ARMENIA ENERGY TRAINING PROGRAM

Contract No. LAG-I-00-98-00011-00, Task Order Two

Technical Report

Electric Transmission and Distribution
Loss Reduction Strategies

September 7, 1999

Submitted to U.S. Agency for International Development

Submitted by the Academy for Educational Development
with Hagler Bailly Services
A. Course Purpose

Although Armenia’s energy sector has undergone substantial changes within the last four years there remain many issues related to the development of an economically sustainable energy sector. This course builds on activities undertaken previously as part of USAID’s technical assistance efforts in the energy sector.

The Armenian electric system has very high rates of technical and commercial transmission and distribution losses. This course discussed both technical and organizational measures to reduce such losses. Course topics included: possible causes of losses; loss estimation methods; meter testing procedures; and procedures for improving internal financial controls to reduce commercial losses.

The course objectives were:

- To provide practical training on technical and organizational measures and techniques to reduce both technical and commercial losses in Armenia’s electric transmission and distribution networks

- To increase participant awareness of the USAID Armenia Power Sector Metering Improvement Program and demonstrate necessary organizational and business measures that need to be taken to reduce losses in line with Government of Armenia targets and sound utility practice.

B. Dates/Trainers/Attendees

The course was held from June 21-24, 1999. Mr Douglas Whyte was the principal trainer. Dean White and Armen Arzumanyan also taught sections of the seminar. Table 1 shows the course participants.
C. Material Covered

The seminar was divided into three main areas. The first part of the course focused on reducing technical losses, including measuring and estimating energy and demand losses on both an annual and an hourly basis, and allocating their electric system components, using the Southern California Edison (SCE) system as an example. This segment also provided a methodology for valuation of both energy and demand losses by voltage level, including methods for forecasting the value of future losses. Following a review of economic analyses, these values were then used in sample loss reduction projects, and assignments were given to the class to analyze and recommend three loss reduction projects using at least two different economic analysis techniques.

The second part of the course covered: commercial loss mitigation, including meter characteristics, accuracy, calibration and testing; billing systems and processes; electric rates and bills, using examples from Southern California Edison; revenue collection and non-payment issues; and energy theft and revenue protection including investigation, past due bill calculation, payment arrangements and criminal prosecution.

The final course component included a demonstration of the hardware provided through the USAID metering, billing and collection system project; a discussion of commercial losses in Armenia; an overview and findings from the USAID/Hagler Bailly commercialization projects, and site visits to the Komitas metering installation and the Yerevan Distribution Company’s meter shop.

Table 1: List of Participants

<table>
<thead>
<tr>
<th>#</th>
<th>Name</th>
<th>Employer</th>
<th>21-Jun</th>
<th>22-Jun</th>
<th>23-Jun</th>
<th>24-Jun</th>
<th>25-Jun</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>Anahit Ayvazyan</td>
<td>Energy Regulatory Commission</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
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<tr>
<td>2</td>
<td>Garegin Baghramyan</td>
<td>Energy Regulatory Commission</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>Armenak Yaoloyan</td>
<td>Energy Regulatory Commission</td>
<td>+</td>
<td>+</td>
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<tr>
<td>4</td>
<td>Victor Sahakov</td>
<td>Institute of Energy</td>
<td>+</td>
<td></td>
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<tr>
<td>5</td>
<td>Svetlana Ganjumyan</td>
<td>Institute of Energy</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
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<tr>
<td>6</td>
<td>Razmik Sardaryan</td>
<td>Central Distribution Company</td>
<td>+</td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>7</td>
<td>Meruzhan Hovsepyan</td>
<td>Central Distribution Company</td>
<td>+</td>
<td>+</td>
<td></td>
<td></td>
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<tr>
<td>8</td>
<td>Vardush Hambartsumian</td>
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<td>+</td>
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<td>9</td>
<td>Arayik Davtyan</td>
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<td>10</td>
<td>Lansa Badalyan</td>
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<tr>
<td>11</td>
<td>Naira Sargsyan</td>
<td>Armenergo</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
</tr>
<tr>
<td>12</td>
<td>Mattik Melkumyan</td>
<td>Armenergo</td>
<td></td>
<td></td>
<td>+</td>
<td>+</td>
<td></td>
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<tr>
<td>13</td>
<td>Martin Ghahramanyan</td>
<td>Armenergo</td>
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<td>+</td>
<td>+</td>
<td>+</td>
<td></td>
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<tr>
<td>14</td>
<td>Derenik Asatryan</td>
<td>Armenergo</td>
<td>+</td>
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<td></td>
<td></td>
<td></td>
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<tr>
<td>15</td>
<td>Karine Saghatelyan</td>
<td>Armenergo</td>
<td></td>
<td>+</td>
<td>+</td>
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<td>16</td>
<td>Alexey Tumanov</td>
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<td>17</td>
<td>Petros Kyalyan</td>
<td>Hrazdan Thermo-power plant</td>
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<td>18</td>
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<td>19</td>
<td>Alexandr Samarchyan</td>
<td>Ministry of Finances</td>
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</tbody>
</table>

| TOTAL | 11 | 13 | 10 | 15 | 10 |

Technical Report Course# 10

September 7, 1999  2
D. **Participant Evaluations**

- The participants expressed concern over the quality of the translation of technical materials and written materials. Because of the course’s highly technical nature, some terms did not translate precisely. AED/Hagler Bailly has taken steps to address this matter for future courses, and to correct the translations on the materials to be left with the co-trainers.

- Although all the participants found the content of the course useful, 44.4% were unsure that they would be able to apply what they had learned in their work.

- The trainers were given good ratings in method, content, technical and training ability by all of the participants.

- Most of the participants (71%) have made arrangements to remain in contact with the course instructors.

E. **Anticipated Outcomes**

The seminar helped to increase awareness of USAID’s Power Sector Metering Improvement Program, and of USAID’s recently-completed pilot commercialization activities. The course improved participants’ understanding of how to better organize metering, billing and collection processes to help identify where losses are occurring on the electric system and to improve power sector financial performance. It is anticipated that some of the approaches presented will be implemented in Armenia’s distribution utilities, which should result in improved losses and reduced expenses in the Armenian power system.

F. **Recommended Follow-up**

Seminar participants seemed reluctant to accept the idea that low losses in world-class utilities are the result of economic system design, as well as hard work on metering, rate-making, billing, collection and energy theft processes. Overall losses in Armenia are around 35%, roughly evenly split between technical and commercial losses. Course participants believe that a reduction in energy theft is likely to result in reduced electricity consumption, rather than increased revenue, due to the fact that electricity bills represent a substantial share of typical family and business income.

Class participants were skilled in technical areas, but could benefit from additional training in power system economics, since they had difficulty grasping the basic economics that motivate reducing both technical and non-technical losses. This type of course would address engineering economic concepts (e.g., net present value, future value, choice of discount rates) and project evaluation concepts (e.g., valuing energy savings from reduction in technical losses.)

Secondly, additional training devoted exclusively to revenue protection, including energy theft mitigation, finding and correcting metering, billing, and collection errors, and revenue recovery
would be of value. This training should be targeted to distribution company representatives.

Third, there is considerable need for more work on metering, especially related to the importance of meter calibration and replacement programs within each utility as well as maintenance of accurate records regarding meters in place, dates of testing, age, and type. This type of training may be better handled as a study tour, to demonstrate the organization and operation of a utility’s metering function. This type of study tour is being considered as part of the Armenia Power Sector Metering Improvement Program.
APPENDIX A

Seminar Outline

Electric Transmission and Distribution Loss Reduction Strategies
Monday - June 21, 1999

10:00 AM  Introductions
Course objectives
Course overview
Desired course outcomes

10:45 AM  Causes of technical losses
Measurement of technical losses
Estimation methods with incomplete metering
International trends in estimating/measuring technical losses in the electric power industry
Comparison of losses in power companies around the world

12:30 PM  Lunch

1:30 PM  Cost of losses
a) energy
b) demand
Calculating benefit/cost of loss reduction projects

4:00 PM  Adjourn

Tuesday - June 22, 1999

10:00 AM  Loss reduction programs under capital rationing
Losses and system design criteria

12:30 PM  Lunch

1:30 PM  Techniques for loss reduction on existing transmission network
Distribution automation techniques for loss reduction and improved service quality
Effect of load shaping/Demand Side Management/Distributed Generation on losses

4:00 PM  Adjourn

Wednesday - June 23, 1999

10:00 AM  Relationship of loss reduction to least-cost plan
Example: Losses in an economic study of renewable energy source
Loss accounting for direct energy sales from generator to consumer
Example: Assignment of losses to facilities with multiple ownership

12:30 PM   Lunch

1:30 PM    Economic dispatch with transmission loss factors
Presentation of class case study exercise
Class will be divided into 3 groups. Each group will develop
recommendations for capital expenditures for sample projects for (technical)
loss reduction

4:00 PM    Adjourn

Thursday - June 24, 1999

10:00 AM   Causes of commercial losses
Estimation of commercial losses
   Metering accuracy, meter testing methods
   Meter reading systems and techniques

12:30 PM   Lunch

1:30 PM    Internal accounting and financial systems
   Billing and billing systems
   Customer information
   Revenue collections and non-payment

4:00 PM    Adjourn

Friday - June 25, 1999

10:00 AM   Energy theft mitigation
Review results of Hagler Bailley’s pilot commercialization projects

12:30 PM   Lunch

1:30 PM    Case study presentations by class
Review and Discussion of course material
Discussion of implementation of course ideas
Course evaluation

4:00 PM    Adjourn
APPENDIX B

Course Materials

Electric Transmission and Distribution Loss Reduction Strategies
ELECTRIC TRANSMISSION and DISTRIBUTION LOSS REDUCTION

Yerevan, Armenia
June 21-25, 1999

INSTRUCTOR: M. D. "DOUG" WHYTE

Professional Engineer,
Retired from
Southern California Edison Company, 1996
Doug's Professional Background

Electrical Engineering - U. C. Berkeley, 1960

Employee - Southern California Edison 1960 - 1996
- Distribution, Transmission, Generation Planning 1960-1974
- Manager, Electric System Planning 1974 - 1986
- Manager, SCE Research Center, 1989-1995
- Manager, SCE Solar Energy Division 1995-1996

Electric Power Related Teaching Experience:
Industrial Relations Depts., U. C. Berkeley and
Cornell University, 1981-1987

IIE / US AID Courses
Moscow & Kraznoyarsk 1995
St. Petersburg & Kyrgyzstan 1996
Moscow 1997
Course Objectives

• Provide training on technical and organizational measures and techniques to reduce losses in the electric transmission and distribution networks.

• Increase understanding of the importance of both T&D loss reduction and T&D network maintenance on reliable and profitable electric service.

• Provide training on measures to reduce commercial losses in an electric power enterprise.
Course Overview

MONDAY
- Discuss Desired Course Outcomes
- Technical Losses: Causes, Measurement, Costs

TUESDAY
- Loss Reduction Programs & Techniques

WEDNESDAY
- Importance of Losses to Economic Efficiency
- Examples of Loss Studies
- Class Case Study Exercise

THURSDAY
- Commercial Losses:
  - Metering, Billing, Revenue Collections, Accounting Systems

FRIDAY
- Energy Theft
- Case Study Presentations
- Review and Sharing of Ideas
North American Electric Reliability Council

ECAR
East Central Area Reliability Coordination Agreement

ERCOT
Electric Reliability Council of Texas

MAAC
Mid-Atlantic Area Council

MAIN
Mid-America Interconnected Network

MAPP
Mid-Continent Area Power Pool

NPCC
Northeast Power Coordinating Council

SERC
Southeastern Electric Reliability Council

SPP
Southwest Power Pool

WSCC
Western Systems Coordinating Council

The North American Electric Reliability Council (NERC) was formed in 1968 by the electric utilities to promote the RELIABILITY of their generation and transmission systems. NERC consists of nine Regional Reliability Councils and one affiliate encompassing virtually all of the electric systems in the United States, Canada, and the northern portion of Baja California, Mexico.

RELIABILITY, in a bulk electric system, is the degree to which the performance of the elements of that system results in electricity being delivered to customers within accepted standards and in the amount desired. The degree of reliability may be measured by the frequency, duration, and magnitude of adverse effects on the electric supply (or service to customers).

