltage is adequate during normal and load transfer periods except for situations mentioned previously where the voltage can be improved by installing capacitors or upgrading the feeder with larger conductor.

6.14 Advanced Metering Infrastructure

Shasta Lake has installed advanced metering infrastructure (AMI). AMI can be used to improve reliability due to the features such as a "blink count" that is included with most AMI products. This feature can help determine the cause of momentary outages. AMI products include a feature to calculate the loading on transformers so outages from overloaded equipment can be avoided. Data from the AMI can be used for planning purposes. Shasta Lake is reviewing options for outage management software (OMS) to track the quantity and duration of outages.

7 COST ESTIMATE SUMMARY

The following are the estimated cost for the projects and equipment additions over the ten year planning period.

7.1 Unit Cost Estimates

The following is a summary of the unit costs used for estimating the cost of the projects. This is based on estimates from Shasta Lake spreadsheets and actual costs for distribution projects from other electric utilities. The cost for overhead conductor is for new tie lines or conversions from single to multi-phase lines. The costs include the removal of existing distribution lines and the engineering and staking costs.

Table 33: Unit Cost Estimates

Description	Cost 2011
No. 2 acsr-1p OH	$20
No. 2 acsr-3p OH	$40
397.5 acsr-3p OH	$50
No. 2 UG-1p conduit	$20
No. 2 UG-3p conduit	$30
750 UG-3p conduit	$50
750 UG-3p conduit drill	$80
Capacitor bank	$5,500
Capacitor bank SCADA	$5,000
Meter - 1-ph	$130
Meter - 3-ph	$600
AMI Communication	$25,000
Pole - ordinary replacement 606	$3,000
System improvement 607	$4,000
Fused cutout/arrester	$600
Recloser 3-ph SCADA	$5,000
Recloser 3-ph	$28,000
Vreg 1ph 100amp	$14,300
Vreg 1ph 150amp	$17,600
Switch OH 3ph	$5,000
Switchgear Padmount UG 3ph	$20,000
Transformer OH	$2,500
Transformer PM residential	$3,500
Transformer PM commercial	$5,500
Extension - OH unit	$6,000
Extension - UG unit	$6,000
Security light	$500
Upgrade service	$3,500
Substation - 15 MVA 12.47 kV 2 feeders	$1,600,000
25 MVA Substation Transformer	$925,000
Transmission 115 kV/mile	$198,000

Notes for the above table:

- Estimated costs are in 2010 dollars and include material and labor costs
- Unit costs are cost/unit, cost/ft. or cost/mile
- Extension – average for cost for new service extensions
- UG costs assume trenching or plowing so costs will be higher for directional boring
- Substation costs do not include land and environmental costs
- UG main and branch feeder estimates from Shasta Lake contribution fee calculation and OH main feeder estimates from PowerPlus

7.2 Distribution Projects Cost Estimate

The following is a summary of the estimated costs for distribution projects over the ten year period.

Table 34 Distribution Project Cost Estimate

Project Description	Cost	Fdr	Feet	Type	Code	Location
Tie Feeder (750 UG) C to F	$50,000	C	1,000	G	205	Mt. Gate Development
Back-feed overhead tie No. 2	$56,000	C	1,400	M	208	Twin Lakes Mobile Homes
Tie Feeder (750 UG) E to C and F	$50,000	E	1,000	G	210	Mt. Gate Development
Replace 3-ph 2 with 3-ph 397	$175,000	B	3,500	M	305	Shasta Dam Blvd N/O S-431 to SB-109 along Rouge Rd
Feeder C to Mt. Gate 750 AL UG	$300,000	C	6,000	G	310	Mt. Gate Development
Replace 3-ph 2 UG with new UG	$111,000	C	3,700	M	320	Twin Lakes Mobile Homes
Replace 1-ph 2 UG with new UG	$66,000	C	3,300	M	325	Twin Lakes Mobile Homes
Feeder E to Mt. Gate 3-ph 397	$350,000	E	7,000	G	330	Mt. Gate Development
Feeder E to Mt. Gate 750 AL UG	$400,000	E	8,000	G	335	Mt. Gate Development
Replace 3-ph 2 with 3-ph 750 AL UG	$40,000	E	500	M	345	Freeway crossing S513
Feeder F to Mt. Gate 750 AL UG	$600,000	F	12,000	G	350	Mt. Gate Development
Replace 3-ph 2 with 3-ph 397	$100,000	F	2,000	M	355	Cascade Blvd. to SB-Temp
Replace 3-ph 2 with 3-ph 397	$85,000	F	1,400	M	360	Crystal St. to S309 along Twin View Blvd.
Replace 3-ph 2 with 3-ph 750 AL UG	$40,000	F	500	M	365	Freeway crossing Cascade Blvd to Virginia Ave.
Total - Projects	$2,423,000		51,300			
Total Projects - Tie Lines	$156,000		3,400			
Total Project Improvements	$2,267,000		47,900			

