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AED

Academy for Educational Development

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

ARMENIA ENERGY SECTOR TRAINING PROGRAM
Technical Report
Course #10: Electric Transmission and Distribution Loss Reduction Strategies

USAID Strategic Objective 1.5	A more economically sustainable and environmentally sound energy sector
Intermediate Result 2	Increased economic efficiency in the energy sector
Participant profile	Armenia's energy companies, government ministries and regulatory entities with competence over the energy sector

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.

Table 1: List of Participants

#	Name	Employer	21-Jun	22-Jun	23-Jun	24-Jun	25-Jun
1	Anahit Avetisyan	Energy Regulatory Commission	+	+	+	+	
2	Garegin Baghramyan	Energy Regulatory Commission	+	+	+	+	+
3	Armenak Yayloian	Energy Regulatory Commission	+	+	+	+	+
4	Victor Sahakov	Institute of Energy	+				
5	Svetlana Ganjumyan	Institute of Energy		+	+	+	+
6	Razmik Sardaryan	Central Distribution Company	+	+			
7	Meruzhan Hovsepyan	Central Distribution Company		+	+	+	
8	Vardush Hambartsumian	Yerevan Distribution Company	+	+	+	+	+
9	Arayik Davtyan	High-Voltage Distribution Company	+	+	+	+	+
10	Larisa Badalyan	High-Voltage Distribution Company	+	+	+	+	+
11	Naira Sargsyan	Armenergo	+	+	+	+	+
12	Martik Melkumyan	Armenergo	+				
13	Martin Ghahramanyan	Armenergo	+	+	+	+	+
14	Derenik Asatryan	Armenergo		+			
15	Karine Saghatelyan	Armenergo		+		+	+
16	Alexey Tumanov	Armenergo				+	
17	Petros Kyalyan	Hrazdan Thermo-power plant				+	+
18	Gagik Sahradyan	Ministry of Finances				+	
19	Alexandr Samarchyan	Ministry of Finances				+	
		TOTAL	**11**	**13**	**10**	**15**	**10**

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.

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

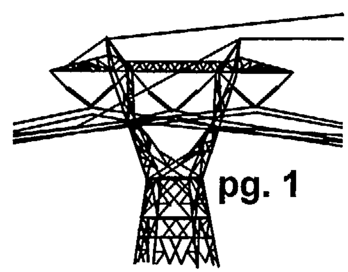
Electric Transmission and Distribution Loss Reduction Strategies

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:

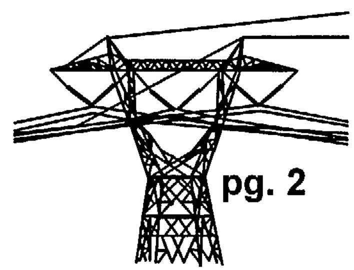
Industrial Relations Depts., U. C. Berkeley and Cornell University, 1981-1987

IIE / US AID Courses

Moscow & Kraznoyarsk 1995

St. Petersburg & Kyrgyzstan 1996

Moscow 1997



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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.

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Course Overview

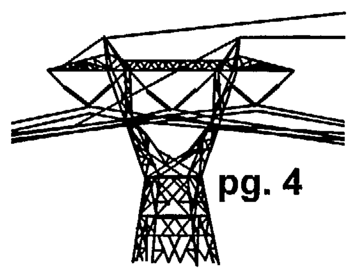
MONDAY
- Discuss Desired Course Outcomes
- Technical Losses: Causes, Measurement, Costs

TUESDAY
- Loss Reduction Programs & Techniques

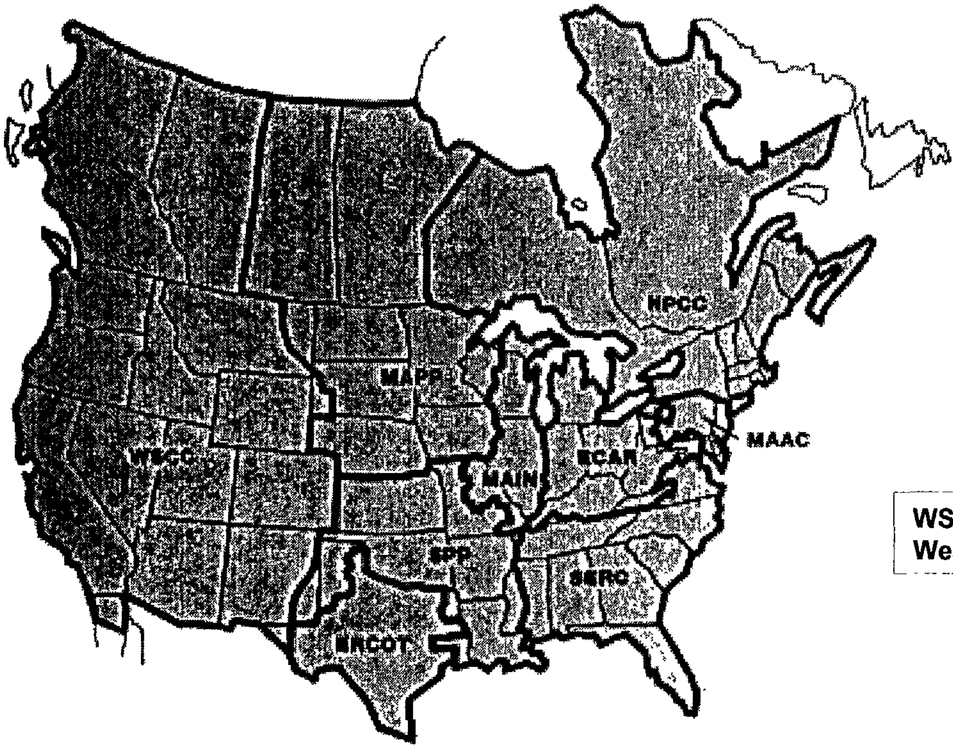
WEDNESDAY
- Importance of Losses to Economic Efficiency
- Examples of Loss Studies
- Class Case Study Exercise

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

AFFILIATE

ASCC
Alaska 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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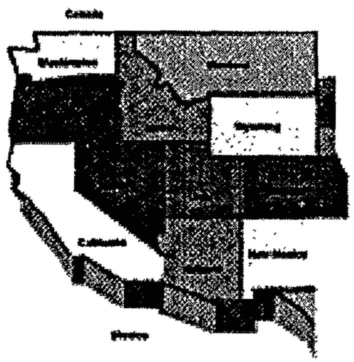
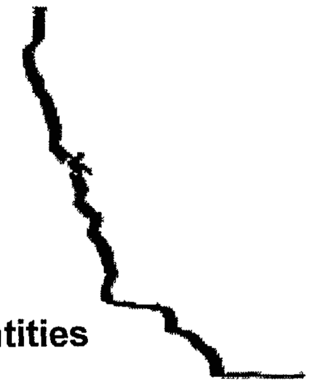
Today's Power System

Western System Coordinating Council



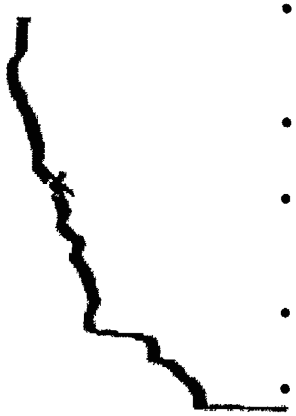
- Territory in 14 western U. S. states, and parts of Canada and Mexico
- 66 Members
- 150,000 MW resources
- 40% of energy supplied by public power and governmental entities
- 112,300 MW peak demand
- 30 control areas



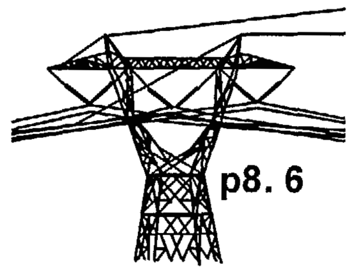
Edison

- $8 Billion Revenue
- 4.2 Million Customers
- 12,642 Employees (1997)
- 11 major interconnections
- 19,935 MW peak demand (1998)

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)



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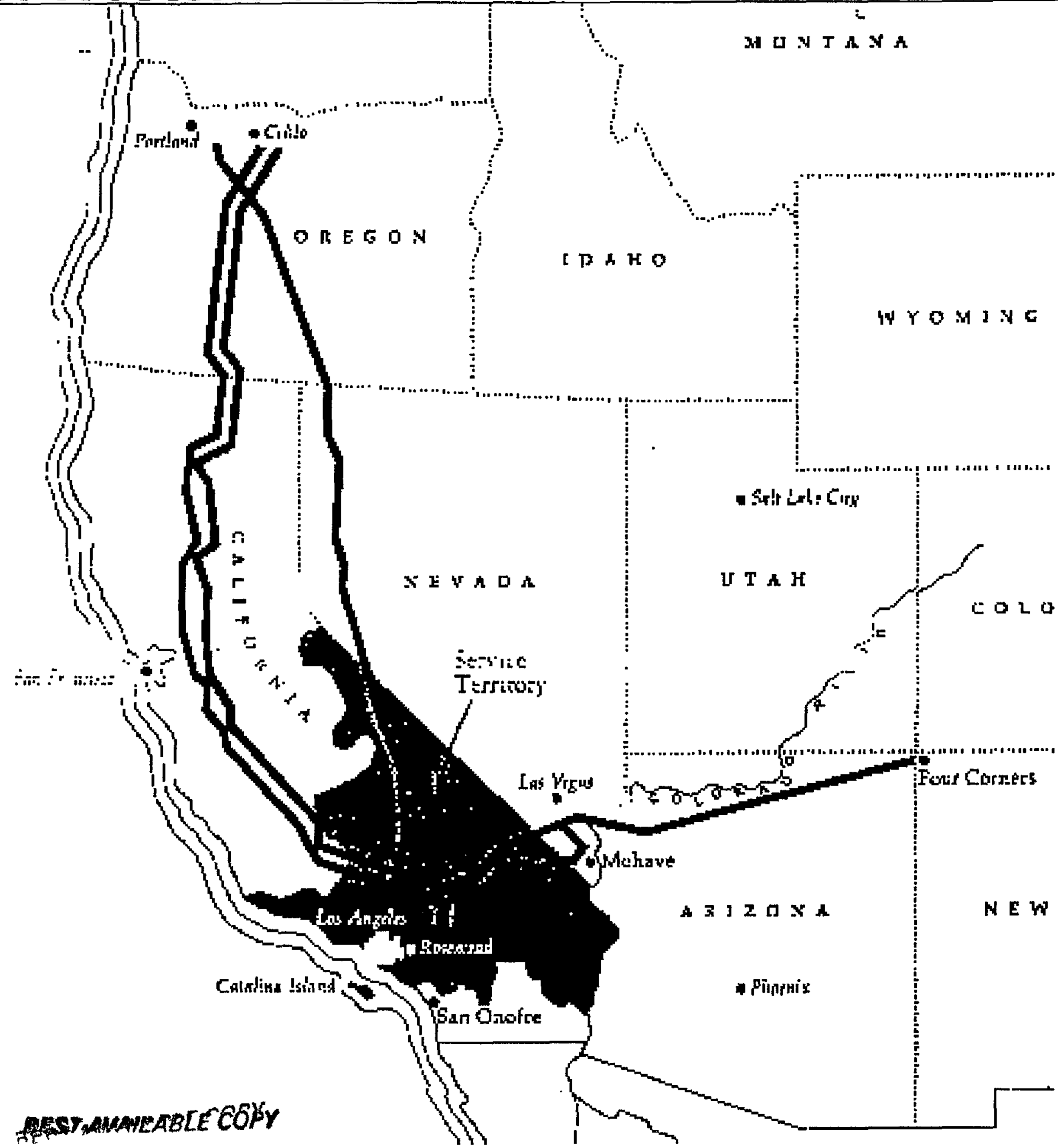
Map of Western States and Edison Service Territory



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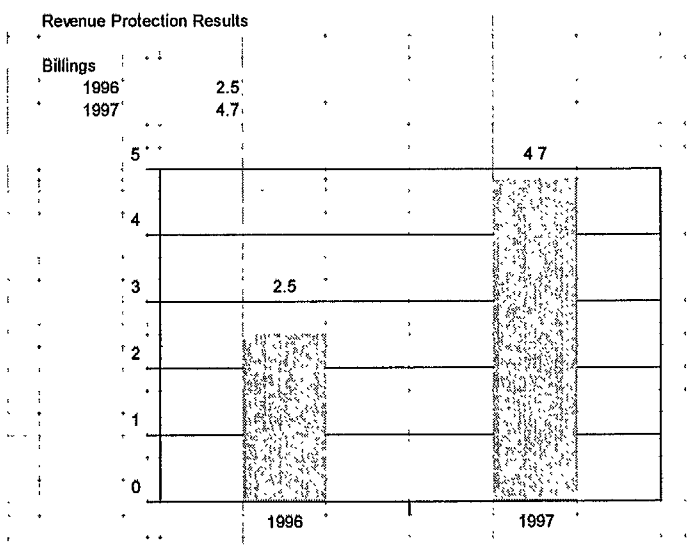
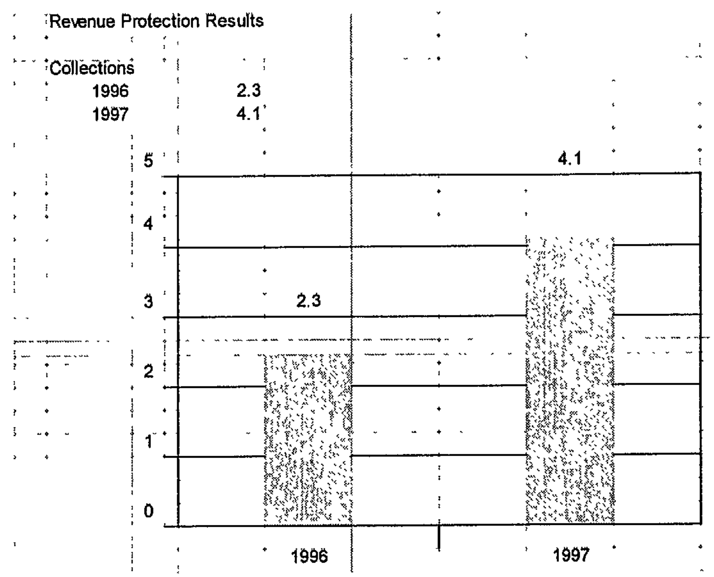
Edison - Sources of Energy





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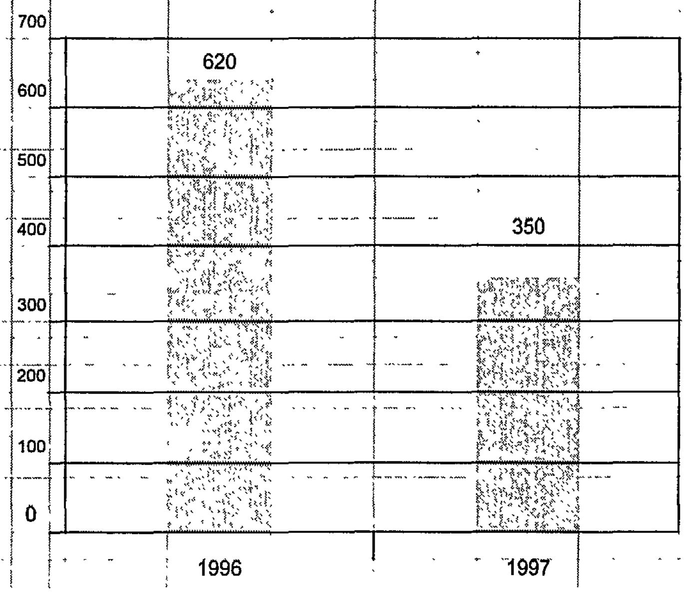
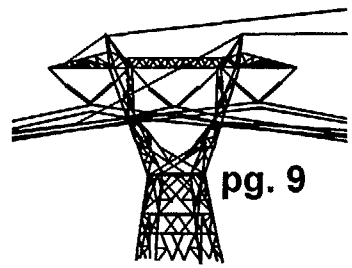
Edison - Sources of Energy

Revenue Protection Results

Write Offs	
1996	620
1997	350





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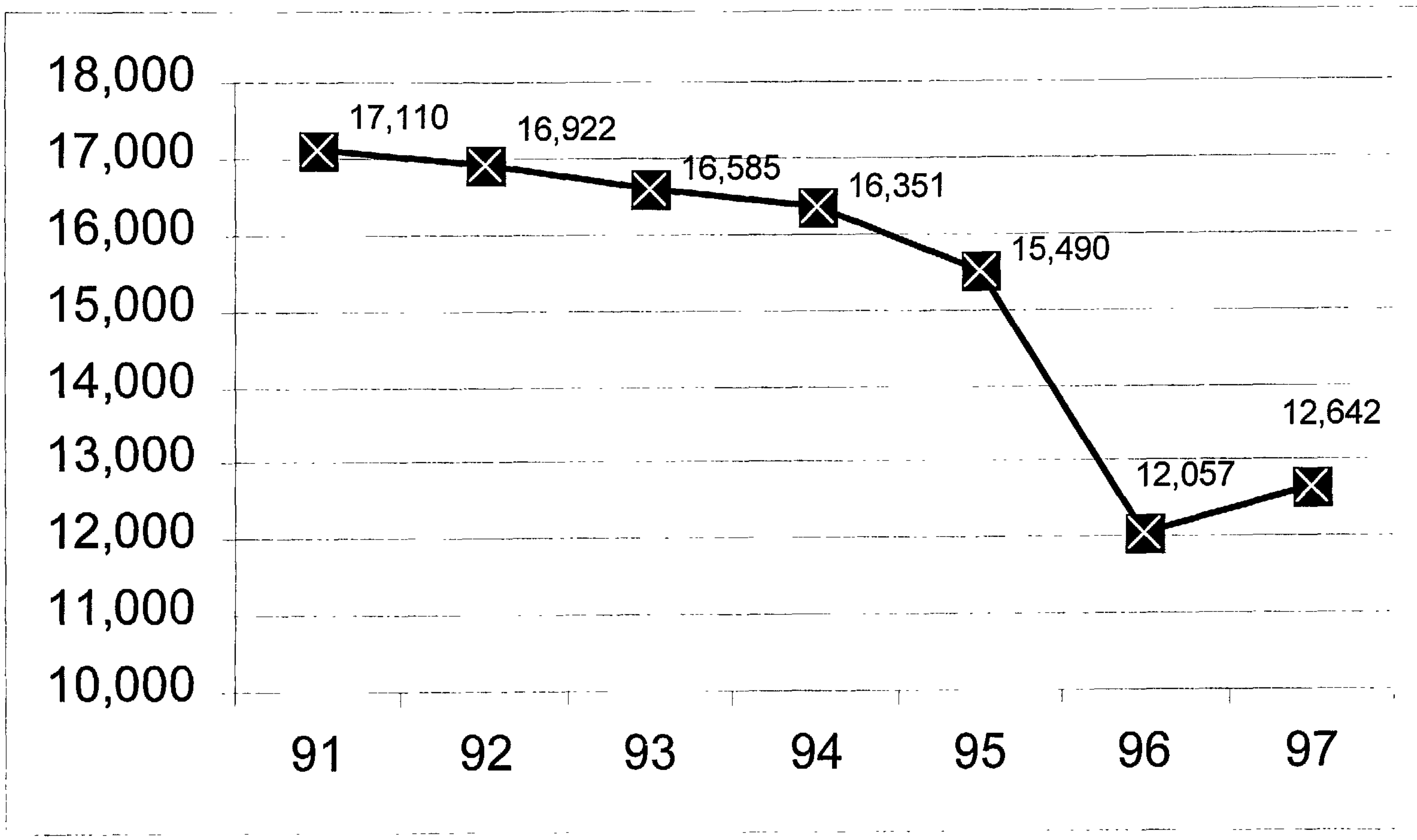
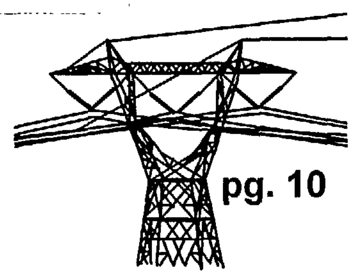
Edison Employees





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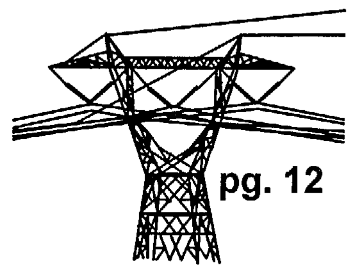
Some Perspective

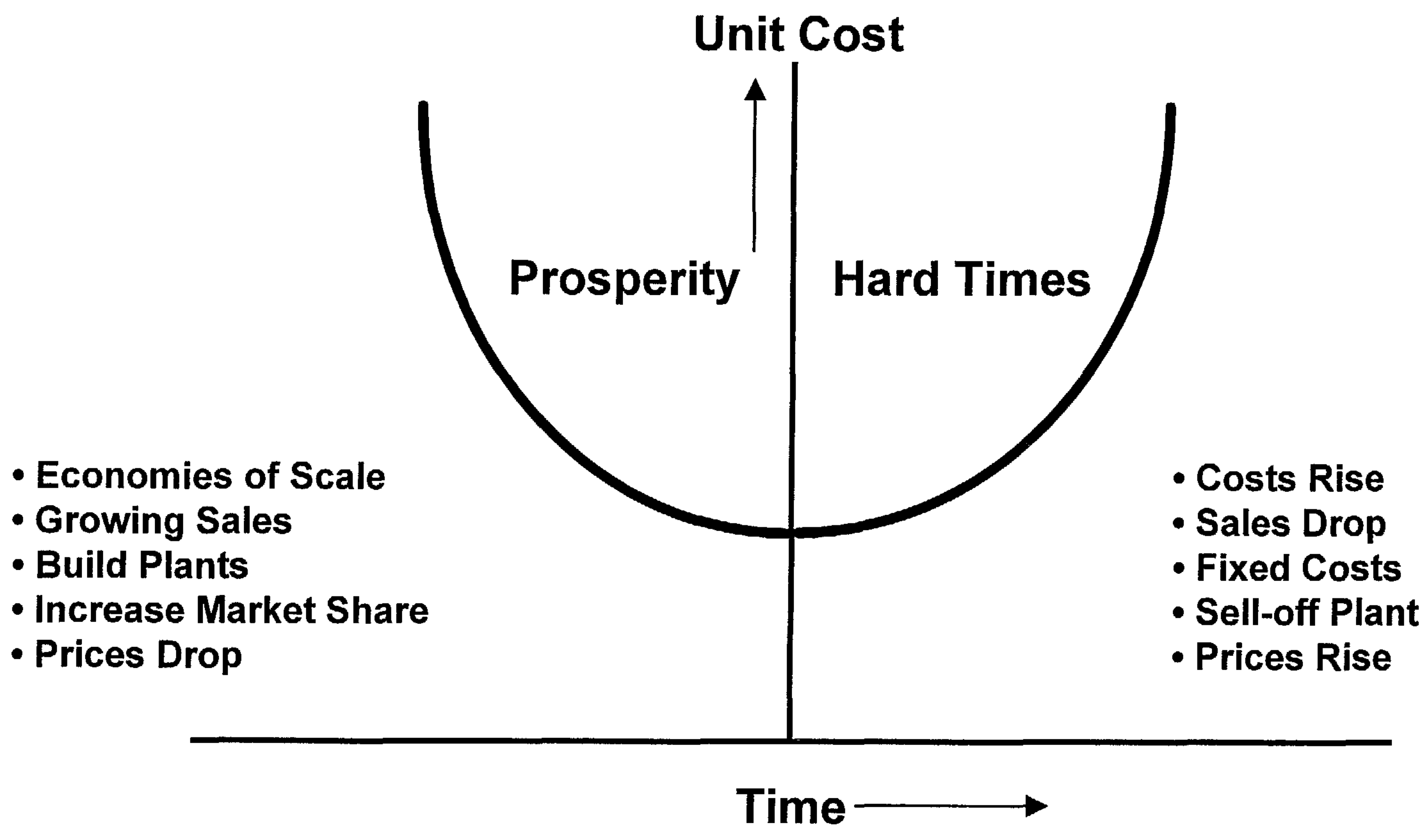
Country/State	Area (sq. Miles)	Population (Millions)
Armenia	11,506	3.6
Georgia	26,911	5.7
Azerbaijan	33,436	7.8
So.Cal Edison	50,000	11.5
Kazakstan	1,049,151	17.4
California	158,706	31.6
Ukraine	233,089	51.9
Turkey	300,947	64.6
Iran	636,293	69
Russia	6,592,745	149.9

Utility Business Eras

Early 20th Century	Competition:	Build Facilities and try to Attract Customers
Early 20th Century to 1980's	Regulation:	Vertically Integrated Utility Monopolies: Build Facilities in Response to Customer Needs
1980's	Change:	Competition Begins at Generation Level
1990's	Competition:	Restructuring in Many Areas to Provide Competition at Generation and Retail Levels

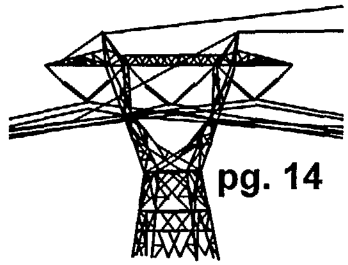


Changing Conditions



Model of Power Industry Structures

	Monopoly	Purchasing Agency	Wholesale Competition	Retail Competition
Definition	Monopoly	Competition Among Power Generators		
	Vertically Integrated	With Single Buyer	Choice for Distributors	Choice for Consumers
Are There Competing Generators?	NO	YES	YES	YES
Do Retailers Have a Choice?	NO	NO	YES	YES
Do Final Customers Have a Choice?	NO	NO	NO	YES



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:	FINANCIAL RISK	COST TO CUSTOMER	RELIABILITY	EFFICIENCY
A. Reduce Financial Risk to the Enterprise	⇩	⇧	⇩	⇩
B. Reduce Cost of Service to Customers	⇧	⇩	⇩	⇧
C. Improve Reliability of Service	⇧	⇧	⇧	⇧
D. Improve Electric System Efficiency	⇩	⇩	⇧	⇧

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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.

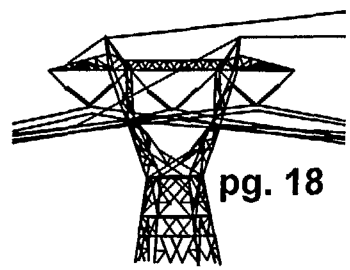
Normal Tendency: **Close Out Options by Raising Constraints**

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



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Losses - Southern California Edison System - 1997

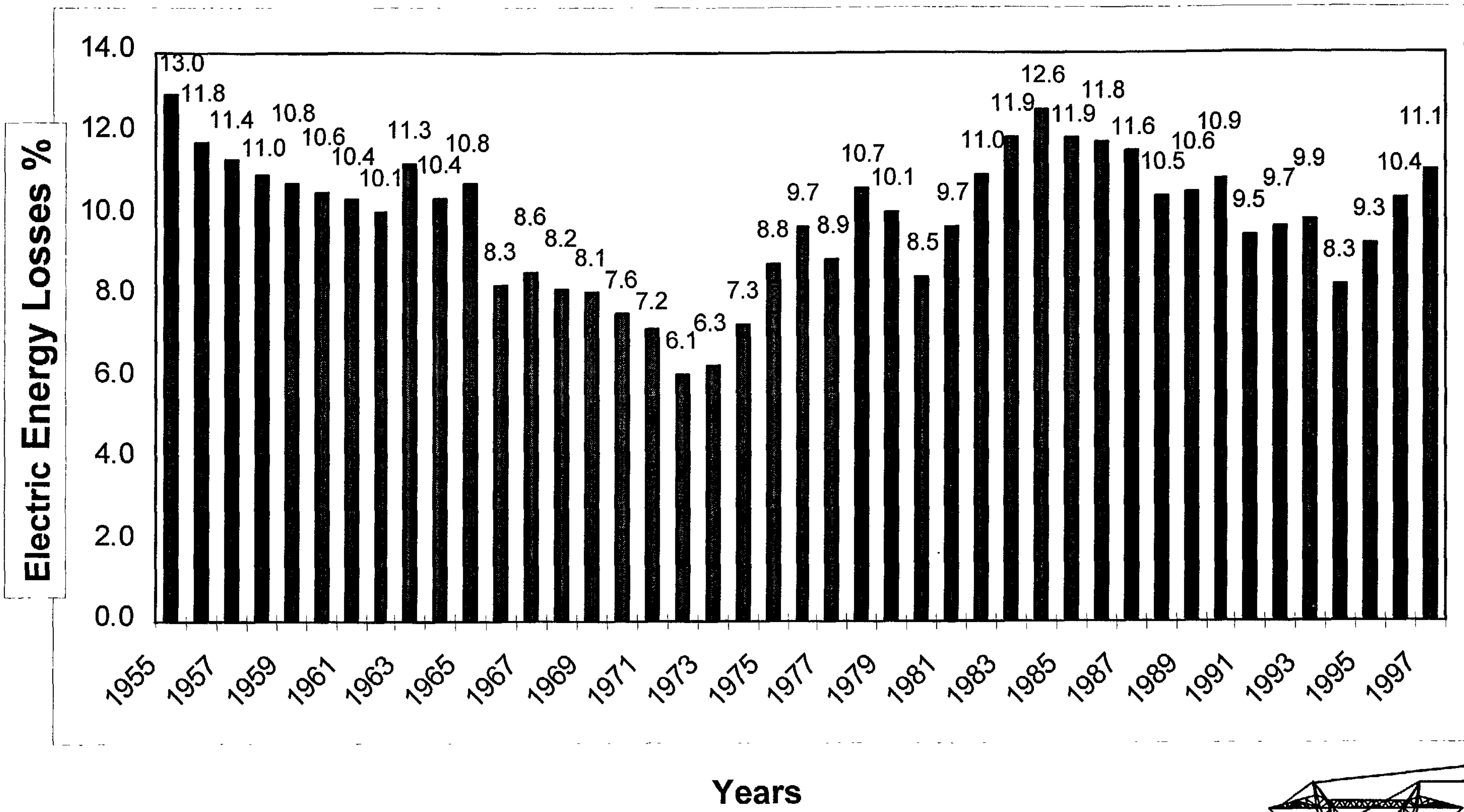
Total Energy Requirement	86,849	
Total Electric Sales*:	77,234	
“Total” Losses	9,615	(11.1%)
Energy Theft	772	
Technical Losses	8,843	(10.2%)
Revenue from Electric Sales	\$7,729	Million
Average Revenue per kWh	10.0	¢

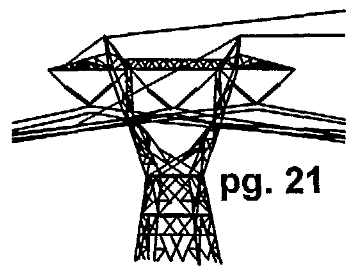
*includes uncollectible accounts

Value of Edison Losses - 1997

		$ Millions	
	MkWh	Cost	Retail Value
Technical Losses	8,843	232.0	884.3
Energy Theft	772	20.2	77.2
Uncollectible Accounts	210	5.5	20.6
TOTALS: Losses and Uncollectibles	9,825	257.7	982.1

Southern California Edison - Losses History





NOTE: Excludes Losses from Uncollectible Accounts

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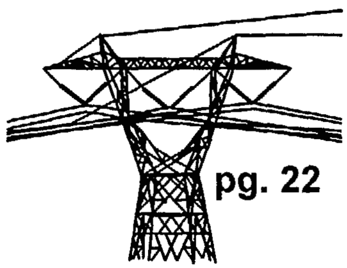
How Are These Losses Determined?