Bulk electric system reliability can be addressed by considering two basic and functional aspects of the bulk electric system — adequacy and security.

ADEQUACY is the ability of the bulk electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and unscheduled outages of system components.

SECURITY is the ability of the bulk electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system components.

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Today’s Power System

Western System Coordinating Council
- Territory in 14 western U.S. states, and parts of Canada and Mexico
- 66 Members
- 150,000 MW resources
- 40% of energy supplied by public power and governmental entities
- 112,300 MW peak demand
- 30 control areas

California
- 3 investor-owned utilities; 22 public power and governmental entities
- 65,000 MW resources
- 30% of energy supplied by public power and governmental entities
- 53,000 MW peak demand (1992)
- 3 control areas, Independent System Operator (ISO), Power Exchange (PX)

Edison
- $8 Billion Revenue
- 4.2 Million Customers
- 12,642 Employees (1997)
- 11 major interconnections
- 19,935 MW peak demand (1998)
Map of Western States and Edison Service Territory
Edison - Sources of Energy
Edison - Sources of Energy
### Some Perspective

<table>
<thead>
<tr>
<th>Country/State</th>
<th>Area (sq. Miles)</th>
<th>Population (Millions)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Armenia</td>
<td>11,506</td>
<td>3.6</td>
</tr>
<tr>
<td>Georgia</td>
<td>26,911</td>
<td>5.7</td>
</tr>
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<td>Azerbaijan</td>
<td>33,436</td>
<td>7.8</td>
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<td>So. Cal Edison</td>
<td>50,000</td>
<td>11.5</td>
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<tr>
<td>Kazakstan</td>
<td>1,049,151</td>
<td>17.4</td>
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<tr>
<td>California</td>
<td>158,706</td>
<td>31.6</td>
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<td>Ukraine</td>
<td>233,089</td>
<td>51.9</td>
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<tr>
<td>Turkey</td>
<td>300,947</td>
<td>64.6</td>
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<tr>
<td>Iran</td>
<td>636,293</td>
<td>69</td>
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<tr>
<td>Russia</td>
<td>6,592,745</td>
<td>149.9</td>
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## Utility Business Eras

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<th>Era</th>
<th>Competition</th>
<th>Regulation</th>
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<td>Early 20th Century</td>
<td>Build Facilities and try to</td>
<td>Vertically Integrated Utility Monopolies: Build Facilities in Response to Customer Needs</td>
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<td>Early 20th Century to 1980’s</td>
<td>Attract Customers</td>
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<tr>
<td>1980’s</td>
<td>Change:</td>
<td>Competition Begins at Generation Level</td>
</tr>
<tr>
<td>1990’s</td>
<td>Competition:</td>
<td>Restructuring in Many Areas to Provide Competition at Generation and Retail Levels</td>
</tr>
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</table>
Economies of Scale
Growing Sales
Build Plants
Increase Market Share
Prices Drop

Changing Conditions

Unit Cost

Prosperity
Hard Times

Time

- Economies of Scale
- Growing Sales
- Build Plants
- Increase Market Share
- Prices Drop

- Costs Rise
- Sales Drop
- Fixed Costs
- Sell-off Plant
- Prices Rise
# Model of Power Industry Structures

<table>
<thead>
<tr>
<th>Definition</th>
<th>Monopoly</th>
<th>Purchasing Agency</th>
<th>Wholesale Competition</th>
<th>Retail Competition</th>
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<tr>
<td>Vertically Integrated</td>
<td>Monopoly</td>
<td>Competition Among Power Generators</td>
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<tr>
<td>With Single Buyer</td>
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<td></td>
<td>Choice for Distributors</td>
<td>Choice for Consumers</td>
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<tr>
<td>Are There Competing Generators?</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
<td>YES</td>
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<tr>
<td>Do Retailers Have a Choice?</td>
<td>NO</td>
<td>NO</td>
<td>YES</td>
<td>YES</td>
</tr>
<tr>
<td>Do Final Customers Have a Choice?</td>
<td>NO</td>
<td>NO</td>
<td>NO</td>
<td>YES</td>
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</table>
Essential Goals of Electric Power Systems

- Safety (Human and Equipment)
- Provide High Quality Electric Service
  - Reliable, Dependable Service
  - Resource, Fuel Diversity
  - Expandable Power System

- Provide electric Service at lowest possible cost to customer
  - Beat the Competition
  - Stay in Business
Balancing Competing Goals

Elements of an Enterprise Strategy:

<table>
<thead>
<tr>
<th></th>
<th>FINANCIAL RISK</th>
<th>COST TO CUSTOMER</th>
<th>RELIABILITY</th>
<th>EFFICIENCY</th>
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<td>A. Reduce Financial Risk to the Enterprise</td>
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<td>B. Reduce Cost of Service to Customers</td>
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<td>↓</td>
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<td>C. Improve Reliability of Service</td>
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<td>D. Improve Electric System Efficiency</td>
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</table>
Institutional Perspective

Old Things Folks Repeat Old Successes eagerly

NEW THINGS CAUSE ANXIETY. THERE WILL ALWAYS BE "OVERWHELMING" OBSTACLES, UNLESS THERE IS MORE ANXIETY IN DOING THE OLD THINGS.

Normal Tendency: Close Out Options by Raising Constraints

THE QUESTION: CAN YOU CONTINUE TO USE THE STRATEGIES THAT HAVE WORKED IN THE PAST?

SHOULD YOU?
Achieve Goals of the Enterprise

- Improve System Efficiency
  - Reduce Technical Losses
  - Improve Revenue Collection
- Improve System Reliability
  - Reduce Power Outages
  - Improve Power Quality
- Reduce Cost To Customers
  - Improved System Efficiency
  - Reduce Operation & Maintenance Cost
- Achieve Financial Stability
  - Improved Collections
  - Reduced Debt Burden
### Losses - Southern California Edison System - 1997

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
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<tbody>
<tr>
<td>Total Energy Requirement</td>
<td>86,849</td>
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<tr>
<td>Total Electric Sales*</td>
<td>77,234</td>
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<tr>
<td>&quot;Total&quot; Losses</td>
<td>9,615 (11.1%)</td>
</tr>
<tr>
<td>Energy Theft</td>
<td>772</td>
</tr>
<tr>
<td>Technical Losses</td>
<td>8,843 (10.2%)</td>
</tr>
<tr>
<td>Revenue from Electric Sales</td>
<td>$7,729 Million</td>
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<tr>
<td>Average Revenue per kWh</td>
<td>10.0 ¢</td>
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*includes uncollectible accounts
### Value of Edison Losses - 1997

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<th>Loss Category</th>
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<td>MkWh</td>
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<td>Technical Losses</td>
<td>8,843</td>
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<td>Energy Theft</td>
<td>772</td>
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<tr>
<td>Uncollectible Accounts</td>
<td>210</td>
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<tr>
<td><strong>TOTALS: Losses and Uncollectibles</strong></td>
<td><strong>9,825</strong></td>
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</tbody>
</table>
Southern California Edison - Losses History

NOTE: Excludes Losses from Uncollectible Accounts
How Are These Losses Determined?

1. Generation Input to the System
   a.) Metered at Power Plants
   b.) Purchases from Other Utilities

2. Power Output to Customer
   a.) Customer Revenue Meters
   b.) Sales to Other Utilities
Source of Errors in Measurement

1. Metering Inaccuracies
   - At Power Plants
   - Revenue Meters

2. Interchange Inaccuracies
   - Allowance for Losses in Utility-to-Utility Transactions
   - Allowance for Losses in Power Transmitted across Neighboring Power Systems

3. Timing Differences
   - Between Power Transmitted and Meter Reading

4. Meter Reading Errors
# Losses - World Utilities

<table>
<thead>
<tr>
<th>Utility</th>
<th>Country</th>
<th>Year</th>
<th>Energy Provided (1000 GWH)</th>
<th>Losses %</th>
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</thead>
<tbody>
<tr>
<td>Hydro Quebec</td>
<td>Canada</td>
<td>1995</td>
<td>186</td>
<td>6.9</td>
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<tr>
<td>Tokyo Electric Power</td>
<td>Japan</td>
<td>1986</td>
<td>170</td>
<td>9.5</td>
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<tr>
<td>Southern Company</td>
<td>USA</td>
<td>1993</td>
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<td>USA</td>
<td>1986</td>
<td>114</td>
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<td>USA</td>
<td>1997</td>
<td>87</td>
<td>11.1</td>
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<tr>
<td>Duke Power</td>
<td>USA</td>
<td>1993</td>
<td>81</td>
<td>5.7</td>
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<td>Houston Lighting</td>
<td>USA</td>
<td>1993</td>
<td>64</td>
<td>4.5</td>
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<td>Kyushu Electric</td>
<td>Japan</td>
<td>1986</td>
<td>49</td>
<td>9.7</td>
</tr>
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<td>Carolina Power &amp; Light</td>
<td>USA</td>
<td>1988</td>
<td>43</td>
<td>7.3</td>
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<td>Southpower</td>
<td>New Zealand</td>
<td>1994</td>
<td>2.4</td>
<td>6.2</td>
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## Losses History -- Tokyo Electric Power

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Sources of Losses

A. Technical Losses
   - Losses Which Vary with Electric Demand (I^2R)
   - Losses Which are Constant (Magnetizing Currents)
   - Losses Which Vary with Weather (Corona)
   - Power Plant Auxiliaries

Commercial Losses
   - Uncollectible Accounts
   - Energy Theft
   - Measurement Errors
   - Unmetered Accounts
Typical Electric System
Technical Losses on a "Typical" Electric Utility

Transmission Substations ——— Transmission Lines ——— Distribution Substations

Secondary Lines ——— Distribution Transformers ——— Distribution Lines

Meters
Power Flow Diagram Showing Components of Each Service Level

<table>
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<th>LEVEL</th>
<th>LOSSES</th>
<th>SYSTEM</th>
<th>DELIVERY</th>
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<td>D BANKS</td>
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SCE System Energy Flow

**SCE System 1978 Energy Flow (GWH)**

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<td>(2) OUTBOUND</td>
<td>TOTAL (ENV + BULK)</td>
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<td>INTERCHANGE</td>
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<td>LARGE CUSTOMERS</td>
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<td>(2) S&amp;A</td>
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</table>

**TOTAL**

- ENV SYSTEM: 136 (1.23%)
- BULK POWER SYSTEM: 837 (1.39%)
- SUBTRANSMISSION SYSTEM: 741 (1.22%)
- DISTRIBUTION SYSTEM: 3,162 (5.25%)

**Total SCE System Losses:** 4876 GWH or (8.09)%

*Note: In percent of main system Edison Net Load Energy of 60,600 GWH (including isolated)
## SCE System Energy Loss Multipliers

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<th>Service Level</th>
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### Notes

(1) Served from Subtransmission System but metered on low side of transformer at primary voltages.

(2) Time-of-Use Periods - Definitions:

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<td>Mid Peak</td>
<td>8-12 and 18-22</td>
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<td>Off Peak</td>
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PSA 130045.A
12/30/79

PS 11-79

pg. 31
SCE System Peak MW Flow

SCE SYSTEM 1978 PEAK MW FLOW (SEPTEMBER 25, 3 PM.)