Notes for the above table:

- Fdr – substation and feeder number feeding the line to be upgraded
- Feet – distance in feet of line to be installed or upgraded
- Code – project identification number used on the project maps to show the proposed project
- Project 360 includes an underground portion of 750 AL for the freeway crossing
- Type – Reason for project where G is for growth driven (added load) and M is to reduce maintenance costs and improve reliability

7.3 Substation and Transmission Projects Cost Estimate

The following is a summary of the estimated costs for substation and transmission projects over the ten year period.

Table 35 Substation Upgrades Cost Estimate

Project - Improvements	Cost
Substation Relaying Upgrade	$400,000
Central Valley Control House Expansion	$300,000
Central Valley Transformer #1 Replace	$925,000
Central Valley Voltage Regulator	$138,000
Total	$1,763,000

Notes for the above table:

- Central Valley (CV) voltage regulator should be retired if the CV1 transformer will be replaced with a new transformer with LTC near the beginning of the ten year planning period

The Mt. Gate substation is not included in the ten year plan at this time. The need for this substation should be reviewed if the Mt. Gate development peak demand is 1.5 to 2 MW or greater. The cost for replacing the Central Valley CV1 transformer is included in the cost estimate. Shasta Lake can replace this transformer during the ten year period or defer the replacement depending on the availability of funds. Shasta Lake engineering staff may decide to replace the transformer during this ten year period due to operating concerns and based on the results of future oil and gas tests.

There are no transmission projects recommended over the ten year period. A transmission line will be required if the Mt. Gate substation is installed as discussed previously.

7.4 Cost Estimate for Ten-Year Plan

The following is a summary of an estimate of equipment to install and the capital expenditures for Shasta Lake for various categories of projects in 2011 dollars. Factors that may change the cost estimate or create new projects include the construction of roads that affect distribution lines, equipment failures resulting in numerous outages, load growth and the replacement of lines based on the age of the lines.

Table 36 Ten-Year Estimate of Equipment Quantity

Equipment	Code	Avg.	10-Yr
New Ext. oh qty.	102	10	100
New Ext. ug qty.	101	40	400
Tie Lines	200		0.6
Line improvements	300		9.7
Substations new	400		0
Substations upgrade	500		1
Transf. - oh - qty	601	50	500
Transf. - pm - qty	601	50	500
Meters - 1-ph qty.	601	50	500
Meters - 3-ph qty.	601	5	50
Upgrades qty.	602	10	100
Fused cutouts	603	50	500
Reclosers -3-ph qty.	603	0	2
Recloser SCADA	603	0	8
Voltage regs. - qty.	604	0	0
Cap. banks - qty	605	0	1
Cap. banks SCADA	605	1	10
Pole Replacement	606	40	400
System Improvements	607	20	200
Communication Equipment	615	0	1
Sec. Lights - qty.	702	10	100
Transmission New	800		0
Transmission Upgrade	1000		0