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

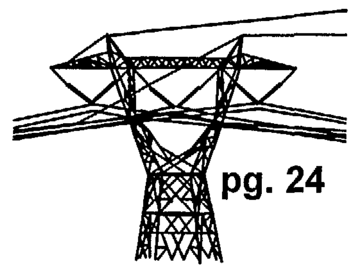


Source of Errors in Measurement

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

Utility	Country	Year	Energy Provided (1000 GWH)	Losses %
Hydro Quebec	Canada	1995	186	6.9
Tokyo Electric Power	Japan	1986	170	9.5
Southern Company	USA	1993	155	6.5
American Electric Power	USA	1986	114	7.3
Southern Calif. Edison	USA	1997	87	11.1
Duke Power	USA	1993	81	5.7
Houston Lighting	USA	1993	64	4.5
Kyushu Electric	Japan	1986	49	9.7
Carolina Power & Light	USA	1988	43	7.3
Southpower	New Zealand	1994	2.4	6.2



Losses History -- Tokyo Electric Power

Losses--percent of Transmitted

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	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	5	5	5	6	6	6	6	7	7
5	5	6	6	6	6	6	7	18	31
10	6	6	10	15	21	27	34	42	51
15	16	22	23	28	33	39	42	55	63
20	23	25	32	37	42	47	53	60	68
25	29	32	36	41	46	51	57	64	72
30	32	35	39	44	49	54	60	67	74
60	38	42	46	50	55	61	67	74	81

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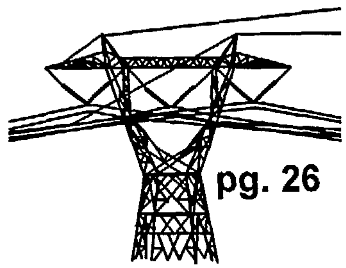
Sources of Losses

A. Technical Losses

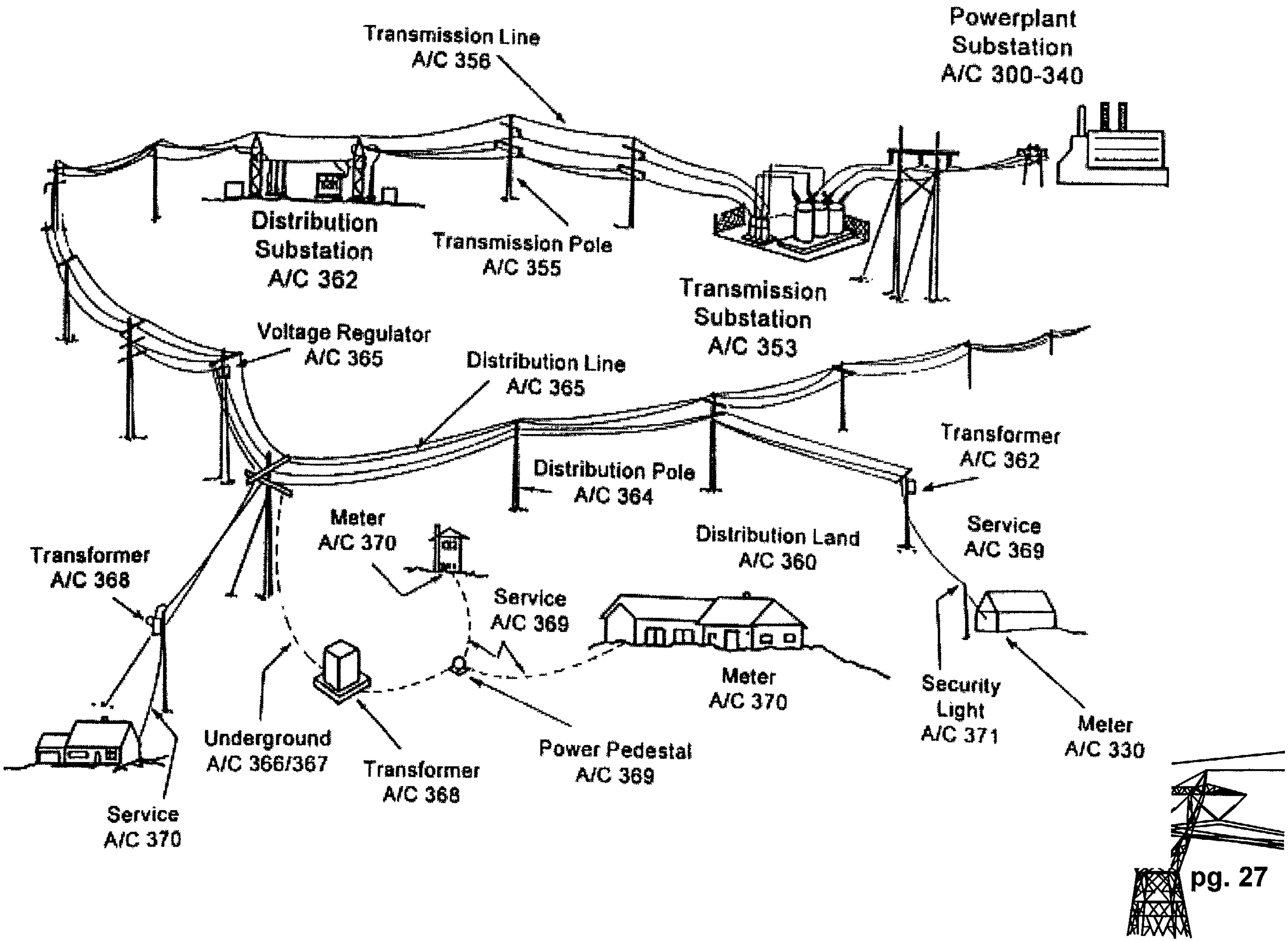
- Losses Which Vary with Electric Demand (I^2R)
- Losses Which are Constant (Magnetizing Currents)
- Losses Which Vary with Weather (Corona)
- Power Plant Auxiliaries

Commercial Losses

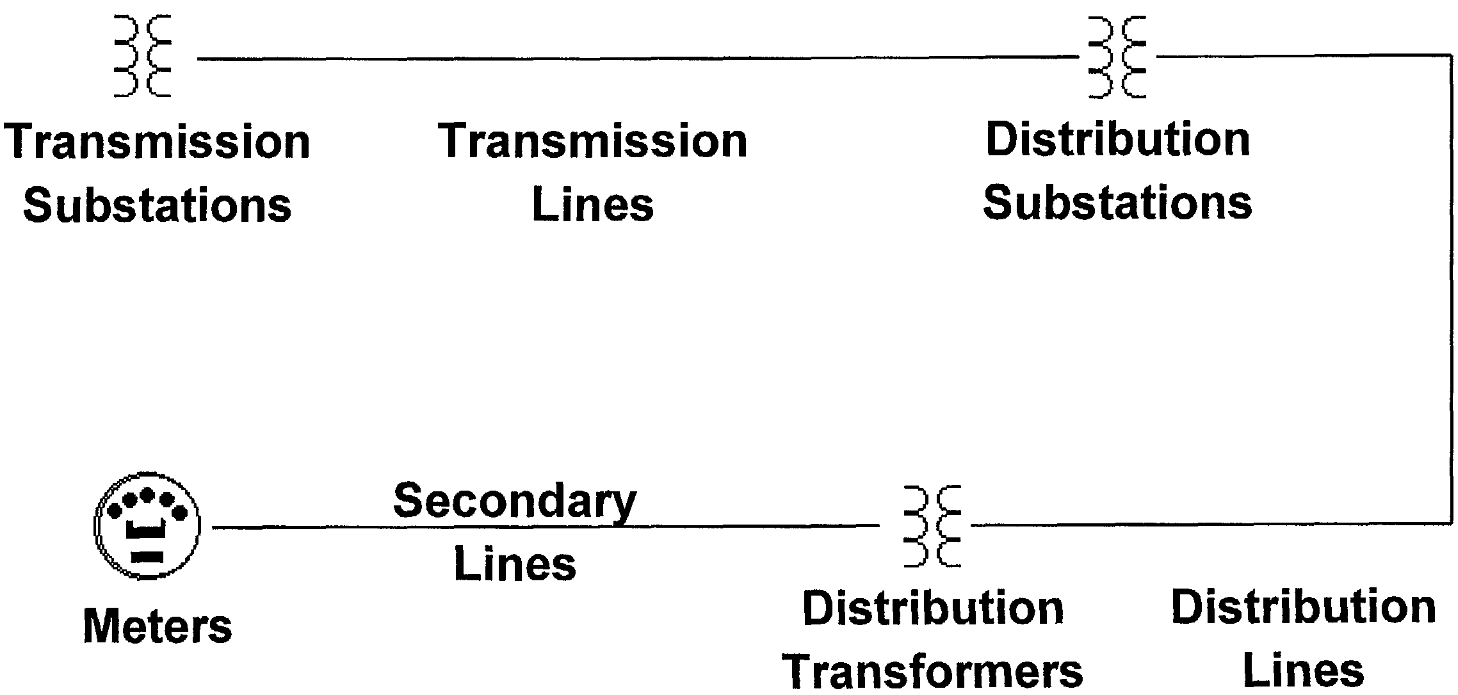
- Uncollectible Accounts
- Energy Theft
- Measurement Errors
- Unmetered Accounts



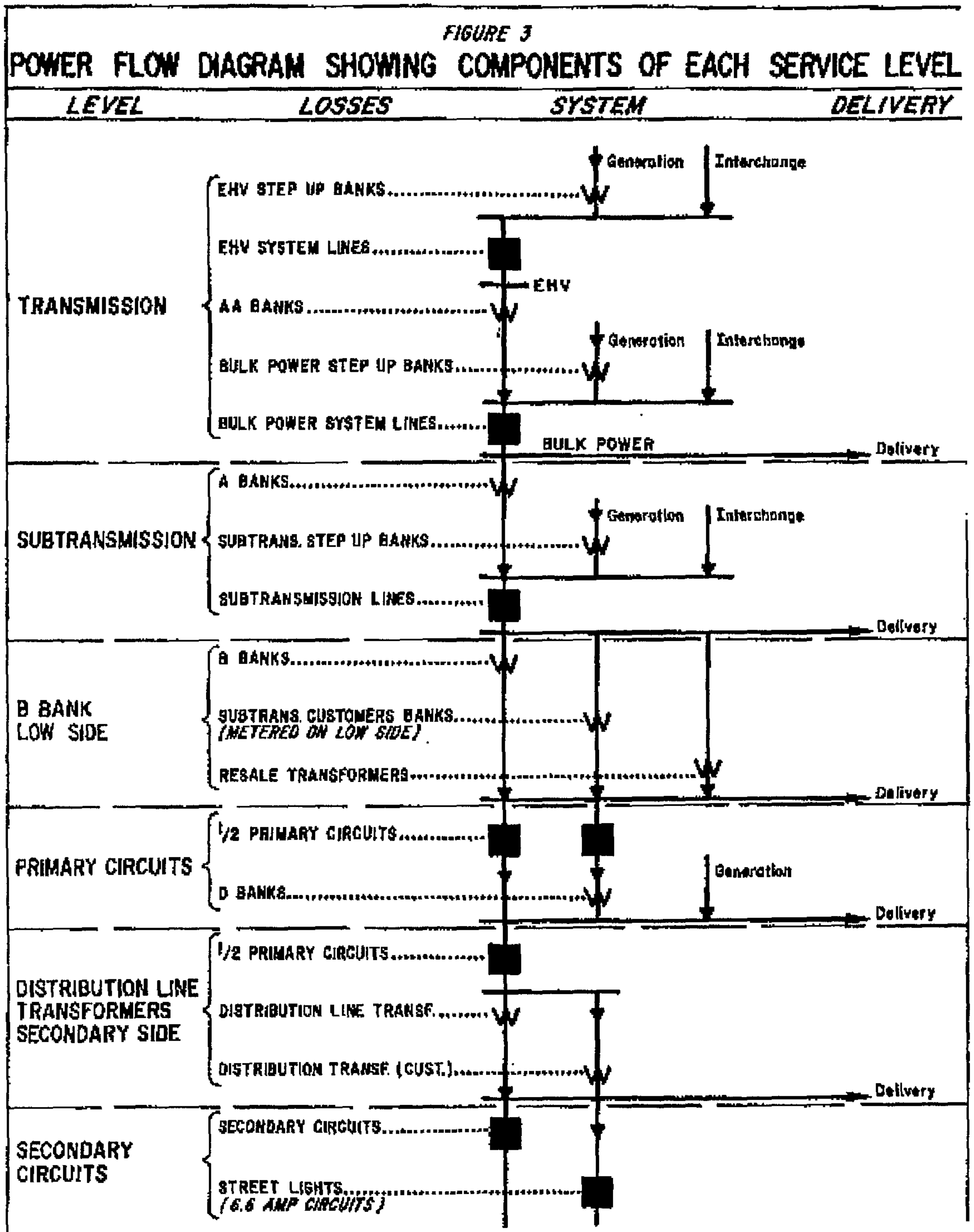
Typical Electric System



Technical Losses on a "Typical" Electric Utility



Power Flow Diagram Showing Components of Each Service Level



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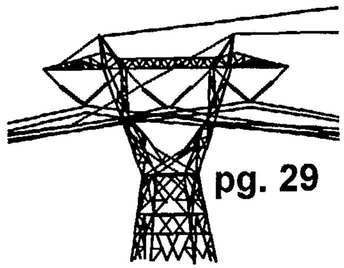
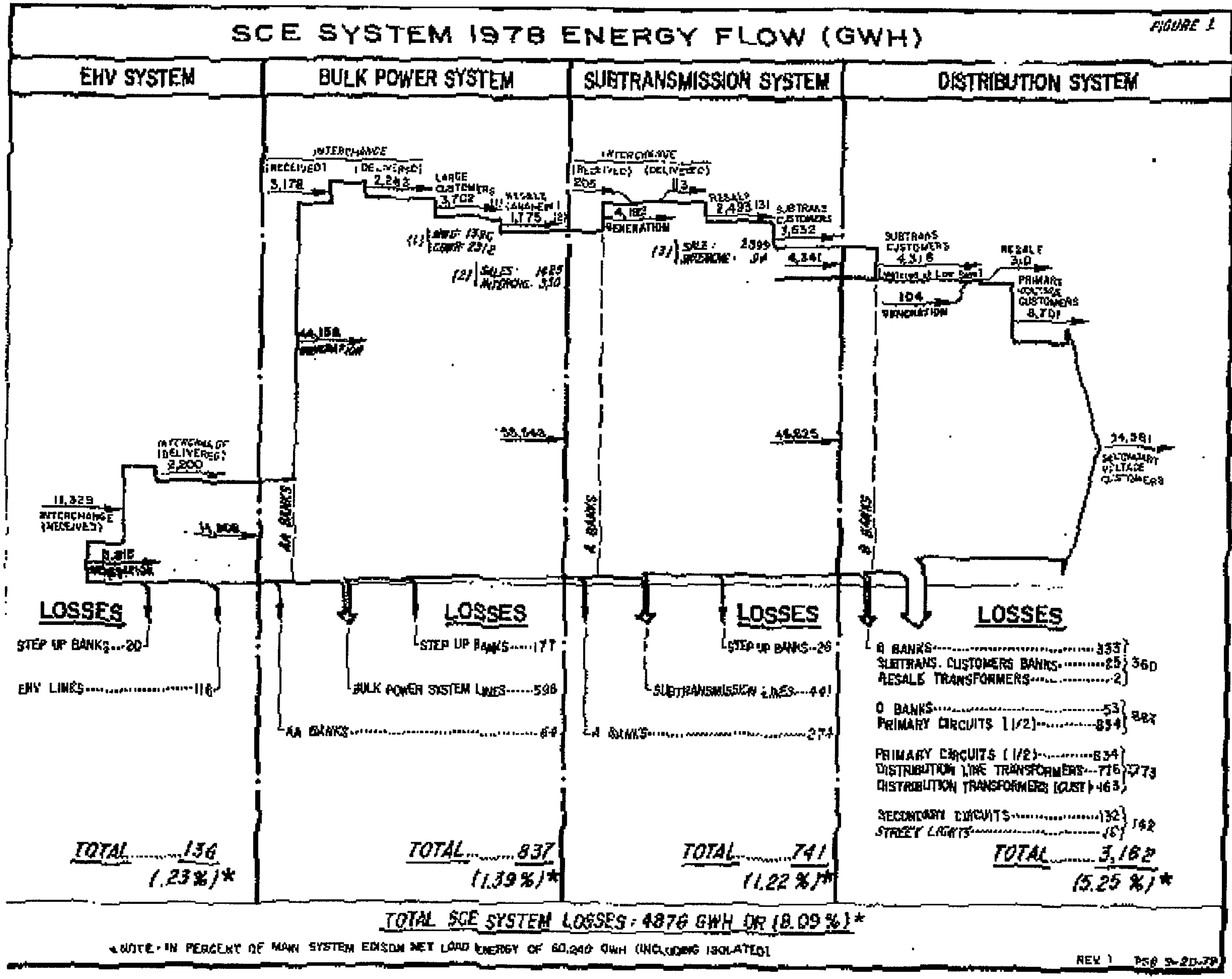


pg. 29

SCE System Energy Flow



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SCE System Energy Loss Multipliers

TABLE A
SCE SYSTEM ENERGY LOSS MULTIPLIERS

Service Level	Customer Groups	ANNUAL	TIME-OF-USE (2) Summer On Peak	Summer Mid Peak	Summer Off Peak	Winter On Peak	Winter Mid Peak	Winter Off Peak
Transmission		1.017	1.018	1.018	1.016	1.017	1.017	1.016
Subtransmission		1.028	1.029	1.029	1.028	1.029	1.029	1.028
Distribution								
1. B Banks Low Side	(Very Large Power (1) (Large Power (1) (Resale	1.036	1.037	1.036	1.035	1.036	1.036	1.035
2. Primary Circuits	(Very Large Power (Large Power (Agricultural & Pumping	1.056	1.063	1.060	1.053	1.058	1.058	1.051
3. Distribution Line Transformers Secondary Side	(Large Power (Agricultural & Pumping	1.110	1.120	1.117	1.106	1.113	1.113	1.103
4. Secondary	(Domestic (Lighting & Small Power (Street Lighting	1.116	1.127	1.123	1.112	1.120	1.119	1.108

NOTES

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

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

	Summer (Hrs.) (May 15-Nov. 14)	Winter (Hrs.) (Nov. 15-May 14)
On Peak	12-18	17-22
Mid Peak	8-12 and 18-22	8-17
Off Peak	22-8	22-8

PS:smc
1PS9049.A
12/10/79

PSB 11-79

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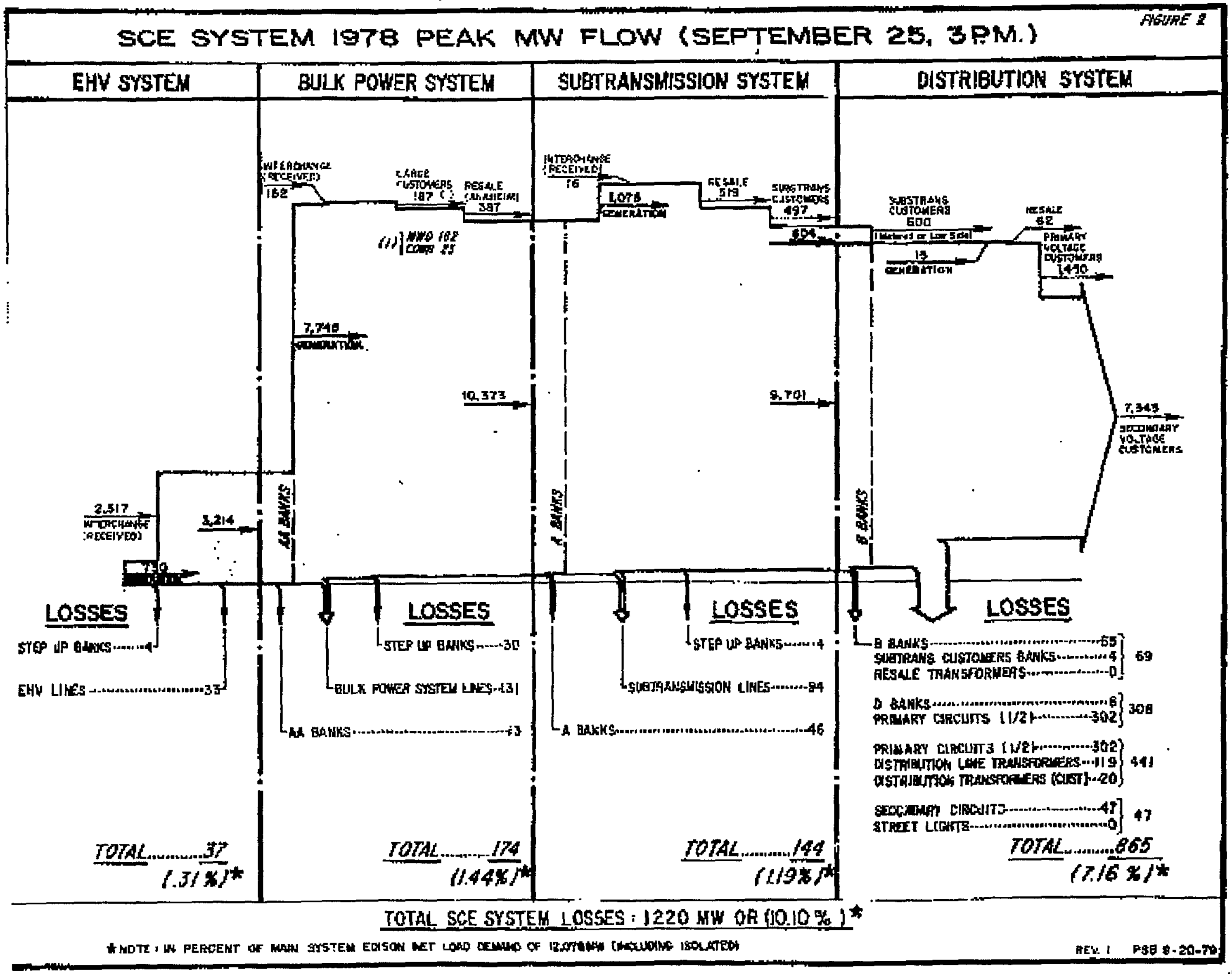
SCE System Peak MW Flow



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SCE System Demand Loss Multipliers

TABLE B
SCE SYSTEM DEMAND LOSS MULTIPLIERS

Service Level	Customer Groups	ANNUAL PEAK	TIME-OF-USE (2) Summer On Peak	Summer Mid Peak	Summer Off Peak	Winter On Peak	Winter Mid Peak	Winter Off Peak
Transmission		1.019	1.019	1.019	1.017	1.018	1.018	1.016
Subtransmission		1.030	1.030	1.029	1.028	1.029	1.029	1.028
Distribution								
1. B Banks Low Side	(Very Large Power (1) (Large Power (1) (Resale	1.037	1.037	1.036	1.036	1.036	1.036	1.035
2. Primary Circuits	(Very Large Power (Large Power (Agricultural & Pumping	1.072	1.072	1.069	1.061	1.066	1.066	1.059
3. Distribution Line Transformers Secondary Side	(Large Power (Agricultural & Pumping	1.136	1.136	1.131	1.119	1.128	1.128	1.115
4. Secondary	(Domestic (Lighting & Small Power (Street Lighting	1.145	1.145	1.140	1.128	1.137	1.136	1.124

NOTES

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

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

	Summer (Hrs.) (May 15-Nov. 14)	Winter (Hrs.) (Nov. 15-May 14)
On Peak	12-18	17-22
Mid Peak	8-12 and 18-22	8-17
Off Peak	22-8	22-8

FS:smc
1FS9049.A1
12/10/79

PSB 11-79

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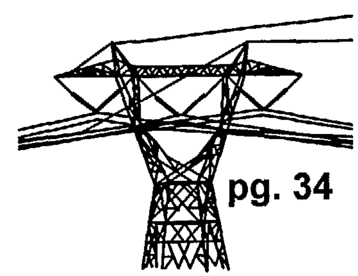
Loss Estimation Methods with Incomplete Metering

- **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

	%
Generator Step-up Banks	0.5-1
Transmission Lines	1-3
Power Transformers	1-2
Distribution Lines	1-2
Distribution Transformers	1-2
secondary Services	0.5-1
Metering	0.1-0.5

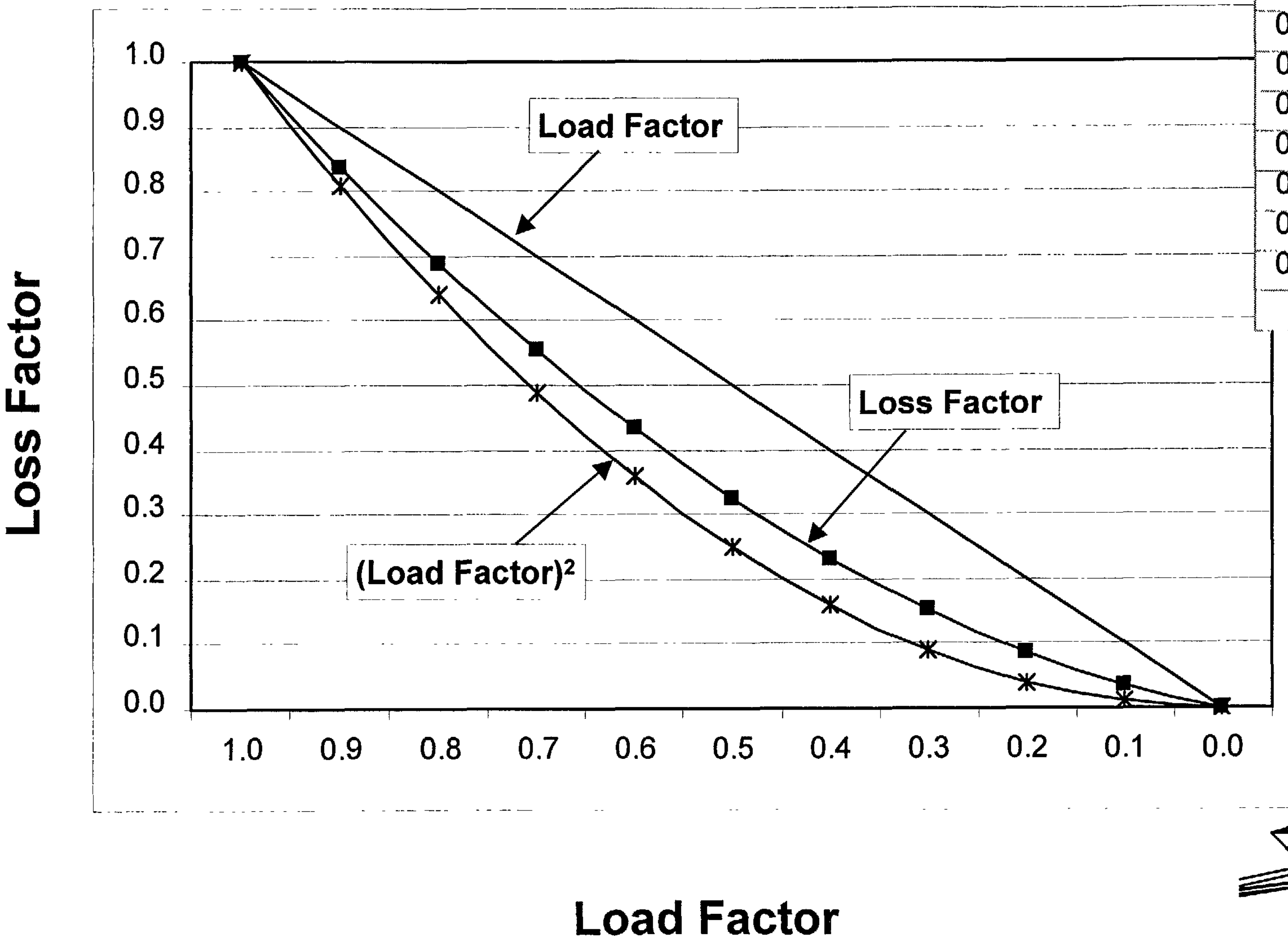
SCE Distribution Line Transformer Losses

Transformer Size (KVA)	Number of Transformers: Management System	Number of Transformers: Total SCE System	Losses (kW) Per Transformer: No Load	Losses (kW) Per Transformer: Load	Losses (%) Per Transformer: No Load	Losses (%) Per Transformer: Load
5	16,555	16,555	0.030	0.100	0.60	2.00
10	49,490	49,490	0.066	0.131	0.66	1.30
15	84,167	121,139	0.090	0.161	0.60	1.10
25	81,658	117,528	0.126	0.253	0.50	1.00
37.5	14,092	20,282	0.169	0.350	0.45	0.93
50	31,299	45,047	0.135	0.460	0.27	0.92
75	15,418	22,192	0.279	0.651	0.37	0.87
100	6,938	6,938	0.345	0.854	0.35	0.85
167	829	829	0.482	1.529	0.29	0.92

Load Factor / Loss Factor

$$L_SF = L_dF^2(.7) + L_dF(.3)$$

L_dF	L_SF	L_dF^2
1.0	1.0	1.0
0.9	0.837	0.81
0.8	0.688	0.64
0.7	0.553	0.49
0.6	0.432	0.36
0.5	0.325	0.25
0.4	0.232	0.16
0.3	0.153	0.09
0.2	0.086	0.04
0.1	0.037	0.01
0	0	0



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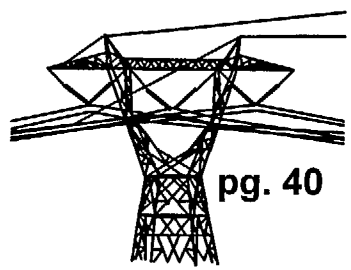
Determine and Allocate System Technical Losses
<u>Using Incomplete Metering</u>

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

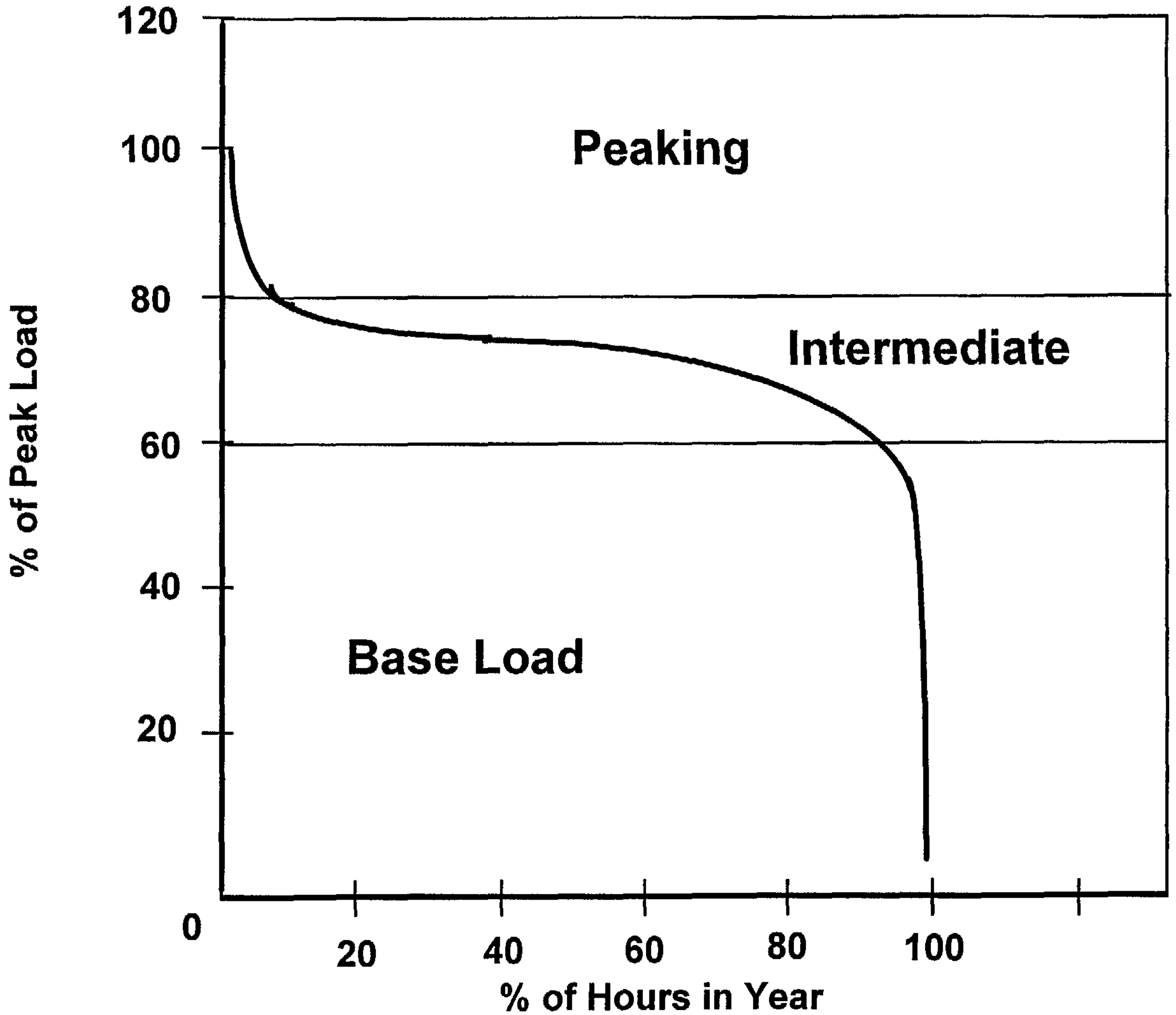
- Marginal Costs
  - Based on Incremental Output of Marginal Generation
  - Includes Price of Fuel, Generator Incremental Efficiency, Variable Operation and Maintenance

- 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:**

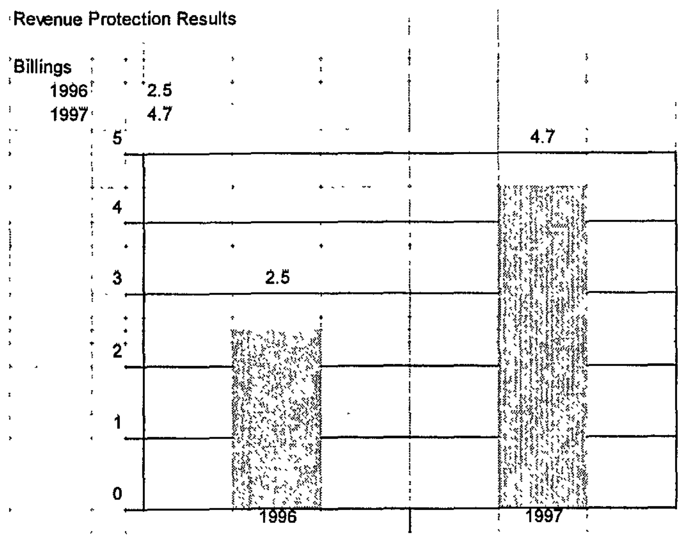
  On-Peak: 12:00 P.M. - 6:00 P.M. weekdays except holidays
  Mid-Peak: 8:00 A.M. - 12:00 P.M., 6:00 P.M. - 11:00 P.M. weekdays except holidays
  Off-Peak All Other Hours

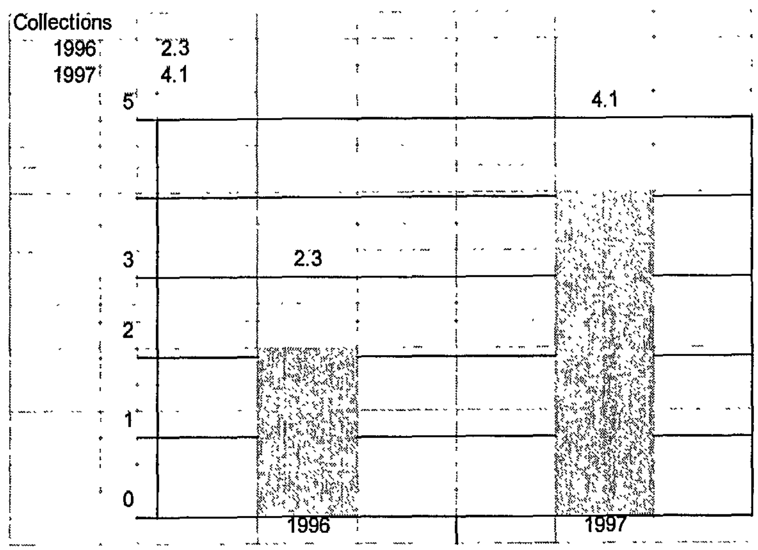
- **Winter:**

  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)