**Table:**

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<th>EHV System</th>
<th>Bulk Power System</th>
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<th>Distribution System</th>
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**Diagram:**

**Legend:**
- STEP UP BANKS
- EHV LINES
- BULK POWER SYSTEM LINES
- 4 BAKES
- LOSS TOTAL
- DISTRIBUTION LINES
- 16 LOSS GENERATION
- SUBTRANS CUSTOMERS BANKS
- PRIMARY CIRCUITS 1/2
- DISTRIBUTION TRANSFORMERS (COST)
- SECONDARY CIRCUITS
- STREET LIGHTS

**Losses:**
- STEP UP BANKS
- EHV LINES
- BULK POWER SYSTEM LINES
- 4 BAKES
- TOTAL: 1.31% (144%)

**SCE System Losses:** 1220 MW OR 0.10% *

*NOTE: 3% PERCENT OF MAIN SYSTEM EDITION NET LOAD DEMAND OF 12200 MW (EXCLUDING ISOLATED)
# SCE System Demand Loss Multipliers

## Table B

### SCE System Demand Loss Multipliers

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<th>Service Level</th>
<th>Customer Groups</th>
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**NOTES**

1. Served from Subtransmission System but metered on low side of transformer at primary voltages.

2. **Time-of-Use Periods - Definitions:**

   - **Summer (Jun. - Nov.)**
     - On Peak: 12-18
     - Mid Peak: 6-12 and 18-22
     - Off Peak: 22-8

   - **Winter (Dec. - May)**
     - On Peak: 17-22
     - Mid Peak: 8-17
     - Off Peak: 22-8

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**Date:** 4/10/79

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Loss Estimation Methods
with Incomplete Metering

• Make Estimates Using:
  - Known Data to the Extent Possible
  - Filling in the Blanks with Best Judgements

• How to make “Best Judgements”:
  - Use Equipment Ratings where available
  - Use typical Equipment Ratings
  - Use computer simulations
## Technical Losses of Power System Components

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<td>Power Transformers</td>
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# SCE Distribution Line Transformer Losses

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<th>Losses (kW)</th>
<th>Losses (%)</th>
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Load Factor / Loss Factor

\[ L_S F = L_d F^2 (0.7) + L_d F (0.3) \]

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<th>( L_s F )</th>
<th>( L_d F^2 )</th>
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</tbody>
</table>

Load Factor

\((\text{Load Factor})^2\)

Load Factor
Determine and Allocate System Technical Losses Using Incomplete Metering

1. Determine Annual Energy Loss
   - Determine/Estimate Energy Inputs and Outputs
   - Metered and Estimated Data - Adjust for Billing Lag
2. Make Reasonable Estimates for
   - Generator Step-up Banks
   - Components where Field Measurement/Metering is not available
3. Transmission Network
   - Use Power Flow Simulation and Load Factor/Loss Factor Approximations
4. Power Transformers
   - Calculate Losses for a "Typical" Transformer, then Multiply by Number of Transformers
5. Distribution Circuits, Distribution Transformers, etc.
   - Calculate Losses for a "Typical" Component by Voltage Class, the Multiply by Number of Components.
Costs of Losses

A. Cost of Energy
B. Cost of Demand or Capacity
Cost of Energy for Use in Loss Analysis

- Marginal Costs
  - Based on Incremental Output of Marginal Generation
  - Includes Price of Fuel, Generator Incremental Efficiency, Variable Operation and Maintenance

- Expressed Hourly or Grouped in Time Periods of Similar Value

- Includes Forecast of Future Values
  - Determined from Computer Simulations

- Values can be Used for Marginal Cost Ratemaking
Energy Cost Depends on Marginal Generation

Peaking Generation: 0 - 5% Capacity Factor
Intermediate: 5 - 65% Capacity Factor
Base Load: 65% Capacity Factor
Time Period Groupings
(Southern California Edison)

- **Summer:**
  - On-Peak: 12:00 P.M. - 6:00 P.M. weekdays except holidays
  - Mid-Peak: 8:00 A.M. - 12:00 P.M., 6:00 P.M. - 11:00 P.M. weekdays except holidays
  - Off-Peak: All Other Hours

- **Winter:**
  - Mid-Peak: 8:00 A.M. - 9:00 P.M. weekdays except holidays
  - Off-Peak: All Hours Not Included in the Mid-Peak and Super-Off-Peak Time Periods
  - Super-Off-Peak: 12:00 A.M. - 6:00 A.M. everyday
Incremental Energy Rates
(Southern California Edison)
Incremental Energy Rates
(Southern California Edison)
## Future Energy Rates by Time Period

(Southern California Edison)

<table>
<thead>
<tr>
<th>Year</th>
<th>Gas Price $/million btu</th>
<th>Time-Period</th>
<th>Energy Value $/kWh</th>
<th>Total Energy Value</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Summer</td>
<td>Mid-peak</td>
<td>Off-peak</td>
</tr>
<tr>
<td>1995</td>
<td>2.41</td>
<td>3.06</td>
<td>2.18</td>
<td>1.62</td>
</tr>
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<td>1996</td>
<td>2.51</td>
<td>6.57</td>
<td>2.31</td>
<td>1.74</td>
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<td>1997</td>
<td>2.60</td>
<td>3.48</td>
<td>2.41</td>
<td>1.76</td>
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<tr>
<td>1998</td>
<td>2.73</td>
<td>3.75</td>
<td>2.60</td>
<td>1.99</td>
</tr>
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<td>2.78</td>
<td>3.35</td>
<td>2.91</td>
<td>2.14</td>
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<td>2.90</td>
<td>3.44</td>
<td>3.27</td>
<td>2.50</td>
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<td>2001</td>
<td>3.03</td>
<td>3.99</td>
<td>3.27</td>
<td>2.51</td>
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<tr>
<td>2002</td>
<td>3.18</td>
<td>3.45</td>
<td>3.73</td>
<td>2.96</td>
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<tr>
<td>2003</td>
<td>3.32</td>
<td>3.80</td>
<td>4.04</td>
<td>3.01</td>
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<td>2004</td>
<td>3.51</td>
<td>3.74</td>
<td>4.67</td>
<td>3.36</td>
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<tr>
<td>2005</td>
<td>3.78</td>
<td>4.03</td>
<td>5.03</td>
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<td>2006</td>
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<td>2007</td>
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<td>5.54</td>
<td>3.99</td>
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<td>2009</td>
<td>4.48</td>
<td>4.78</td>
<td>5.96</td>
<td>4.29</td>
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<tr>
<td>2010</td>
<td>4.65</td>
<td>4.96</td>
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<tr>
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<td>5.01</td>
<td>5.34</td>
<td>6.67</td>
<td>4.80</td>
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<td>2013</td>
<td>5.20</td>
<td>5.55</td>
<td>6.92</td>
<td>4.98</td>
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<tr>
<td>2014</td>
<td>5.40</td>
<td>5.76</td>
<td>7.19</td>
<td>5.18</td>
</tr>
</tbody>
</table>
Actual and Projected Oil Prices

ACTUAL AND PROJECTED OIL PRICES (1968-1985)

- Actual
- Projected

1968 Projected Oil Prices
1975 Projected Oil Prices
April 1980 Projected Oil Prices
Sept. 1980 Projected Oil Prices
Cost of Demand (or Capacity)

- Marginal Costs of Capacity
  - Based on Plans for New Generation Capacity or Refurbishments
  - Includes Installed Cost of New Capacity, Ownership Costs (Financing, Depreciation, Taxes, Etc.), “Fixed” Operation and Maintenance, Inflation

- Takes Into Account:
  - Reserve Margin

- Expressed Annually or by Grouping in Time Periods with Similar Hourly Values.
- Calculated for Future Years
- Values Can Be Used for Marginal Cost Ratemaking
Utility Loads and Resources Step-Chart

Resources Under Construction and Planned

Existing Resources

Forecast Peak Load

Recorded Peak Load

YEARS

MEGAWATTS
# Generation Reliability Multiplier

(Southern California Edison)

<table>
<thead>
<tr>
<th>Reserve Margin</th>
<th>Multiplier</th>
</tr>
</thead>
<tbody>
<tr>
<td>over 20%</td>
<td>0.1</td>
</tr>
<tr>
<td>16-20%</td>
<td>1.0 - 0.1</td>
</tr>
<tr>
<td>under 16%</td>
<td>1.0</td>
</tr>
</tbody>
</table>
Capital - Related Assumptions

Installed Cost of Combustion Turbine
Cost of Capital
Amortization Period
Taxes, Insurance, Etc.
Fixed Operation & Maintenance
Inflation
## General Carrying Charge Rates

<table>
<thead>
<tr>
<th>Term (years)</th>
<th>Levelized</th>
</tr>
</thead>
<tbody>
<tr>
<td>10</td>
<td>0.230</td>
</tr>
<tr>
<td>15</td>
<td>0.191</td>
</tr>
<tr>
<td>20</td>
<td>0.173</td>
</tr>
<tr>
<td>25</td>
<td>0.164</td>
</tr>
<tr>
<td>30</td>
<td>0.158</td>
</tr>
<tr>
<td>35</td>
<td>0.155</td>
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</table>
# First Year Capacity Value

<table>
<thead>
<tr>
<th>Year</th>
<th>Com. Turbine Capacity Cost (3)</th>
<th>Capacity Value Multiplier</th>
<th>Adjusted Capacity Value</th>
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<tbody>
<tr>
<td>1995</td>
<td>$51.23</td>
<td>0.10</td>
<td>$5.12</td>
</tr>
<tr>
<td>1996</td>
<td>$53.03</td>
<td>0.10</td>
<td>$5.30</td>
</tr>
<tr>
<td>1997</td>
<td>$54.88</td>
<td>0.10</td>
<td>$5.49</td>
</tr>
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<td>1998</td>
<td>$56.80</td>
<td>0.10</td>
<td>$5.68</td>
</tr>
<tr>
<td>1999</td>
<td>$58.79</td>
<td>0.10</td>
<td>$5.88</td>
</tr>
<tr>
<td>2000</td>
<td>$60.85</td>
<td>0.10</td>
<td>$6.08</td>
</tr>
<tr>
<td>2001</td>
<td>$62.98</td>
<td>0.10</td>
<td>$6.30</td>
</tr>
<tr>
<td>2002</td>
<td>$65.18</td>
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<td>$6.52</td>
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<tr>
<td>2003</td>
<td>$67.47</td>
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<td>$6.75</td>
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<td>2004</td>
<td>$69.83</td>
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<td>$6.98</td>
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<td>2005</td>
<td>$72.27</td>
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<td>$9.78</td>
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<tr>
<td>2006</td>
<td>$74.80</td>
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<td>$74.80</td>
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<tr>
<td>2007</td>
<td>$77.42</td>
<td>1.00</td>
<td>$77.42</td>
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<td>2008</td>
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<td>1.00</td>
<td>$85.83</td>
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<tr>
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<td>$91.95</td>
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<tr>
<td>2013</td>
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<tr>
<td>2014</td>
<td>$98.50</td>
<td>1.00</td>
<td>$98.50</td>
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</table>
# Capacity Valuation Factors

*The Capacity Valuation factors are used to convert annual capacity values ($/kWh-yr) to monthly values by time period. The factors were derived from the February 15, 1995 “Avoided Cost Posting”.*

<table>
<thead>
<tr>
<th></th>
<th>On-peak</th>
<th>Mid-peak</th>
<th>Off-peak</th>
<th>Super-off</th>
<th>Total</th>
</tr>
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<tbody>
<tr>
<td>Summer</td>
<td>0.7778</td>
<td>0.1345</td>
<td>0.0026</td>
<td>0.0000</td>
<td>0.9149</td>
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<tr>
<td>Winter</td>
<td>0.0000</td>
<td>0.0773</td>
<td>0.0048</td>
<td>0.0030</td>
<td>0.0851</td>
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<tr>
<td>Total</td>
<td>0.7778</td>
<td>0.2118</td>
<td>0.0074</td>
<td>0.0030</td>
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</table>
## Estimated Future Capacity Values by Time Period

<table>
<thead>
<tr>
<th>Year</th>
<th>Capacity Value $/kWh-yr</th>
<th>SUMMER</th>
<th>WINTER</th>
<th>Annual Average</th>
</tr>
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<tbody>
<tr>
<td></td>
<td></td>
<td>On-peak</td>
<td>Mid-peak</td>
<td>Off-peak</td>
</tr>
<tr>
<td>1995</td>
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<td>1996</td>
<td>5.30</td>
<td>0.79</td>
<td>0.09</td>
<td>0.00</td>
</tr>
<tr>
<td>1997</td>
<td>5.49</td>
<td>0.82</td>
<td>0.09</td>
<td>0.00</td>
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<td>1998</td>
<td>5.68</td>
<td>0.85</td>
<td>0.10</td>
<td>0.00</td>
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<tr>
<td>1999</td>
<td>5.88</td>
<td>0.88</td>
<td>0.10</td>
<td>0.00</td>
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<td>2000</td>
<td>6.08</td>
<td>0.91</td>
<td>0.10</td>
<td>0.00</td>
</tr>
<tr>
<td>2001</td>
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<td>0.94</td>
<td>0.11</td>
<td>0.00</td>
</tr>
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<td>2002</td>
<td>6.52</td>
<td>0.97</td>
<td>0.11</td>
<td>0.00</td>
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<td>2003</td>
<td>6.75</td>
<td>1.01</td>
<td>0.12</td>
<td>0.00</td>
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<td>2004</td>
<td>6.98</td>
<td>1.04</td>
<td>0.12</td>
<td>0.00</td>
</tr>
<tr>
<td>2005</td>
<td>9.78</td>
<td>1.46</td>
<td>0.17</td>
<td>0.00</td>
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<td>0.01</td>
</tr>
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<td>11.54</td>
<td>1.33</td>
<td>0.01</td>
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<td>1.38</td>
<td>0.01</td>
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<td>0.01</td>
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<td>12.79</td>
<td>1.47</td>
<td>0.01</td>
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<td>2011</td>
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<td>13.24</td>
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<td>13.70</td>
<td>1.58</td>
<td>0.01</td>
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<tr>
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<td>95.17</td>
<td>14.18</td>
<td>1.63</td>
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<tr>
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<td>98.50</td>
<td>14.68</td>
<td>1.69</td>
<td>0.02</td>
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</table>
## Levelized Capacity Value $/kW-yr