Table 37 Ten-Year Total Cost Summary

Equipment	Code	Units	Unit Cost	Total Cost
New Ext. - OH	102	100	$6,000	$600,000
New Ext. - UG	101	400	$6,000	$2,400,000
Tie Lines	200	0.8		$156,000
Line improvements	300	9.8		$2,267,000
Substations new	400	0	$1,600,000	$0
Substation upgrades	500			$1,763,000
Transformers - oh	601	500	$2,500	$1,250,000
Transformers - pm	601	500	$3,500	$1,750,000
Meters - 1-ph	601	500	$130	$65,000
Meters - 3-ph	601	50	$600	$30,000
Upgrades	602	100	$3,500	$350,000
Fused Cutouts	603	500	$600	$300,000
Recloser	603	2	$28,000	$56,000
Recloser SCADA	603	8	$5,000	$40,000
Voltage regs.	604	0	$14,300	$0
Cap. banks	605	1	$5,500	$5,500
Cap. Bank SCADA	605	10	$5,000	$50,000
Ord. Replacement	606	400	$3,000	$1,200,000
SI Poles replace	607	200	$4,000	$800,000
Communication Equipment	615	1	$25,000	$25,000
Security Lights	702	100	$500	$50,000
Trans. - new - miles	800	0		$0
Trans. - rebuild - mi.	1000	0		$0
Total				$13,157,500

8 CONCLUSION

This plan provides a guide for future system development. The plan will be used by Shasta Lake to develop their annual construction budgets. Changes in the load growth or system conditions may require some departure from the proposed plan in this report.

9 SOURCES USED IN THIS REPORT

National Rural Electric Cooperative Association, “Distribution System Loss Management Manual,” 1991

National Rural Electric Cooperative Association, “Underground Distribution System Design and Installation Guide”, 1993

RUS Bulleting 1730-1, “Electric System Operation and Maintenance (O&M)”

RUS Bulleting 1724D-101A, “Electric System Long-Range Planning Guide”

RUS Bulleting 1724D-101B, “System Planning Guide, Construction Work Plan”

RUS Bulleting 1724D-102, “Considerations for Replacing Storm-Damaged Conductors”, July 2005

RUS Bulleting 1730A-119, “Interruption Reporting and Service Continuity Objectives for Electric Distribution Systems”

H. Lee Willis, “Power Distribution Planning Reference Book,” New York, 2004

Cooper Power Systems, “Analysis of Distribution System Reliability and Outage Rates,” December 1987

CRN project 96-5 final report, “Ground Fault Impedance Values for System Protection”, August 1997

City of Shasta Lake Coordination Study, Draft Report, February 2006

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T. A. Short, “Electric Power Distribution Handbook”, 2004

William H. Bartley, P.E., “Analysis of Transformer Failures”, 2003

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Resource Management International Inc., “Shasta Dam Area Public Utility District Electric System Master Plan”, January 1986

Economic Sciences Corporation, load forecast spreadsheets, 2007

10 APPENDIX

10.1 System Load, Consumer Data and Losses

Table 38: Peak Demand and Energy Use Central Valley Substation

Year	MWH sold	kW	Cons.	kW/ cons	kWh/ cons	MWH Increase
2005	67,767	18,500	4,426	4.2	15,311	
2006	71,265	19,300	4,440	4.3	16,051	5.2%
2007	71,205	18,800	4,463	4.2	15,954	-0.1%
2008	71,759	19,500	4,486	4.3	15,996	0.8%
2009	71,546	19,600	4,470	4.4	16,006	-0.3%
Average						1.4%

Notes for the above table:

- MWh sold – annual energy sold for all consumers
- kW – substation peak demand
- Consumers – average number of consumers by year
- kWh each – average yearly energy use for each consumer
- kW/cons – peak kW use for each consumer

Table 39 Energy Purchase, Sales and Losses Central Valley 2009

Class	MWH
Residential	34,143
Multi-family	3,470
Civic	357
Mobile Home	2,640
Commercial	7,033
Ind-small	20,127
Schools	1,661
Government	2,116
Total	71,546
MWH purchase	74,430
Loss MWH	2,884
Loss%	3.9%

The following provides the estimated losses for distribution transformers.