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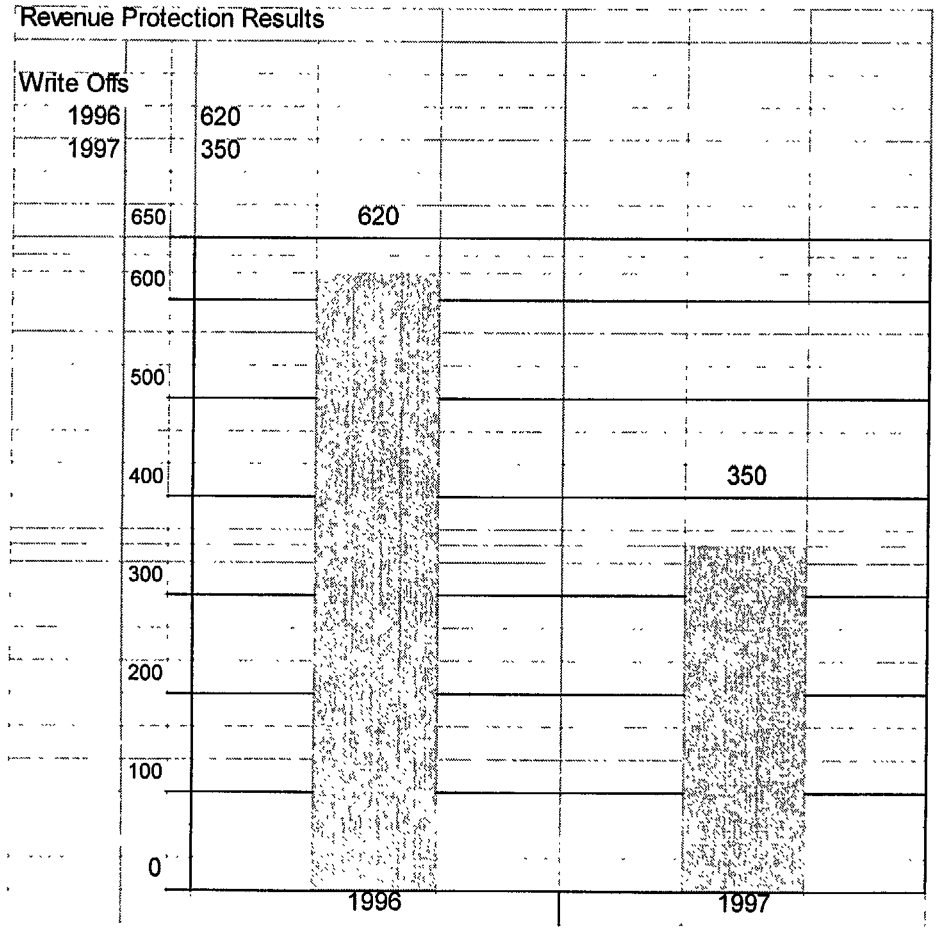
Incremental Energy Rates

(Southern California Edison)



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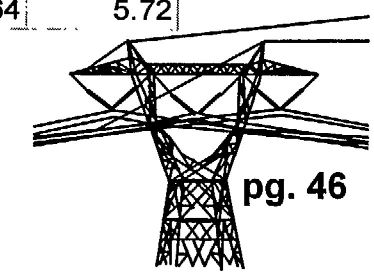
Future Energy Rates by Time Period

(Southern California Edison)

	Time-Period Summer				Energy Value ¢/kWh			
Year	Gas Price $/million btu	On-peak	Mid-peak	Off-peak	Mid-peak	Off-peak	Super-off	Total Energy Value
1995	2.41	3.06	2.18	1.62	2.33	2.13	1.61	2.06
1996	2.51	6.57	2.31	1.74	2.59	2.26	1.72	2.24
1997	2.60	3.48	2.41	1.76	2.83	2.42	1.89	2.38
1998	2.73	3.75	2.60	1.99	2.91	2.61	2.13	2.56
1999	2.78	3.35	2.91	2.14	3.10	2.77	2.24	2.70
2000	2.90	3.44	3.27	2.50	3.08	2.62	2.39	2.79
2001	3.03	3.99	3.27	2.51	3.40	2.90	2.64	3.01
2002	3.18	3.45	3.73	2.96	3.72	3.26	2.77	3.30
2003	3.32	3.80	4.04	3.01	3.74	3.55	2.87	3.44
2004	3.51	3.74	4.67	3.36	4.03	3.79	3.01	3.72
2005	3.78	4.03	5.03	3.62	4.34	4.08	3.24	4.01
2006	4.01	4.28	5.34	3.84	4.61	4.33	3.44	4.25
2007	4.16	4.44	5.54	3.99	4.78	4.49	3.57	4.41
2008	4.32	4.61	5.75	4.14	4.96	4.66	3.71	4.58
2009	4.48	4.78	5.96	4.29	5.15	4.83	3.85	4.75
2010	4.65	4.96	6.19	4.46	5.34	5.02	3.99	4.93
2011	4.83	5.15	6.43	4.63	5.55	5.21	4.15	5.12
2012	5.01	5.34	6.67	4.80	5.76	5.40	4.30	5.31
2013	5.20	5.55	6.92	4.98	5.97	5.61	4.46	5.51
2014	5.40	5.76	7.19	5.18	6.20	5.82	4.64	5.72



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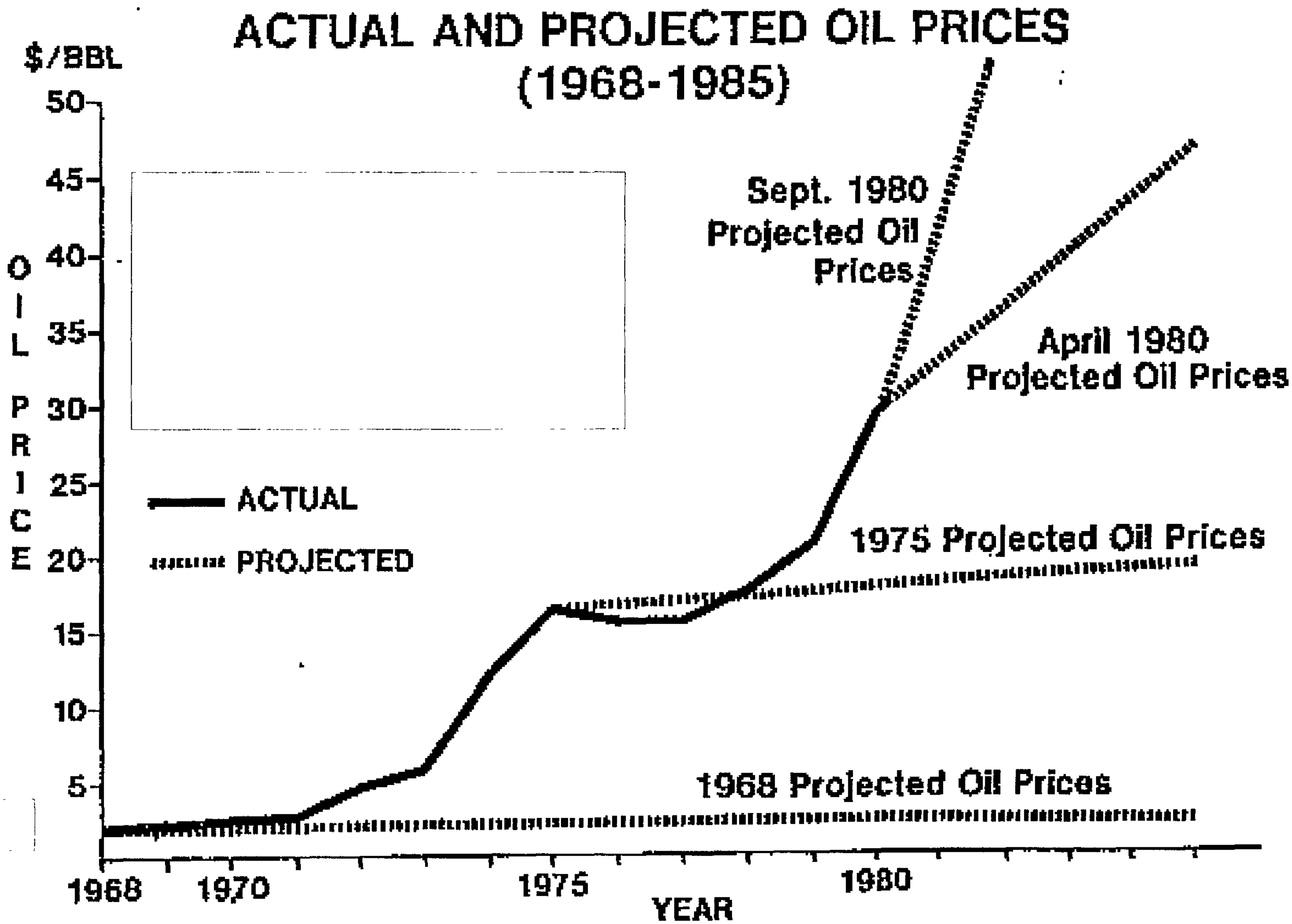
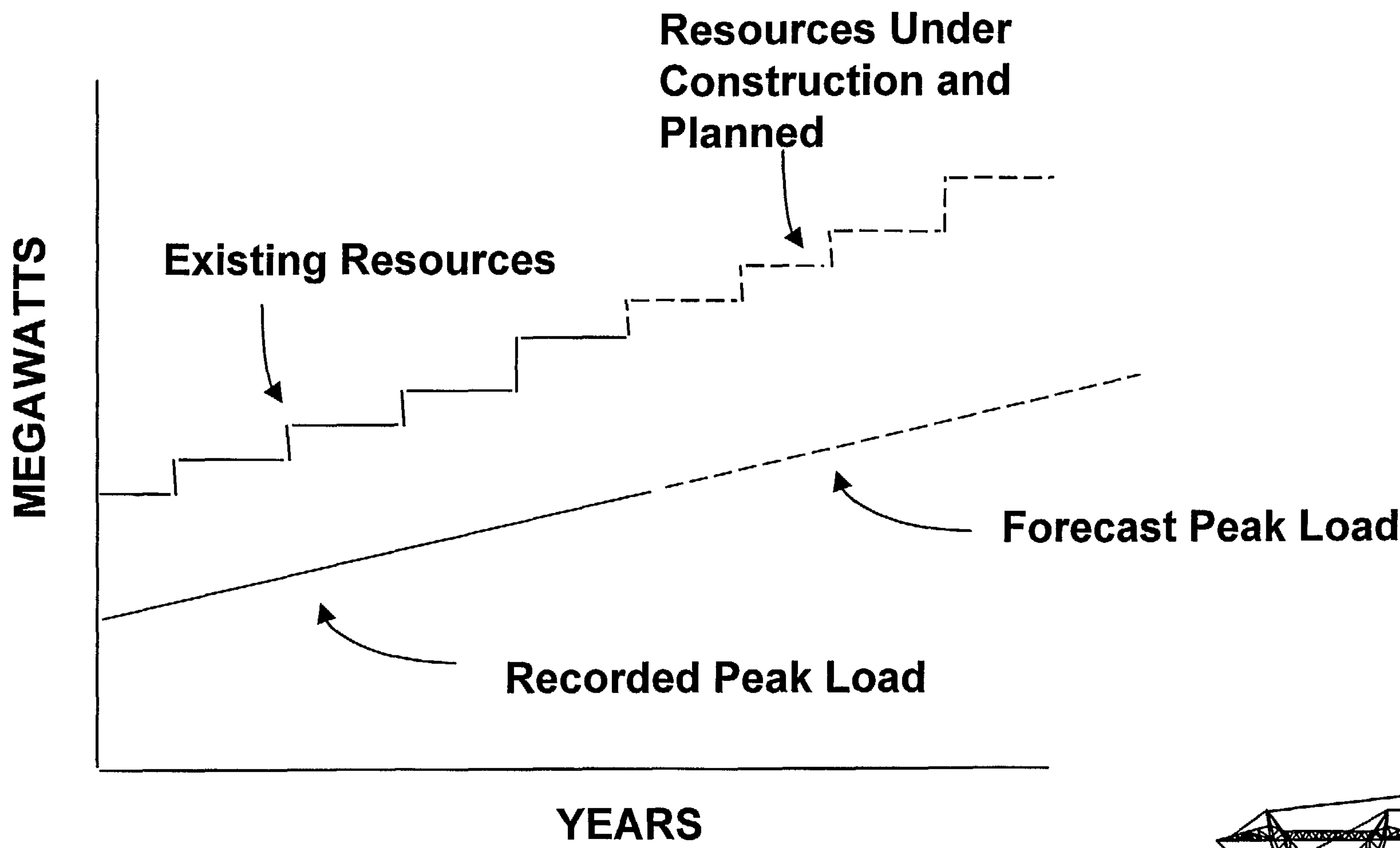
Actual and Projected Oil Prices



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:
  - Probability That Losses Will Affect Timing Decisions On New Generation Capacity
  - 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



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Generation Reliability Multiplier

(Southern California Edison)

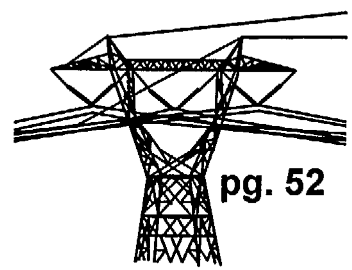
Reserve Margin	Multiplier
over 20%	0.1
16-20%	1.0 - 0.1
under 16%	1.0

Capital - Related Assumptions

Installed Cost of Combustion Turbine
Cost of Capital
Amortization Period
Taxes, Insurance, Etc.
Fixed Operation & Maintenance
Inflation

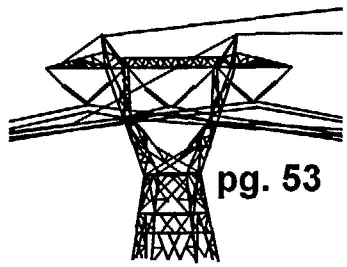
General Carrying Charge Rates

Term (years)	Levelized
10	0.230
15	0.191
20	0.173
25	0.164
30	0.158
35	0.155



First Year Capacity Value

	First Year Capacity Value			
			$/kw-yr	
Year		Com. Turbine Capacity Cost (3)	Capacity Value Multiplier	Adjusted Capacity Value
1995		$51.23	0.10	$5.12
1996		$53.03	0.10	$5.30
1997		$54.88	0.10	$5.49
1998		$56.80	0.10	$5.68
1999		$58.79	0.10	$5.88
2000		$60.85	0.10	$6.08
2001		$62.98	0.10	$6.30
2002		$65.18	0.10	$6.52
2003		$67.47	0.10	$6.75
2004		$69.83	0.10	$6.98
2005		$72.27	0.14	$9.78
2006		$74.80	1.00	$74.80
2007		$77.42	1.00	$77.42
2008		$80.93	1.00	$80.13
2009		$82.93	1.00	$82.93
2010		$85.83	1.00	$85.83
2011		$88.84	1.00	$88.84
2012		$91.95	1.00	$91.95
2013		$95.17	1.00	$95.17
2014		$98.50	1.00	$98.50



Capacity Valuation Factors *

	On-peak	Mid-peak	Off-peak	Super-off	Total
Summer	0.7778	0.1345	0.0026	0.0000	0.9149
Winter	0.0000	0.0773	0.0048	0.0030	0.0851
Total	0.7778	0.2118	0.0074	0.0030	1.0000

* 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".

Estimated Future Capacity Values by Time Period

		Capacity Value ¢/kWh						
		SUMMER			WINTER			
Year	Capacity Value $/kWh-yr	On-peak	Mid-peak	Off-peak	Mid-peak	Off-peak	Super-off	Annual Average
1995	5.12	0.76	0.09	0.00	0.02	0.00	0.00	0.06
1996	5.30	0.79	0.09	0.00	0.02	0.00	0.00	0.06
1997	5.49	0.82	0.09	0.00	0.02	0.00	0.00	0.06
1998	5.68	0.85	0.10	0.00	0.02	0.00	0.00	0.06
1999	5.88	0.88	0.10	0.00	0.02	0.00	0.00	0.07
2000	6.08	0.91	0.10	0.00	0.02	0.00	0.00	0.07
2001	6.30	0.94	0.11	0.00	0.02	0.00	0.00	0.07
2002	6.52	0.97	0.11	0.00	0.02	0.00	0.00	0.07
2003	6.75	1.01	0.12	0.00	0.02	0.00	0.00	0.08
2004	6.98	1.04	0.12	0.00	0.02	0.00	0.00	0.08
2005	9.78	1.46	0.17	0.00	0.03	0.00	0.00	0.11
2006	74.80	11.15	1.28	0.01	0.26	0.02	0.02	0.85
2007	77.42	11.54	1.33	0.01	0.27	0.02	0.02	0.88
2008	80.93	11.94	1.38	0.01	0.27	0.02	0.02	0.91
2009	82.93	12.36	1.42	0.01	0.28	0.02	0.02	0.95
2010	85.83	12.79	1.47	0.01	0.29	0.02	0.02	0.98
2011	88.84	13.24	1.52	0.01	0.30	0.02	0.02	1.01
2012	91.95	13.70	1.58	0.01	0.31	0.02	0.02	1.05
2013	95.17	14.18	1.63	0.02	0.33	0.02	0.02	1.09
2014	98.50	14.68	1.69	0.02	0.34	0.02	0.02	1.12

Levelized Capacity Value $/kW-yr

Project Length (years)	In-service or contract start year								
	1995	1996	1997	1998	1999	2000	2001	2002	2003
1	5	5	5	6	6	6	6	7	7
5	5	6	6	6	6	6	7	18	31
10	6	6	10	15	21	27	34	42	51
15	16	22	23	28	33	39	42	55	63
20	23	25	32	37	42	47	53	60	68
25	29	32	36	41	46	51	57	64	72
30	32	35	39	44	49	54	60	67	74
60	38	42	46	50	55	61	67	74	81

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

Common Stock		0.48 X 0.12 = 0.0576
Preferred Stock		0.05 X 0.07 = 0.0035
Bonds		0.47 X 0.08 = 0.0376
Total	1.00	0.0987

SAY 10%

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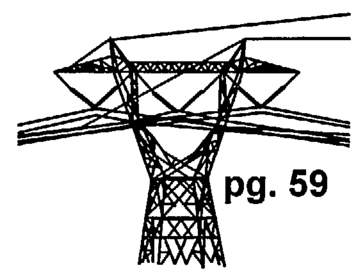
1994 Edison ($1,000,000)

			%
Revenues		7798	100
Expenses			
Fuel & Purchased Power	3403		43.6
Operations & Maintenance	1727		22.1
Depreciation	891		11.4
Property Tax	230*		2.6
	6224	6224	
		1574	
Interest	429	429	5.5
Pre-Tax Income		1145**	
Income Tax	507***	507	6.5
Net Income		638	8.2

$\frac{507^{***}}{1145^{**}}$ = .44 or 44%

TOTAL TAXES = 203* + 507*** = 710

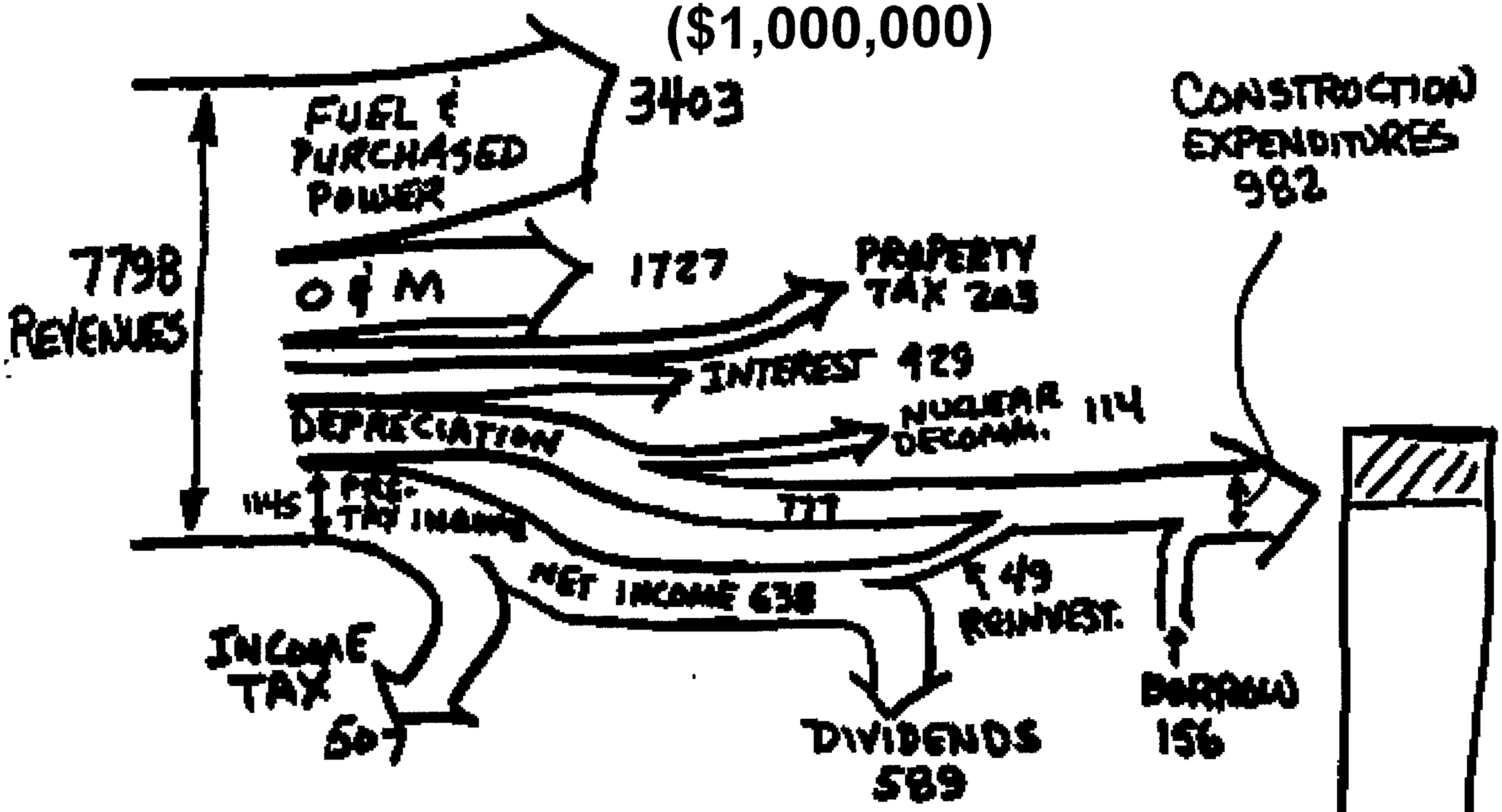


Edison Taxes 1994

Pre-Tax Profit	=	$100
State Tax 11%	=	11
		89
Federal 34% (89) (.34)	=	30
TOTAL TAX	=	41

Edison - Source & Uses of $ - 1994

($1,000,000)



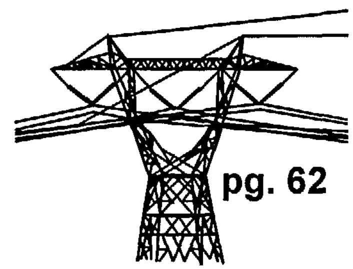
$$\text{RETURN} = \frac{638 + 429}{10,800} = 9.9\%$$

"RATE BASE" 10,800

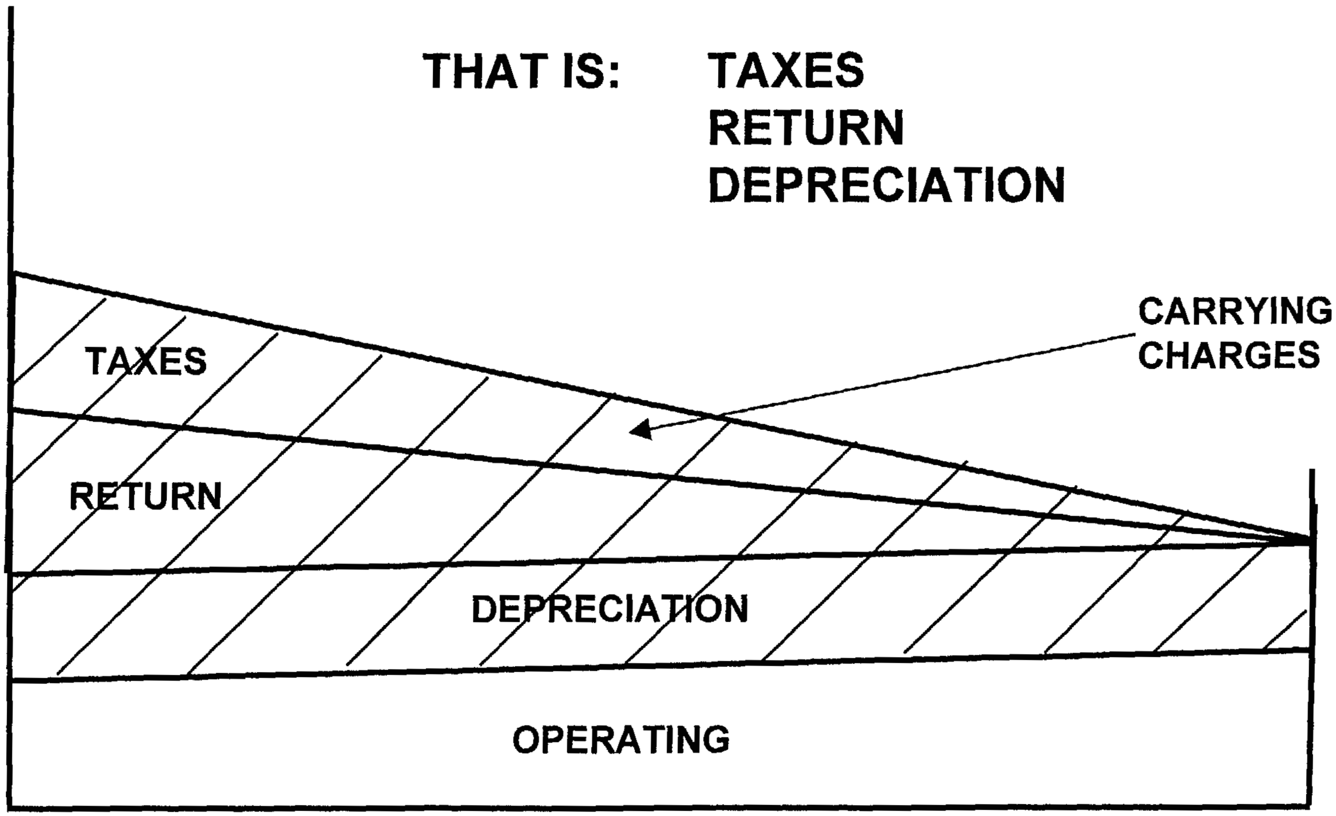
$$\text{RETURN ON EQUITY} = \frac{638}{5662} = 11.3\%$$

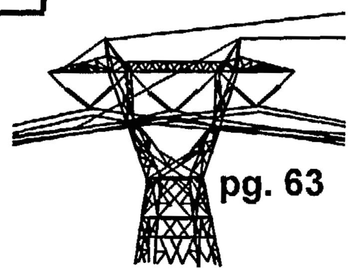
Edison Operating Ratios 1988-97 (%)

	Fuel & Purchased Power	Operation & Maintenance	Investment Related
1997	41.8	20.4	37.8
1996	41.0	19.9	39.1
1995	43.5	20.2	36.3
1994	44.4	21.1	34.5
1993	40.6	22.0	37.4
1992	44.4	20.0	35.6
1991	45.2	20.5	34.3
1990	44.4	19.6	36.0
1989	43.2	20.2	36.6
1988	41.3	21.0	37.7



Carrying Charges, or Fixed Charges, are those based on Capital Investment in Project, <u>Not its Operating Costs:</u>





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Typical "Carrying Charge Components" for a 30 Year Facility

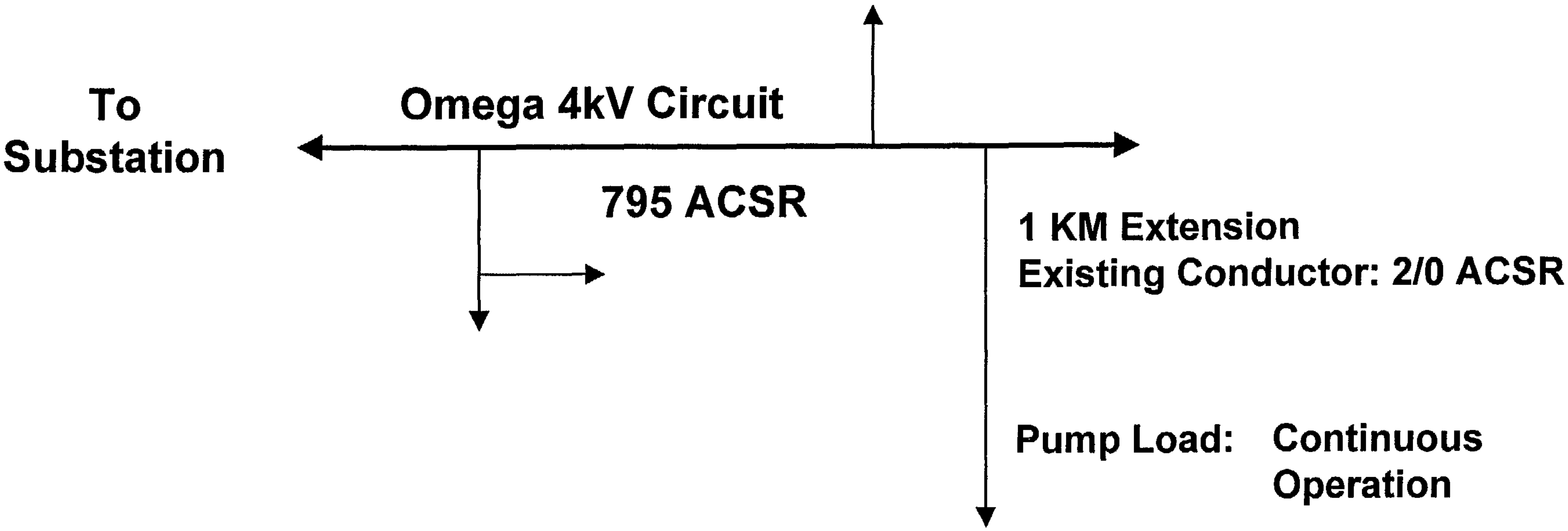
RETURN	10.0%
DEPRECIATION	0.6%
INCOME TAXES	2.9%
PROPERTY TAXES	1.2%
ADMINISTRATIVE & GENERAL	1.0%
INSURANCE	0.1%
TOTAL	15.8%

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

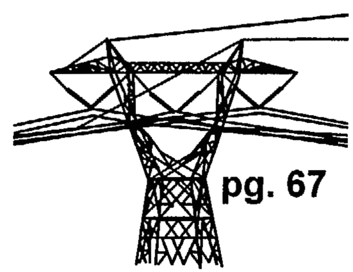
Estimated Cost to Reconductor with 336 ACSR

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 Reconductor

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"

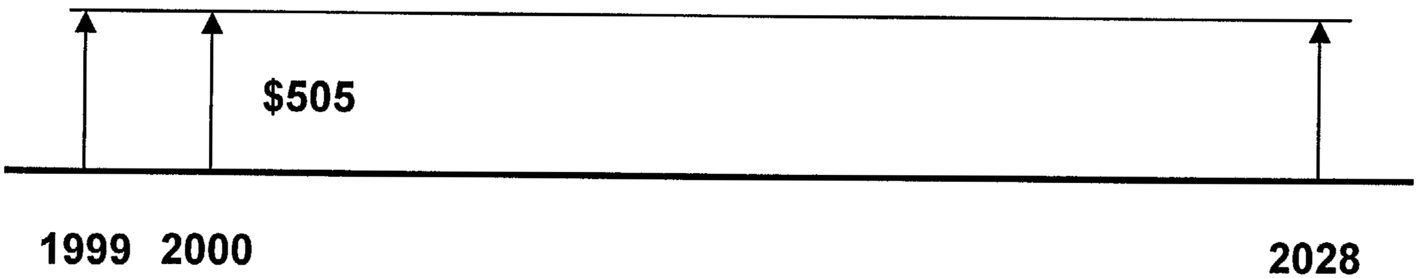
To Perform Engineering Economic Studies Net Present Value (NPV) Future Revenue Requirements.