<table>
<thead>
<tr>
<th>Project Length (years)</th>
<th>In-service or contract start year</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>6</td>
</tr>
<tr>
<td>5</td>
<td>6</td>
</tr>
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<td>10</td>
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<td>25</td>
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</tr>
<tr>
<td>30</td>
<td>32</td>
</tr>
<tr>
<td>60</td>
<td>38</td>
</tr>
</tbody>
</table>
Carrying Charges

RETURN OF CAPITAL (I.E., DEPRECIATION)

+ RETURN ON CAPITAL (I.E., INTEREST AND PROFIT)

+ TAXES ON RETURN ON CAPITAL

+ OPERATING EXPENSES
## SCE -- Composite Cost of Capital

<table>
<thead>
<tr>
<th></th>
<th>Calculation</th>
<th>Result</th>
</tr>
</thead>
<tbody>
<tr>
<td>Common Stock</td>
<td>0.48 \times 0.12</td>
<td>0.0576</td>
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<tr>
<td>Preferred Stock</td>
<td>0.05 \times 0.07</td>
<td>0.0035</td>
</tr>
<tr>
<td>Bonds</td>
<td>0.47 \times 0.08</td>
<td>0.0376</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>1.00</strong></td>
<td><strong>0.0987</strong></td>
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</tbody>
</table>

**SAY 10%**
### 1994 Edison ($1,000,000)

<table>
<thead>
<tr>
<th>Category</th>
<th>Amount</th>
<th>%</th>
</tr>
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<tbody>
<tr>
<td><strong>Revenues</strong></td>
<td>7798</td>
<td>100</td>
</tr>
<tr>
<td><strong>Expenses</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Fuel &amp; Purchased Power</td>
<td>3403</td>
<td>43.6</td>
</tr>
<tr>
<td>Operations &amp; Maintenance</td>
<td>1727</td>
<td>22.1</td>
</tr>
<tr>
<td>Depreciation</td>
<td>891</td>
<td>11.4</td>
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<tr>
<td>Property Tax</td>
<td>230*</td>
<td>2.6</td>
</tr>
<tr>
<td><strong>Total Expenses</strong></td>
<td>6224</td>
<td></td>
</tr>
<tr>
<td>Interest</td>
<td>429</td>
<td>5.5</td>
</tr>
<tr>
<td><strong>Pre-Tax Income</strong></td>
<td>1145**</td>
<td></td>
</tr>
<tr>
<td>Income Tax</td>
<td>507***</td>
<td>6.5</td>
</tr>
<tr>
<td><strong>Net Income</strong></td>
<td>638</td>
<td>8.2</td>
</tr>
</tbody>
</table>

\[
\frac{507***}{1145**} = 0.44 \text{ or } 44\%
\]

\[
\text{TOTAL TAXES} = 203* + 507*** = 710
\]
Edison Taxes 1994

Pre-Tax Profit = $100

State Tax 11% = 11

Federal 34%
(89) (.34) = 30

TOTAL TAX = 41
Edison - Source & Uses of $ - 1994

($1,000,000)

7,798 Revenues

O&M 1727 Property Tax 243

Net Income 638

Depreciation 429 Interest 727 Nuclear Decom 114

Return = \frac{638 + 429}{10,800} = 9.9\% 

INCOME TAX 507

7,798 Revenues

Construction Expenditures 982

Return on Equity = \frac{638}{5662} = 11.3\% 

"Rate Base" 10,800

pg. 61
<table>
<thead>
<tr>
<th>Year</th>
<th>Fuel &amp; Purchased Power</th>
<th>Operation &amp; Maintenance</th>
<th>Investment Related</th>
</tr>
</thead>
<tbody>
<tr>
<td>1997</td>
<td>41.8</td>
<td>20.4</td>
<td>37.8</td>
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<tr>
<td>1996</td>
<td>41.0</td>
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<tr>
<td>1988</td>
<td>41.3</td>
<td>21.0</td>
<td>37.7</td>
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</table>
Carrying Charges, or Fixed Charges, are those based on Capital Investment in Project, Not its Operating Costs:

That is: Taxes, Return, Depreciation.
Typical "Carrying Charge Components" for a 30 Year Facility

<table>
<thead>
<tr>
<th>Component</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>RETURN</td>
<td>10.0%</td>
</tr>
<tr>
<td>DEPRECIATION</td>
<td>0.6%</td>
</tr>
<tr>
<td>INCOME TAXES</td>
<td>2.9%</td>
</tr>
<tr>
<td>PROPERTY TAXES</td>
<td>1.2%</td>
</tr>
<tr>
<td>ADMINISTRATIVE &amp; GENERAL</td>
<td>1.0%</td>
</tr>
<tr>
<td>INSURANCE</td>
<td>0.1%</td>
</tr>
<tr>
<td><strong>TOTAL</strong></td>
<td><strong>15.8%</strong></td>
</tr>
</tbody>
</table>

DEPRECIATION + AVERAGE RETURN = SINKING FUND
DEPRECIATION + COST OF CAPITAL
Calculating Benefit/Cost of Loss Reduction Projects

- Simple Payback
- Annual Cost Method
- Classical or "Net Present Value" Method
- Decision Trees
Example: Distribution Line Reconductor Project

The Existing Circuit is in Good Repair, but Would it be Cost-Effective to Reconductor with Heavier Wire, Either 336 or 795 ACSR?
Technical and Economic Factors

Pump = 1000 Horsepower, 0.9 PF, 115 Amps per Phase

Estimated Cost to Reconductor with 336 ACSR
Material $2500
Labor $1000
Salvage $<300>
Total Cost $3200

Year of Installation: 1999
Estimated Life of Project: 30 years
Cost of Money = 10%
Value of Loss Savings by Reconductur

Existing Losses

(115 Amps)² (0.538Ω/KM) (1KM) (3 Phases) (8760 hrs/yr) ÷ 1000 = 62,328 kWh/yr

Value:
62,328 kWh (0.027 + 0.0007)$/kWh = $1,726 in 1999
62,328 kWh (0.0425 + 0.0085)$/kWh = $3,178 in 2006

Loss Savings by Installing 336 Conductor

1999: $1726 (0.538 - 0.19) ÷ 0.538 = $1116
2006: $3178 (0.538 - 0.19) ÷ 0.538 = $2056
Example: Simple Payback
(also known as "Businessman’s Approach")

Cost of Project         $3200
Savings from Losses     $1116

Payback Ratio = 3200/1116 = 2.9 years
Example: Annual Cost

Estimated Project Useful Life = 30 years
Carrying Charge = 15.8%

Annual Cost = $3200 (0.158) = $505
Annual Loss Savings = $1116

Benefit/Cost Ratio = 2.2 to 1
Example: “Classical Method”

To Perform Engineering Economic Studies
Net Present Value (NPV) Future Revenue Requirements.

Solution:

Find the NPV of Each Plan, Using Cost of Money as the Discount Factor
Example: Net Present Value

Present Value of Annual Cost:

\[ PV \text{ Annual Cost} = \frac{505}{1.1} + \frac{505}{1.1^2} + \ldots + \frac{505}{1.1^{30}} = 505(9.427) = 4,761 \]

NOTE: Cost of Money = Discount Rate = 10%
Present Value of Annual Benefits

Cost of Money = $10%

PV Annual Savings =
$1,116/1.1 + 1,152/(1.1)^2 + 1,241/(1.1)^3 + 1,358/(1.1)^4 \ldots$
$2,755/(1.1)^{30} = $17,288

NPV Savings = $17,288
NPV Annual Costs = $4,761
Benefit/Cost Ratio = 17,288/4,761 = 3.6
Decision Analysis and Decision Trees

- List Decision We Can Make, and Our Choices

- List Chance Events Beyond Our Control with Possible Outcomes and Their Probabilities

- List Out All Possible Combinations of Decision and Chance Events, and Compute Present Worth and Probability of Each

- Accumulate into Probability Distribution and Choose Best Decisions
Omega Circuit Reconductor

Influence Diagram

- Benefit/Cost
- Annual Benefit
- Energy Costs
- Probabilistic Factors
- Decision
- Annual Cost
- Cost of Money
- Project Cost
- Reconductor
- pg. 75
Probabilistic Factors

<table>
<thead>
<tr>
<th></th>
<th>Medium</th>
<th>High</th>
<th>Low</th>
</tr>
</thead>
<tbody>
<tr>
<td>Project Cost ($)</td>
<td>3200 (.75)</td>
<td>4000 (.20)</td>
<td>3000 (.05)</td>
</tr>
<tr>
<td>Energy Cost (¢/kWh)</td>
<td>2.77 (.80)</td>
<td>3.0 (1.0)</td>
<td>2.7 (.10)</td>
</tr>
<tr>
<td>Cost of Money(%)</td>
<td>10 (.50)</td>
<td>15 (.40)</td>
<td>8 (.10)</td>
</tr>
</tbody>
</table>

Variables:

Project Cost  Energy Cost  Cost of Money

3  X  3  X  3  =  27 Branches
Probability of One Branch

\[ 0.75 \times 0.80 \times 0.50 = 0.30 \]

NOTE: THIS BRANCH HAS THE LARGEST PROBABILITY OF THE 27 BRANCHES

AND

\[ \sum_{i=1}^{27} P_i = 1.0 \]
\[ i = 1 \]
Results of Decision Tree/Probabilistic Analysis

Cumulative

(Annual Cost Method)

Benefit/Cost Ratio
(0.5 = 1.94)
Example Problem: Ratios Summary

1. Payback Ratio = 2.9 years

2. Annual Cost Method
   Benefit/Cost = 2.2 to 1

3. Net Present Value Method
   Benefit/Cost = 3.6

4. Decision Analysis Using Annual Cost Method
   Benefit/Cost at 50% Probability = 1.94
Coping with Unknowns

Technical Unknowns
- Load Patterns, Load Growth
- Construction Costs
- Operations and Maintenance Costs

Financial/Economic Unknowns
- Cost of Money/Inflation Rate
- Future Costs/Values:
  - Demand, Energy
  - Property Taxes
  - Project Life
- Salvage Value

Customer Unknowns
- Consumption Patterns
- Dependability of Loads
Why do Analysis when Measured Data are Incomplete?