Table 40 Distribution Transformer Loss Estimate

kVA rating	Core loss watts %	Load loss watts %	Qty.	Core Loss kW	Load Loss kW	Annual Losses - kWh	Total kVA
5	0.40%	1.10%	3	0	0	708	15
7.5	0.35%	1.10%	0	-	-	-	0
10	0.28%	1.10%	186	5	7	68,244	1860
15	0.25%	1.10%	521	20	31	266,198	7815
25	0.20%	1.10%	580	29	57	430,396	14500
37.5	0.20%	1.10%	186	14	28	207,035	6975
45	0.20%	1.10%	0	-	-	-	0
50	0.20%	1.10%	202	20	40	299,793	10100
75	0.15%	1.10%	47	5	14	89,191	3525
100	0.15%	1.10%	12	2	5	30,363	1200
112.5	0.15%	1.10%	4	1	2	11,386	450
150	0.15%	1.10%	1	0	1	3,795	150
167	0.15%	1.10%	7	2	5	29,579	1169
225	0.15%	1.10%	3	1	3	17,079	675
300	0.15%	1.10%	5	2	6	37,954	1500
333	0.15%	1.10%	0	-	-	-	0
500	0.15%	1.10%	24	18	48	303,630	12000
750	0.15%	1.10%	4	5	12	75,907	3000
1000	0.15%	1.10%	1	2	4	25,302	1000
1500	0.15%	1.10%	3	7	18	113,861	4500
2000	0.15%	1.10%	2	6	16	101,210	4000
2500	0.15%	1.10%	0	-	-	-	0
Totals			1,791			2,111,634	74,434

Notes for the above table:

- Qty. – quantity of distribution transformers in-service based on Shasta Lake transformer data
- Ratio of connected kVA to peak demand is 3.8. This ratio is within the RUS guideline range of 2 to 4 from RUS Bulletin 1730-1. Shasta Lake should size transformers so the peak demand on the transformer is 70 to 80% of the nameplate capacity.

10.2 Conductor Loading Tables

The following is the recommended maximum load in amps for various overhead conductors.

Table 41 Overhead Conductor Rating in Amps

Size	Amps
477 acsr	550
397 acsr	490
267 acsr	380
4/0 acsr	320
3/0 acsr	280
2/0 acsr	240
1/0 acsr	200
2 acsr	150
4 acsr	110
4/0 cu	400
2/0 cu	290
1/0 cu	250
2 cu	180
4 cu	140
6 cu	100
8 cu	70
2A CW	200
4A CW	150
6A CW	110
8A CW	80

Table 42 Overhead Conductor Constants for Amp Ratings

	Deg F	Deg C
Conductor temp.	167	75
Ambient temp.	115	46
Wind speed	2	ft./sec.
Emissivity	0.5	

Table 43 Overhead Secondary Amp Rating

Size	Amps-TRX	Amps-QRX	Amps-DPX	Amps-Single
2 AL	150	135	150	180
1/0 AL	205	180		240
4/0 AL	315	275		370

Notes for the above table:

- TRX – triplex
- QRX – quadruplex
- DPX – duplex
- Ambient temperature – 104 Degrees C
- De-rate by 10% for ambient temperatures of 115 degrees F

Table 44 Underground Secondary Amp Rating

Cable	Riser	DB-75%	DB-100%	Conduit-1	Conduit-2
6 AL UG	58	101	92	82	77
1/0 AL UG	139	218	198	178	166
4/0 AL UG	217	320	291	262	243
500 CU UG	477	651	592	531	488

Notes for the above table:

- DB-75% - direct buried 75% load factor
- DB-100% - direct buried 100% load factor
- Conduit – 1 set of cables in conduit
- Conduit – 2 – 2 sets of cable in conduit
- Riser – ambient temperature of 104 degrees F, de-rate by 10% for ambient temperature of 115 degrees F

The following is the recommended maximum load in amps for various underground conductors.

Table 45 Underground 15 kV Cable Rating in Amps

15 kV	Amps
2 al ug - 1-ph	90
1 al ug - 1-ph	100
1/0 al ug - 1-ph	120
1/0 al ug	130
2/0 al ug	150
3/0 al ug	170
4/0 al ug	200
250 al ug	220
350 al ug	270
500 al ug	340
750 al ug	430
1000 al ug	510
2 cu ug	130
1 cu ug	150
1/0 cu ug	170
2/0 cu ug	200
3/0 cu ug	230
4/0 cu ug	260
250 cu ug	290
350 cu ug	350
500 cu ug	420
750 cu ug	520
1000 cu ug	600

Notes for the above table:

- Cables are three-phase unless indicated otherwise
- Amp rating for cables in riser – de-rating required for multiple sets of cables in duct
- Cable temperature – 90 degrees Celsius
- Ambient outdoor temperature – 50 degrees Celsius (122 degrees F)

The following is the maximum current on overhead and underground conductors to prevent damage to the conductors.