Solution:

Find the NPV of Each Plan, Using Cost of Money as the Discount Factor

Example: Net Present Value

Present Value of Annual Cost:



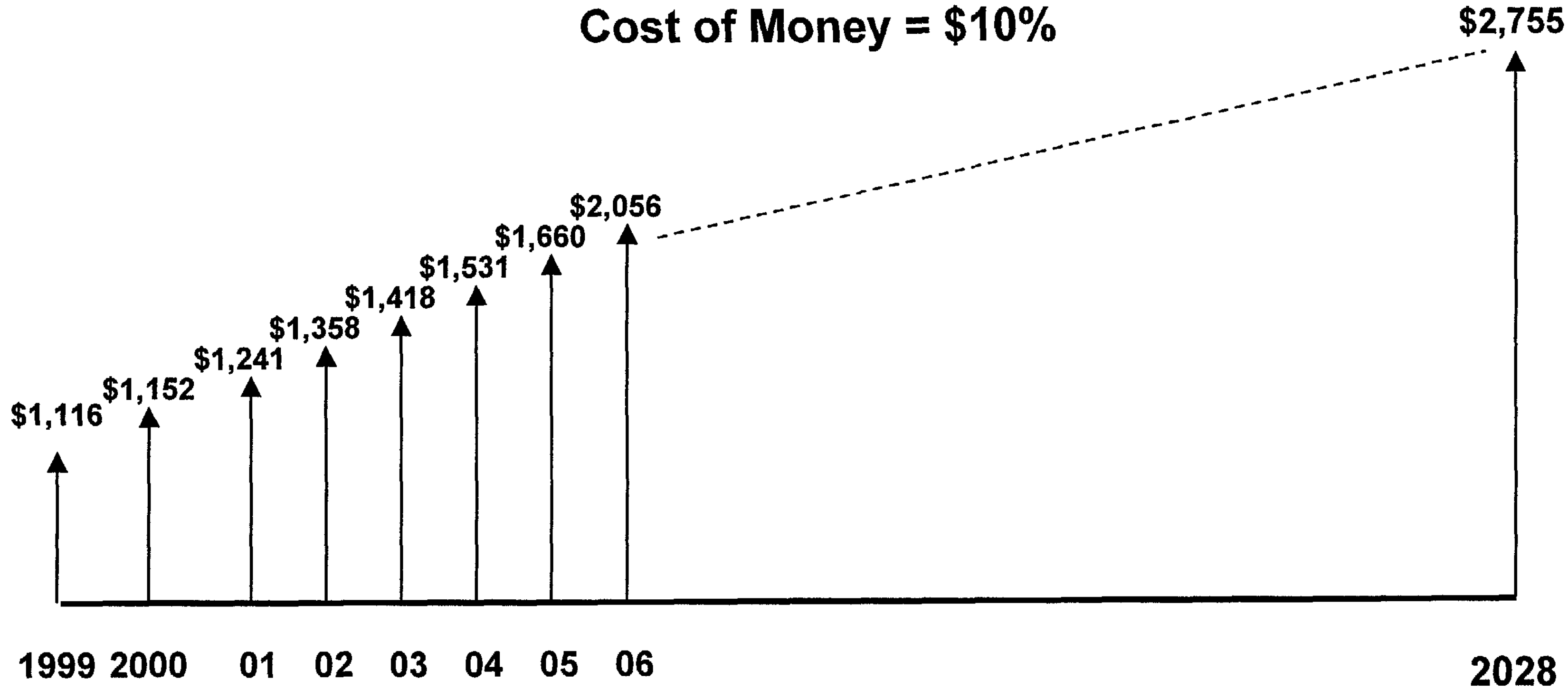
PV Annual Cost =

$$\$505/1.1 + \$505/(1.1)^2 + \ldots \$505/(1.1)^{30} = 505(9.427) = \$4,761$$

NOTE: Cost of Money = Discount Rate = 10%

Present Value of Annual Benefits

Cost of Money = $10%

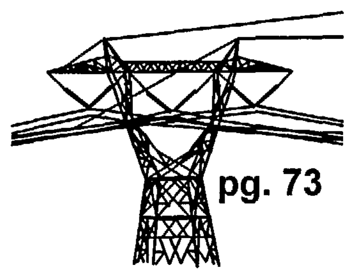


PV Annual Savings =

$$\$1{,}116/1.1 + 1{,}152/(1.1)^2 + 1{,}241/(1.1)^3 + 1{,}358/(1.1)^4 \ldots$$

$$\$2{,}755/(1.1)^{30} = \$17{,}288$$

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



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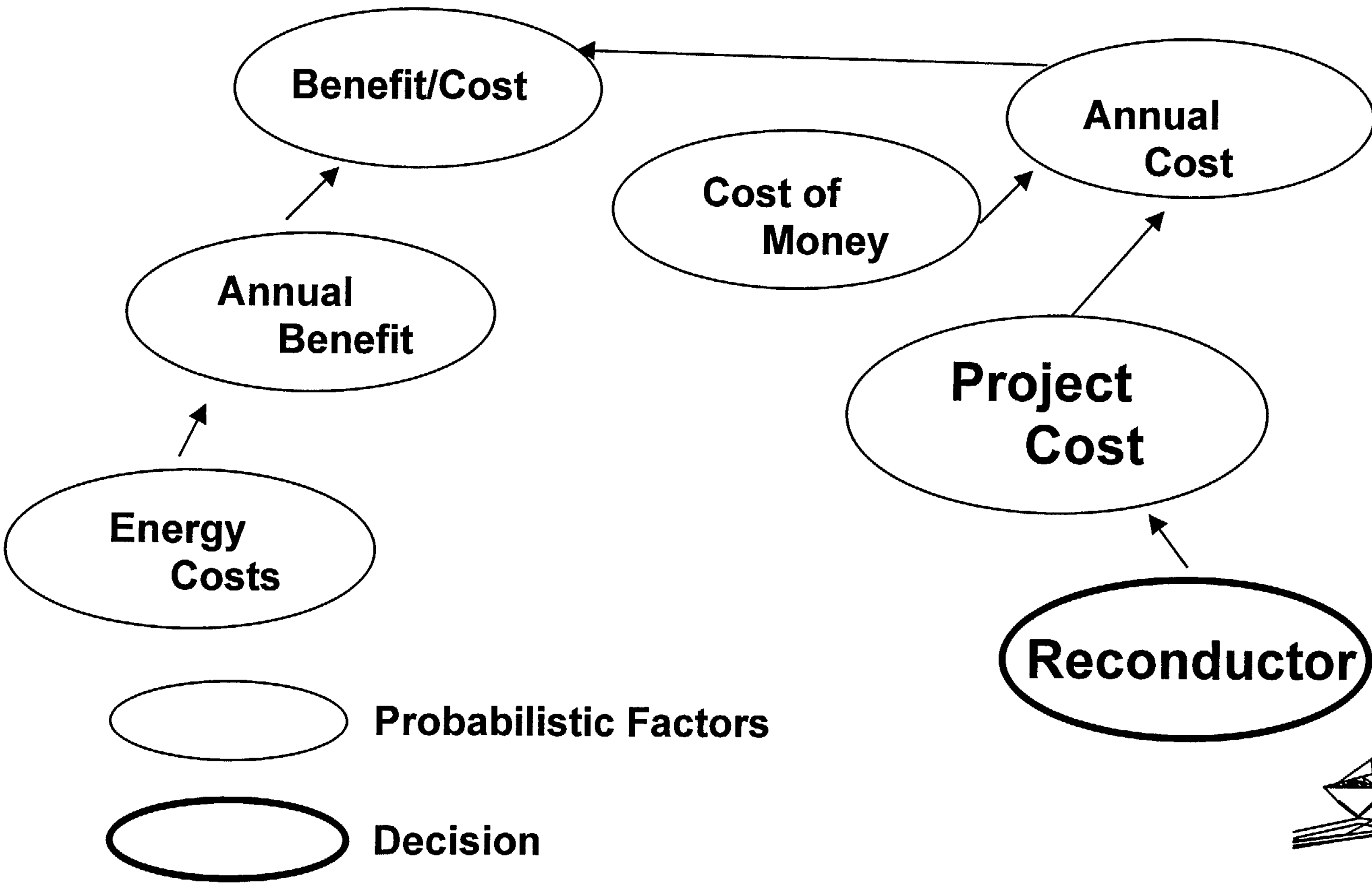
Decision Analysis and Decision Trees

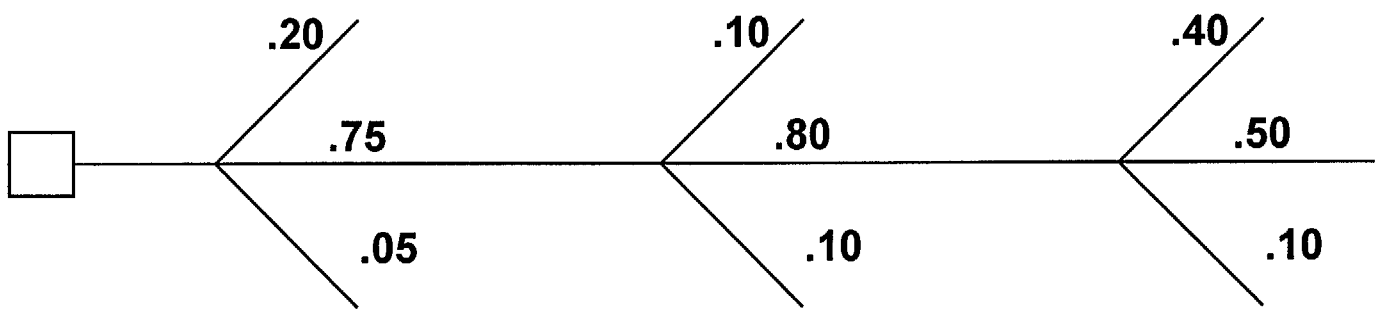
- List Decision We Can Make, and Our Choices
- List Chance Events Beyond Our Control with Possible Outcomes and Their Probabilities
- List Out All Possible Combinations of Decision and Chance Events, and Compute Present Worth and Probability of Each
- Accumulate into Probability Distribution and Choose Best Decisions

Omega Circuit Reconductor Influence Diagram



Probabilistic Factors

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



	3	X	3	X	3	= 27 Branches
Variables:	Project Cost		Energy Cost		Cost of Money	

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Probability of One Branch

0.75 X 0.80 X 0.50 = 0.30

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

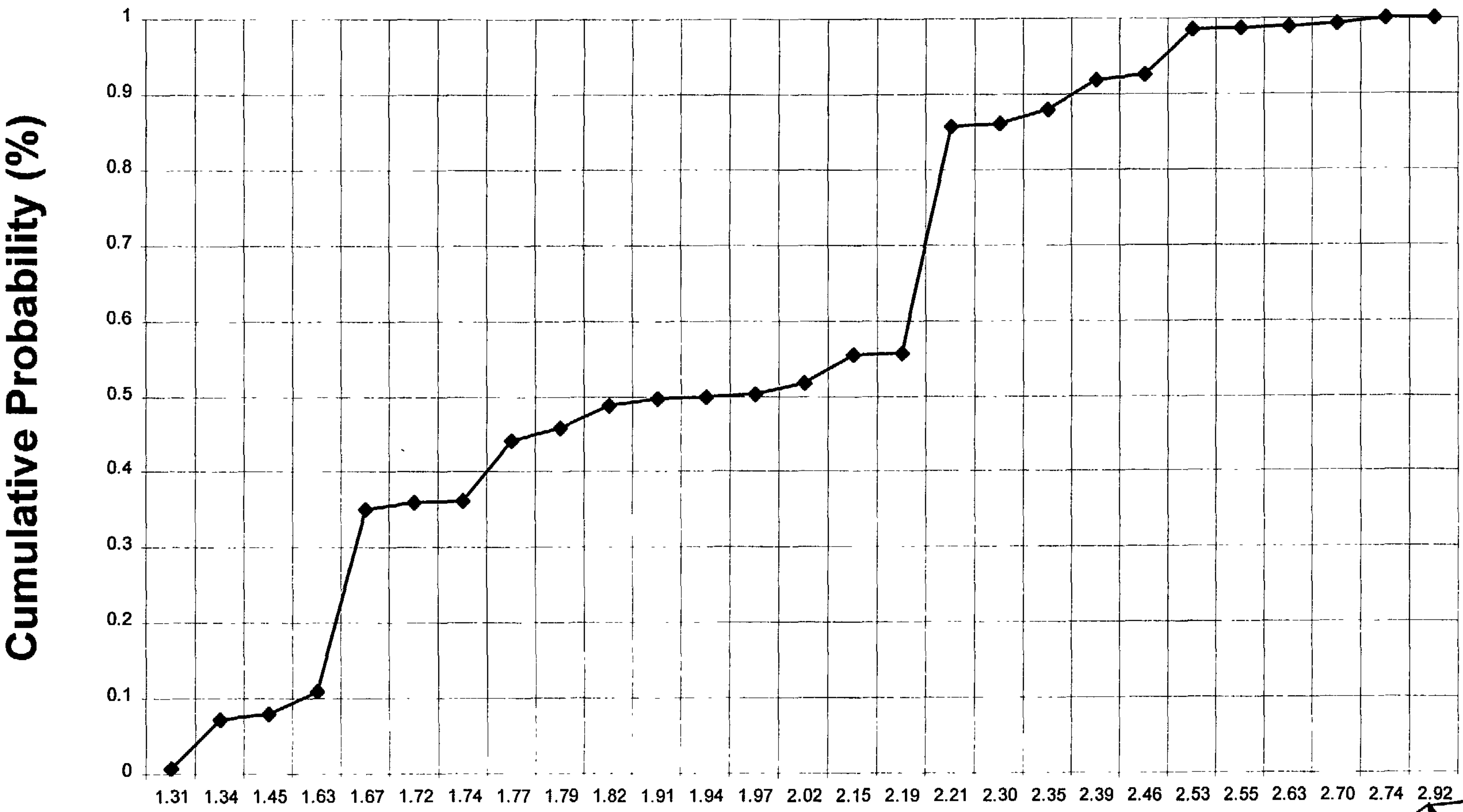
AND

$$\sum_{I=1}^{27} P_I = 1.0$$

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

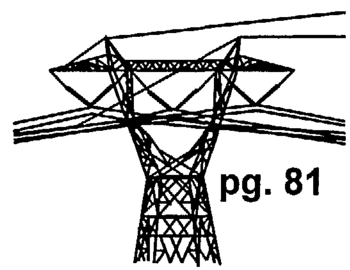
- Cost of Money/Inflation Rate
- Future Costs/Values:
    - Demand, Energy
    - Property Taxes
    - Project Life
- Salvage Value

Customer Unknowns

- Consumption Patterns
- Dependability of Loads

Why do Analysis when
<u>Measured Data are Incomplete?</u>

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



Comment on Analysis

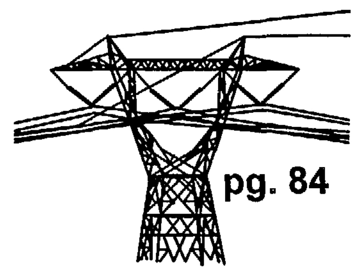
To do a proper job of project analysis, you must know a great deal about your business

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

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

Program Results

- Each Year, Projects with Benefit/Cost Ratios of 3.0 or better were Eligible

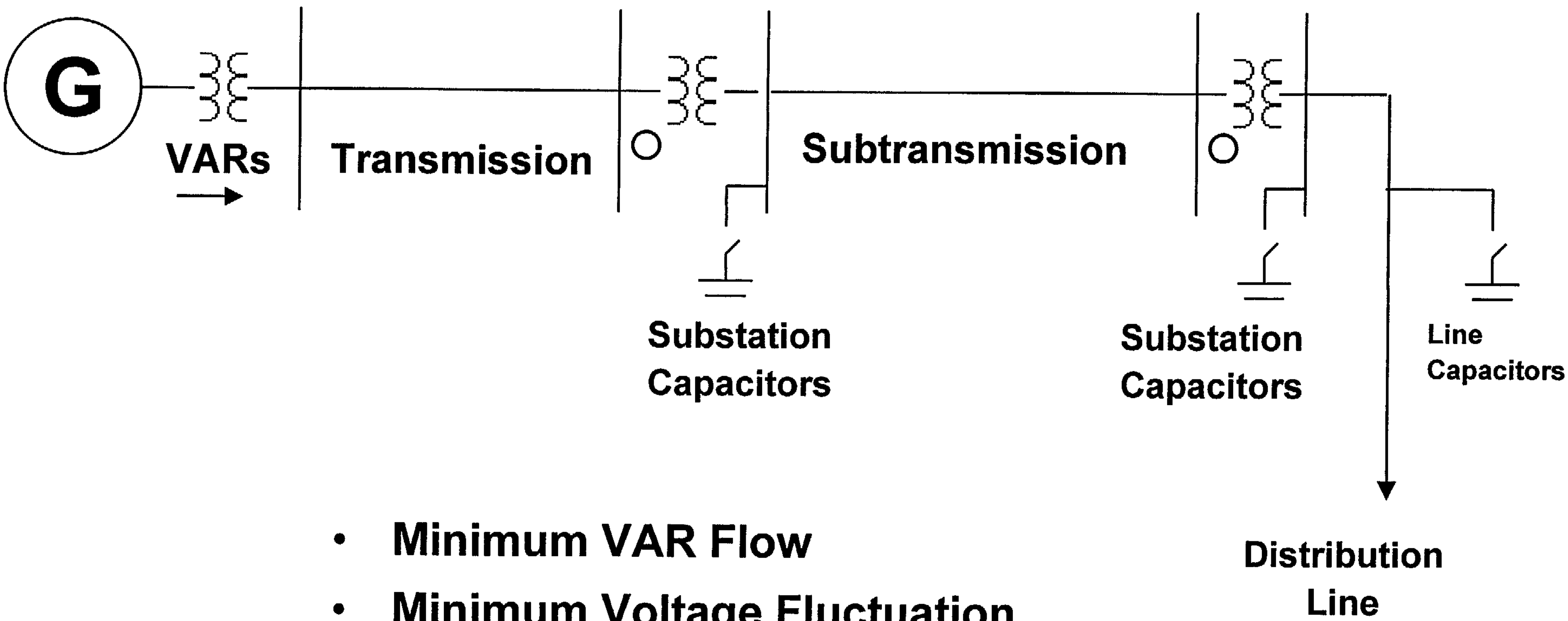
- Viewed with Enthusiasm by Engineers

- Received Favorably by Investment Community and Regulators

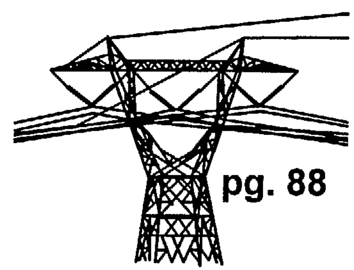
Losses and System Design Criteria

- 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

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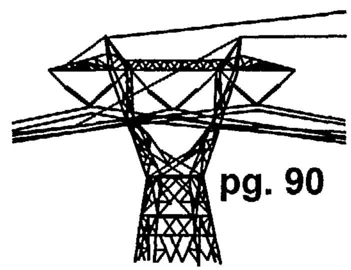
*Southern California Edison Field Studies

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,

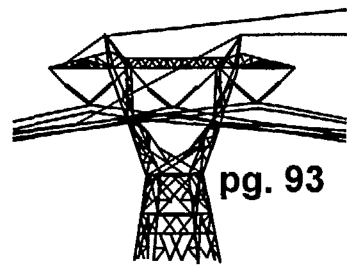
  Located at 12 substations

- **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

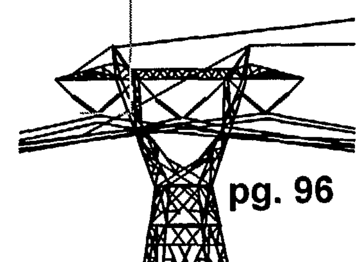
1. Establish a criteria for synchronous condenser removal/replacement
2. Identify function of each synchronous condenser
3. Do economic analysis
4. Evaluate operational effects of removing and/or replacing synchronous condensers
5. Make recommendations.

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

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



Chino Substation

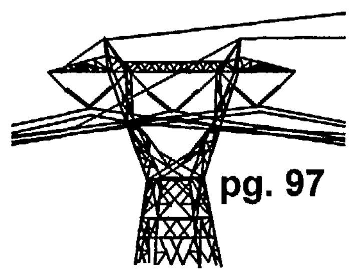
Economic Evaluation
Project Description:
Alternative Selected: ALT 2 - Install new 66kV, 4-28 MVAR Shunt Capacitor Banks
Oper. Date: 12/1/99

ALT. 1 - Continue Maintenance for Operation of 2-60 MVAR Synchronous Condensers
ALT. 2 - Install new 66kV 4-28 MVAR Shunt Capacitors Banks

SUMMARY

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

Benefit Ratio $= \dfrac{\$4,363,661.00}{2,918,267.00} = 1.5$



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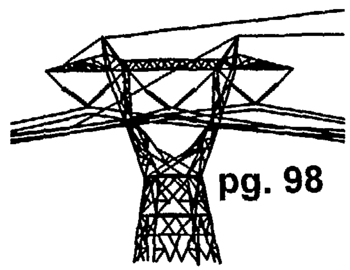
Calculations

CALCULATIONS		
DESCRIPTIONS	ALT 1	ALT 2
A. CAPITAL EXPENDITURES		
SYNCHROUS CONDENSERS		
66 KV SHUNT CAPACITOR BANKS Levelized Annual Cost= $1,833,496.00 x 18% = $330,029 Present Worth Amount $330,029 x 8.69 (PWF) =		$ 1,833,496.00 $ 2,867,952.00
B. OPERATION AND MAINTENANCE		
SYNCHRNOUS CONDENSERS Labor required 250 Mandays/unit @ $250/MD = $62,500/Unit Total =$62,500x2units= $125,000 95% Labor Adder = 118,750 -------- $243,750 Levelized Cost= $243,750 x 1.41 = $343,688 Present Worth Amount $343,688 x 8.69(PWF) =	$ 2,986,644.00	
66KV SHUNT CAPACITORS		
C. LOSSES		
SYNCHRONOUS CONDENSERS Energy Loss: Machine = 618,112 kwh/unit Transformer = 133,456 kwh/unit Aux & Load = 36,866 kwh/unit ----------------- 788,444 kwh/unit Total losses= 1,576,888kwh (For two (2) Units) Levelized Cost = 1,576,888 x 0.0554(LRRL)= $ 87,360 Present Worth Amount = $ 87,360 x 8.69 (PWF)	$ 759,158.00	
Capacity (Demand Loss): Demand loss = 450 kw/unit Levelized Cost = 450 x 2 x$79/kw (For two (2) Units) = $ 71,100 Present Worth Amout = $71,100 x 8.69 (PWF)	$ 617,859.00	



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Calculations (CON'T)

(CON'T)

CALCULATIONS		
DESCRIPTIONS	ALT 1	ALT 2
C. LOSSES		
66KV SHUNT CAPACITORS Energy: Loss/kvar = 0.08 watts/kvar 56,000kvar x 0.08/1000 = 4.5kw 4.5kw x 8760 hrs/year = 39,420kwh Levelized Cost= 39,420 x 2 x 0.0554 (LLRR)=$4,368 Present Worth Amount= $4,368 x 8.69 (PWF)		$ 37,958.00
Capacity (Demand Loss): 4.5 x 4 x $79/kw = $1422 Present Worth Amount = $1422 x 8.69 (PWF)		$ 12,357.00

ECONOMIC FACTORS & ASSUMPTIONS

Base Year	1993
Economic Life	30 Years
Escalation Rate (Capital & O&M)	4 %
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
Levelize revenue req'mt over life	$79
PW Revenue requirement	$688
Energy	
Base Year Cost	$0.0290
Levelized revenue req'mt over life	$0.0554
PW revenue requirement	$0.4813

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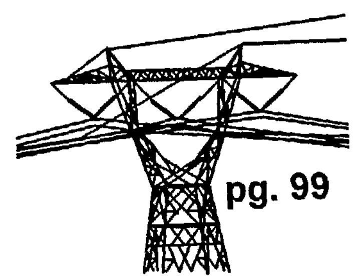

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Refurbishing Costs

- $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

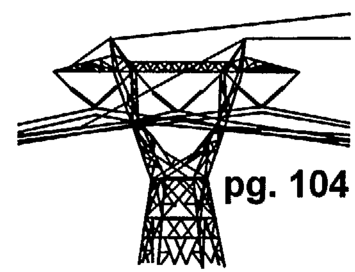
- Voltage rises (0 to 3%)due to condensers during faults (3-phase & single-phase): Not Significant
- Not significant to reduce risk of air conditioners stalling (to avoid voltages of less than 60%)
- Beneficial at La Fresa for Mobil Oil, and Springville for voltages sensitive customers (Smoothing or 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)

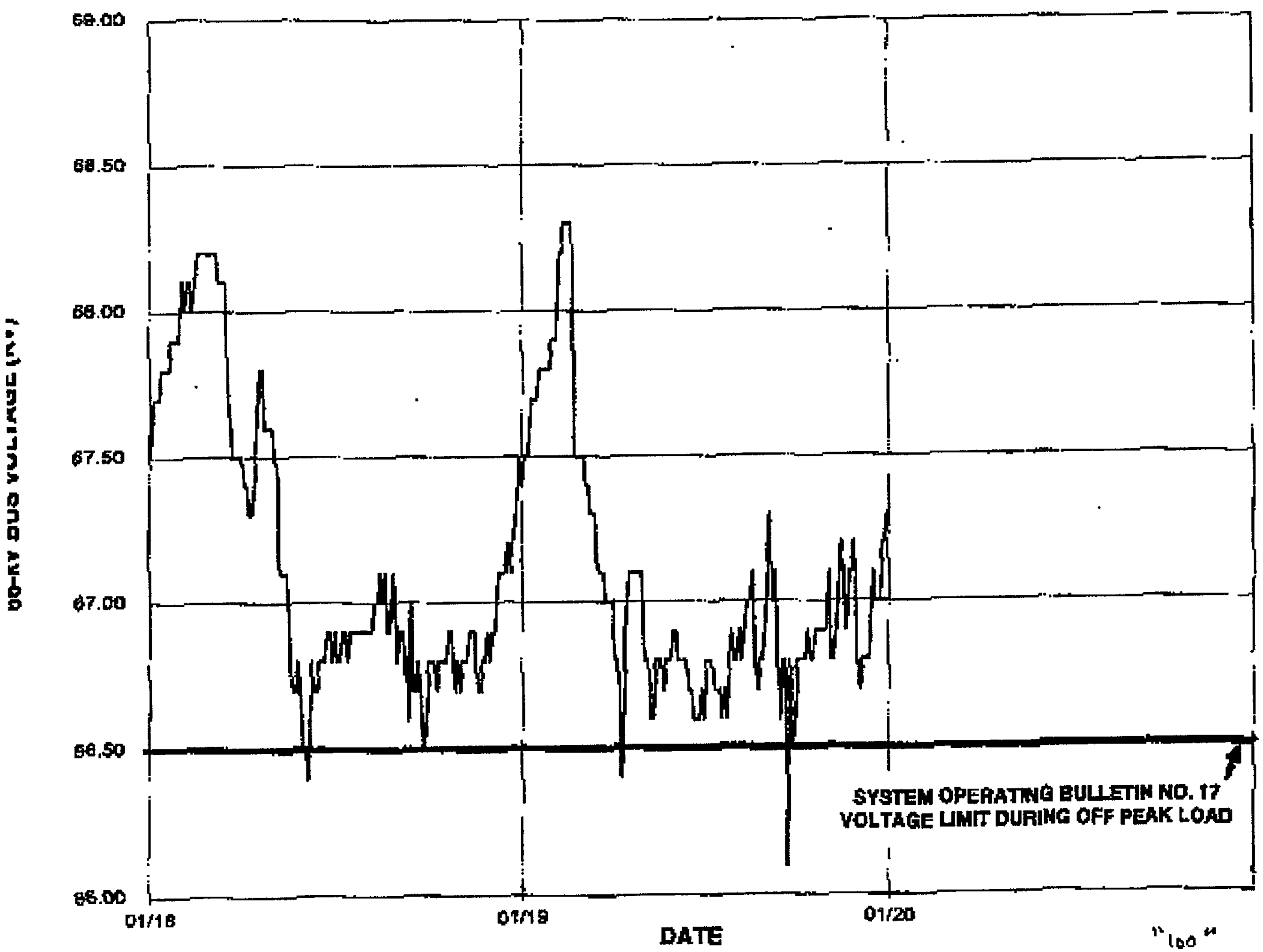
- **<u>However it would result in Much Larger Costs:</u> $40 M for refurbishing and $40 M PW for O&M versus $16.5 M for 675 MVAR of RMR Caps.**



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



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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)

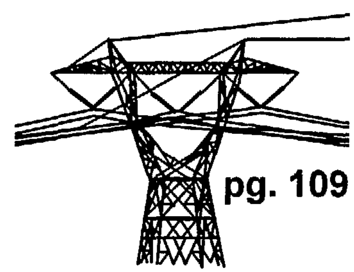
MacNeil Switching Substation Line and Bus Arrangement <u>Modification</u>

March 2, 1999

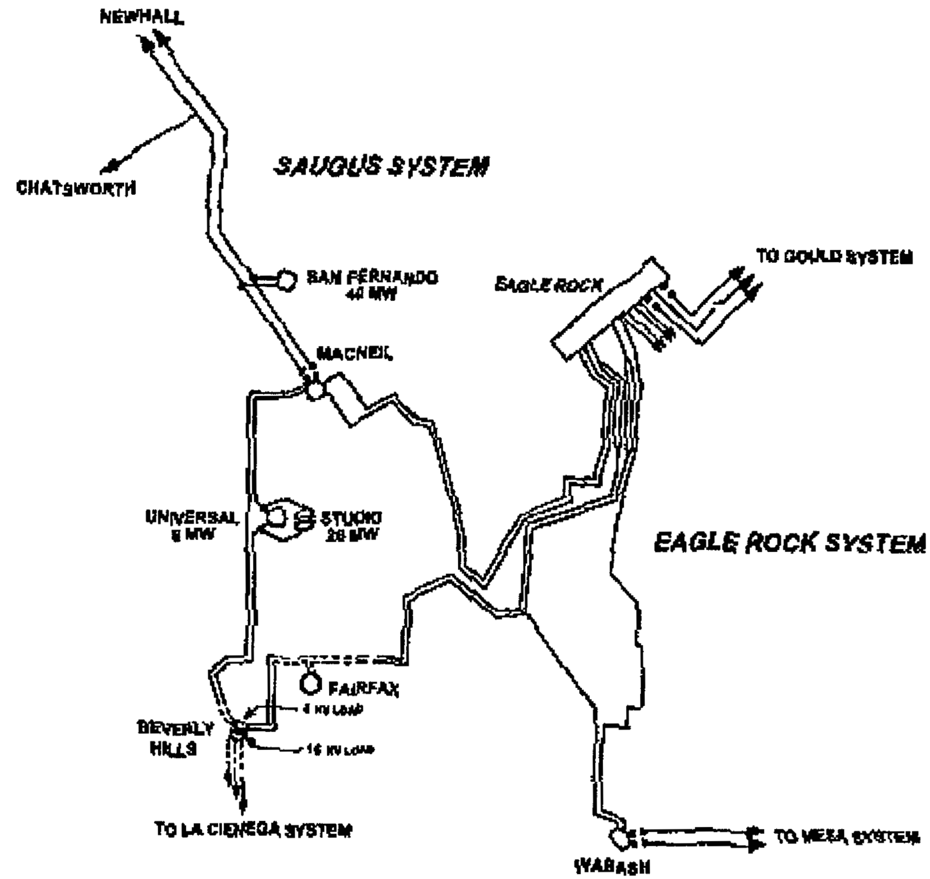
Phil Save
Electric Grid Planning

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

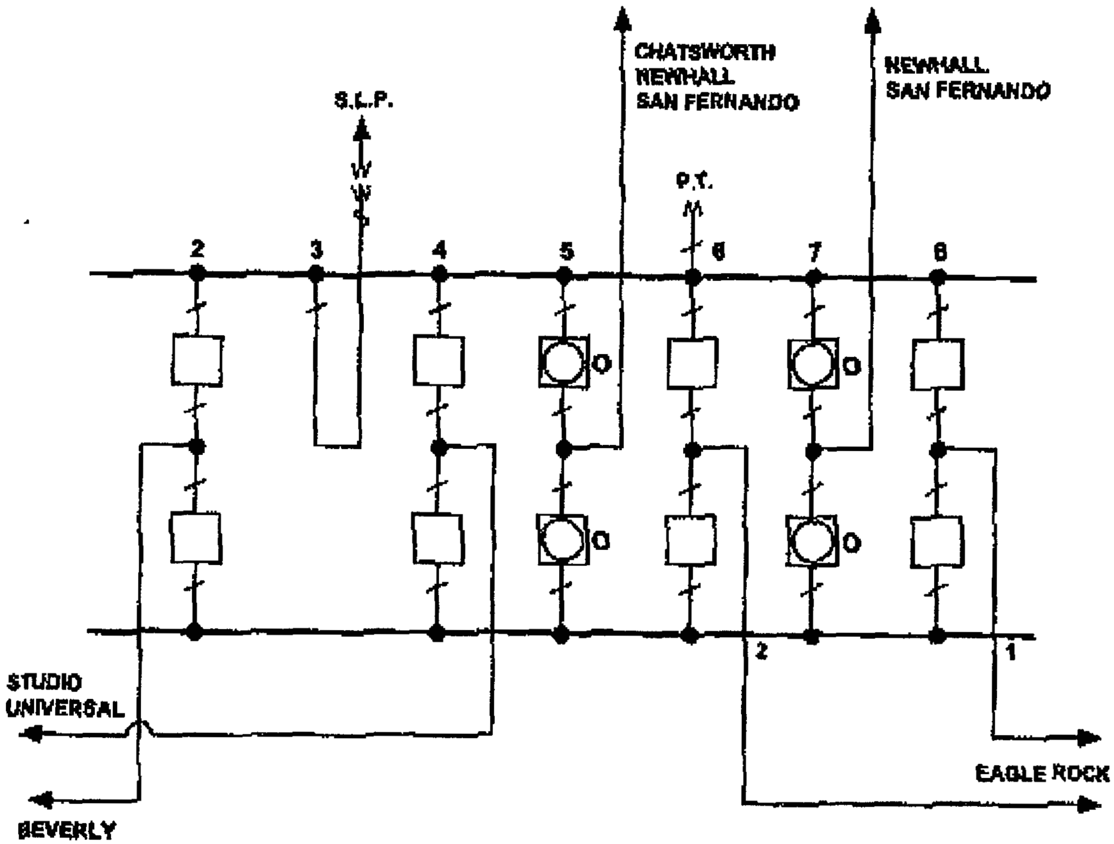


Eagle Rock and Saugus 66-kV Systems in Vicinity of MacNeil Switching 66-kV Substation