- Calibrate Your Judgement
- Rank Projects by Benefit/Cost Ratio
- Maximize Beneficial Use of Scarce Money
Comment on Analysis

To do a proper job of project analysis, you must know a great deal about your business
Loss Reduction Program under Capital Rationing

- Southern California Edison Program
- Capital Scarce
  - Credit Rating in Jeopardy
- Program Established by Head of Capital Expenditure Review Committee
Program Parameters

- Capital Expenditure Limit $1 Million per Year
- Projects Ranked by Benefit/Cost Ratio in Descending Order
- Only Projects with Benefit/Cost Ratios of 3.0 to 1 or greater were chosen
- Included Distribution lines, Transmission Lines, Substations and other equipment
- Administered by Transmission Planning Committee
## Example of Loss Reduction Program Project Ranking

<table>
<thead>
<tr>
<th>Benefit/Cost Ratio</th>
<th>Capital Expenditure ($1,000s)</th>
<th>Project Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>5.6</td>
<td>16,000</td>
<td>Reconductor 4.0 KM Apple kV</td>
</tr>
<tr>
<td>5.1</td>
<td>72,000</td>
<td>Reconductor 4.8 KM Victor-Kramer 33kV</td>
</tr>
<tr>
<td>4.8</td>
<td>27,000</td>
<td>Reconductor 3.6 KM Bluebird 16kV</td>
</tr>
<tr>
<td>4.3</td>
<td>184,000</td>
<td>Reconductor 7.8 KM Mesa-Flair 66kV</td>
</tr>
<tr>
<td>4.2</td>
<td>293,000</td>
<td>Add Line Capacitors to Grazide 12kV</td>
</tr>
<tr>
<td>3.6</td>
<td>172,000</td>
<td>Remove/Replace SEDCO 66/12kV Transformers</td>
</tr>
<tr>
<td>3.5</td>
<td>3,200</td>
<td>Reconductor 1KM Omega 4kV</td>
</tr>
<tr>
<td>3.2</td>
<td>365,000</td>
<td>Reconductor 15KM Anita-Eaton 66kV</td>
</tr>
<tr>
<td>3.0</td>
<td>92,000</td>
<td>Add Line Capacitors to Chalfant 12kV</td>
</tr>
</tbody>
</table>
Program Results

- Each Year, Projects with Benefit/Cost Ratios of 3.0 or better were Eligible
- Viewed with Enthusiasm by Engineers
- Received Favorably by Investment Community and Regulators
Losses and System Design Criteria

- Economic Conductor Size
- Distribution Transformer
- Distribution System Voltage Level
- Placement and Sizing of Station Capacitors
- Placement and Sizing of Distribution Circuit Capacitors
- Edison: Zero VAR flow at Substation
Voltage, Reactive Power and Losses

- Minimum VAR Flow
- Minimum Voltage Fluctuation
- Minimum Losses
Placement and Sizing of Distribution Circuit Capacitors

- If voltage increases from 1.0 to 1.01:
  Current decreases from 1.0 to 0.99
  Losses decrease by \((0.99)^2 = 0.98\) or 2%

- If voltage increases from 1.0 to 1.01:
  Customer load increases by 1.0%*

- Size of capacitor bank limited by voltage rise

*Southern California Edison Field Studies
Techniques for Reducing Losses on Existing System

- Distribution System
- Transmission System
- Substations
Loss Reduction - Distribution

- Circuit Balancing
- Circuit Management
- Power Factor Correction
- Voltage Upgrade/Cutovers
- Replace Oldest Transformers
- Reconductor
- Load Shaping/Demand-Side Management
- Maintain Voltage with Distribution Automation
- Add Distributed Generation
Loss Reduction - Transmission and Substations

- Transmission
  - Correct Power Factor
  - Reconductor Existing Circuits
  - Improve Voltage Plane
  - Balance Loads on Circuits

- Substations
  - Add Station VARs to Match Transformer Reactive Demand
  - Replace Aging Transformers
  - Retire Synchronous Condensers and Add Static Capacitors
Synchronous Condensers Study
Southern California Edison

- **Synchronous Condenser Status:**
  21 synchronous condensers, total 869 MVAR capacity,
  Located at 12 substations

- **Problem**
  High operation & maintenance costs, high losses

- **Study Objectives:**
  1. Reduce operation & maintenance costs and losses
  2. Maintain or exceed present quality of service to customers
Study Procedure

1. Establish a criteria for synchronous condenser removal/replacement
2. Identify function of each synchronous condenser
3. Do economic analysis
4. Evaluate operational effects of removing and/or replacing synchronous condensers
5. Make recommendations.
Removal/Replacement Criteria

- Identify units which perform "special" functions (dynamic regulation, reactive buck or boost)
- Laguna Bell short circuit duty requirements
- Units which only provide VAR support may be replaced by shunt capacitors
- Units not needed for above 3 functions may be removed without replacement.
## Synchronous Condenser Functions

<table>
<thead>
<tr>
<th>Synchronous Condenser</th>
<th>Nameplate Rating (MVA)</th>
<th>Age (Years)</th>
<th>% of &quot;A&quot; Bank VAR Load Supplied by</th>
<th>Condenser Function</th>
</tr>
</thead>
<tbody>
<tr>
<td>Antelope</td>
<td>48</td>
<td>35</td>
<td>27%</td>
<td>Voltage Regulation &amp; VAR Program</td>
</tr>
<tr>
<td>Barre No. 1</td>
<td>60</td>
<td>52</td>
<td>168%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Barre No. 2</td>
<td>60</td>
<td>42</td>
<td>88%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Center No. 1</td>
<td>60</td>
<td>35</td>
<td>388%</td>
<td>Short Circuit Tests &amp; VAR Program</td>
</tr>
<tr>
<td>Center No. 2</td>
<td>60</td>
<td>37</td>
<td>82%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Chino No. 1</td>
<td>60</td>
<td>54</td>
<td>129%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Chino No. 2</td>
<td>60</td>
<td>52</td>
<td>34%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>La Fresa</td>
<td>72</td>
<td>61</td>
<td>51%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Laguna Bell No. 1</td>
<td>45</td>
<td>69</td>
<td>128%</td>
<td>Short Circuit Tests &amp; VAR Program</td>
</tr>
<tr>
<td>Laguna Bell No. 2</td>
<td>30</td>
<td>68</td>
<td>91%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Laguna Bell No. 3</td>
<td>30</td>
<td>67</td>
<td>37%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Laguna Bell No. 4</td>
<td>60</td>
<td>65</td>
<td>72%</td>
<td>Short Circuit Tests &amp; VAR Program</td>
</tr>
<tr>
<td>Lighthipe No. 2</td>
<td>60</td>
<td>65</td>
<td>83%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Lighthipe No. 3</td>
<td>60</td>
<td>54</td>
<td>83%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Lighthipe No. 4</td>
<td>60</td>
<td>30</td>
<td>98%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Mesa</td>
<td>60</td>
<td>43</td>
<td>90%</td>
<td>VAR Program</td>
</tr>
<tr>
<td>Rector No. 1</td>
<td>30</td>
<td>44</td>
<td>33%</td>
<td>Buck/Boost &amp; VAR Program</td>
</tr>
<tr>
<td>Rector No. 2</td>
<td>30</td>
<td>44</td>
<td>30%</td>
<td>Buck/Boost &amp; VAR Program</td>
</tr>
<tr>
<td>Springville</td>
<td>40</td>
<td>42</td>
<td>205%</td>
<td>Buck/Boost &amp; VAR Program</td>
</tr>
<tr>
<td>Vestal No. 2</td>
<td>15</td>
<td>66</td>
<td>33%</td>
<td>Buck/Boost &amp; VAR Program</td>
</tr>
<tr>
<td>Vista</td>
<td>60</td>
<td>46</td>
<td>49%</td>
<td>VAR Program</td>
</tr>
</tbody>
</table>
Chino Substation

Economic Evaluation
Project Description:
Alternative Selected: ALT 2 - Install new 66kV, 4-28 MVAR Shunt Capacitor Banks
Oper. Date: 12/1/99
ALT. 1 - Continue Maintenance for Operation of 2-60 MVAR Synchronous Condensers
ALT. 2 - Install new 66kV 4-28 MVAR Shunt Capacitors Banks

<table>
<thead>
<tr>
<th></th>
<th>ALT 1</th>
<th>ALT 2</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Continue Maint.</td>
<td>Install 66kV,</td>
</tr>
<tr>
<td></td>
<td>For Oper. Of Sync</td>
<td>4-28 MVAR Shunt</td>
</tr>
<tr>
<td></td>
<td>Condensers</td>
<td>Capacitor Banks</td>
</tr>
<tr>
<td>A. Capital Expenditures</td>
<td>-</td>
<td>$2,867,952.00</td>
</tr>
<tr>
<td>B. Operating &amp; Maintenance</td>
<td>$2,986,644.00</td>
<td>-</td>
</tr>
<tr>
<td>C. Losses: Energy</td>
<td>$759,158.00</td>
<td>$37,958.00</td>
</tr>
<tr>
<td></td>
<td>Capacity</td>
<td>617,859.00</td>
</tr>
<tr>
<td></td>
<td></td>
<td>12,357.00</td>
</tr>
<tr>
<td>D. Total Present Worth Amount</td>
<td>$4,363,661.00</td>
<td>$2,918,267.00</td>
</tr>
</tbody>
</table>

Benefit Ratio = $4,363,661.00 / 2,918,267.00 = 1.5
### Calculations

#### A. Capital Expenditures

<table>
<thead>
<tr>
<th>DESCRIPTIONS</th>
<th>ALT 1</th>
<th>ALT 2</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SYNCHRONOUS CONDENSERS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>66 KV SHUNT CAPACITOR BANKS</strong></td>
<td></td>
<td>$1,833,496.00</td>
</tr>
<tr>
<td>Levelized Annual Cost = $1,833,496.00 x 1.84</td>
<td>$330,029</td>
<td></td>
</tr>
<tr>
<td>Present Worth Amount</td>
<td></td>
<td>$2,867,952.00</td>
</tr>
<tr>
<td>$330,029 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### B. Operation and Maintenance

<table>
<thead>
<tr>
<th>DESCRIPTIONS</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SYNCHRONOUS CONDENSERS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Labor required 250 Man-days/ unit</td>
<td>$243,750</td>
<td></td>
</tr>
<tr>
<td>@ $250/MD = $62,500/Units</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Total = $62,500 x units = $125,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>95% Labor Adder = 110,750</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>$243,750</td>
<td></td>
</tr>
<tr>
<td>Levelized Cost = $243,750 x 1.41</td>
<td>$343,688</td>
<td></td>
</tr>
<tr>
<td>Present Worth Amount</td>
<td></td>
<td>$2,986,644.00</td>
</tr>
<tr>
<td>$343,688 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

#### C. Losses

<table>
<thead>
<tr>
<th>DESCRIPTIONS</th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>SYNCHRONOUS CONDENSERS</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy Loss:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Machine = 618,112 kwh/unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Transformer = 133,456 kwh/unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Aux &amp; Load = 36,866 kwh/unit</td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>788,444 kwh/unit</td>
<td></td>
</tr>
<tr>
<td>Total losses = 1,576,888kwh {For two (2) Units}</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Levelized Cost = 1,576,888 x 0.0554 (LRRL)</td>
<td>$87,360</td>
<td></td>
</tr>
<tr>
<td>Present Worth Amount</td>
<td></td>
<td>$759,158.00</td>
</tr>
<tr>
<td>$87,360 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity (Demand Loss):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Demand Losses = 450 kwh/unit</td>
<td></td>
<td>$759,158.00</td>
</tr>
<tr>
<td>Levelized Cost = 450 x 2 x379/kw</td>
<td></td>
<td></td>
</tr>
<tr>
<td>{For two (2) Units}</td>
<td></td>
<td>$71,100</td>
</tr>
<tr>
<td>Present Worth Amount</td>
<td></td>
<td>$617,859.00</td>
</tr>
<tr>
<td>$71,100 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
### Calculations (CON'T)

<table>
<thead>
<tr>
<th>DESCRIPTIONS</th>
<th>ALT 1</th>
<th>ALT 2</th>
</tr>
</thead>
<tbody>
<tr>
<td>66kV SHUNT CAPACITORS</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Energy:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Loss/kvar = 0.08 watts/kvar</td>
<td></td>
<td></td>
</tr>
<tr>
<td>56,000kvar x 0.08/1000 = 4.5kw</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4.5kw x 8760 hrs/year = 39,420kwh</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Levelized Cost=</td>
<td></td>
<td></td>
</tr>
<tr>
<td>39,420 x 2 x 0.02554 (LDR)= $4,368</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Present Worth Amount=</td>
<td></td>
<td>$37,956.00</td>
</tr>
<tr>
<td>$4,368 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Capacity (Demand Loss):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>4.5 x 4 x 879/kw = $1422</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Present Worth Amount=</td>
<td></td>
<td>$12,357.00</td>
</tr>
<tr>
<td>$1422 x 8.69 (PWF)</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

**ECONOMIC FACTORS & ASSUMPTIONS**

- **Base Year**: 1993
- **Economic Life**: 30 Years
- **Escalation Rate (Capital & G&W)**: 4.7%
- **Cost of Money**: 11%
- **Carrying Charges**
  - Levelized Over Economic Life: 18%
  - Present Worth: 156%
  - Present Worth Factor: 8.69