Table 46 Maximum Current Annealing of No. 2 ACSR

Amps	Sec
1,100	15
3,000	2
4,200	1
6,000	0.5
9,500	0.2

Table 47 Maximum Current Annealing of 397 ACSR

Amps	Sec
6,600	15
18,000	2
25,400	1
36,000	0.5
56,800	0.2

Table 48 Maximum Current Insulation Damage No. 2 AL Cable

Amps	Sec
800	15
2,200	2
3,100	1
4,400	0.5
6,900	0.2

Table 49 Maximum Current Insulation Damage 750 AL Cable

Amps	Sec
9,000	15
24,800	2
35,000	1
49,000	0.5
78,000	0.2

10.3 Cost Estimate for Central Valley No. 1 Transformer

Cost Estimate for Transformer Re-Winding

Corporate Headquarters
823 Fairview Road Wytheville Va 24382
Phone 276-620-0617
Fax 276-228-7953

Transformer Services
1776 Constitution Ave Louisville OH 44641
Email: **pdooley@mtctransformers.com**

QUOTATION

Date: July 21, 2010

Quote Reference Number:PowerPlus072110

To: Power Plus Engineering
Attn: Tom Nigon
Ref: email 7/16/10 Rewind 25 MVA
Email: tnigon@powerpluseng.com

Technical Description

Quantity 1

Liquid Filled Transformer— Rewind new coils
25 MVA OA Taps: + - 2 X 2.5%
3 Phase 60 Hertz Impedance: 7.5 %
55/65 °C Temperature Rise
115,000 V Delta Primary 450 KVBIL
12470/7200 V Wye Secondary 110 KVBIL
Copper Conductor
Existing Tank and Radiators
Existing Gauges and Accessories
Existing Bushings
New oil 6800 gallons not included in quote (Assume customer to supply for field filling)
New Nameplate

Scope of Work

Inspection & Analysis – Upon receipt of the failed unit, MTC will perform incoming electrical tests, untank the core and coil assembly, and conduct a visual inspection. Operational checks will be performed on all gauges, and accessories. An inspection report with a price for replacements if necessary will be provided No rewind, repair or replacements will be performed until the owner has reviewed the report and approved the work to proceed**.**

Rewind and repair—An engineering design will be done for the replacement coils utilizing today's technology and materials. New insulating material including core insulation will be used in the replacement of the existing coils. New fluid is not included. Assuming unit will be shipped without oil.

Transportation is not included in the base quote. MTC can obtain quotes for the transportation both ways and this adder can be quoted
See attached email for estimated freight from California to Louisville Ohio

UNIT PRICE........................$ 312,857

1. Any repair to accessories such as gauges, tap changer, bushings, fans will require an additional quote with a price increase on above price

2. Price includes full ANSI standard testing including Impulse temperature and sound tests are not included in the quoted price .

3. Any core damage will require a price addition to this quotation.

4. PCB report required prior to receipt of equipment at our plant

5. Leads and cable connections will be reused/replaced as necessary

6. Price does not include 6800 gallons of new oil

Freight not included in the quoted price (see email for estimate)

Shipment: 22-24 Weeks from receipt of unit at our plant
Freight: FOB Louisville, OH, Freight Prepay & Add
Price Policy per attached document
Payment Terms: Net 30 days
Warranty: MTC Transformers Standard 12 months from shipment

Email from Pat Dooley, MTC Transformers, 7/21/10

Tom -- Sorry for the delay on getting you the budget info you requested on this 25 KVA unit

Late Monday before I got the freight estimate and I was off on vacation yesterday

Attached is the quote based on the limited info

I have assumed the unit will be shipped to us without oil and we will ship back the same – customer to fill the unit with his oil after arrival