MacNeil Switching 66-kV Substation
<u>Line and Bus Arrangement</u>

Existing: 12 breakers



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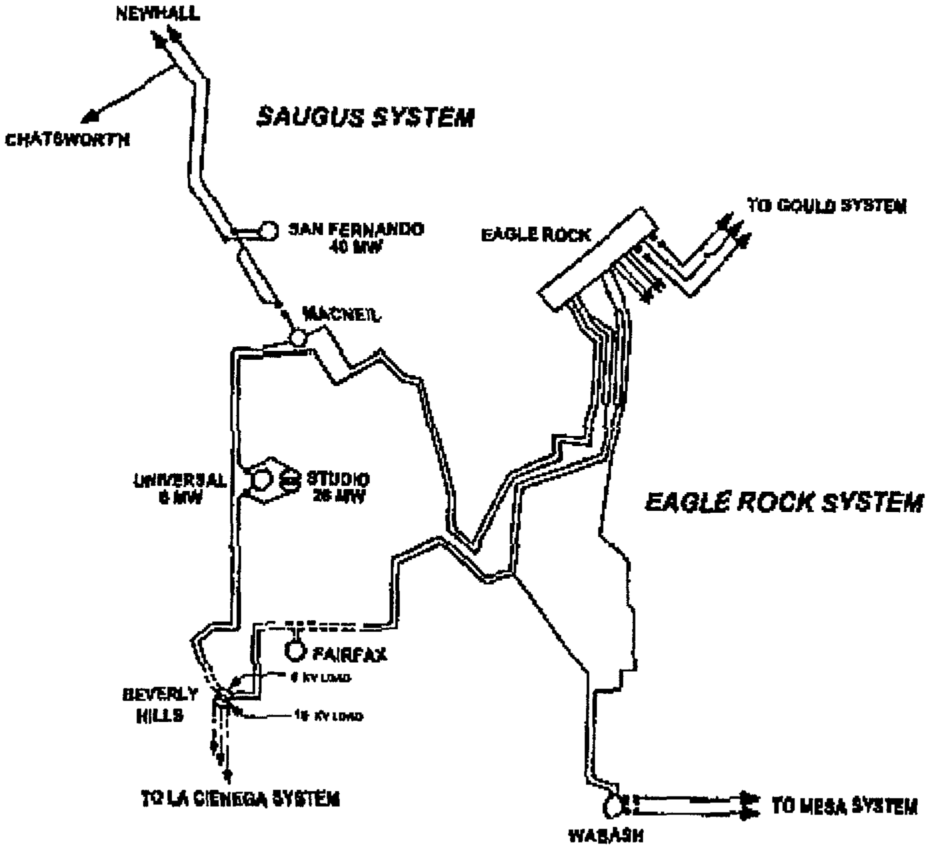
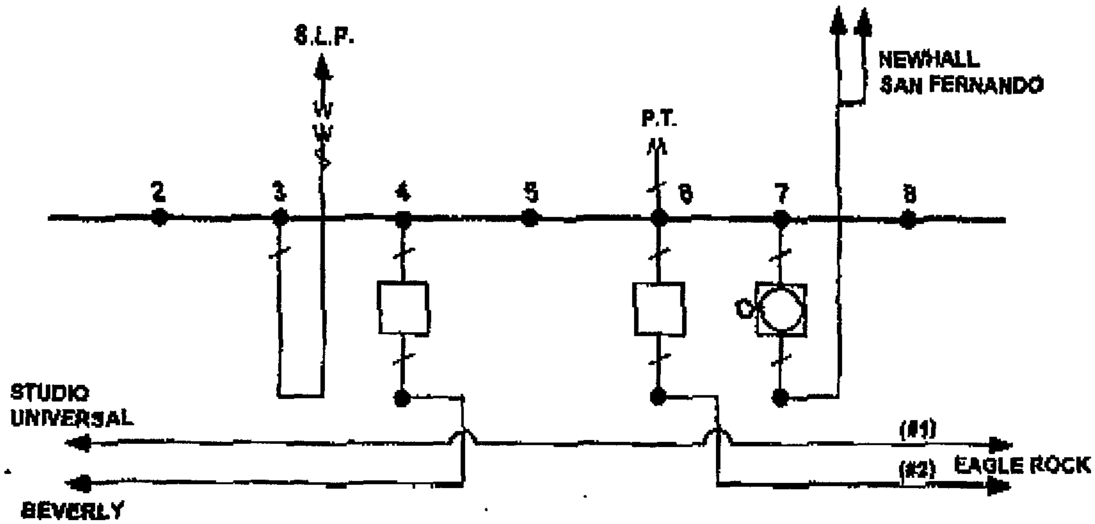
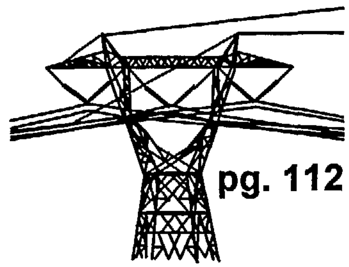
Alternative 3



3 breakers





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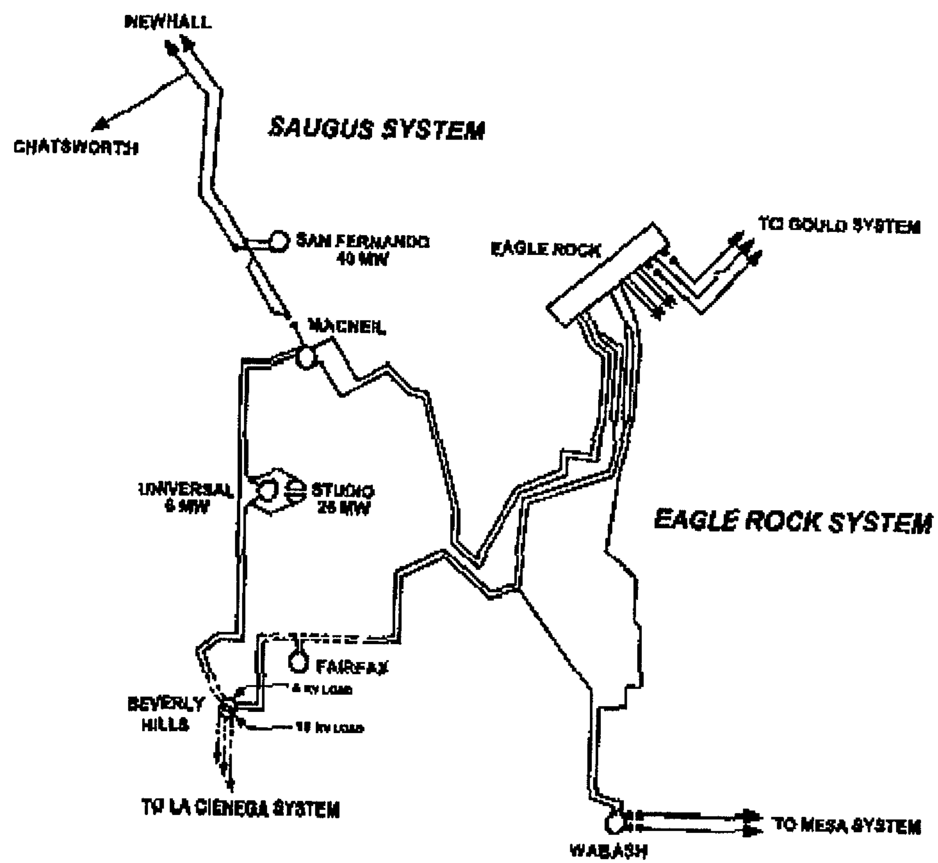
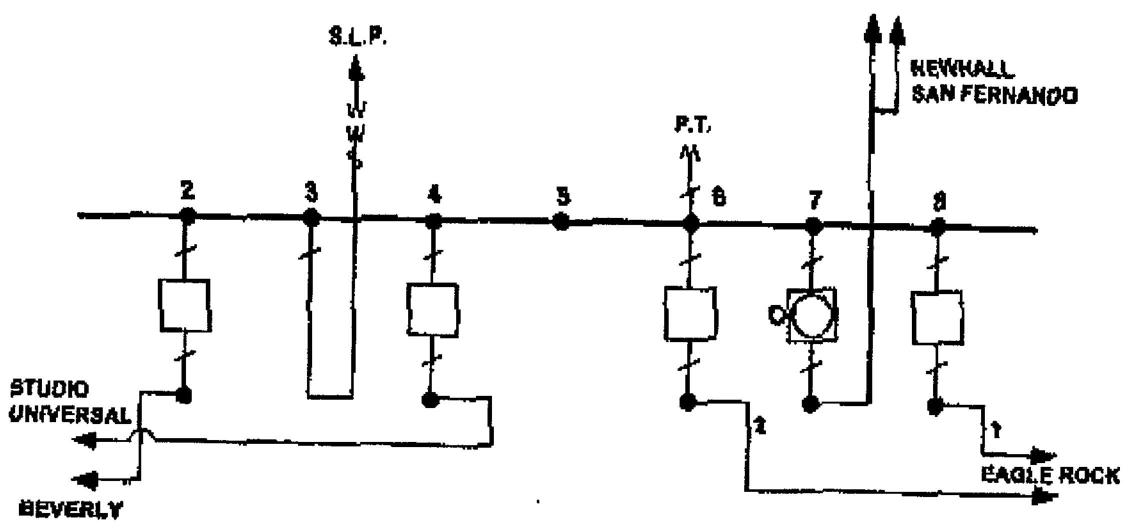
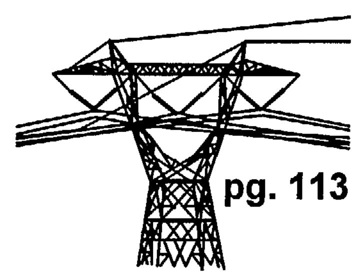


Alternative 4

5 breakers





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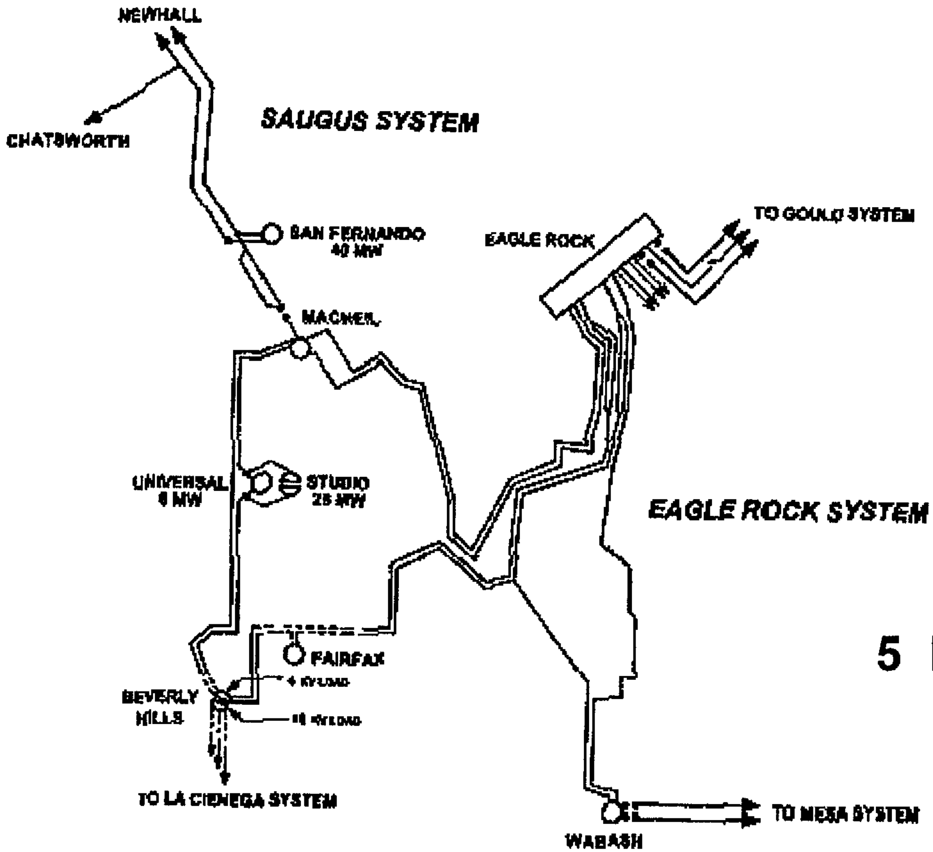
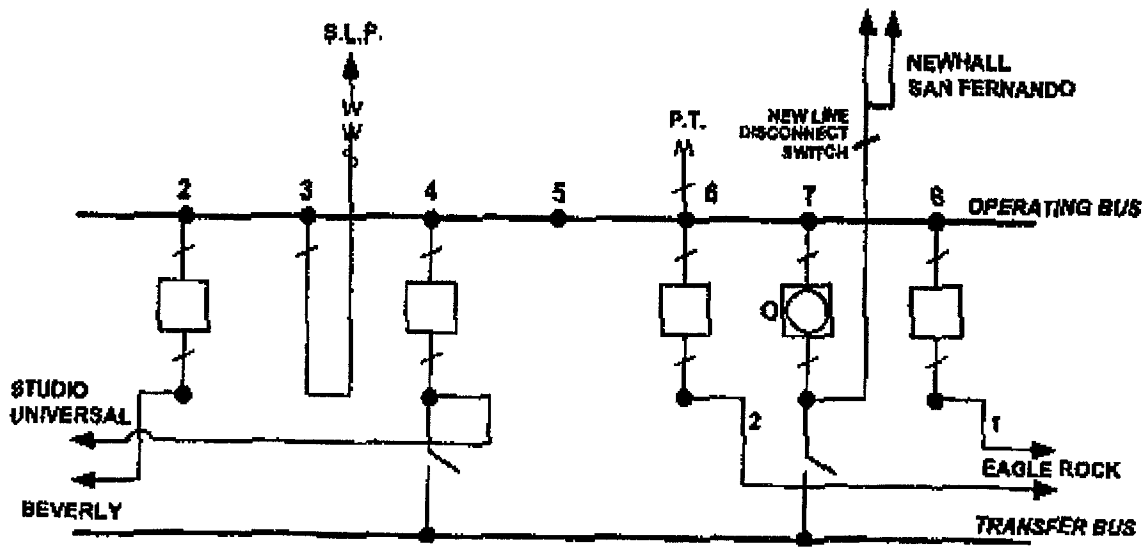
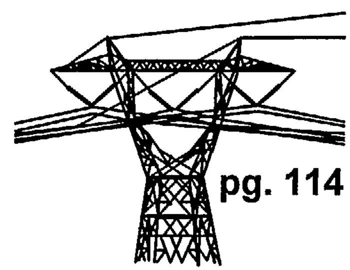


Alternative 5

5 breakers with Operating and Transfer Bus





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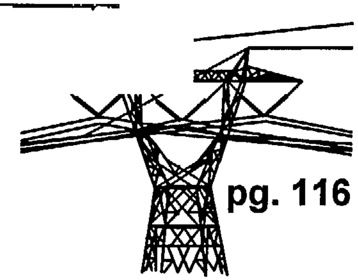
MacNeil Substation 3-Breakers Alternative and 5-Breakers_Alternative Comparison for Reliability of Service to Studio and Universal Substations

N-2 LINE OUTAGE CASES RESULTING IN OUTAGE OF STUDIO AND UNIVERSAL SUBSTATIONS			OUTAGE RATE AND DURATION FOR EACH LINE		OUTAGE OF BOTH STUDIO AND UNIVERSAL SUBSTATIONS (OUTAGE OF BOTH LINES)			
LINES	MILES	OUTAGE TYPE	RATE (PER YEAR)	DURATION (MINUTES / OUTAGE)	OUTAGE FREQUENCY F PER YEAR	OUTAGE FREQUENCY F ONCE IN N YEARS	OUTAGE DURATION R (MINUTES / OUTAGE)	ANNUAL DOWN T U = F x R (MINUTES/YEA
3-BREAKERS ALTERNATIVE - SINGLE BUS								
DELOOP 66-KV LINES: EAGLE ROCK-MACNEIL AND MC-NEAL-STUDIO-UNIVERSAL								
BEVERLY HILLS-STUDIO-UNIVERSAL	7.2	FORCED	0.7	16.4				
EAGLE ROCK-STUDIO-UNIVERSAL	18.7	FORCED	1.9	98.0	2.89E-04	3,454	14.0	4.07E-03
5-BREAKERS ALTERNATIVES								
A. SINGLE BUS								
BEVERLY HILLS-STUDIO-UNIVERSAL	7.2	FORCED	0.7	16.4				
MACNEIL-STUDIO-UNIVERSAL	3.5	FORCED	0.2	15.0	8.36E-06	119,563	7.8	6.55E-05
BEVERLY HILLS-STUDIO-UNIVERSAL	7.2	FORCED	0.7	16.4				
MACNEIL-STUDIO-UNIVERSAL (DURING BREAKER MAINTENANCE)	3.5	MAINTENANCE	0.5	630.0	5.03E-04	1,988	16.0	8.05E-03
TOTAL FOR BOTH N-2 OUTAGES					5.12E-04	1,954	15.9	8.11E-03
B. OPERATING AND TRANSFER BUSES								
BEVERLY HILLS-STUDIO-UNIVERSAL	7.2	FORCED	0.7	16.4				
MACNEIL-STUDIO-UNIVERSAL	3.5	FORCED	0.2	15.0	8.36E-06	119,563	7.8	6.55E-05

Maintenance of SCE Circuit Breakers
Typical Outage Rates and Duration

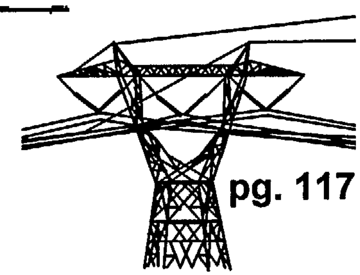
MAINTENANCE TYPE	BREAKER TYPE	TRANSMISSION RATE (PER YEAR)	TRANSMISSION DURATION (DAY)	TRANSMISSION DURATION (HOUR)	SUBTRANSMISSION RATE (PER YEAR)	SUBTRANSMISSION DURATION (DAY)	SUBTRANSMISSION DURATION (HOUR)	DISTRIBUTION RATE (PER YEAR)	DISTRIBUTION DURATION (DAY)	DISTRIBUTION DURATION (HOUR)
OVERHAUL	AIR BLAST	0.1	30	720						
	GAS	0.1	5	120	0.1	2	48	0.1	0.42	10
	OIL	0.1	5	120	0.1	2	48	0.1	0.42	10
	VACUUM				0.1	2	48	0.1	0.42	10
	AIR MAGNETIC							0.2	0.42	10
GAS REFILLING	AIR BLAST	1.0	0.25	6						
	GAS	1.0	0.25	6	1.0	0.25	6	1.0	0.25	6
BREAKER MECHANISM MAINTENANCE	ALL	0.5	0.17	4	0.5	0.13	3.0	0.5	0.13	3.0
BREAKER MAINTENANCE EQUIVALENT	AIR BLAST	1.6	2.08	50						
	GAS	1.6	0.52	12.5	1.6	0.32	7.7	1.6	0.07	1.6
	OIL	0.6	0.97	23.3	0.6	0.44	10.6	0.6	0.17	4.2
	VACUUM				0.6	0.44	10.5	0.6	0.17	4.2
	AIR MAGNETIC							0.7	0.21	5.0



122A

MacNeil Substation Line and Bus Arrangement Alternatives
Economic and Reliability Comparison

ALTERNATIVES	SAVINGS ($ MILLIONS)	OUTAGE OF BOTH STUDIO AND UNIVERSAL SUBSTATIONS DUE TO 66-kV LINE OUTAGES	
		OUTAGE FREQUENCY (ONCE IN N YEAR)	OUTAGE DURATION (MINUTES PER OUTAGE)
3-BREAKERS ALTERNATIVE - SINGLE BUS	0.973	1 in 3,450	14
5-BREAKERS ALTERNATIVES			
A. *SINGLE BUS*	0.753	1 in 1,950	16
B. *OPERATING AND TRANSFER BUS*	0.729	1 in 119,000	8
OUTAGES OF BOTH SUBSTATIONS DUE TO BUS FAULTS OR EARTHQUAKES		**1 in 5**	



Recommendation

- **Recommended Alternative:**
  3-breakers with single bus arrangement

  Savings: From $1.3 M to 0.367 M = $0.967 M

- **5-breaker with operating and transfer bus:**

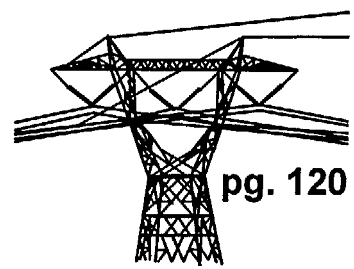
  No significant increase of reliability
  Additional expenditure of $244,000 is not justified

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

	Lower Cost per kWh	Higher Cost per kWh
Level of Service	Higher Voltage	Lower Voltage
Efficiency		
• Peak Load	Off-Peak	On-Peak
• Load Factor	High	Low
Amount of Usage	High	Low



Demand Side Management Choices

BUILT-IN INCENTIVES

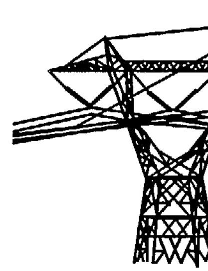
- TOU RATES
- OFF-PEAK STORAGE
- SWIMMING POOL TRIPPERS
- CONSUMER EDUCATION

UTILITY-ACTUATED

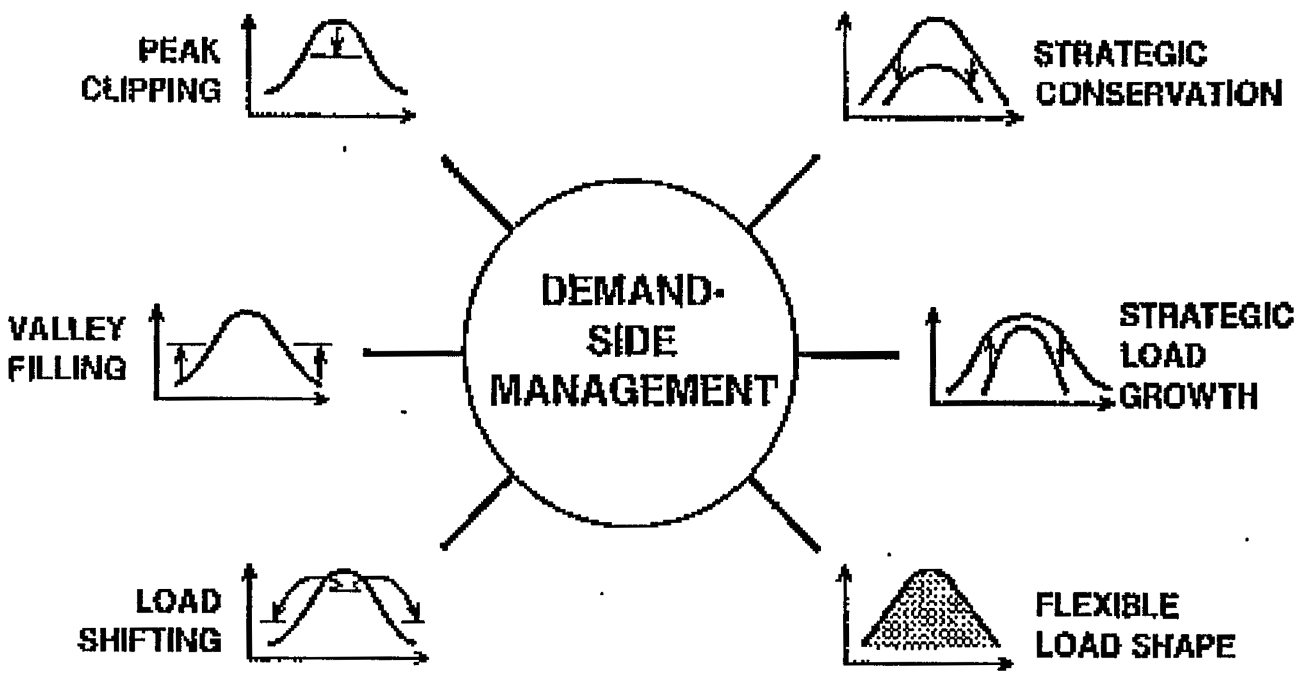
- HEATING & AIR CONDITIONER CYCLES
- INTERRUPTIBLE LOAD
- DEMAND SUBSCRIPTION SERVICE

CONSERVATION

- PRICE INDUCED
- PROGRAMS
- COMMUNICATION

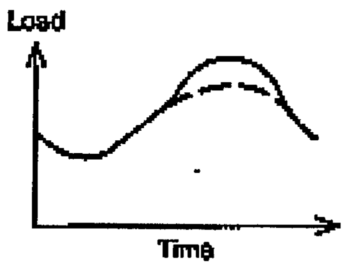


Demand-Side Management Embraces Several Load Shape Objectives



Peak Clipping, Load Shifting

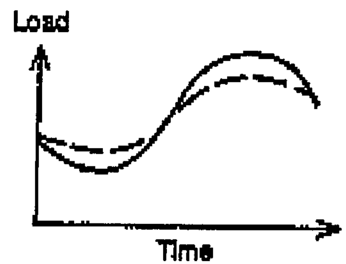
PEAK CLIPPING



Defined as reduction during peak hours

Examples
- Dual fuel heating
- Heat pumps
- Interruptible loads
- Some conservation options

LOAD SHIFTING

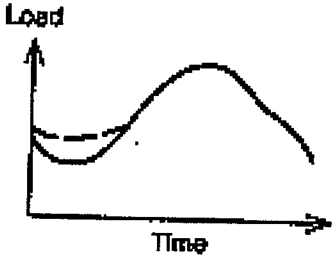


Defined as shift from peak to off-peak

Examples
- Water heater control
- Air conditioner control
- Storage heating
- Storage cooling
- Interlocks
- Irrigation control

Valley Filling, Conservation

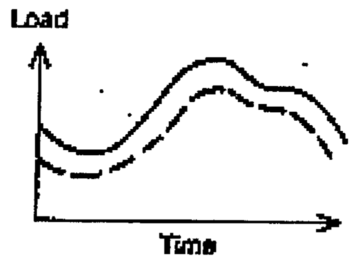
VALLEY FILLING



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

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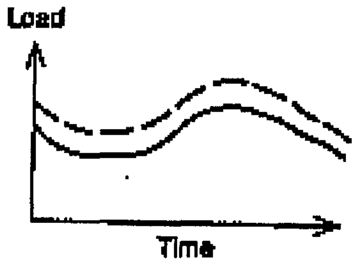
Growth, Flexible Load Shape

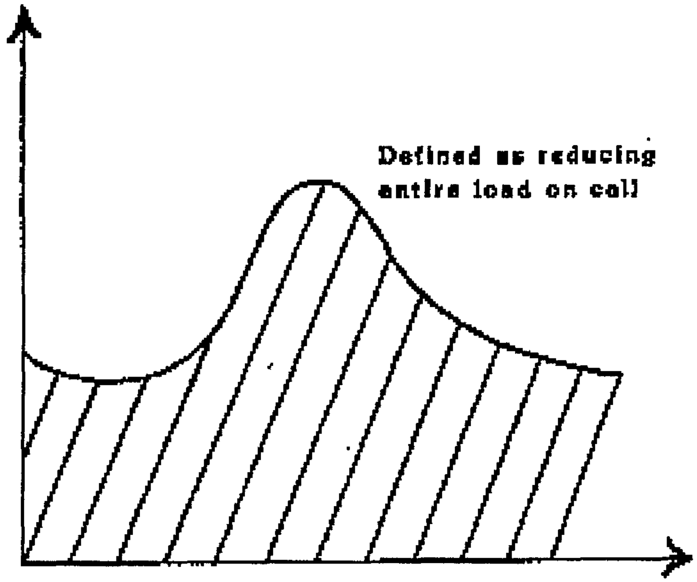
GROWTH



Defined as growth during peak and off-peak hours

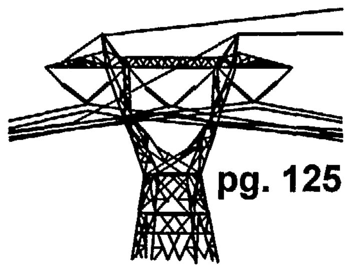
Examples
- New electric space heating loads
- Increased appliance saturation
- Area development
- Electrification

FLEXIBLE LOAD SHAPE



Defined as reducing entire load on call

Examples
- Interruptible Loads
- Dual Fuel Heating
- Stand-by Generation
- Levels of Reliability



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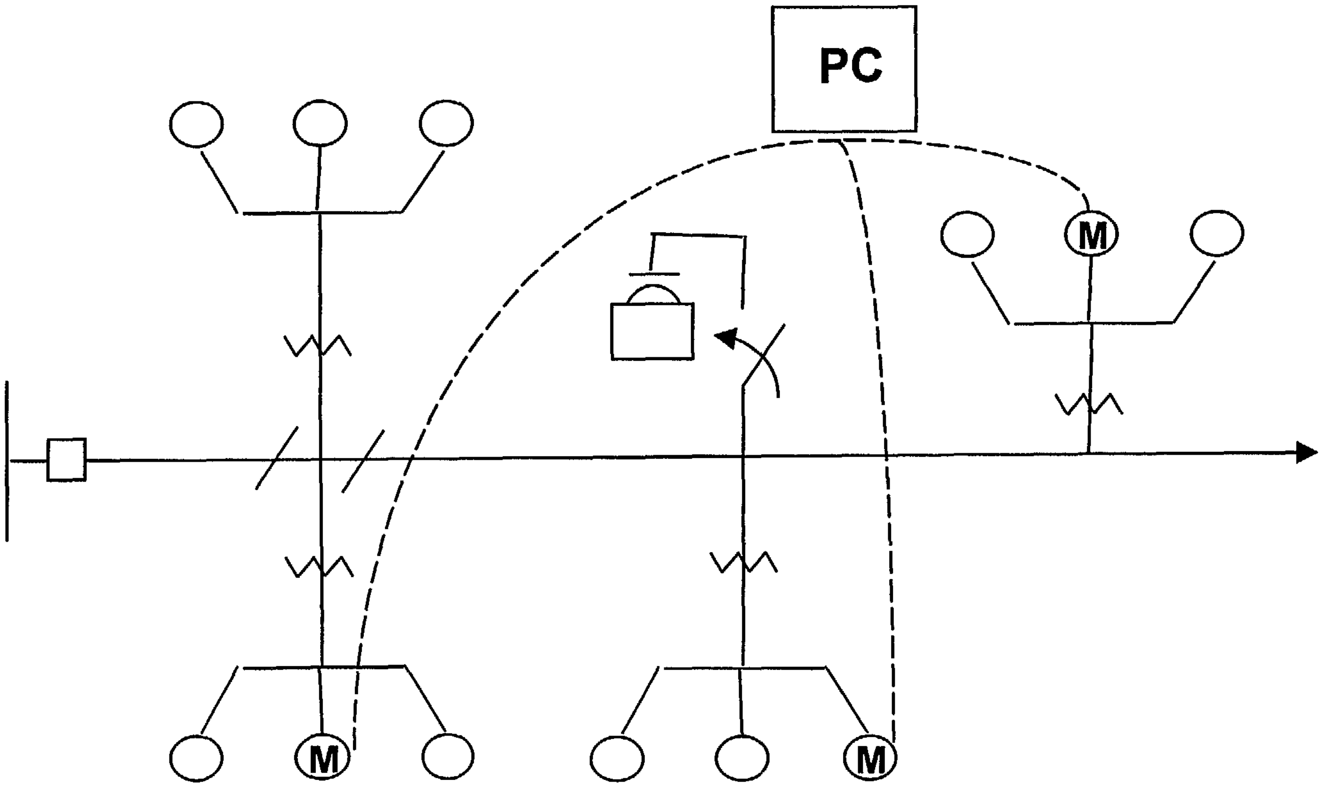
Automatic Regulation of Customer Voltage and VAR Control

Voltage Range Required by California Code: 126 Volts Maximum, 120 Volts, 114 Volts Minimum

Voltage Range Agreed To: 120 Volts to 114 Volts Minimum



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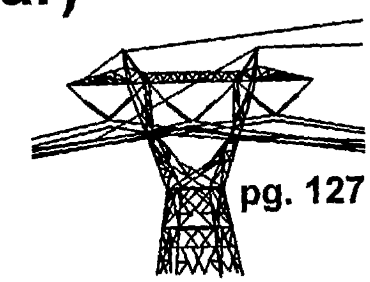
Relationship of Loss Reduction to Distributed Generation

- 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)

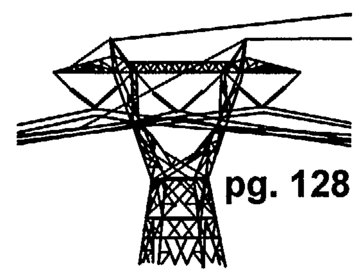


Relationship of Loss Reduction to Least-Cost Plan

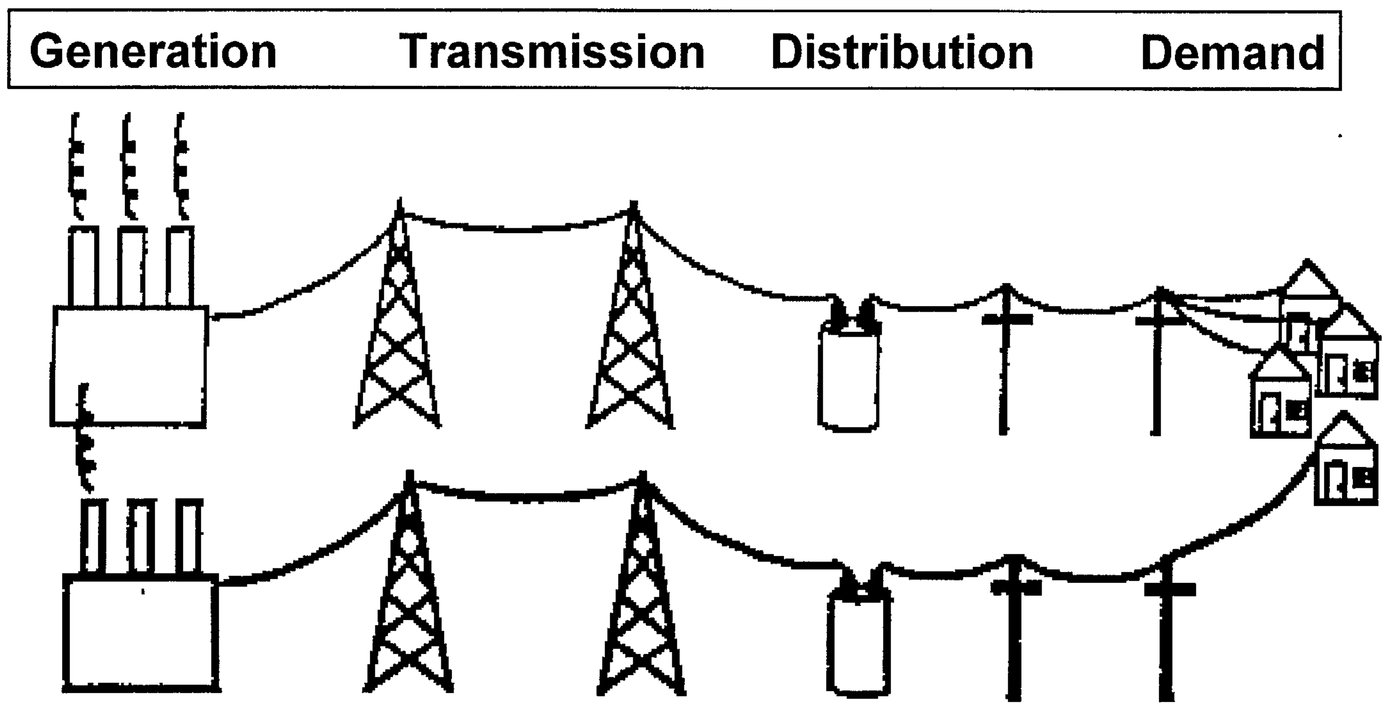
- Least Cost Planning Includes:
  - Supply and Demand-Side Planning
  - Proper accounting for losses
  - Weighing of Fixed versus Variable Costs
  - Assessment of the Future