**System Incremental Cost**

- **Capacity**
  - Base Year Cost: $89
  - Levelized revenue req'mt over life: $79
  - PW Revenue requirement: $938

- **Energy**
  - Base Year Cost: $0.0290
  - Levelized revenue req'mt over life: $0.0554
  - PW revenue requirement: $0.4813

12/26/93
Refurbishing Costs

- $2.4 M for each condenser for a 30-year life
Vista Substation Synchronous Condenser

Work that has been or will be completed by April 1, 1999

1. Equipment Replacement (Total Capital Expenditure: $507,000)
   - Cooling Tower
   - Main Hydrogen cooling coils (2)
   - Circulating water pumps and motors
   - Repair and coating of cooling tower basin
   - Exciter hydrogen cooler
   - Cooling tower basin

2. Maintenance (O&M Expense: $54,000)
   - Repair and calibrate condenser instrumentation
   - Repair babbit bearings
   - Repair bearing oil seals
   - Repair shaft exciter compartment selas
   - Resurface exciter collector rings and exciter commutator
   - Repair exciter brush rigging and exciter commutator and replace brushes
Operational Effects

Synchronous Condensers Study

Study completed by addressing 3 issues:

1. Impact on Power Quality
2. Contributions to System Voltage Stability
3. Extent of High Voltages Problems during off peak load - Need for VAR bucking
1. Impact on Power Quality

- Voltage rises (0 to 3%) due to condensers during faults (3-phase & single-phase): Not Significant

- Not significant to reduce risk of air conditioners stalling (to avoid voltages of less than 60%)

- Beneficial at La Fresa for Mobil Oil, and Springville for voltages sensitive customers (Smoothing or eliminating voltage fluctuations)
2. System Voltage Stability

- Resuming operation of all synchronous condensers (655 MVAR) could have reduced 1999 RMR capacitor Banks by 675 MVAR

(Same post transient voltage drops following worst N-1 Palo Verde-N Gila 500-kV line)

- However it would result in Much Larger Costs: $40 M for refurbishing and $40 M PW for O&M versus $16.5 M for 675 MVAR of RMR Caps.
3. High Off Peak Load Voltages

- Voltages in excess of Operating Bulletin 17 Limit (66.5 kV) during off peak load at 6 substations with tapped out 220/68.7 kV transformers

- No apparent adverse impacts

- Problem can be corrected with 28-MVAR 66-kV reactors instead of condensers (La Fresa & Vista)
Mesa 66-kV Bus Voltage
During Week End of January 18-19, 1998
Recommendations

• Out of 21 SCE condensers only 3 still in service:

• Maintain 2 condensers for power quality: at La Fresa and Springville substations.

• Maintain condenser at Vista substation until failure requires major O&M or capital cost

• Install voltage regulator at Springville substation (transferred from Lighthipe substation condenser)
MacNeil Switching Substation Line and Bus Arrangement Modification

March 2, 1999

Phil Save
Electric Grid Planning
Need for Equipment Replacement at MacNeil Switching Substation

- All 66-kV insulators and disconnects
- All 66-kV oil breakers
- Total Cost: $1.3 million
- Northern T/S requested study to minimize cost
- Study Considered Six Alternatives
Eagle Rock and Saugus 66-kV Systems in Vicinity of MacNeil Switching 66-kV Substation
MacNeil Switching 66-kV Substation Line and Bus Arrangement

Existing: 12 breakers
Alternative 3

3 breakers
Alternative 4

5 breakers
Alternative 5

5 breakers with Operating and Transfer Bus
### MacNeil Substation 3-Breakers Alternative and 5-Breakers Alternative Comparison for Reliability of Service to Studio and Universal Substations

<table>
<thead>
<tr>
<th>Lines</th>
<th>Miles</th>
<th>Outage Type</th>
<th>Rate (Per Year)</th>
<th>Duration (Minutes / Outage)</th>
<th>Outage Frequency (Per Year)</th>
<th>Outage Duration (Min in Years)</th>
<th>Annual Down Time (Minutes / Year)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-Breakers Alternative - Single Bus</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Delco 66KV Lines - Eagle Rock McNeil and Mc-Neil Studio-Universal</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beverly Hills Studio-Universal - Eagle Rock Studio-Universal</td>
<td>7.2</td>
<td>Forced</td>
<td>0.7</td>
<td>16.4</td>
<td>2.9E-04</td>
<td>3.454</td>
<td>14.0</td>
</tr>
<tr>
<td>5-Breakers Alternatives</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A. Single Bus</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beverly Hills Studio-Universal - MacNeil Studio-Universal</td>
<td>7.2</td>
<td>Forced</td>
<td>0.7</td>
<td>16.4</td>
<td>3.3E-04</td>
<td>19.983</td>
<td>7.8</td>
</tr>
<tr>
<td>Beverly Hills Studio-Universal - MacNeil Studio-Universal (During Breaker Maintenance)</td>
<td>3.5</td>
<td>Forced</td>
<td>0.2</td>
<td>15.0</td>
<td>5.05E-04</td>
<td>1.086</td>
<td>16.0</td>
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<tr>
<td>Total for Both N-2 Outages</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>B. Operating and Transfer Buses</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Beverly Hills Studio-Universal - MacNeil Studio-Universal</td>
<td>7.2</td>
<td>Forced</td>
<td>0.7</td>
<td>18.4</td>
<td>8.3E-05</td>
<td>119.083</td>
<td>7.8</td>
</tr>
</tbody>
</table>
### Maintenance of SCE Circuit Breakers

#### Typical Outage Rates and Duration

<table>
<thead>
<tr>
<th>Maintenance Type</th>
<th>Breaker Type</th>
<th>Transmission</th>
<th>Subtransmission</th>
<th>Distribution</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td>Rate (Per Year)</td>
<td>Duration (Day)</td>
<td>Rate (Per Year)</td>
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<tr>
<td>OVERHAUL</td>
<td>AIR BLAST</td>
<td>0.1</td>
<td>30</td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>GAS</td>
<td>0.1</td>
<td>5</td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>OIL</td>
<td>0.1</td>
<td>5</td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>VACUUM</td>
<td>0.1</td>
<td>2</td>
<td>0.1</td>
</tr>
<tr>
<td></td>
<td>AIR MAGNETIC</td>
<td>0.2</td>
<td>0.25</td>
<td>0.2</td>
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<tr>
<td>GAS REFILLING</td>
<td>AIR BLAST</td>
<td>1.0</td>
<td>0.25</td>
<td>1.0</td>
</tr>
<tr>
<td></td>
<td>GAS</td>
<td>1.9</td>
<td>0.25</td>
<td>1.0</td>
</tr>
<tr>
<td>BREAKER MECHANISM MAINTENANCE</td>
<td>ALL</td>
<td>0.4</td>
<td>0.17</td>
<td>0.5</td>
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<tr>
<td>BREAKER MAINTENANCE EQUIVALENT</td>
<td>AIR BLAST</td>
<td>1.8</td>
<td>2.08</td>
<td>1.8</td>
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<td></td>
<td>GAS</td>
<td>1.8</td>
<td>0.52</td>
<td>1.8</td>
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<td></td>
<td>OIL</td>
<td>0.9</td>
<td>0.91</td>
<td>0.9</td>
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<tr>
<td></td>
<td>VACUUM</td>
<td>0.6</td>
<td>0.44</td>
<td>0.6</td>
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<tr>
<td></td>
<td>AIR MAGNETIC</td>
<td>0.7</td>
<td>0.31</td>
<td>0.7</td>
</tr>
</tbody>
</table>
### MacNeil Substation Line and Bus Arrangement Alternatives

#### Economic and Reliability Comparison

<table>
<thead>
<tr>
<th>Alternatives</th>
<th>Savings ($ Millions)</th>
<th>Outage Frequency (Once in N Year)</th>
<th>Outage Duration (Minutes Per Outage)</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-Breakers Alternative - Single Bus</td>
<td>0.973</td>
<td>1 in 3,450</td>
<td>14</td>
</tr>
<tr>
<td>5-Breakers Alternatives</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>A. Single Bus</td>
<td>0.783</td>
<td>1 in 1,050</td>
<td>16</td>
</tr>
<tr>
<td>B. Operating and Transfer Bus</td>
<td>0.729</td>
<td>1 in 118,000</td>
<td>8</td>
</tr>
</tbody>
</table>

#### Outages of Both Substations Due to Bus Faults or Earthquakes

1 in 5

---

Outages of both substations due to bus faults or earthquakes.
Recommendation

• Recommended Alternative:
  3-breakers with single bus arrangement

Savings: From $1.3 \text{ M} \text{ to } 0.367 \text{ M} = $0.967 \text{ M}

• 5-breaker with operating and transfer bus:

No significant increase of reliability
Additional expenditure of $244,000 is not justified
Relationship of Loss Reduction to:

- Demand-Side Management
- Load Shaping
- Distribution Automation
- Distributed Generation
Impact of Customer Load Profile on Cost of Service and Losses

<table>
<thead>
<tr>
<th>Level of Service</th>
<th>Lower Cost per kWh</th>
<th>Higher Cost per kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>Higher Voltage</td>
<td></td>
<td>Lower Voltage</td>
</tr>
</tbody>
</table>

Efficiency

- Peak Load       | Off-Peak           | On-Peak            |
- Load Factor     | High               | Low                |

Amount of Usage

- High             | Low
Demand Side Management Choices

BUILT-IN INCENTIVES
- TOU RATES
- OFF-PEAK STORAGE
- SWIMMING POOL TRIPPERS
- CONSUMER EDUCATION

UTILITY-ACTUATED
- HEATING & AIR CONDITIONER CYCLES
- INTERRUPTIBLE LOAD
- DEMAND SUBSCRIPTION SERVICE

CONSERVATION
- PRICE INDUCED
- PROGRAMS
- COMMUNICATION
Demand-Side Management embraces several load shape objectives:

- Peak clipping
- Valley filling
- Load shifting
- Strategic conservation
- Strategic load growth
- Flexible load shape
Peak Clipping, Load Shifting

**Peak Clipping**
- Defined as reduction during peak hours
- Examples:
  - Dual fuel heating
  - Heat pumps
  - Interruptible loads
  - Some conservation options

**Load Shifting**
- Defined as shift from peak to off-peak
- Examples:
  - Water heater control
  - Air conditioner control
  - Storage heating
  - Storage cooling
  - Interlocks
  - Irrigation control
Valley Filling, Conservation

Valley Filling

- Defined as increased off-peak loads

Examples
- Electric vehicles
- New loads
- Thermal energy storage

Conservation

- Defined as reduction during peak and off-peak hours

Examples
- Weatherization
- Heat pump water heaters
- Heat pumps replacing resistance
Growth, Flexible Load Shape

**GROWTH**

- Load
- Time
- Defined as growth during peak and off-peak hours

**Examples**
- New electric space heating loads
- Increased appliance saturation
- Area development
- Electrification

**FLEXIBLE LOAD SHAPE**

- Defined as reducing entire load on call

**Examples**
- Interruptible Loads
- Dual Fuel Heating
- Stand-by Generation
- Levels of Reliability
Automatic Regulation of Customer Voltage and VAR Control

Voltage Range Required by California Code

\[ \{ 126 \text{ Volts Maximum} \quad 120 \text{ Volts} \quad 114 \text{ Volts Minimum} \} \] Voltage Range Agreed To
Relationship of Loss Reduction to Distributed Generation

• Types of Distributed Generation:
  - Small Hydro
  - Cogeneration
  - Solar

• How These Sources Can Reduce Losses:
  - Placed adjacent to the load (cogeneration, solar)
  - Can match load patterns (cogeneration, solar)
  - Highly efficient (small hydro)
  - Are used to replace distributed lines (solar)
Relationship of Loss Reduction to Least-Cost Plan

- Least Cost Planning Includes:
  - Supply and Demand-Side Planning
  - Proper accounting for losses
  - Weighing of Fixed versus Variable Costs
  - Assessment of the Future

- Example:
  Duke Power
  - Low Losses: 5.7%
  - Low Cost of Service - 7.3¢
  - High profitability: Price/Earnings - 17
Traditional Response to Demand: Build Power Lines
Alternative Response: Distributed Generation
Solar (PV) Grid-Support Value Analysis Definitions

Traditional Value
- **Energy** (generation displacement)
- **Capacity** (system reliability enhancement)