We have assumed the height of 14 FT 2 inches after removal of the bushings
Field work to remove the bushings and drain the oil and rigging are not included in the quoted price

There may be an additional freight charge to ship the bushings separate   ADD $5000 net estimate

Any questions call me

From: Chris Matney [mailto:cmatney@mtctransformers.com]
Sent: Monday, July 19, 2010 4:29 PM
To: 'Pat Dooley'; 'Robert Ganser'
Subject: RE: budget quote for 25 mva transformer re-wind

Freight of just the transformer is approximately $44,000 with permits EACH WAY using: 14.2' height, 12' length, 6' width at approx 70,000lbs

The height and weight are not exact and are approximate. An accurate number cannot be given until the dimensions and weights are verified.

Thank you,

Christopher Matney
Project Manager
MTC Transformers
1776 Constitution Ave.
Louisville, Ohio 44641
P. 330-871-2444
F. 330-871-2506
cmatney@mtctransformers.com

Cost Estimate for Regulator Replacement – Howard Industries

Email from Jeff Foxworth, Howard Industries, 7/13/10

Tom
This price is for budget purposes only. We look forward to providing a quote to you in the future.
833 KVA = $26000.00

Thanks,

Jeff Foxworth

Howard Industries
Sales Manager
601-422-1420
jfox@howard-ind.com

Cost Estimate for 25 MVA Transformer Replacement – Waukesha

Email from Barry Vaughn, Waukesha, 7/7/10

Tom,
The budgetary price for the below transformer is $805,000.00 (+ / - 15%) per unit. This is a budgetary price only. Price is based on shipment in the fourth quarter of 2010 or first quarter of 2011. Waukesha does not use silicon oil. We use FR-3 fluid (please see attached). the LTC will however contain standard transformer mineral oil.

Regards,

Barry Vaughn

Waukesha Electric Systems, Inc.
2701 U.S. Highway 117 South
Goldsboro North Carolina 27530
Phone: 919-580-3211
Cell: 919-394-7926
Fax: 919-580-3254

Cost Estimate for 25 MVA Transformer Replacement – Virginia Transformers

Email from Virginia Transformers, 7/26/10

Hi Tom,

I have attached your spec sheet along with some good budget numbers that will include freight to the job site. Please let me know if you have any questions.

Best regards,

Thomas Aikens
Sales Manager
Virginia Transformer
3770 Poleline Rd. Bldg. 37
Pocatello, Idaho 83201
800.377.0720 ext. 222
208.238.9810 fax

208.317.4548 cell
Tom_Aikens@vatransformer.com

Budget Estimate for Power Transformer

Contact:
Tom Nigon
PowerPlus Engineering
115 S. 5th Ave., Ste. 501
La Crosse, WI 54601
608-793-1780 x 1

Client: City of Shasta Lake, CA

Transformer Specifications Overview:

Quantity: 1

Quote 1: MVA: 15/20/25 at 55C with a top rating of 28 MVA at 65C with 2 stages of cooling **$525,000**

Quote 2: MVA: 25/33/42 at 55C with a top rating of 47 MVA at 65C with 2 stages of cooling **$650,000**

All other specifications are the same for the 15 and 25 MVA transformer quote as follows:

Voltage: 115 kV to 12.47Y/7.2 kV

Taps – 5 high voltage taps at the following voltages:
120,750
117,875
115,000
112,125
109,250

Impedance: 8.3%

Voltage regulation: Load tap changing equipment, +/- 10% voltage regulation

Cooling: 2 stages of cooling such as ONAN/ONAF/OFAF

BIL: 110 kV secondary, 450 kV BIL primary

Surge arresters: 3 each on 115 kV terminals and 12.47 kV terminals of transformer

Include estimate of shipping costs to Shasta Lake, CA

10.4 System Model Data

The results of the Milsoft load flow program are not included in the report. The results show the amp flow, voltage at each segment, and other power flow information. Contact the engineer if interested in obtaining a copy of the results from the load flow program.

10.5 System Maps

Maps showing the recommended projects by substation have been prepared. Copies of the maps are included at the end of this report.