- Example:

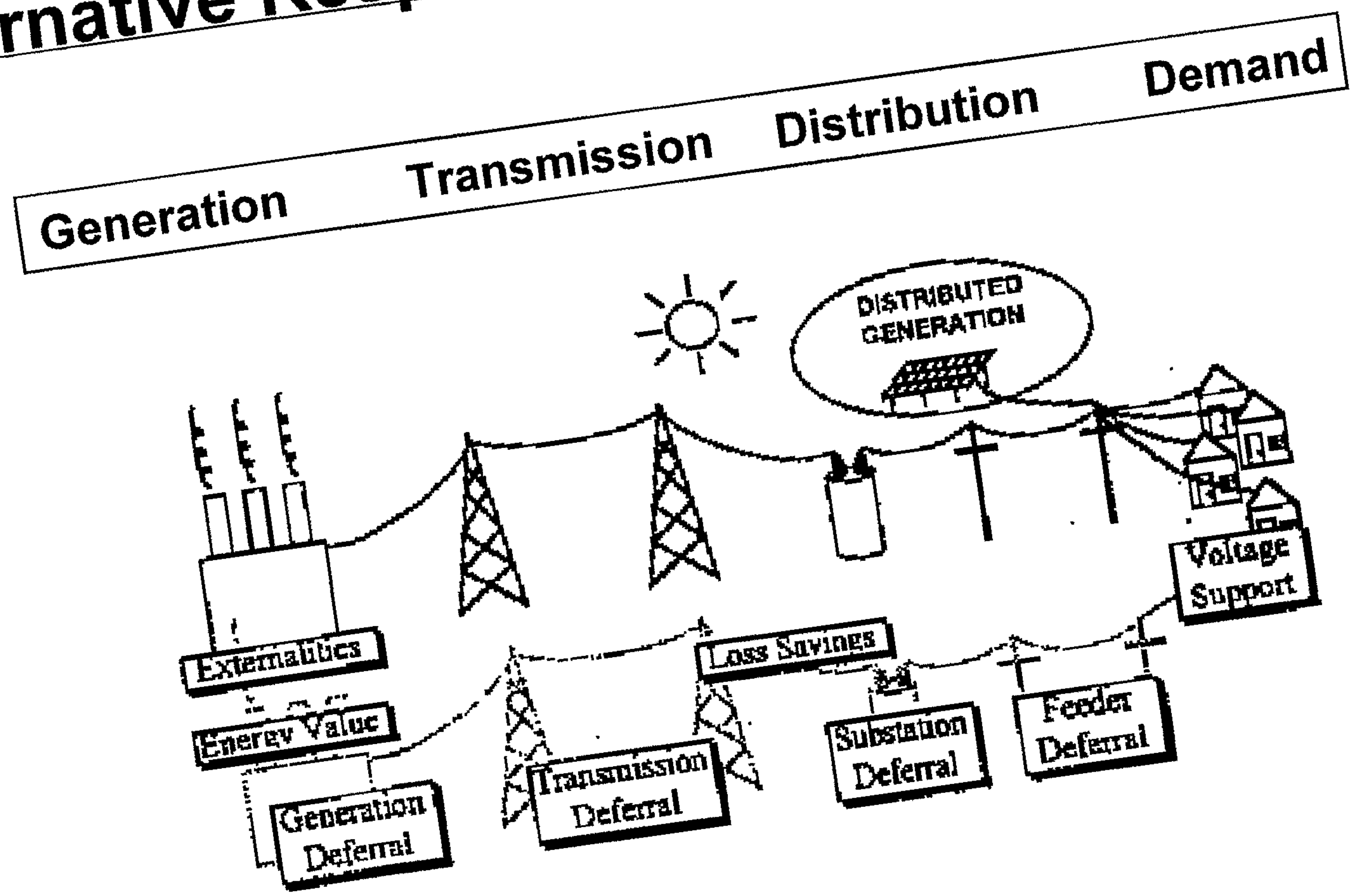
  Duke Power
  - Low Losses: 5.7%
  - Low Cost of Service - 7.3¢
  - High profitability: Price/Earnings - 17

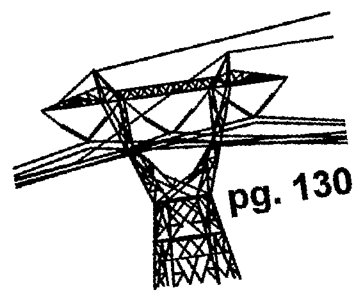


Traditional Response to Demand: Build Power Lines



Alternative Response: Distributed Generation





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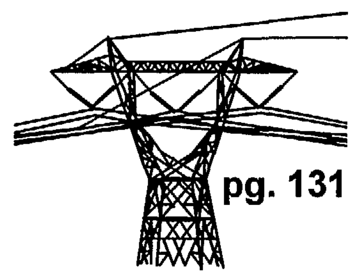
Solar (PV) Grid-Support Value Analysis Definitions

Traditional Value

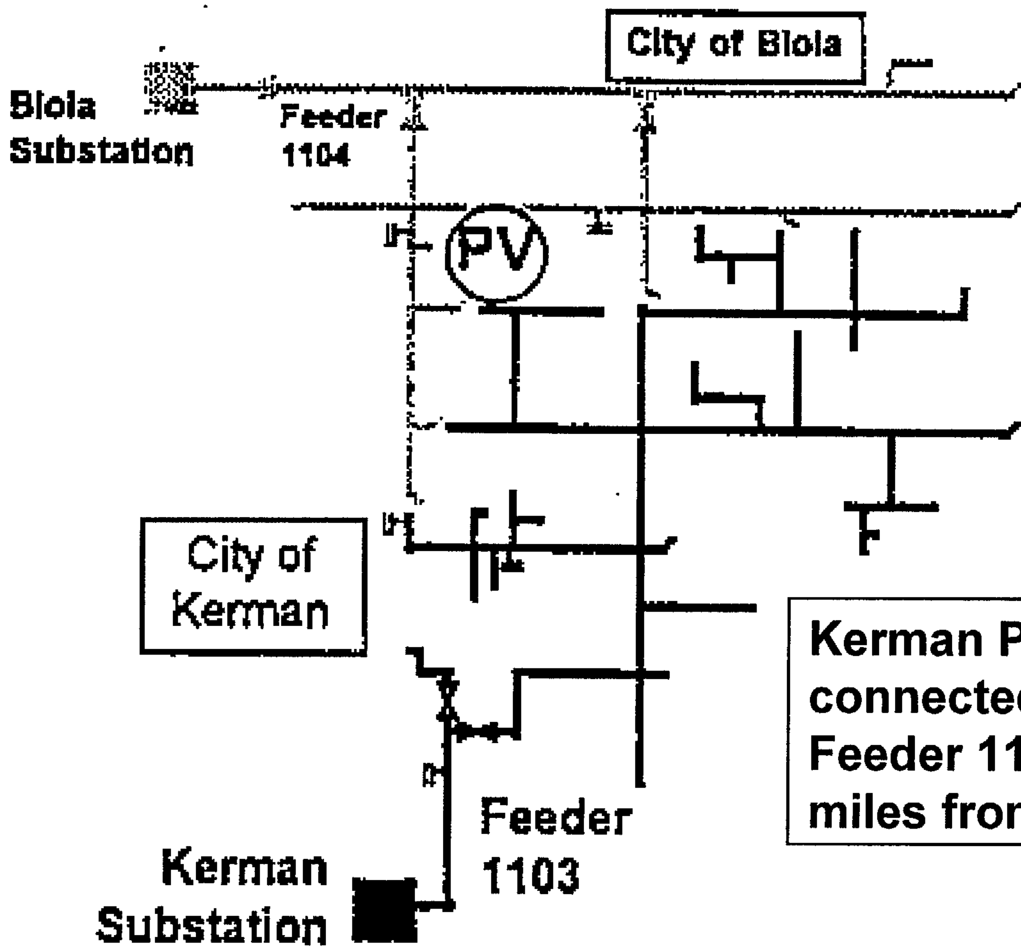
- *Energy* (generation displacement)
- *Capacity* (system reliability enhancement)

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)

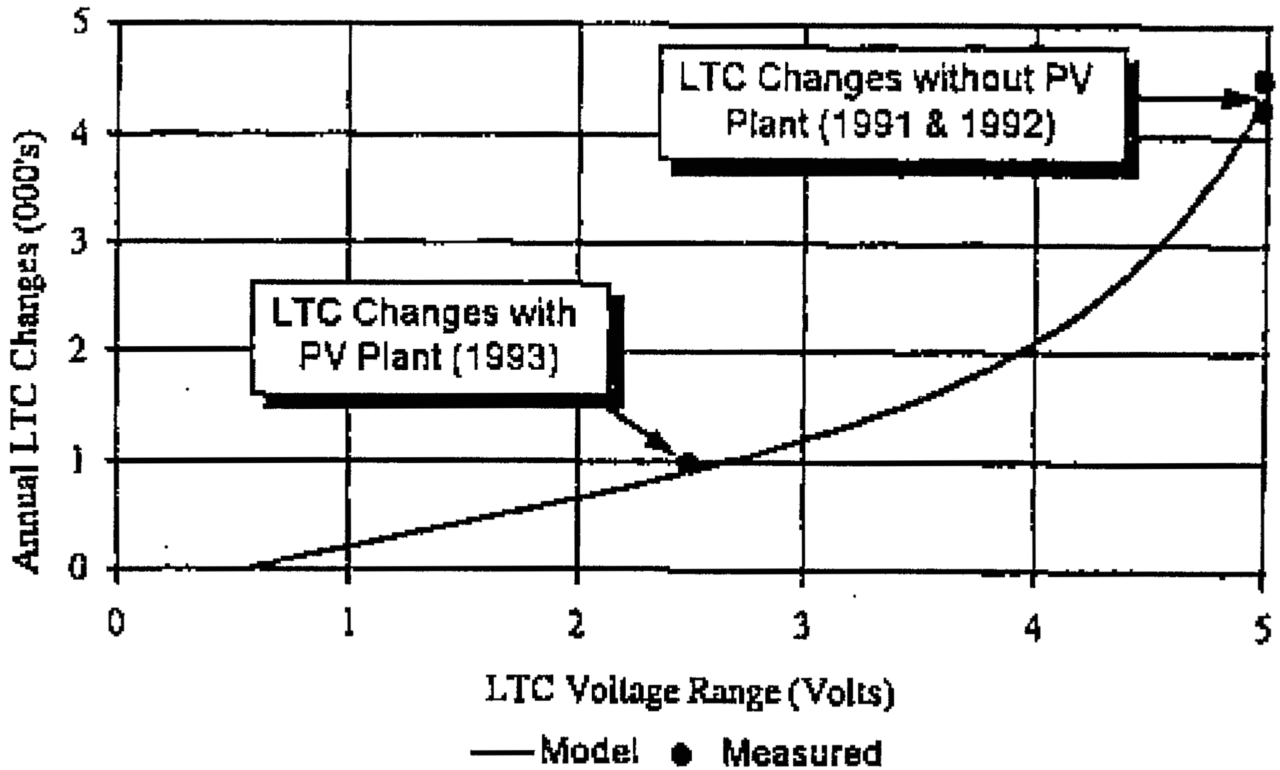


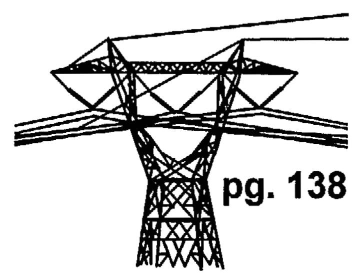
Grid-support PV in action: The Kerman Project



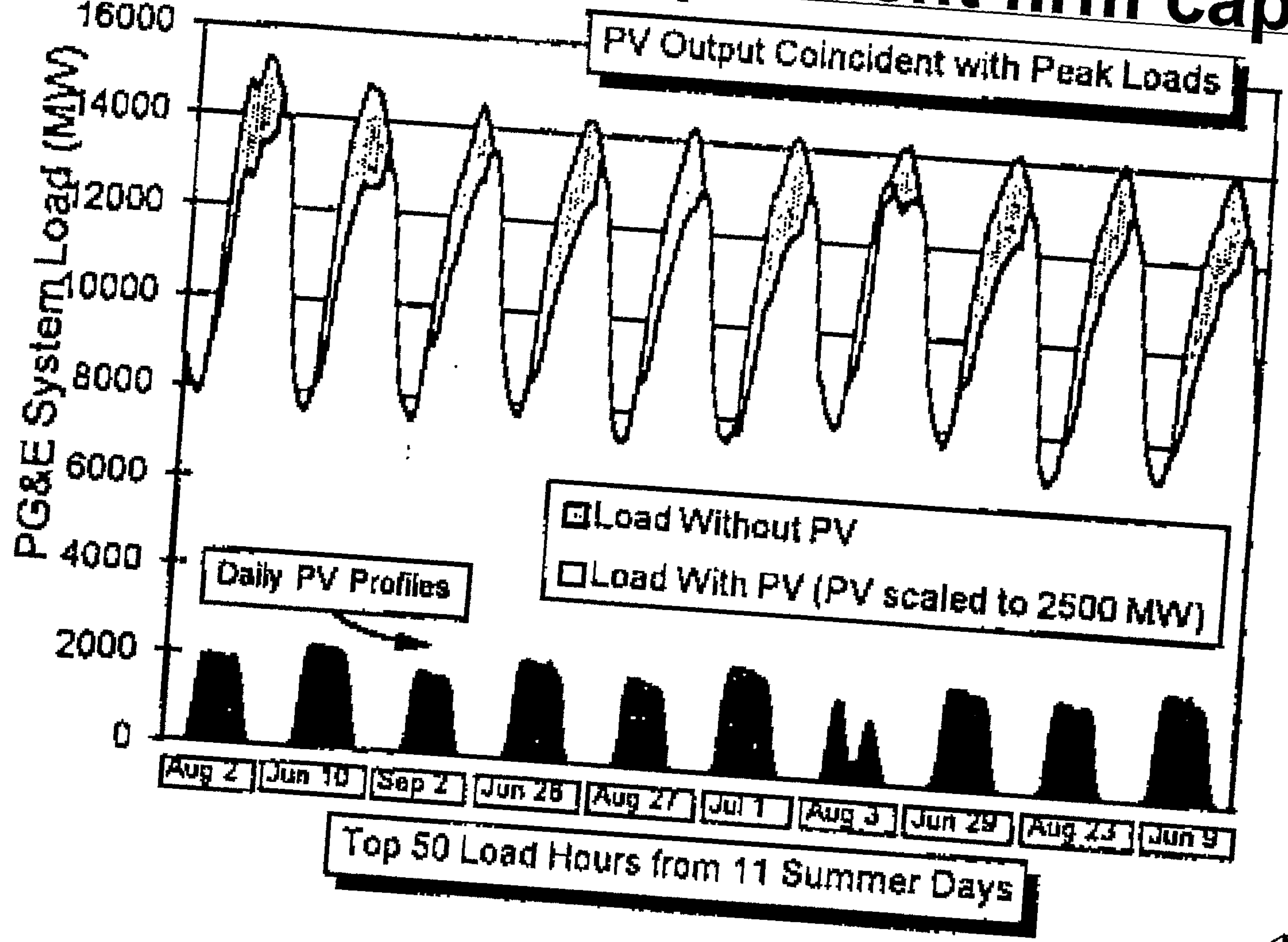
Kerman PV plant connected on 12 kV Feeder 1103, 8 circuit miles from substation

PV plant reduces number of LTC changes





PV provides 75% equivalent firm capacity



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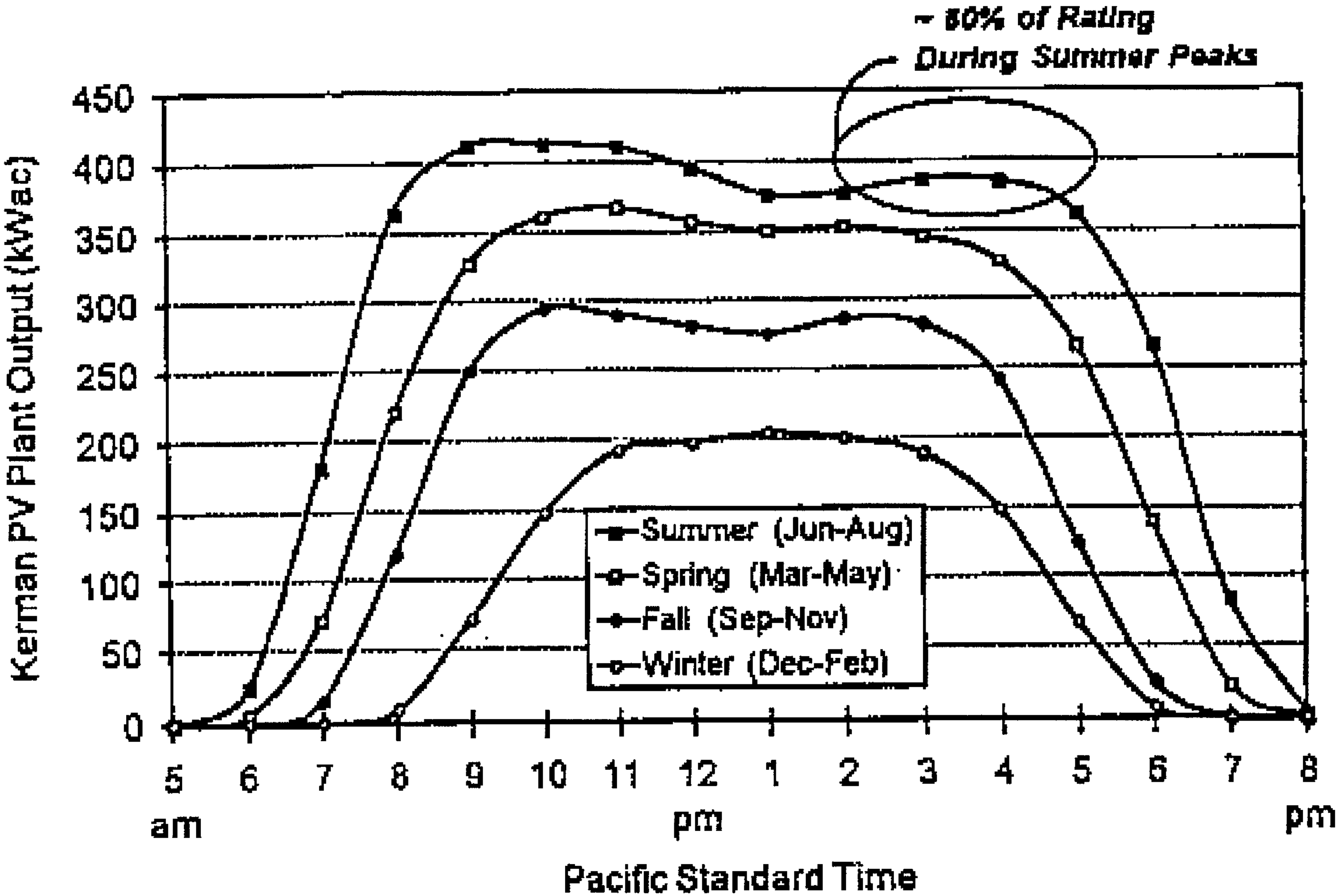
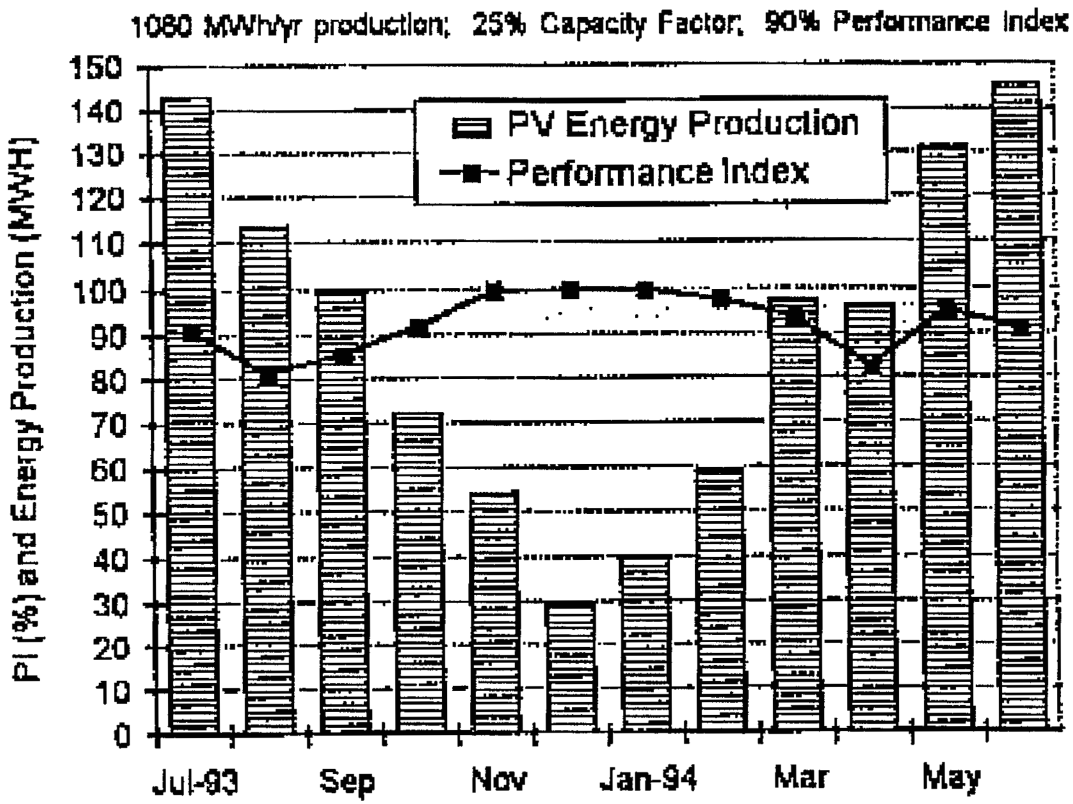
Kerman plant power profiles



Kerman plant performs close to design



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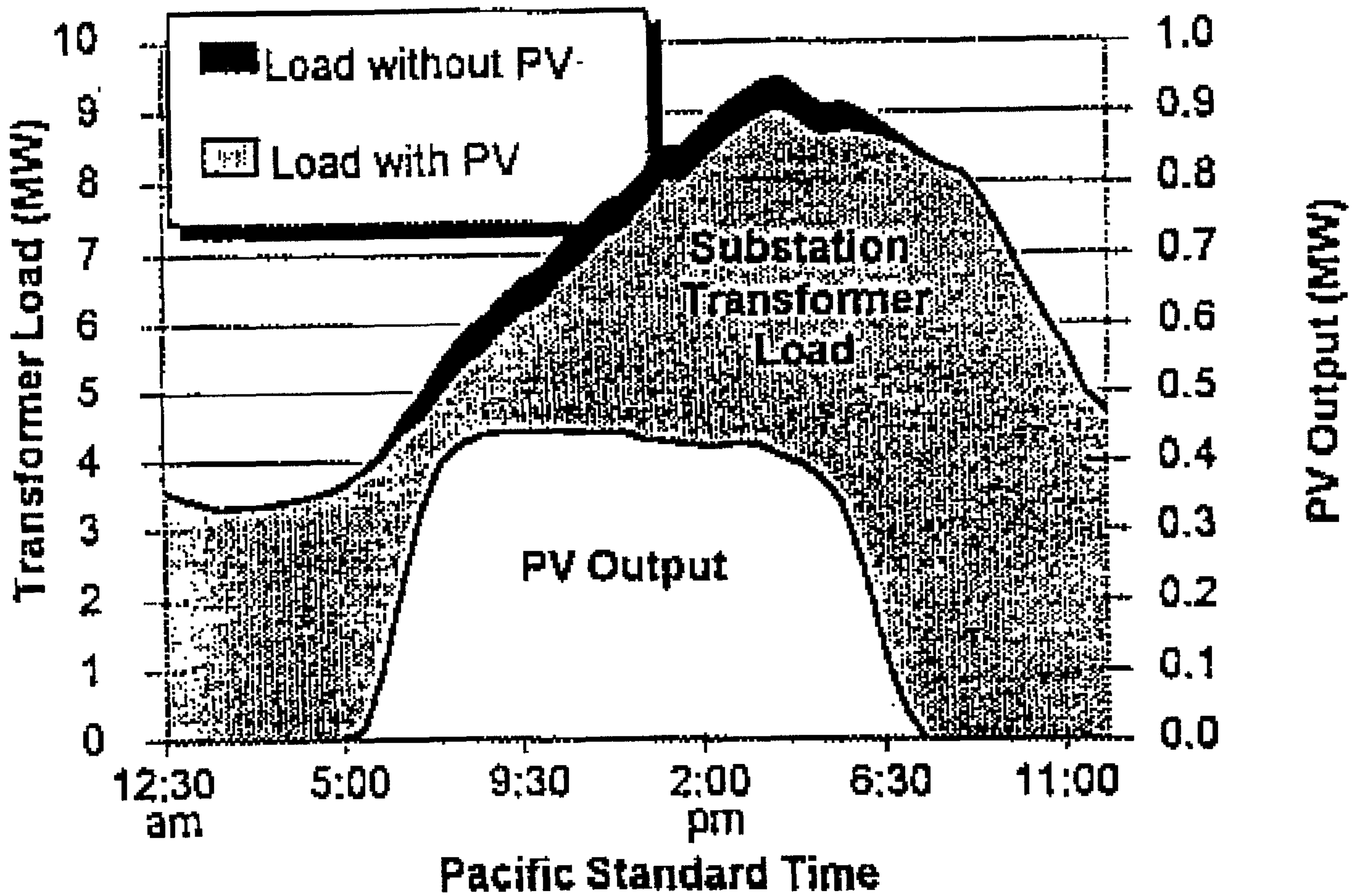
Kerman PV plant reduces transformer loads



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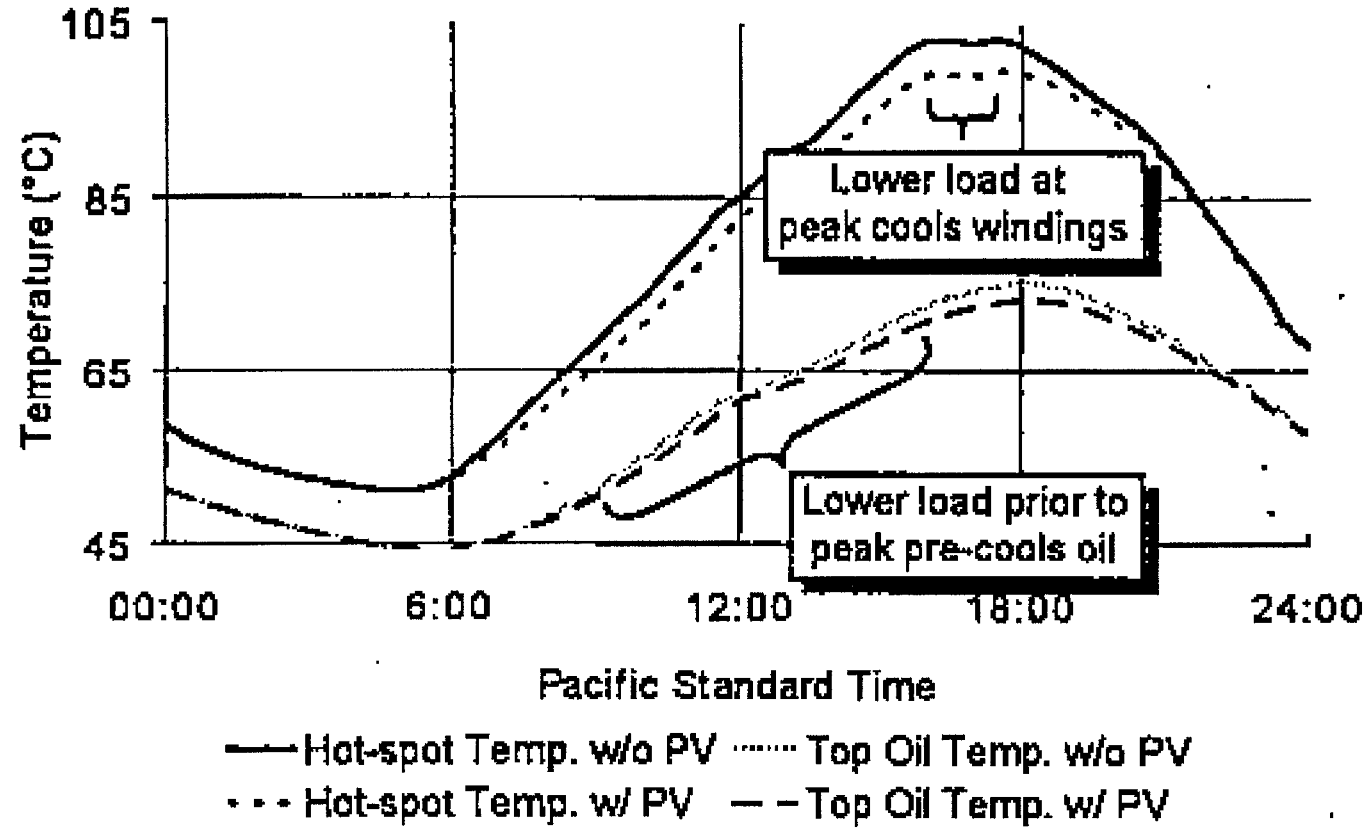
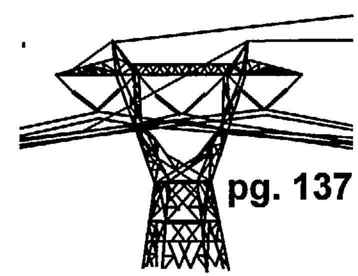
Kerman PV plant reduces transformer loads

Extends equipment life and defers need for upgrades





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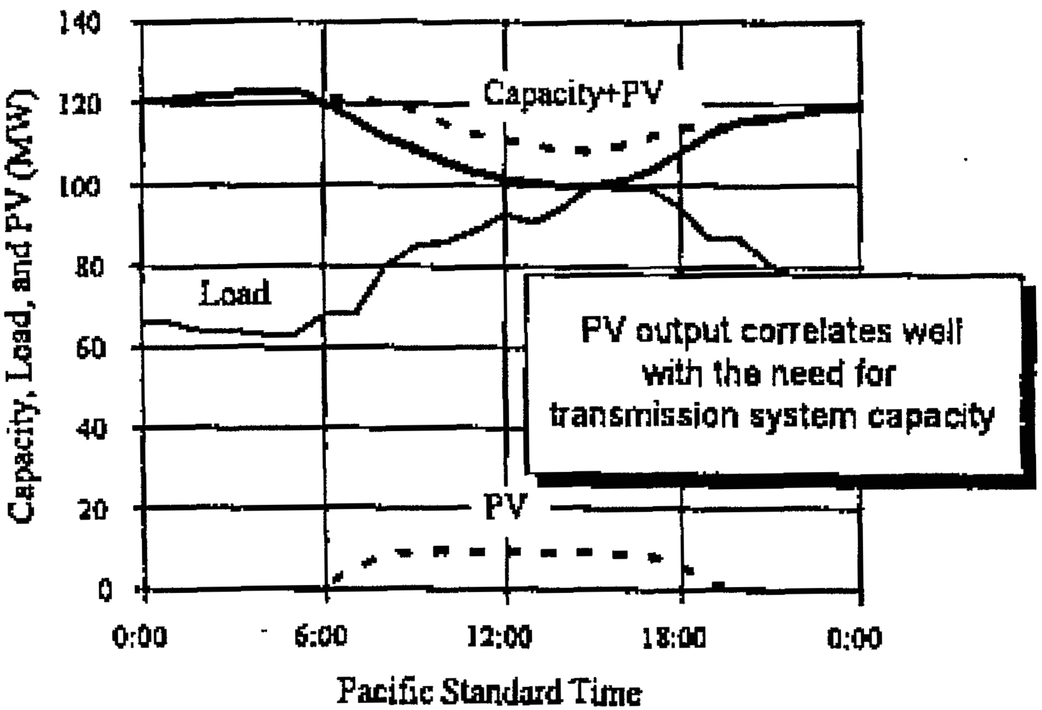
PV plant increases transmission system capacity