Non-Traditional Value
- **Substation** (transformer and LTC deferral)
- **Feeder** (feeder upgrade deferral)
- **Loss Savings** (energy and VAR loss reduction on T&D)
- **Reliability** (local reliability enhancement)
- **Externalities** (fossil fuel emissions reduction)
- **Transmission** (transmission deferral)
- **Minimum Load** (power plant dispatch savings)
Grid-support PV in action: The Kerman Project

Kerman PV plant connected on 12 kV Feeder 1103, 8 circuit miles from substation
PV plant reduces number of LTC changes

The graph shows the relationship between LTC voltage range (Volts) and annual LTC changes (in 1000s). The data is divided into two categories:

- LTC Changes with PV Plant (1993)

The graph indicates that the presence of a PV plant significantly reduces the number of LTC changes compared to the period without a PV plant.
PV provides 75% equivalent firm capacity
Kerman plant power profiles

- Summer (Jun-Aug)
- Spring (Mar-May)
- Fall (Sep-Nov)
- Winter (Dec-Feb)

\( \approx 80\% \) of Rating During Summer Peaks

Kerman PV Plant Output (kW/acre)

Pacific Standard Time

pg. 134
Kerman plant performs close to design

1080 MWh/yr production; 25% Capacity Factor; 90% Performance Index
Kerman PV plant reduces transformer loads

![Graph showing transformer load with and without PV output, with peak loads and PV output curves. The graph illustrates how PV output reduces peak loads.](image-url)
Kerman PV plant reduces transformer loads

Extends equipment life and defers need for upgrades

![Graph showing temperature variations with and without PV integration.](image-url)

- Hot-spot Temp. w/o PV
- Top Oil Temp. w/o PV
- Hot-spot Temp. w/ PV
- Top Oil Temp. w/ PV
PV plant increases transmission system capacity

PV output correlates well with the need for transmission system capacity
Kerman PV Plant Reduces System Losses

- Reduces energy losses by 98,600 kWhs (that's 9.3% of plant output)
- Value of Reduced Losses $6,900
- That's $13.8/kW-year
Kerman PV plant provides externality value of $0.015/kWh
Tangible benefits translate into economic value to PG&E

Non-Traditional Benefits Double Plant Value

Kemn PV Plant Value ($/kW-yr)

- Externalities
- Reliability
- Electrical Losses
- Substation
- Transmission
- Minimum Load
- Capacity (Traditional Value)
- Energy (Traditional Value)

Nominal

High

$295

$425
Loss Accounting for Direct-Service Customers

- By Contract
  - "Postage Stamp"
  - Point-to-Point
  - Network or MW-Mile Approach

- Through month-end settlement process
  - Allocation proportioned to size

- The California Approach
Loss Accounting Details

- “Postage Stamp” Method
  If transmission system losses are X%, each direct customer is assigned X% losses.

- Point-to-Point Method
  Assign losses to a direct service customer based upon losses in an identified transmission path.

- Network or MW-Mile Approach
  From a Power flow study or from measurements, calculate

\[
\frac{\sum \text{Losses in Network}}{\sum \text{MWX Miles (for each transmission line in the network)}} = \text{Losses MW-Mile}
\]

1. Add up the transmission line miles for the shortest path in the network for direct service customer
2. Multiply
Network or MW-Mile Transmission Map
California’s Loss Accounting for Direct-Service Customers

- % Loss Factors
  - Modified “Postage Stamp” Approach
  - % Loss Factors by Voltage Levels
  - % Loss Factors by Hours (8760/year)

- Generators
  - “Loss Multipliers” Depending on Connection Point

- Consumers
  - “% Loss Factors” Depending on Connection Point

- Data Available “On Line” on Public Utilities Commission Web Site
Economic Dispatch with Transmission Loss Factors

- Appropriate where Generation is Remote from load
- Loss penalty factors assigned to Power Plants
- Dynamic methods available
Class Study Exercise

Analyze Loss Reduction Projects under conditions of Limited Investment Capital

- 3 Different Projects
- Use at least Two Methods to analyze each Project
- Use Results to convince management to Approve 1, 2, or all 3 Projects
Loss Reduction Project #1

Project: Reconductor section of Omega 4kV Circuit

Project Factors:
Reconductor 2 KM section from 2/0 ASCR to 336 ACSR
(requires replacement of about 1/2 the crossarms)

Material $6000  
Labor $2500  
Salvage Value (600)  
Total $7900

Customer Factors:
• Only one customer, a 1000 HP pump, 3Ø, 90% PF
  (115 amps per phase)
• Customer plans to retire the pump in 10 years, no other
customer load expected on the circuit
Loss Reduction Project #2

Project: Reconductor section of Alpha 4kV Circuit

Project Factors:
Reconductor 2 KM section from 2/0 ASCR to 336 ACSR
Total Investment $7900

Customer Factors:
• Only one customer, a 1000 HP pump, 3Ø, 90% PF
  (115 amps per phase)
• There is a 50% chance the customer will retire the pump in 10 years, and a 50% chance the pump will run for 20 years. No other customer load expected at this time
Loss Reduction Project #3

Project: Add Capacitor Bank to 4kV Beta Circuit

Project Factors:
- 300 CkVa Capacitor Bank
- Installed cost $4000
- 2% voltage rise due to capacitor
- Bank expected life = 20 years

Customer Factors:
- Customer load at the end of the 4 KM long circuit
- 3,200,000 kWhs/year, with an estimated 90% power factor
- The load factor is typical for such a circuit, about 50%
- Load is not expected to change in the future.
Economic Parameters

- Use Economic Parameters from Omega Circuit example
  e.g.
  10% cost of money
  15.8% carrying charge (for 30 years)
  2.7¢/kWh Energy Value of Losses (1999)
  Also energy cost increases, etc.

- Use energy loss multipliers from course
  e.g.
  Subtransmission 1.028
  B Banks low side 1.036

- Use conductor loss characteristics from course
Commercial Losses - Causes: Metering, Billing and Collections

- Metering and Meter Testing
- Billing and Billing Systems
- Collections and Non-payment
- Energy Theft
Sources of Metering Errors

- Current Transformers and potential transformers used for customers above 240 volt service
- Older jeweled-type meters
- Mechanical meter characteristics
- Calibration
Meter Characteristics
(Examples)

Meter #
Assignment Status
Manufacturer Type
Device Type
Material Code
Profile Types
Measurement Values
Set & Remove Dates
Typical 2-S Meter
Edison Metrology Laboratory
Metering System for 500kW and Larger Customers
Electronic Metricom Meter
Metricom Radio
ABB Electronic Meter with RS232 Port
Meter Testing & Calibration

- Large Customer Meters (500 kW & above)
  15 minute interval data - test every six months

- Medium Customer Meters (200 - 500 kW)
  Test once per year

- New Meter Purchases
  Spot check several before accepting

- Qualifying new meter types for company use -
  One year process
Billing and Billing Systems

- Edison Billing Organization

- Customer Information and Customer Choice
  - CSS Billing features (example: GS-1 Rate)
  - Residential bills and choices
  - Direct Access Customers
Edison Meter Reader
CSS Features

• We can bill
  Agricultural
  Commercial/Industrial
  Catalina
  Domestic
  Special Billing
  Streetlights
  Cal Trans
  Sub-ledger
  Memo bills
CSS Features

• Summary Billing
  • For any customer
  • Reorganization of services among multiple summary bills upon customer request
  • Automated collections services for summary billed accounts
CSS Features

- Pick your bill date
- Receivables corrections made easy
- Perpetual customer history
- Extensive on-line bill and payment history
- Automated deposit management
Who’s Eligible?

- Medium-sized commercial and industrial customers with demands greater than 20 kilowatts and no more than 500 kilowatts
How are you billed?

- **Customer Charge**
  Recovers costs to install, operate and maintain, read and bill your meter

- **Single Phase Service Credit**
  A $1.65 per month credit is applied to customers who receive single phase service

General Service 2 (GS-1) Rate
How are You Billed?

- **Demand Charge**
  - Non-time related
    - Maximum monthly registered demand or 50% of the highest demand in the previous 11 months
    - Recovers costs for facilities dedicated to meeting your demand any time of the year
  - Time related
    - Applies only during summer months
      Varies by time of day
    - Recovers costs to generate electricity during certain times of the day

General Service 2 (GS-1) Rate
How are You Billed? (con’t)

• Energy Charge
  - Recovers costs to operate and maintain Edison’s system
  - Broken down by “1st Block” and “2nd Block”
  - Recovers cost of fuel and purchased power
  - Surcharge paid to:
    - Customers
      Who meet specified income guidelines
    - California Public Utilities Commission

• Power Factor Adjustment
  - A charge for the inefficient use of equipment

General Service 2 (GS-1) Rate
How are You Billed?

- **Voltage Discount**
  - Applied to
    - Customer who can receive power at higher voltages
      Charged to monthly non-time related demand charge and base rate energy charge

- **City/County Taxes**
  - Certain cities and counties contract with Edison to bill their energy taxes

- **State Energy Tax**
  - Funds energy planning activities of the California Energy Commission
    - State law enacted in 1975

General Service 2 (GS-1) Rate
How Does the “Blocked Energy Charge” Work?

• **Two-tiered charge**
  - One rate for first block of kilowatt hours (kWh)
    • Approximately 9¢/kWh
  - Lower rate for second block of kWh
    • Approximately 5¢/kWh

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Demand registered in a billing period</td>
<td>25 kW</td>
</tr>
<tr>
<td>kWhs consumed in a billing period</td>
<td>10,000 kWh</td>
</tr>
<tr>
<td>Calculate kWhs in first block (normal rate)</td>
<td>25 kW</td>
</tr>
<tr>
<td></td>
<td>x 300 kWh</td>
</tr>
<tr>
<td></td>
<td>= 7,500 kWh</td>
</tr>
<tr>
<td>Calculate kWhs in second block (lower rate)</td>
<td>10,000 kWh</td>
</tr>
<tr>
<td></td>
<td>- 7,500 kWh</td>
</tr>
<tr>
<td></td>
<td>= 2,500 kWh</td>
</tr>
<tr>
<td>What appears on the bill</td>
<td>7,500 kWh-normal rate</td>
</tr>
<tr>
<td></td>
<td>2,500 kWh-lower rate</td>
</tr>
</tbody>
</table>
# Residential Bill - January 1997

## Customer and Service Address
WHYTE, M DOUGLAS  
505 GREENVIEW RD  
LAHABITIS CA 90631

## Date Bill Prepared
Dec 26, 1996

## Next Meter Read on or about
Jan 22, 1997

## Rate Schedule
DE

## Charges & Credits
- Balance from previous bill: $90.00
- Credits Account Balance: $0.00

## Update
- Service / Billing Period: 11/22/96 to 12/24/96 (32 days) - Winter Season

## Energy Charge:
- Baseline: 336 kWh x 9.61c = $75.84
- Basic Charge: 429 kWh x 10.62c = $0.80
- State Tax: 765 kWh x 0.15c = $0.11

### Current amount must be paid by 01/14/97
$76.79

### Estimated Electricity Usage
- Meter Number: 208-556865
- Dates and Readings: 11/22/96 to 12/24/96
- Usage: 765 kWh

### Usage Comparison
- This Year: 765 kWh  
- Last Year: 0 kWh

### Kilowatt hour (kWh) used:
- Number of days: 32  
- Average usage per day: 23.9

## Message
A SPECIAL THANKS AND HOLIDAY WISH
Thank you for paying your Edison bills promptly. We appreciate the opportunity to serve you and wish you a happy Holiday Season. Look for our all-electric float in the Rose Parade, honoring Thomas Alva Edison.

WINTER SAFETY TIP - ALWAYS use a flashlight... NEVER use candles during a power outage.
Residential Bill - August 1998

Customer and Service Address
WHYTE, M DOUGLAS
505 GREENVIEW ROAD
LAHABYTS CA 90631

Date Bill Prepared
Aug 22, 1998
Next Meter Read on or about
Sept 21, 1998

Your Customer Account Number
2-07-553-2069
24-hr. Customer Service
1 (800) 632-2533

Service Account
3-004-0278-58
Old Account #
65-47-018-2030 03
Rate Schedule
DE

Update
Amount of previous statement 07/24/98
$61.65
Payment received 08/06/98 - Thank you
0 (61.65)

Account Balance: $ 0.00

Summary
Service / Billing Period: 07/22/98 to 08/20/98 (29 days) - Summer Season

Basic Charge
29 days x $0.053300 $0.96

Energy Charge:
Baseline
500 kWh x $0.12800 #55.63
Over Baseline
505 kWh x $0.14187 $71.21
Employee Discount $29.43

Subtotal $88.37
Legislated 10% Rate Reduction (8.84)
Current Billing Detail Subtotal $79.53
State Tax 805 kWh x $0.00003 $0.18

Current amount must be paid by 09/10/98 $79.71

$2.75 is your daily average cost this period
Service Voltage: 240 Volts
Your Baseline Allocation for this Billing Period is: 380 U kWh
Average PX Energy Charge during this period was: 5.26 cents/kWh
Of your total charges, Franchise Fees represents: $0.04
<table>
<thead>
<tr>
<th>Detail</th>
<th>This Year</th>
<th>Last Year</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Charges</td>
<td>99.71</td>
<td>17.72</td>
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<tr>
<td>Total Usage Charges</td>
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<tr>
<td>Current Account Due</td>
<td></td>
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<tr>
<td>Meter Number</td>
<td>ZED-594863</td>
<td>67/27</td>
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<tr>
<td>Usage Comparison</td>
<td>14467</td>
<td>14640</td>
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<tr>
<td>Usage</td>
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<td></td>
</tr>
<tr>
<td>Surcharges and Add-ons</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Usage</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

---

**Message**

WE ARE HERE FOR YOU, WHEREVER YOU NEED US.

**Usage**

ZED-594863

---

**Summer Smat**

Summer Smat is the latest innovation that makes saving money on your air conditioning easier than ever. By monitoring your energy usage, our system automatically adjusts the temperature to keep you comfortable while minimizing your energy costs. Whether you're at home or on the go, Summer Smat ensures you're always getting the most out of your energy dollars. Check it out today and see how much you can save!
Direct Access Customers

Payments to Generation Provider
  - for Electric Power

Payment to ISO
  - for Dispatching Service

Payment to Edison
  - for Transmission and Distribution
Revenue Collections and Non-Payment

- CSS Collection System
- Customer Credit Rating
- Collection Rules and Queues
- Uncollectable Accounts
- Uniform Accounting System
CSS Collection Path

- Expired Overdue Notice
- Deferred (Less than $25.00)
- Autodialer

5 Days Later

CSS Collections Event Scheduler

- Real-Time Scheduling
- NO 3-Day Process
- NO Pony
- NO Manual Sorting

Urgent Notice

Credit Administration Queue

PWS → T-4000 Final Call Disconnect Still Off
CSS Collection Path (con’t)

CSS COLLECTIONS
PATH FOR NEW DOMESTIC

OPEN COLLECTION

$50 AND OVER

GOOD PHONE #

AUTODIALER ATTEMPTS TO COLLECT

NO REASONABLE ATTEMPT

FINAL CALL MAILED

BAD PHONE #

6 TIMES

FINAL CALL DELIVERED

NO

TO THE FIELD FOR A 48

REASONABLE ATTEMPT

FINAL CALL EXPIRES

FIELD FOR DISCONNECTION

6 TIMES

FINAL CALL EXPIRED

MAILED/DELIVERED

EXPIRES

DISCONNECTION
Collection System Benefits

- The system accumulates information from various CIS screens and displays within one transaction:
  - RETURN CHECKS -- Reflects number of check returned since customer was brought into collections
  - URGENT MAILED/EXPIRED -- Displays number of notices mailed and expired
  - EXTENSION/PAYMENT ARRANGEMENT -- Displays number of extensions and payment arrangements made
  - DEFAULTS -- Defaults on extensions or payment arrangements displayed
  - FINAL CALL VERBAL -- Final calls by phone (Autodialer)
  - OVERDUE MAILED -- Number of overdue notices mailed in last 12 months
  - FINAL CALL FIELD -- Final calls presented in the field
- Credit Score utilized in place of Credit Code
- Credit Action not restricted by group cycles
- Real-time processing
- KMFC displays action scheduled
- Accelerated cash flow/Reduced write-off
- Provides work flow management
Behavior Credit Score

- Based on CIS data
- Calculated at billing time
- LOW, MEDIUM, and HIGH (like a test score)
  - LOW indicates unacceptable payment pattern
  - MEDIUM is acceptable payment pattern
  - HIGH indicates exceptional payment pattern
Collection Rules and Queues

- **Rules**
  - Corporate set of rules
  - 974 pages of rules (more now)
  - 108 events recognized
  - 62 attributes/profiles

- **Queues**
  - 25 dispatcher queues
  - Error, training, and review queues
  - Worker queues
    - Work sorted alphabetically,
    - by region,
    - by organization,
    - by work group
Southern California Edison
Uncollectible Accounts

% of Collected Revenue


0.35

0.30

0.31

0.32

0.27

0.26

0.25

0.26

0.25

0.33

0.23

0.15

pg. 185
Pricing Theories in a Regulated Utility

- Try to Emulate Competition
- Economically Efficient Use of Resources
- Provide a Stable Revenue Stream
- Equity Among Customer Groups
- Conservation of Energy Resources
Ratemaking - Neither Art Nor Science

- Revenue Stability
- Influence Behavior of Consumers
- Price Signals
- Rate of Return/Cost of Service
- Reflect Social Cost/Taxes
- Avoid Undue Discrimination
- Simplicity, Certainty, Convenience
- Reflect Service Quality
- Respond to Market Conditions
Service Configuration to Retail Customers

Diagram showing the flow from a Generator, through a Distribution Substation, Primary Service, Distribution Line, Transmission Line, Transmission Substation, Primary Transformer, and finally to Secondary Service.

Table showing the service configuration:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>2</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>3</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td></td>
</tr>
<tr>
<td>4</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

Additional notes:
- PG. 188
Planning Criteria, Reliability and Rates

• Generation Reliability applies to Entire Power Company

• Transmission Criteria applied uniformly throughout the power company

• Distribution Criteria applied uniformly throughout the power company

• Customers Receive (Approximately) Equal Reliability for Standard Rates

• Individual Customers can Upgrade their Reliability of Service through “Added Facilities”
### Impact of Customer Load Profile on Cost of Service

<table>
<thead>
<tr>
<th></th>
<th><strong>Lower Cost per kWh</strong></th>
<th><strong>Higher Cost per kWh</strong></th>
</tr>
</thead>
<tbody>
<tr>
<td>Level of Service</td>
<td>Higher Voltage</td>
<td>Lower Voltage</td>
</tr>
<tr>
<td>Quality of Service</td>
<td>Curtailable</td>
<td>Firm</td>
</tr>
<tr>
<td>Efficiency</td>
<td></td>
<td></td>
</tr>
<tr>
<td>- Peak Load</td>
<td>Off-Peak</td>
<td>On-Peak</td>
</tr>
<tr>
<td>- Load Factor</td>
<td>High</td>
<td>Low</td>
</tr>
<tr>
<td>Level of Usage</td>
<td>High</td>
<td>Low</td>
</tr>
</tbody>
</table>
## Southern California Edison Rates

**Effective: May 1, 1996**

<table>
<thead>
<tr>
<th>Rate Group</th>
<th>Rate (¢/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Domestic</td>
<td>12.7</td>
</tr>
<tr>
<td>GS-1</td>
<td>13.6</td>
</tr>
<tr>
<td>TC-1</td>
<td>7.3</td>
</tr>
<tr>
<td>GS-2</td>
<td>10.1</td>
</tr>
<tr>
<td>TOU-GS-2</td>
<td>9.1</td>
</tr>
<tr>
<td>TOU-8-SEC</td>
<td>8.6</td>
</tr>
<tr>
<td>TOU-8-PRI</td>
<td>7.5</td>
</tr>
<tr>
<td>TOU-8-SUB</td>
<td>4.5</td>
</tr>
<tr>
<td>PA-1</td>
<td>11.1</td>
</tr>
<tr>
<td>PA-2</td>
<td>8.7</td>
</tr>
<tr>
<td>TOU-PA-5</td>
<td>7.1</td>
</tr>
<tr>
<td>AG-TOU</td>
<td>7.9</td>
</tr>
<tr>
<td>Street/Area Lighting</td>
<td></td>
</tr>
<tr>
<td>System Average</td>
<td>10.1</td>
</tr>
</tbody>
</table>

5-1-96 Average
Energy Theft Mitigation

• Energy Theft Program
  - Prevention:
  - Detection
    Observation, Tip Cards, Computer Detection, Detection Bonus, Energy Theft Hotline, Tap Detector.
  - Investigation:
    Resealing Meters, Meter Testing, Service Investigations
  - Prosecution
  - Restitution
    Revenue Recovery

• Revenue Protection Group
• Revenue Protection Manual
• International Utilities Revenue Protection Newsletter
Security Locking Ring Address

Inner-Tite Corp.
1094 Globe Avenue
Mountainside, New Jersey, 07092, U.S.A.

Telephone 908/232-4000
FAX 908/232-7281
STOP ENERGY THEFT with Meter Sentry II.

Ever since the installation of the first residential socket watt/hour meter, the industry has been waiting for a simple, LOW COST method of detecting meter tampering.

MEET THE METER SENTRY II...
Meter Sentry Address

Universal Protection Corp.
3620 Clearview Parkway
Atlanta, Georgia, 30340, U.S.A.

Telephone  770/936-8070
            800/635-5042
FAX  770/936-0188
# Edison Tip Card

## Revenue Protection Tip

<table>
<thead>
<tr>
<th>CIS</th>
<th>Addtl.</th>
<th>CA No.</th>
<th>Cus. No.</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

## Suspect Conditions

<table>
<thead>
<tr>
<th>Meter</th>
<th>CT Installations</th>
</tr>
</thead>
<tbody>
<tr>
<td>Seen Inverted</td>
<td>Insulated Test Switch</td>
</tr>
<tr>
<td>Suspect Inverted</td>
<td>Open Test Switch</td>
</tr>
<tr>
<td>Hole in Glass</td>
<td>Improper Test Switch</td>
</tr>
<tr>
<td></td>
<td>Wiring</td>
</tr>
<tr>
<td></td>
<td>Improper CT wiring</td>
</tr>
<tr>
<td></td>
<td>Wrong CTs</td>
</tr>
<tr>
<td></td>
<td>Tampered CTs</td>
</tr>
<tr>
<td></td>
<td>Other (explain below on back)</td>
</tr>
<tr>
<td>Foreign Meter</td>
<td>Tampered Seals</td>
</tr>
<tr>
<td>(give meter no. and read)</td>
<td>(not missing seals)</td>
</tr>
<tr>
<td></td>
<td>Magnet on Meter</td>
</tr>
<tr>
<td></td>
<td>Tampered Scale</td>
</tr>
<tr>
<td></td>
<td>Tampered Drum</td>
</tr>
<tr>
<td></td>
<td>Suspension</td>
</tr>
<tr>
<td></td>
<td>Tampered Gears</td>
</tr>
<tr>
<td></td>
<td>Photo Cell</td>
</tr>
<tr>
<td></td>
<td>Incorrect Register</td>
</tr>
<tr>
<td></td>
<td>Open Pot Link</td>
</tr>
<tr>
<td></td>
<td>Worn Stamps</td>
</tr>
<tr>
<td></td>
<td>(excessive/epoxy color)</td>
</tr>
<tr>
<td></td>
<td>Improper Meter (wrong volt, etc.)</td>
</tr>
<tr>
<td></td>
<td>Other (explain below on back)</td>
</tr>
</tbody>
</table>

## Other Orders Required

- Jumper/Tip/Bypass
  - At Synch/Secondary
  - At Roof/At Weatherhead
  - Seen in Riser
  - Suspected in Riser
  - In New Panel (bring in old meter)
  - In Meter Socket
  - Pull Section
  - Test Blocks
  - At line-side main switch
  - A-Base Wiring
  - In Hand-Hole
  - Other (explain below on back)

---

**BEST AVAILABLE COPY**

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Revenue Protection Results

Billings ($millions)

- 1996: 2.5
- 1997: 4.7

Collections ($millions)

- 1996: 2.3
- 1997: 4.1

Write-Offs ($thousands)

- 1996: 620
- 1997: 350