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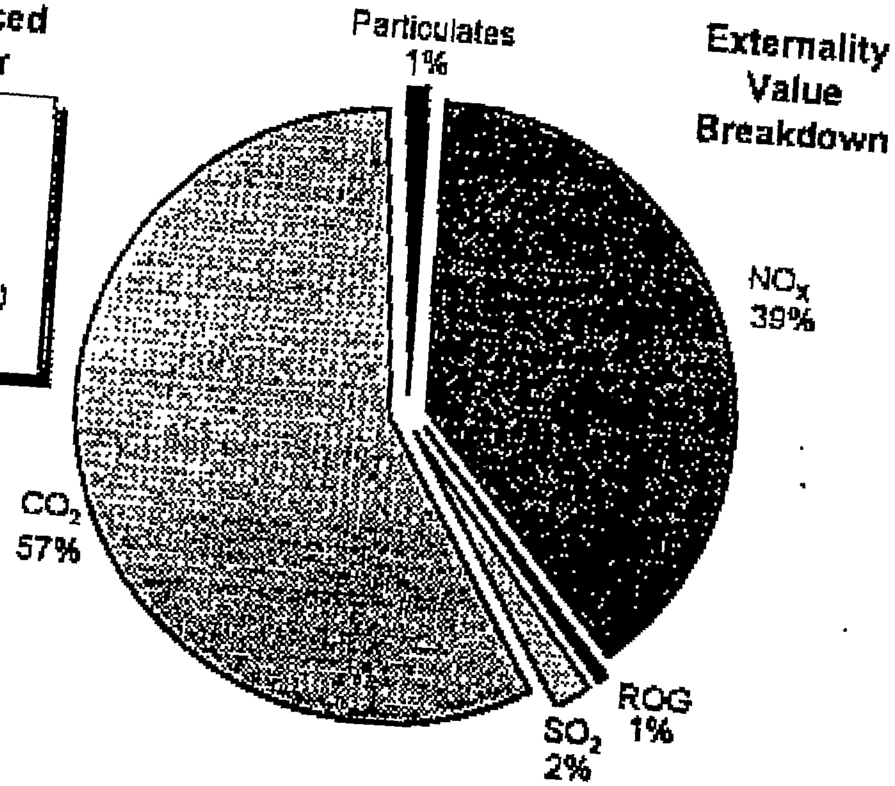
Kerman PV Plant Reduces System Losses

- 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

Tons Reduced Each Year

- 4700 (CO_2)
- 13 (NO_X)
- 3 (SO_2)
- 1 (particulates)
- 0.5 (ROG)



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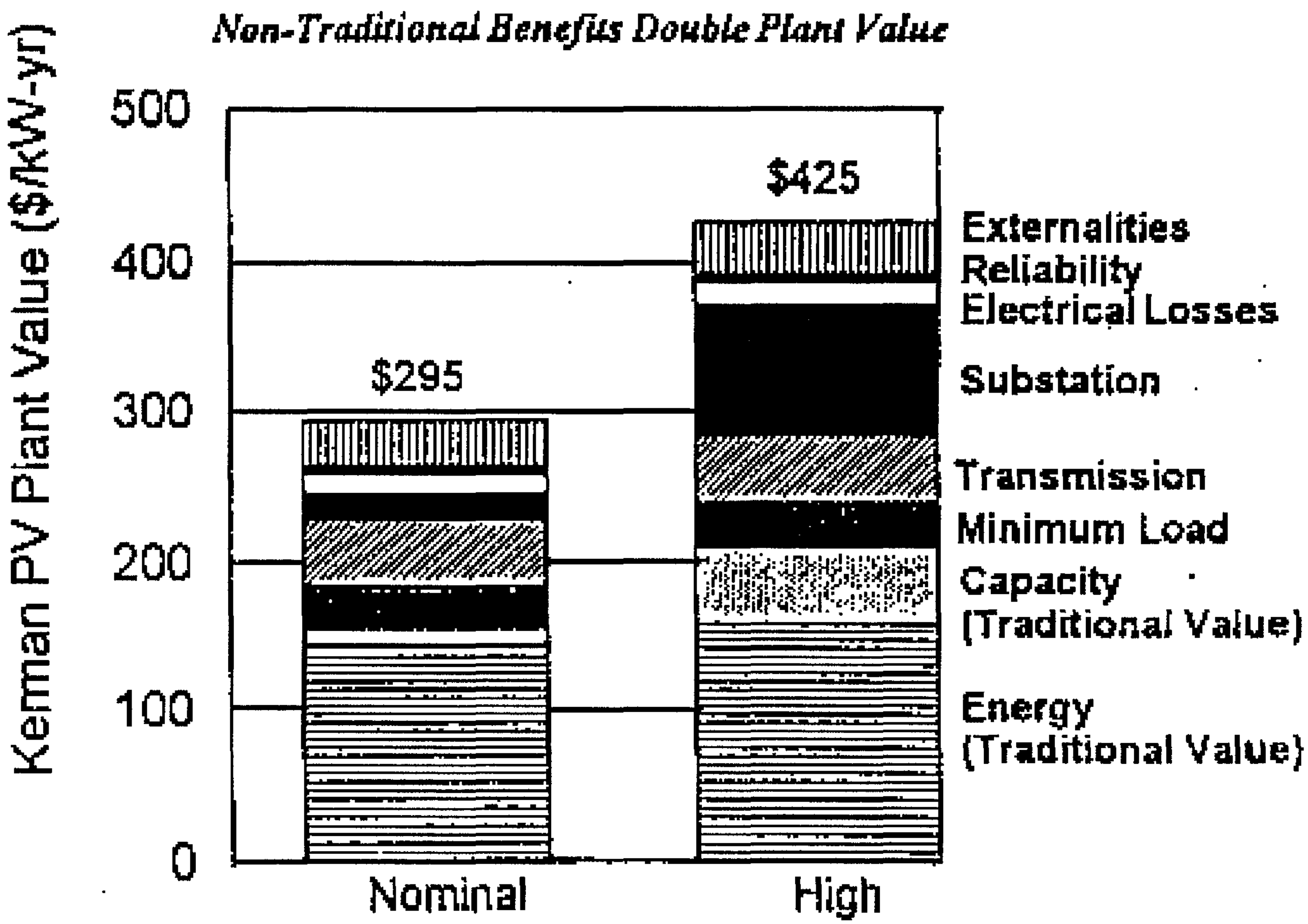
Tangible benefits translate into economic value to PG&E



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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.

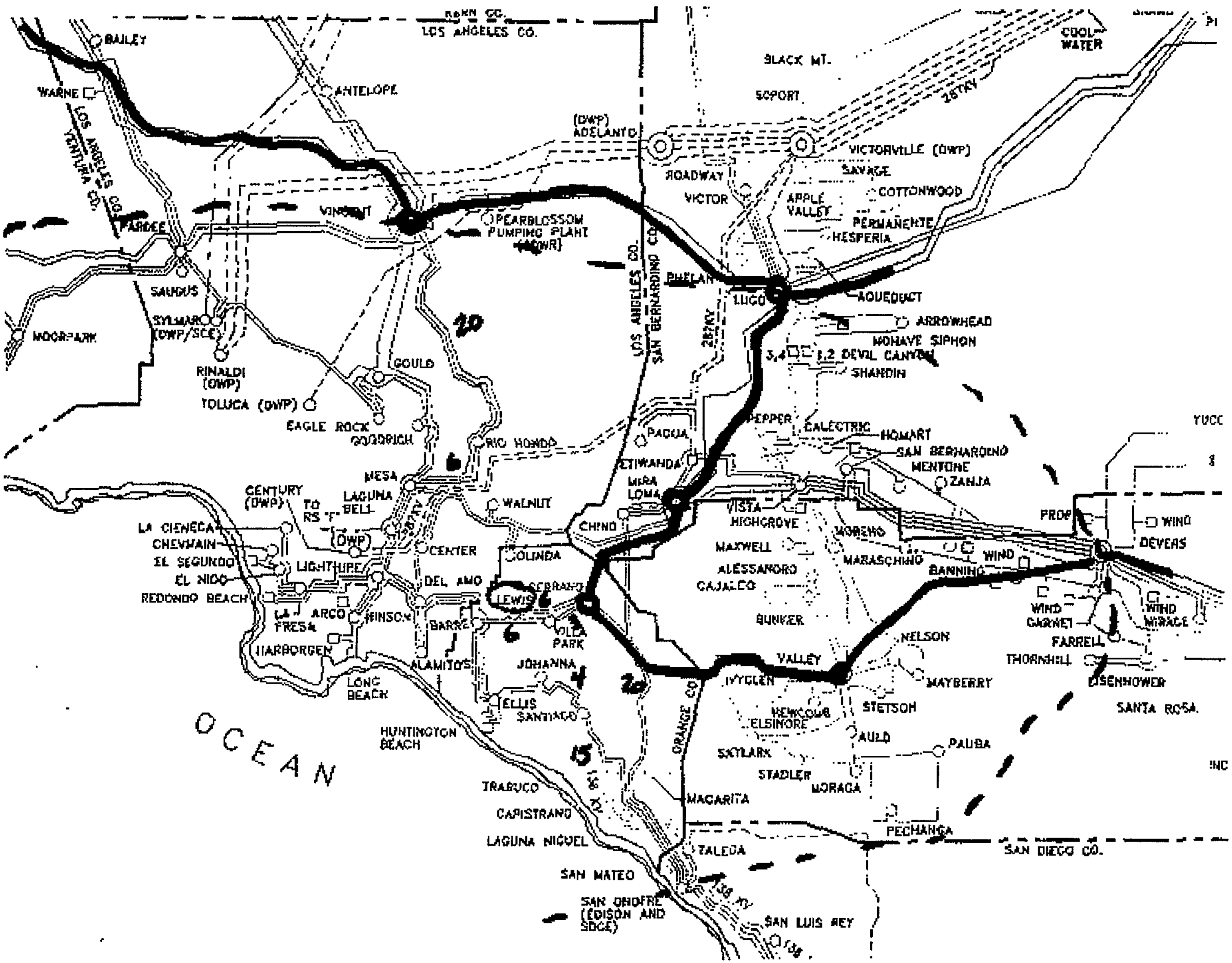
- Point-to-Point Method
  Assign losses to a direct service customer based upon losses in an identified transmission path.

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

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

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



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California's Loss Accounting for <u>Direct-Service Customers</u>

- % 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

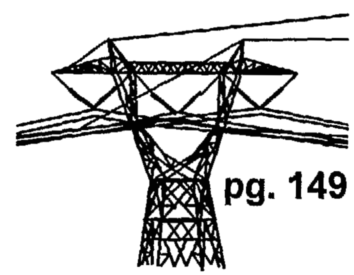
Project Factors:

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.

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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

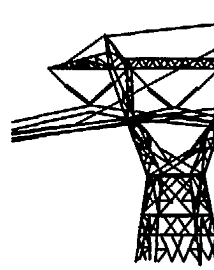
- Use conductor loss characteristics from course

Commercial Losses - Causes: Metering, Billing and Collections

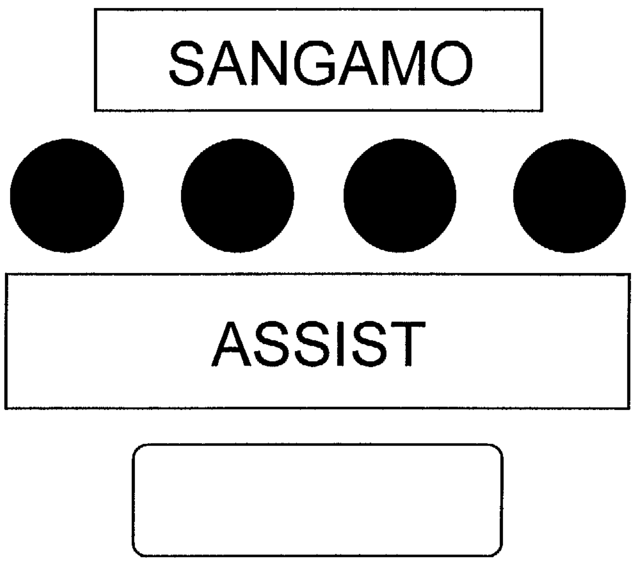
- Metering and Meter Testing
- Billing and Billing Systems
- Collections and Non-payment
- Energy Theft

Sources of Metering Errors

- Current Transformers and potential transformers used for customers above 240 volt service
- Older jeweled-type meters
- Mechanical meter charateristics
- Calibration

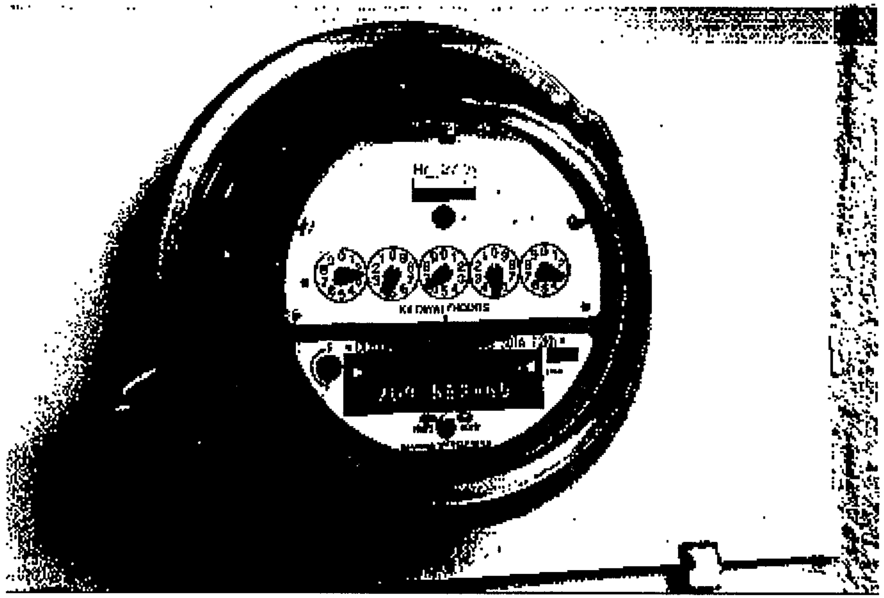


Meter Characteristics
(Examples)

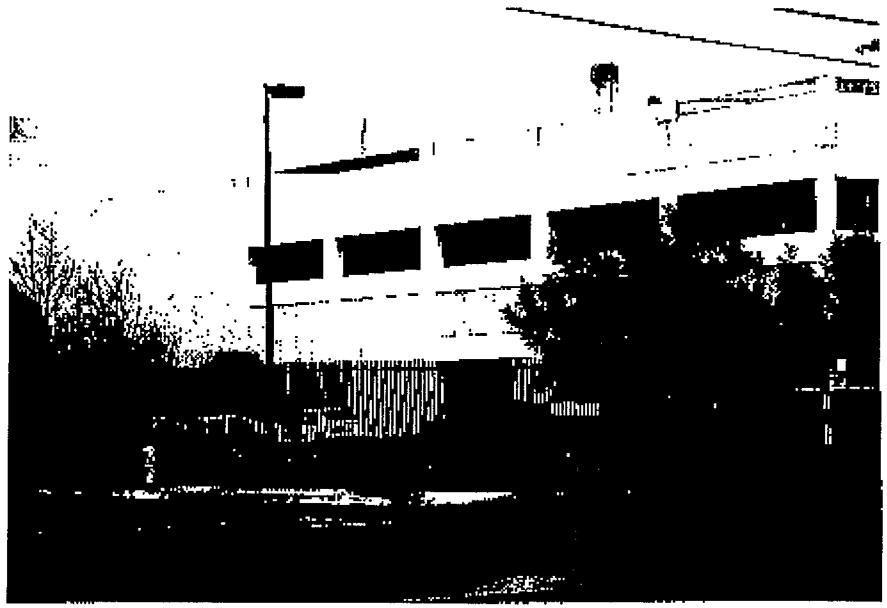


Meter #
Assignment Status
Manufacturer Type
Device Type
Material Code
Profile Types
Measurement Values
Set & Remove Dates

Typical 2-S Meter



Edison Metrology Laboratory



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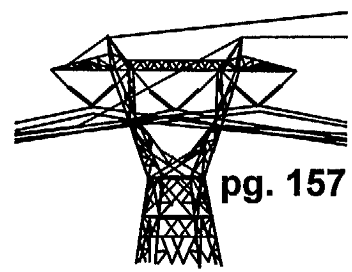
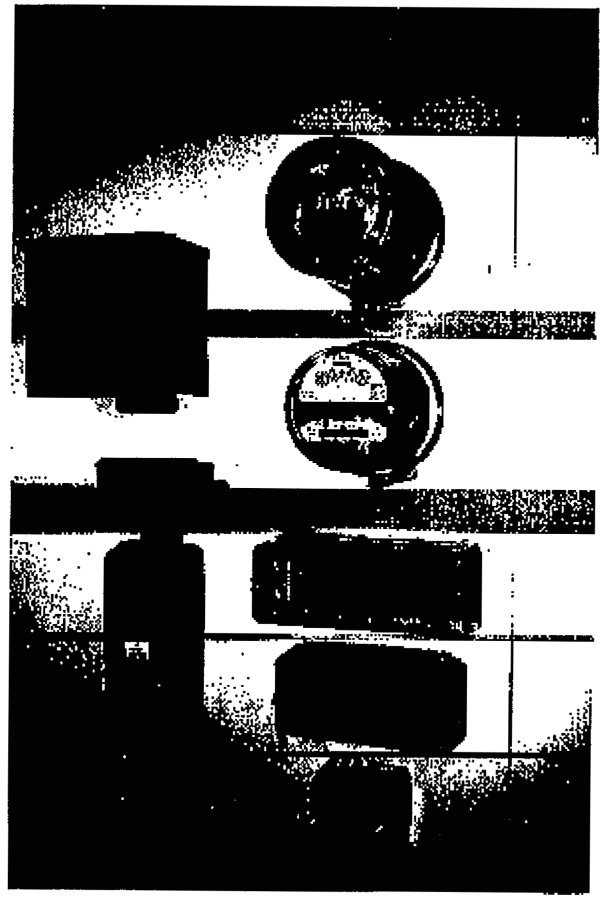


Metering System for 500kW and Larger Customers



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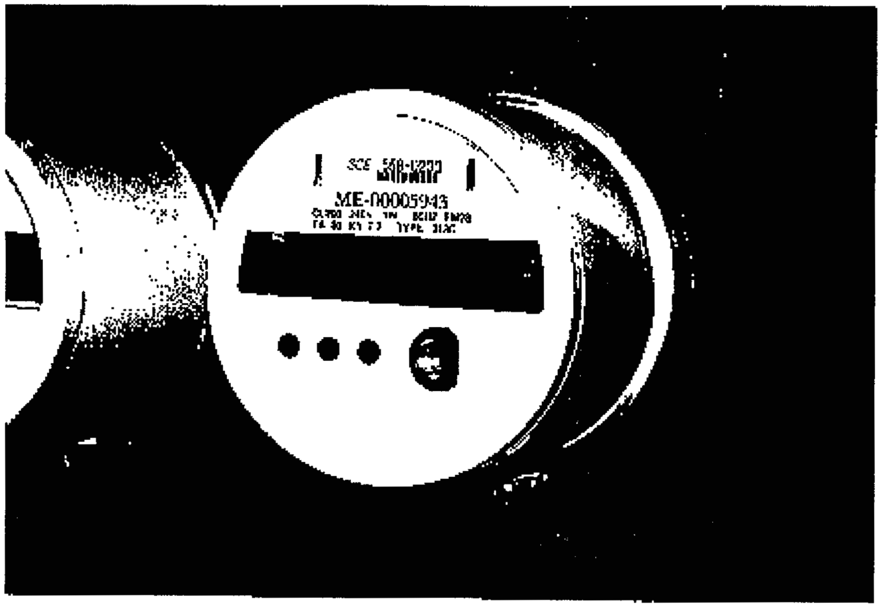
Electronic Metricom Meter



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Metricom Radio

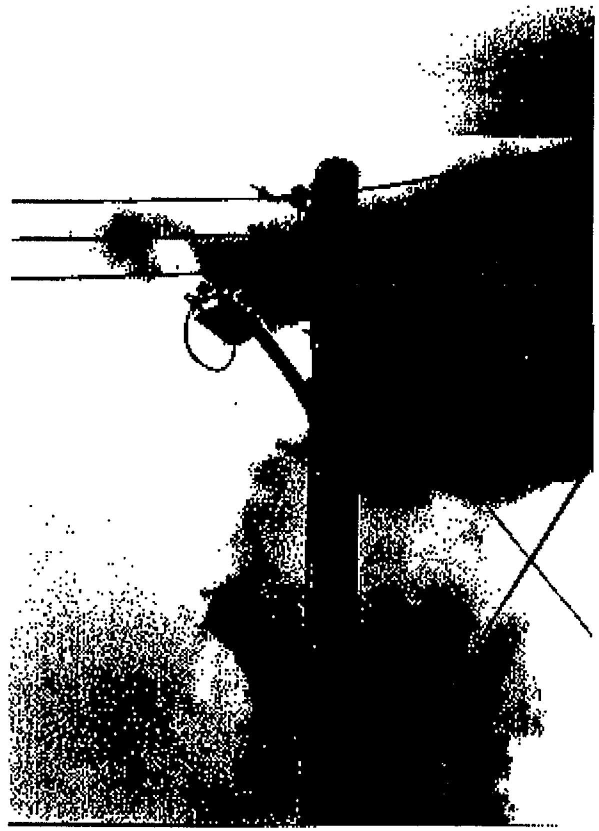

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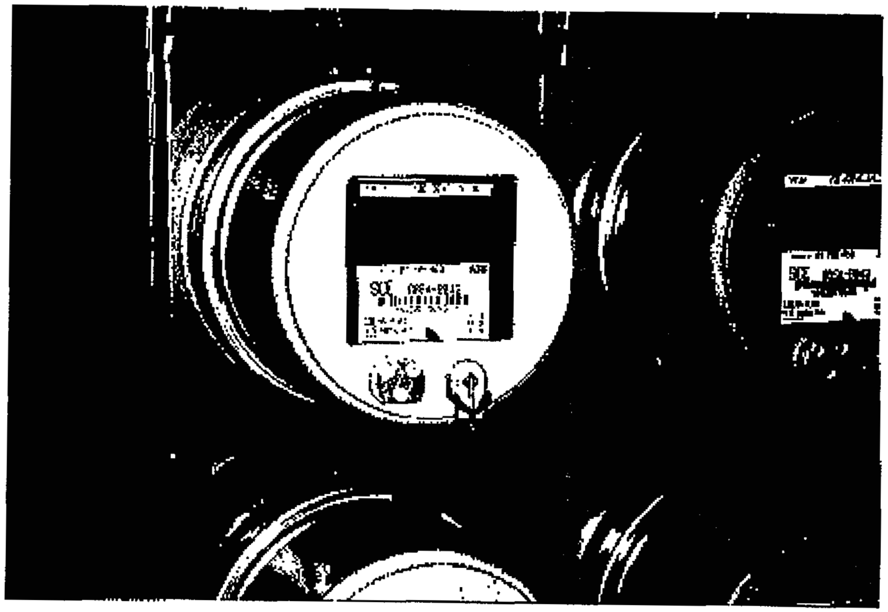
ABB Electronic Meter with RS232 Port



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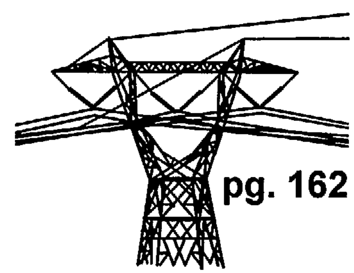
Meter Testing & Calibration

- 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

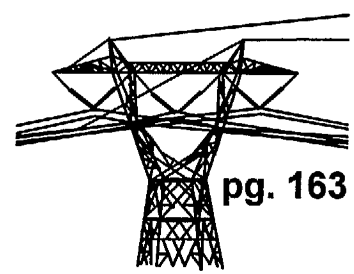
- Qualifying new meter types for company use -
  One year process



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

pg. 164

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Billing Process Organization

Ernie R Lewis (W)
Manager,
Billing Process Organization
00429

Keith Dobson
Leadership Development BPO Y2K

Evangelina Torres
Mgr Project/ Program

Jeannie Wilson (IR42)
Manager,
BPO Special Projects
01825

Ken Meyer (IOC)
Manager,
FUM Regions 1, 2, 3, 4, 5 6
01663

Kevin Higashi
Manager,
Direct Access Retail Billing
01758

Maureen Bekins
Manager,
Retail Billing
00433

Ron Schaefer (AV)
Manager, Direct Access
Usage Measurement
01801

Afarah Board (IR42)
Manager,
Business Operations Support
00952

Vernie Travis (W)
Manager, U.M.D.M. / AMR Ops/
Revenue Protection
01217

Management Support
Hozubin, Betsy (W)*
Vacant-Programmer*

Current as of:
March 1,1999
CCampos
x8-23882

LEGEND

A	- Alhambra	**IR**	- CTAC-Irwindale	**O**	- Ontario D/O	**SA**	Santa Ana D/O	**TO**	- Thousand Oaks D/O	*	- Temporary Assignment (Agency/Contract)		
AV	- Antelope Valley D/O	**IR30**	Irwindale Bldg 6033	**OC**	Orange Coast D/O	**SARO**	Santa Ana R.O	**V**	- Victorville D/O	**	- Temporary Employee (Edison)		
B	- Badillo St	**IR42**	- Irwindale Bldg 6042	**POM**	- Pomona Auto HD	**SB**	- Santa Barbara D/O	**VL**	Valencia D/O	**PT**	- Part Time		
C	- Compton D/O	**LB**	- Long Beach S/C	**PS**	- Palm Springs D.O	**SBRO**	- San Bernardino R/O	**VRO**	- Ventura R/O	**CT**	- Cross Training	^^	- Support Only
CC	- CSAS-Covina	**LBOB**	Long Beach Off Bldg	**R**	- Rosemead	**SBY**	South Bay D.O	**VT**	Ventura S/C	**MTL**	- Mgmt Team Lead	**DIS**	Disability
CV	Covina D/O	**LBPP**	Long Beach Parking Plaza	**RC**	- Ridgecrest D/O	**SD**	- San Dimas	**W**	- Whittier D/O	–	- Acting Manager	**LTD**	- Long Term Disability
F	- Fontana	**M**	- Monrovia D/O	**RL**	- Redlands D/O	**SJ**	- San Jacinto D/O	**WB**	- Whittier-Bright St	—	- Acting Supervisor/Lead		
FT	- Foothill D.O	**MB**	- Montebello D/O	**RO**	- Rialto	**SJT**	- San Joaquin/ Tulare D/O	**WT**	- Westminster	+	- Sick Leave	**OLI**	- On Loan In
IOC	- Irvine O/C	**NOC**	- N Orange C D/O	**S**	- Saddleback D/O	**SM**	- Santa Monica D/O			++	- Leave of Absence	**OLO**	- On Loan Out

Edison	899
EdPT	153
Agency	102
SubTotal	1154
LOA/SL	13
Disability	45
Total	1212

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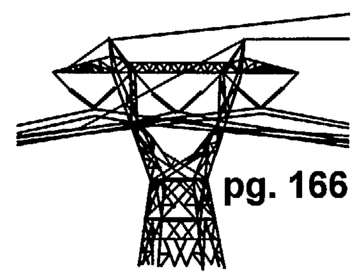
CSS Features

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

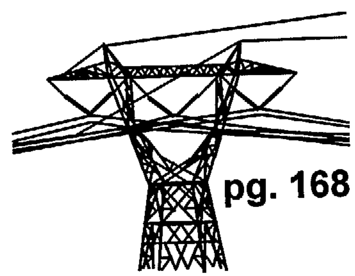


CSS Features

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

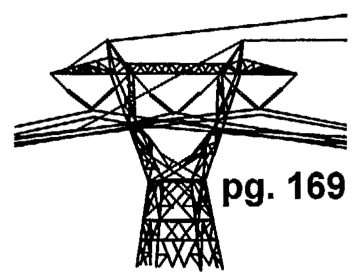
CSS Features

- 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



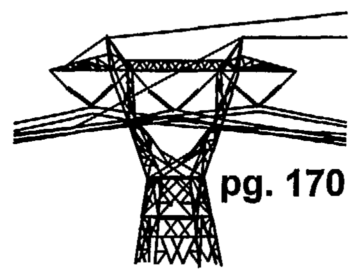
How are you billed?

- **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

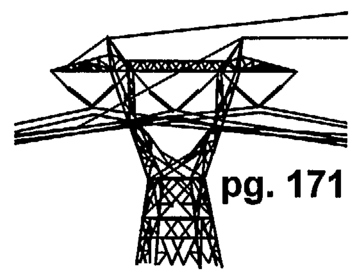


How are You Billed?

- 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

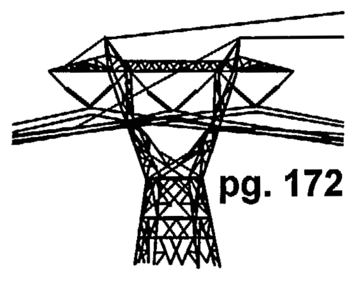
General Service 2 (GS-1) Rate



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



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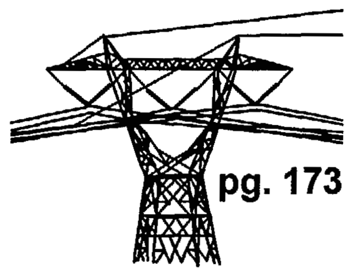
How are You Billed?

- 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

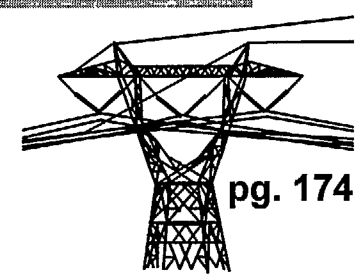


How Does the "Blocked Energy Charge" Work?

- 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

Demand registered in a billing period	25 kW
kWhs consumed in a billing period	10,000 kWh
Calculate kWhs in first block (normal rate)	25 kW x 300 kWh = 7,500 kWh
Calculate kWhs in second block (lower rate)	10,000 kWh - 7,500 kWh = 2,500 kWh
What appears on the bill	7,500 kWh-normal rate 2,500 kWh-lower rate

General Service 2 (GS-1) Rate



Residential Bill - January 1997

SOUTHERN CALIFORNIA EDISON

Southern California Edison Company
An EDISON INTERNATIONAL Company
P.O. Box 600, Rosemead, CA 91771-0001

ESTIMATED BILL

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

Date Bill Prepared
Dec 26, 1996
Next Meter Read on or about
Jan 22, 1997

Rate Schedule
DE

Your Customer Account Number
65-47-818-2030-03
000-3

24-hr. Customer Service
1 (800) 684-8123

Charges & Credits Update

Balance from previous bill	$0.00		
Account Balance........................		$	0.0(

Current Billing Detail

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

Energy Charge:					
Baseline	336 kWh	x 9.010¢			
+ Over Baseline	429 kWh	x 10.621¢	=	$	75.84
Basic Charge					0.80
State Tax	765 kWh	x 0.02¢			0.15

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

(Includes 25% employee discount)
$2.40 is your average daily cost this period.

Estimated Electricity Usage

Meter Number	Dates and Readings From	To	Usage
208-556865	11/22/96 05177	12/24/96 05942	765 kWh

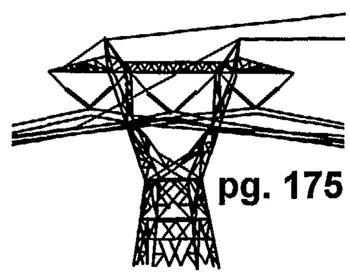
Usage Comparison	This Year	Last Year
kilowatthour (kWh) used	765.00	No
Number of days	32	Comparable
Average usage per day	23.9	Usage

Message

THIS IS YOUR ESTIMATED BILL FOR THE CURRENT BILLING PERIOD.

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

EDISON

Southern California Edison Company
An EDISON INTERNATIONAL Company
P.O. Box [illegible], Rosemead, CA [illegible]

Customer and Service Address	Date Bill Prepared
WHYTE, M DOUGLAS	Aug 22, 1998
505 GREENVIEW ROAD	Next Meter Read on or about
LAHABHTS CA 90631	Sept 21, 1998

Service Account	Old Account #	Rate Schedule
3-004-0278-58	65-47-818-2030 03	DE

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

Update

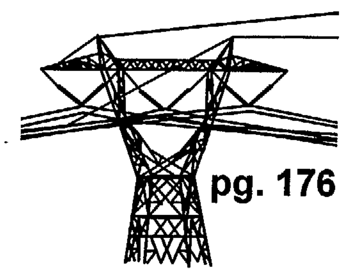
Amount of previous statement 07/24/98	$61.65		
Payment received 08/06/98 - Thank you	$ (61.65)		
Account Balance.		$	0.00

Summary

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

Basic Charge	29 days x $0.03300	$	0.96
Energy Charge:			
Baseline	380 kWh x $0.12009		45.63
Over Baseline	503 kWh x $0.14157		71.21
Employee Discount			(29.43)
Subtotal		$	88.37
Legislated 10% Rate Reduction			(8.84)
Current Billing Detail Subtotal		$	79.53
State Tax	883 kWh x $0.00020		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 : 380.0 kWh
Average PX Energy Charge during this period was : 5.28 cents/kWh
Of your total charges, Franchise Fees represents : $0.84



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Residential Bill - August 1998

EDISON

Southern California Edison Company
An EDISON INTERNATIONAL Company
P.O. Box 800, Rosemead, CA 91770

Customer and Service Address	Date Bill Prepared
WHYTE, M DOUGLAS	Aug 22, 1998
505 GREENVIEW ROAD	Next Meter Read on or about
LAHABHTS CA 90631	Sept 21, 1998

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

Service Account	Old Account #	Rate Schedule
3-004-0278-58	65-47-818-2030-03	DE

Detail

CTC Charges	$	28.53
PX Energy Charge (1)		46.64
Transmission Charges		3.43
Distribution Charges		(19.68)
Nuclear Decommissioning Charges		1.64
Public Purpose Program Charges		3.47
Trust Transfer Amount (2)		15.21
Other Charges		0.27
Current Amount Due	$	79.71

(1) The Average PX Charge is based upon the weighted average costs for purchases through the Power Exchange. This service is subject to competition. You may purchase electricity from another supplier.

(2) A portion of historic electric generation costs has been financed through low-cost bonds to reduce your total bill by 10%. The TTA reflects the costs of these bonds, which are less expensive than the type of financing the utilities previously employed. The TTA does not offset your 10% rate reduction, nor does it increase the total amount you otherwise would have paid.

Usage

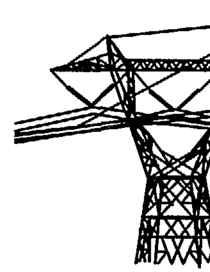
Meter Number	Dates and Readings From	To	Usage
208-556865	07/22/98 10967	08/20/98 19850	883 kWh

Usage Comparison	This Year	Last Year
Kilowatthour (kWh) used	883.00	514.00
Number of days	29	29
Average usage per day	30.45	17.72

Message Just for You

WE'RE HERE FOR YOU WHENEVER YOU NEED US..
Our call centers are available to respond to your requests 24 hours a day, 7 days a week. We are busiest from 8:00am - 5:00pm weekdays, so usually the best times to call us are evenings and weekends.

SUMMER SIZZLE.....
Summer's heat is here! Remember that using evaporative coolers or air conditioning will increase your electric bill. Take steps now to help save money by managing your energy use. For example, setting your air conditioning thermostat at 78F instead of 70F will help cut your energy costs significantly. Check the enclosed Customer Connection for other "hot tips" for keeping cool.



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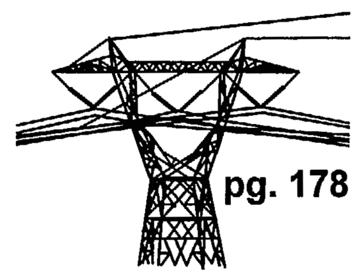
Direct Access Customers

Payments to Generation Provider
– for Electric Power

Payment to ISO
– for Dispatching Service

Payment to Edison
– for Transmission and Distribution



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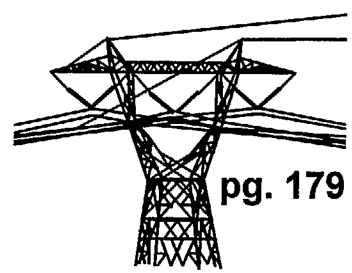
Revenue Collections and Non-Payment

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



CSS Collection Path

Expired Overdue Notice

5 Days Later

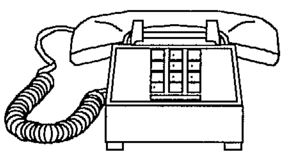
CSS Collections Event Scheduler

*

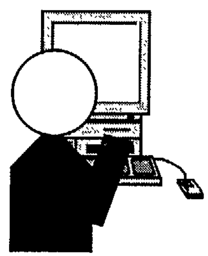
Urgent Notice

Deferred
(Less than $25.00)

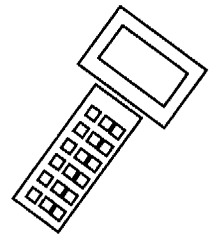
Autodialer

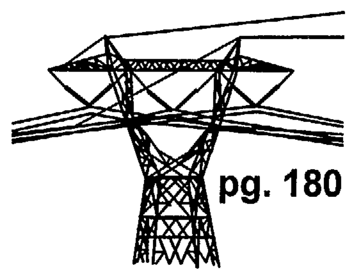


Credit Administration Queue



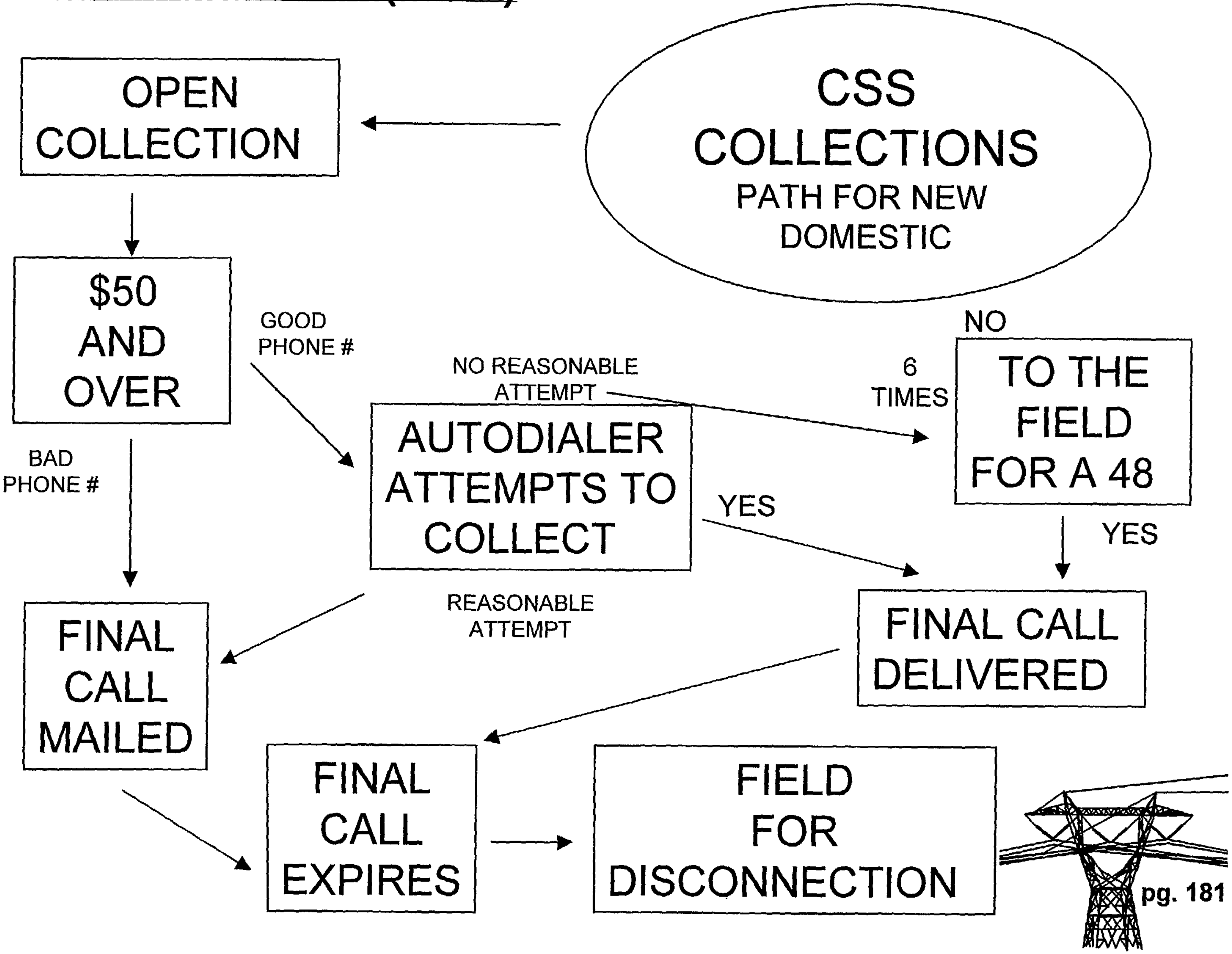
PWS → T-4000
Final Call
Disconnect
Still Off





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

CSS Collection Path (con't)



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

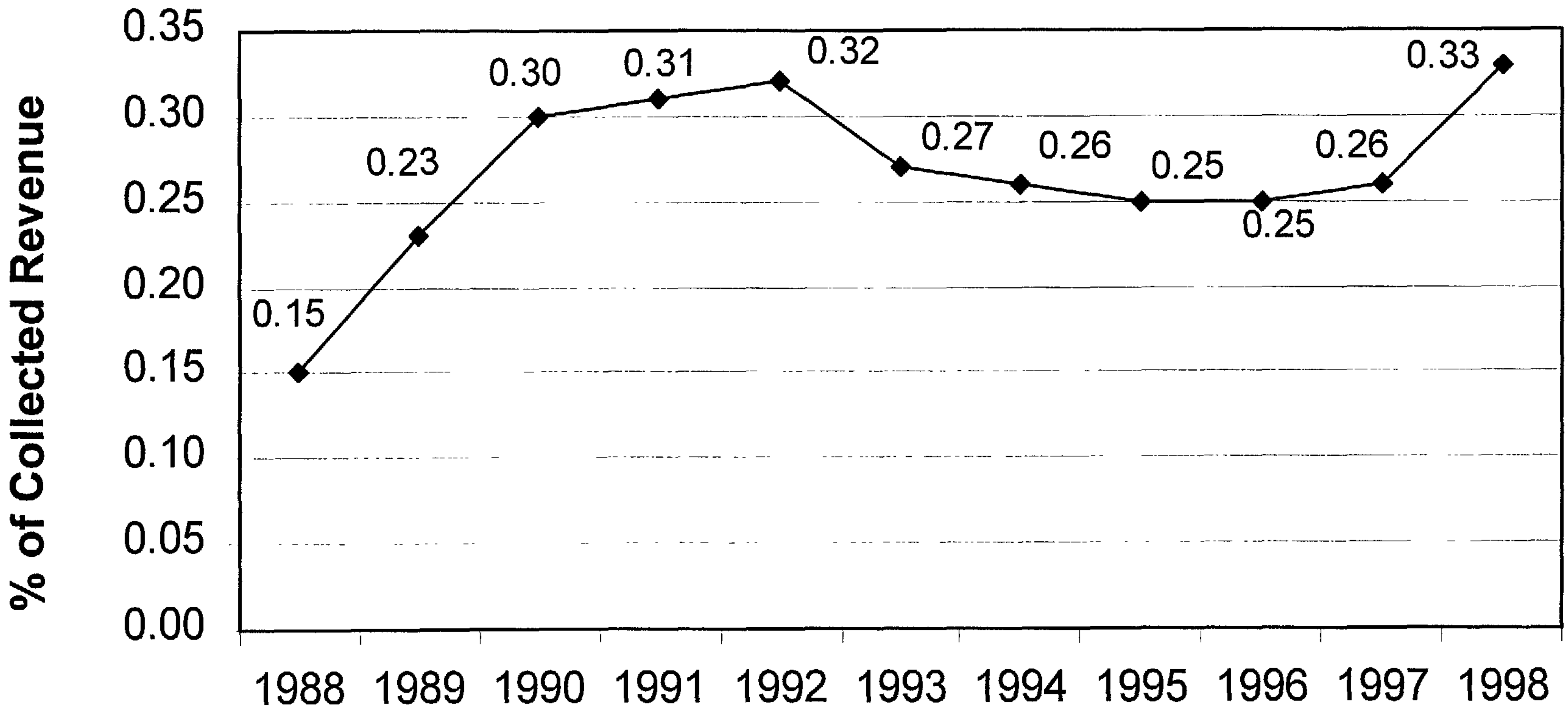
- Based on CIS data
- Calculated at billing time
- LOW, MEDIUM, and HIGH (like a test score)
  - LOW indicates unacceptable payment pattern
  - MEDIUM is acceptable payment pattern
  - HIGH indicates exceptional payment pattern

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



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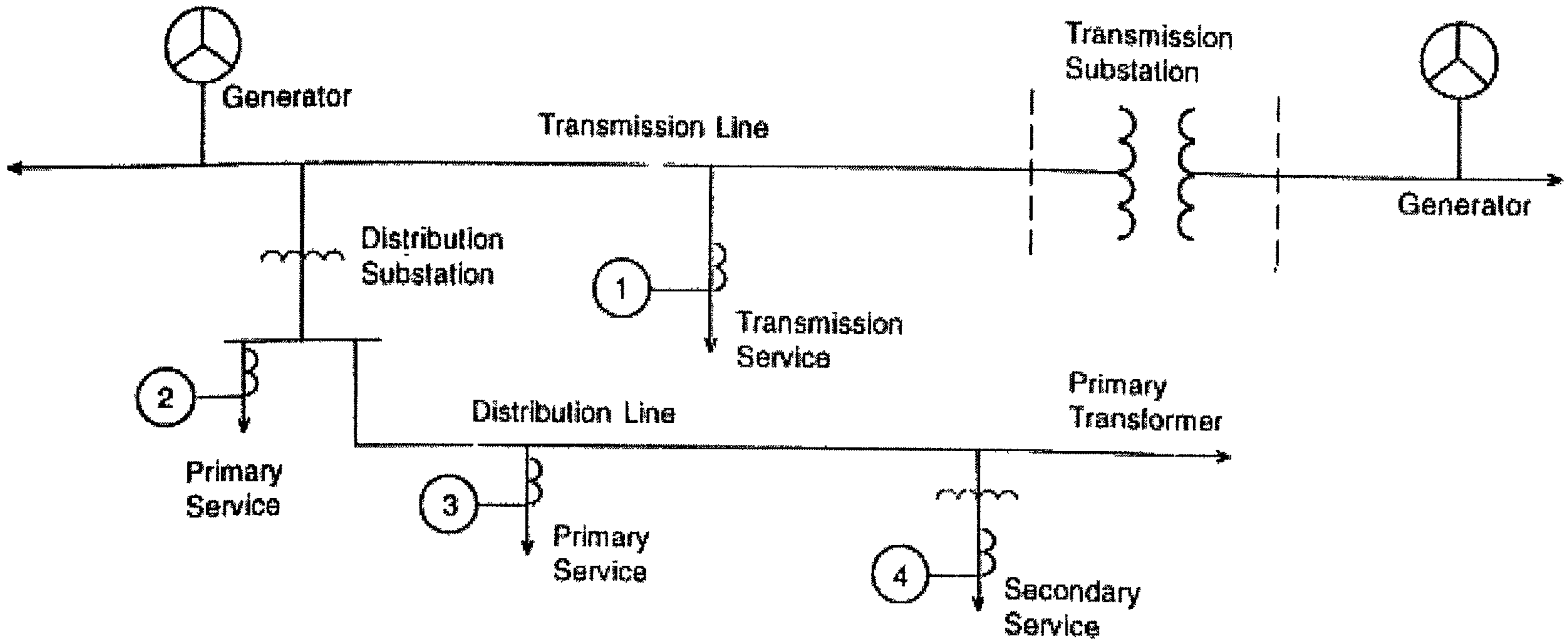
Pricing Theories in a Regulated Utility

- 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



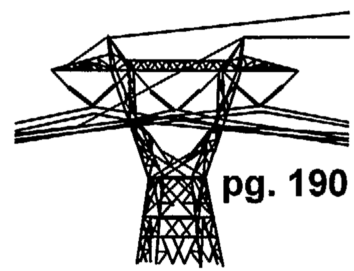
	Generation Facilities 301-340	Trans. Facilities 350-359	Dist. Subs. 362	OH Primary Line 364/365	UG Primary Line 366/367	Transformer 368	Regulator 368	Service 369	Meter 370
1	X	X							X
2	X	X	X						X
3	X	X	X	X	X		X		X
4	X	X	X	X	X	X	X	X	X

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"

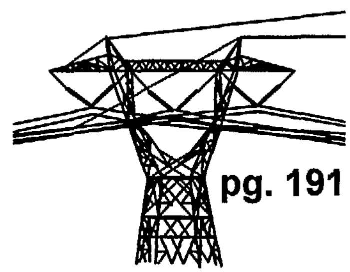
Impact of Customer Load Profile on Cost of Service

	Lower Cost per kWh	Higher Cost per kWh
Level of Service	Higher Voltage	Lower Voltage
Quality of Service	Curtailable	Firm
Efficiency		
• Peak Load	Off-Peak	On-Peak
• Load Factor	High	Low
Level of Usage	High	Low



Southern California Edison Rates
Effective: May 1, 1996

Rate Group	5-1-96 Average Rate (¢/kWh)
Domestic	12.7
GS-1	13.6
TC-1	7.3
GS-2	10.1
TOU-GS-2	9.1
TOU-8-SEC	8.6
TOU-8-PRI	7.5
TOU-8-SUB	4.5
PA-1	11.1
PA-2	8.7
TOU-PA-5	7.1
AG-TOU	7.9
Street/Area Lighting	14.7
System Average	10.1



Energy Theft Mitigation

- Energy Theft Program
  - Prevention:

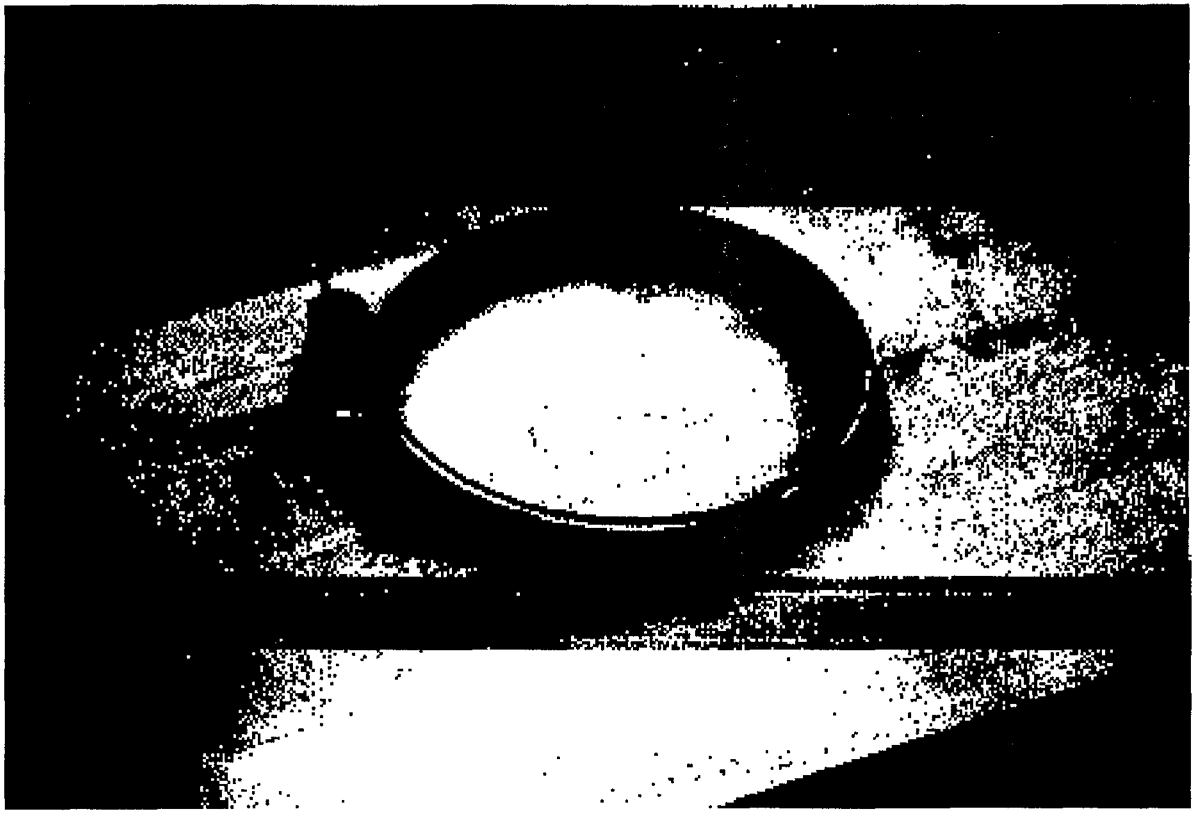
    Security Locking Rings, "Meter Sentries", Sealing, "Eagle Eye", Video "To Catch a Thief".
  - Detection

    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



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Security Locking Ring Address

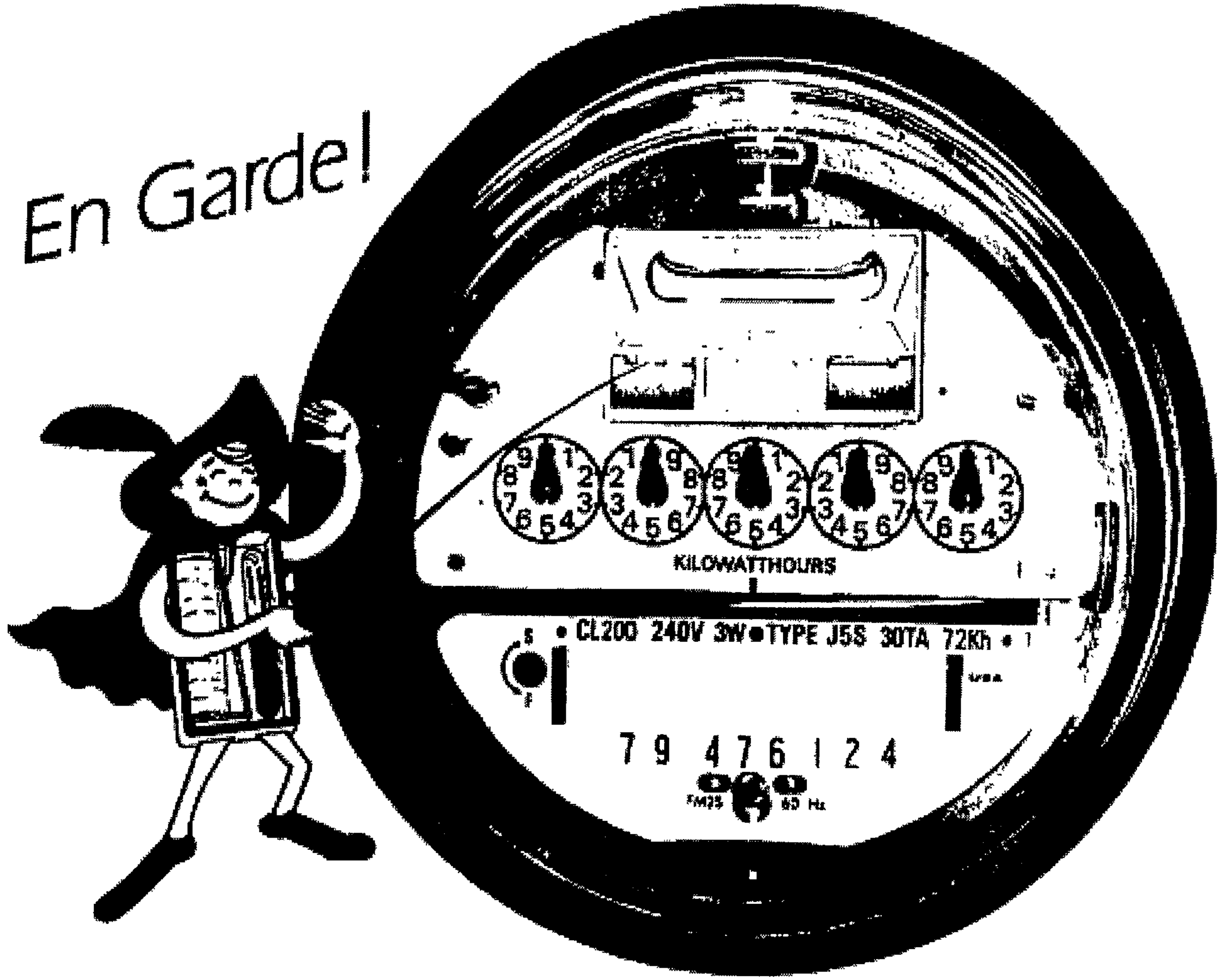
Inner-Tite Corp.
1094 Globe Avenue
Mountainside, New Jersey, 07092, U.S.A.

Telephone	908/232-4000
FAX	908/232-7281

STOP ENERGY THEFT with Meter Sentry II.™ PAT. PEND.

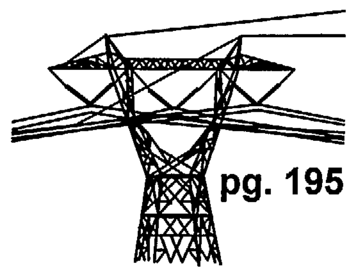
Meter Sentry

En Garde!



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...



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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

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Edison Tip Card

fold

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL Company

REVENUE PROTECTION TIP

CIS Acct.

CA No.

Cust. No.

ADDRESS | APT NO.

CITY

METER NO.

SERVICE TYPE
- ☐ Underground
- ☐ Overhead
- ☐ Residential
- ☐ Commercial/Industrial

WHY WERE YOU HERE?

VEHICLE LICENSE NO. AT SITE

DATE OBSERVED | TIME OBSERVED

EMPLOYEE NAME (PRINT)

SOC. SEC. NO.

OCCUPATION | WORK LOC.

House/Unit vacant? .... ☐ Yes ☐ No
Did customer see you? .... ☐ Yes ☐ No
Any customer comments? .... ☐ Yes ☐ No
(if yes, state in Misc. Info area)
Pictures? .... ☐ Yes ☐ No
Dog .... ☐ Yes ☐ No
CAP requested? .... ☐ Yes ☐ No
Test requested? .... ☐ Yes ☐ No
Tip from third party? .... ☐ Yes ☐ No

LOAD INFO
☐ Pool ☐ Spa ☐ A/C ☐ Electric Heat
☐ Electric Water Heater ☐ Other________

SUSPECT CONDITIONS

METER
- ☐ Seen Inverted
- ☐ Suspect Inverting
- ☐ Hole in Glass
- ☐ Hole in Glass *(foreign object/jamming)*
- ☐ Disc Turning Backward *(right to left)*
- ☐ Meter Not in Route *(give meter no. and read)*
- ☐ Foreign Meter *(give meter no. and read)*
- ☐ Magnets on Meter
- ☐ Tampered Dials
- ☐ Tampered Disc/ Suspension
- ☐ Tampered Gears
- ☐ Photo Cell
- ☐ Incorrect Register
- ☐ Open Pot Link
- ☐ Worn Stabs *(excessive/copper color)*
- ☐ Improper Meter *(wrong volt, etc.)*
- ☐ Other *(explain below/on back)*

JUMPERS/TAP/BYPASS
- ☐ At Svc Pole/Secondaries
- ☐ At Roof or 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)*

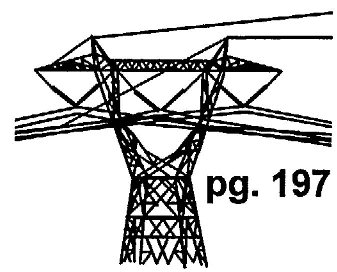
CT INSTALLATIONS
- ☐ Insulated Test Switch
- ☐ Open Test Switch
- ☐ Improper Test Switch Wiring
- ☐ Improper CT wiring
- ☐ Wrong CTs
- ☐ Tampered CTs
- ☐ Other *(explain below/on back)*

TAMPERED SEALS *(not missing seals)*
- ☐ Meter Cover *(test seal)*
- ☐ Snap Ring/Lock Ring
- ☐ Test Switches
- ☐ Test Blocks
- ☐ Pull Section
- ☐ Raceway
- ☐ Other *(explain below/on back)*

OTHER ORDERS REQUESTED

MISC. INFO

SEE OTHER SIDE FOR SKETCH AREA/MAP AREA/OTHER COMMENTS



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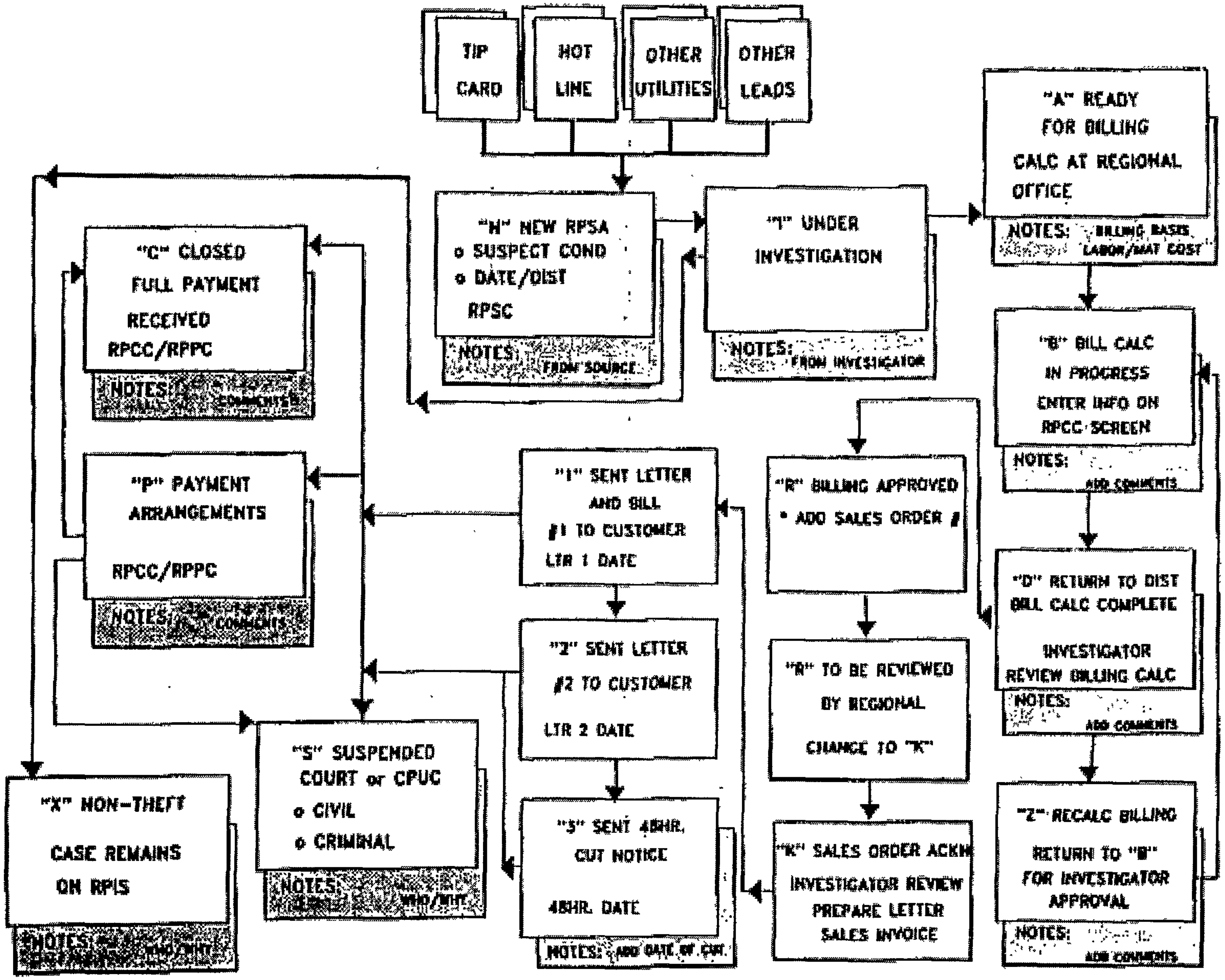
BEST AVAILABLE COPY

Revenue Protection Flow Chart



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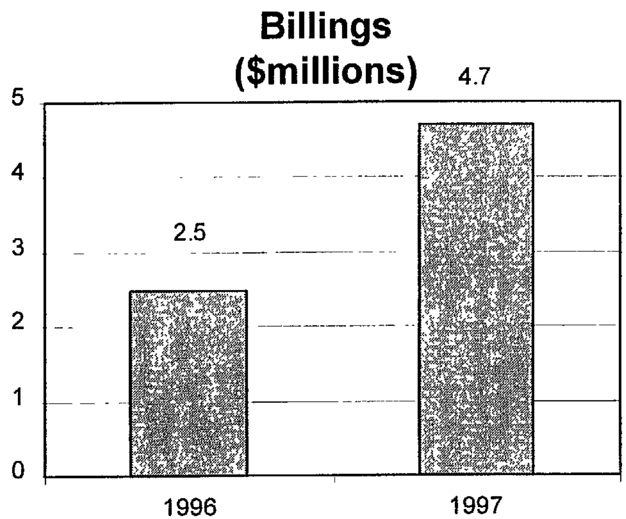
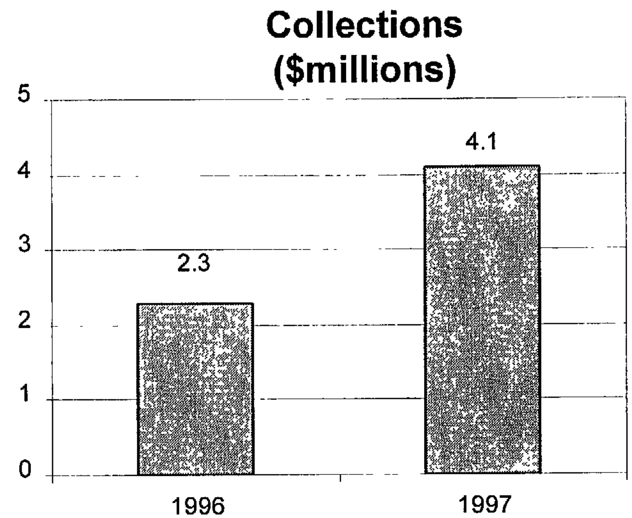
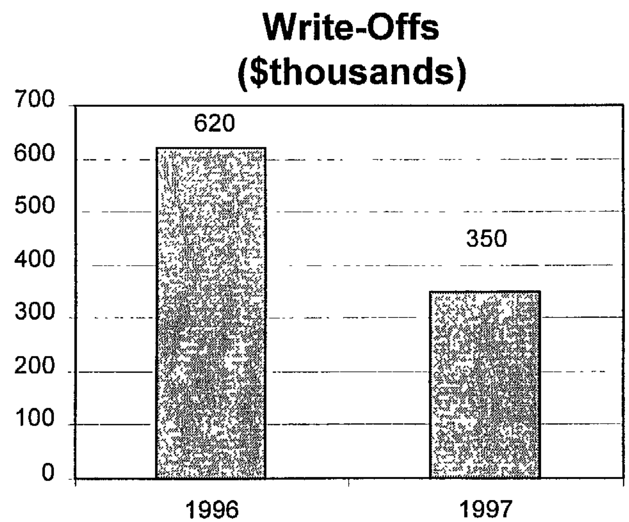
Revenue Protection Results







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